MINIMIZE ROD BUCKLING
TO REDUCE TUBING FAILURES

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INTRODUCTION

Repairing tubing leaks can easily result in the most expensive operating cost incurred in rod pumped wells. Tubing leak repairs are not only expensive but lost revenue from downtime can be significant. The prevention of tubing failures will greatly enhance operating profits from a rod pumping system. This paper will discuss rod buckling, which is one common cause of tubing failures, and how to minimize this problem by adjusting pumping parameters and installing a designed sinker bar section. Methods for designing a proper sinker bar section, utilizing dynamometer surveys and well failure histories, will also be discussed

ROD BUCKLING - DEFINITION AND AFFECTS

The reciprocating action of sucker rods inside tubing tends to remove metal from both tubing wall and the sucker rods. In most cases tubing failures occur wherever rod-on-tubing contact is concentrated over a relatively short span. These points of concentrated wear can occur due to severe deviation in well bore, insufficient tubing anchor tension, or most commonly, from rod buckling above pump during the down stroke.

Rod buckling occurs in a sucker rod string whenever stress loads reverse from a positive tensile stress to a negative compressive stress. Oil well sucker rods are built to handle thousands of pounds of tensile stress but will bend when just a small compressive load is applied. The resulting bending motion is referred to as rod buckling. Since the rod string is not supporting a fluid load during pumping unit down-stroke, compressive loads cause rod buckling to occur in the lower portion of rod string (Figure 1). Compressive loads, on the down-stroke, are an accumulation of mechanical pump friction, rod-on-tubing friction, and dynamic fluid friction.

During pumping unit down-stroke, most of the upper rod-string is held in tensile loading due to the weight of attached rods. However, at some point in the lower rod string, a “neutral point” occurs and compressive loads are applied to rods below this point. It is in this section below the “neutral point” that rod buckling will occur.

Rod buckling affects are detrimental to tubing because of the combination of side loading on rods causing impact against tubing wall, and a concentrated reciprocal wear effect on tubing wall. These two factors not only tend to remove metal, they also remove the protective corrosion inhibitor film on both rods and tubing. When the corrosion factor is added to a concentrated wear pattern, accelerated metal removal results by creating what is described as a “Corrosion/Abrasion” effect. “Corrosion/Abrasion” is a descriptive term for metal that has corrosion occurring in a concentrated wear area such as that caused by a reciprocating rod box (Figure 2). Corrosion pits occur resulting in reduced mating surface between tubing and rods. Since mating surface area is reduced by corrosion pits, wear is accelerated at that point. This Corrosion/Abrasion area can be identified by taking a section of tubing that has failed due to rod wear and clean out the wear pattern with a wire brush. Corrosion pits will be visible underneath the iron sulfide buildup.

SURFACE PUMPING PARAMETER REVIEW

When attempting to reduce rod buckling effects, a look at surface pumping parameters are in order. Changes in surface pumping parameters are usually much less expensive and sometimes even more cost effective than making changes to down-hole equipment. Of course these changes are only practical if they can be accomplished without substantially reducing oil or gas production.

Surface pumping parameters should be adjusted to match the lift capacity of pumping equipment to inflow capability of well. If pumping unit operates 75% of the time or less to produce a well at its maximum potential, slowing pumping speed or reducing stroke length may be all that’s needed to minimize rod buckling. Since Polished Rod Velocity greatly affects the buckling force in rods, negative rod loads will be reduced in magnitude by reducing this velocity. The “neutral point” also tends to move downward in rod-string as rod velocity is reduced and compressive loads are more easily contained within the sinker bar section, if one is needed.

As a “rule of thumb” most rod pumped wells will not need a sinker bar section if polished rod velocity is less than 1500 inches /minute. Of course there are exceptions, and these wells will show themselves soon enough with tubing or rod failures caused by rod-on-tubing wear. The following formula can be used to calculate Polished Rod Velocity:

PRV = 2 X SL X SPM

Where:
PRV = Polished Rod Velocity (inches / minute)
SL = Stroke Length (Inches)
SPM = Strokes per Minute

As demonstrated by this formula, reducing either pumping speed (SPM) or stroke length (SL) will result in reduced polished rod velocity.

PUMP OFF CONTROLLER

Installing a Pump-Off Controller (POC) on a rod pumped well will reduce excessive fluid pounding in pump and the resulting rod buckling effects. Even with a properly set POC, the pumping unit may pound fluid for a minimum of three strokes before shut down occurs. For this reason, minimizing polished rod velocity will still be of value to prevent damage resulting from rod buckling during this shutdown process.

SINKER BAR DESIGN

Since negative rod loads cannot be totally eliminated during the pumping unit down-stroke, a larger diameter and more rigid (than rods) sinker bar section can be installed to reduce the damaging effects of rod buckling (Figure 3). **(As a point of clarification, negative rod loads described in this paper are loads calculated without buoyancy effects.)**

When designing a sinker bar section to contain compressive forces in a negatively loaded rod section, consider the following:

1. Utilize the largest diameter sinker bar for the available internal diameter of your tubing
   a. 1.500” O.D. sinker bars for 2-3/8” tubing
   b. 1.750” to 1.625” O.D. sinker bars for 2-7/8” tubing
      Use 1.625” when concerned with possible high fluid velocities between rods and tubing

2. Design for the shortest sinker bar length to contain the compressive forces within the sinker bar section while maintaining +200 psi to +300 psi actual bottom minimum stress in the last rod above the sinker bar section during the down-stroke to account for possible sticking of the pump plunger.

3. Maximizing the contact area between sinker bars (or rods) and tubing to distribute the side load over a larger contact area, reducing the pounds per square inch loading caused by compression and buckling.

Refer to Figure 4 for results from a 1996 study measuring tubing wall loss at 50# side loads for rods and sinker bars. This study (2) showed that after 90,000 cycles there was an approximate 60% reduction in tubing wall loss by using large diameter sinker bars instead of small diameter rods to reduce the rod-on-tubing wear caused by a 50# side load.

In order to design a correct sinker bar section the “neutral point” or point at which negative loading begins to occur in rod string must be determined. This is not as easy as it may seem due to the fact that often predictive pumping design programs do not correctly model existing down-hole measured rod loads. Through trial and error methods, which are described in the included field study, a fairly solid method for determining adequate sinker bar section length is possible.

SINKER BAR DESIGN METHOD UTILIZING WELL FAILURE DATA

One simple way to find depth of negative rod loading is by locating the depth of tubing failure and inspecting corresponding tubing wall for the effects of rod buckling. In most cases tubing failures caused by rod buckling will occur in the span of tubing from seating nipple up to approximately 600 feet above seating nipple. When tubing failures occur due to rod buckling, installing a sinker bar section that spans the rod length from slightly above failed point down to pump will minimize buckling in this area. This method of determining sinker bar length is re-active instead of pro-active but can give valuable information for future designs and prevent future failures in the observed well.

SINKER BAR DESIGN METHOD UTILIZING DYNAMOMETER SURVEY DATA

Quantitative dynamometer surveys are necessary to more closely determine the "neutral point" or actual point of origin of compressive rod loads. As mentioned earlier, predictive rod pumping programs rarely agree with actual dynamometer analysis programs when compressive loading near the pump is considered. A comparison of predicted down-hole compressive loading versus actual analysis of data from quantitative dynamometer measurements is shown in Figure 5. As can be seen in this figure, "predictive" negative loads tend to originate much lower in a rod string than actual measured data indicate. Once actual "neutral point" is determined, a sinker bar section can be added to span the length from top of pump to just above the neutral load point. When sinker bars are added to rod-string, the "neutral point" moves downward due to additional weight. The result of a properly designed sinker bar section will be that all negative rod loads are contained within this more rigid section.

Comparing actual measured "neutral point" to predictive "neutral point" provides the operator valuable information for designing future sinker bar sections. Using this comparative data, a correction factor can be derived and used with predictive rod loading programs to more accurately calculate the actual "neutral point". The ultimate goal is to estimate the actual "neutral point" above seating nipple and install a sinker bar section that spans this length. Sinker bars will keep this section rigid and minimize rod buckling damage.

CORROSION INHIBITOR APPLICATION

Once the rod buckling section has been reinforced with sinker bars, a corrosion inhibitor program must be incorporated and monitored to insure rods and tubing are being coated. The combination of minimized rod buckling along with appropriate and adequate corrosion inhibitor film should result in lower lifting costs by reducing tubing failures in a rod pumped well.

FIELD DATA REVIEW

The Analysis Design and Scorecard Process

1. A producing well was weighed with dynamometer equipment and the predictive surface card was matched to the measured surface card following either a down-hole failure or a production related issue

2. All dynamometer well data was collected. Only data from "full pump" cards was utilized to minimize errors due to "Fluid Pound" or "Gas Interference" conditions in the pump.

3. All pumping information was inputted into the Rodstar Predictive Design Program. A first predictive design was completed using the pump friction default, upstroke and down-stroke rod-tubing friction coefficients defaults and **with the "include buoyancy effects" box not checked**.

4. Rodstar predictive results were compared to measured dynamometer well data. Pump friction and upstroke and down-stroke rod-tubing friction coefficients defaults were adjusted to match predictive output to measured dynamometer data.

    a. The pump friction default (200 lbs.) was increased or decreased until the "bottom minimum" stress on the bottom sinker bar (or desired sucker rod) matched the measured "bottom minimum" stress on the bottom sinker bar (or desired sucker rod) from the dynamometer survey.

The Analysis Design and Scorecard Process - Continued

b. The upstroke and down-stroke rod-tubing coefficients friction defaults (1.0) were increased or decreased equally until the "bottom minimum" stress on the last sucker rod above the sinker bar section (or desired sucker rod) matched the measured "bottom minimum" stress on the last sucker rod above the sinker bar section (or desired sucker rod) from the dynamometer survey.

5. Adjustment of these friction defaults to match measured dynamometer data created a predictive software program modeling down-stroke conditions at or near the sinker bar section (or desired sucker rod) at the time of the down-hole failure or production related issue.

6. Adjustments to the rod string design or operating conditions were recommended from results utilizing the Rodstar Predictive Software and these new friction defaults.

7. From this new design, the location of first buckling (neutral point) was recorded in feet above pump.

8. The location of the tubing leak was compared to the location of first buckling (neutral point) in feet above pump.

9. A scorecard was created to evaluate the accuracy of each location of first buckling prediction to the actual depth of the next tubing leak.

    a. When the next tubing leak was above the predicted location of first buckling, the prediction under-predicted the location of the tubing leak. The difference in depth between the prediction and the tubing leak was recorded as a "negative" percentage of seating nipple depth.

    b. When the next tubing leak was below the predicted location of first buckling, the prediction over-predicted the location of the tubing leak. The difference in depth between the prediction and the tubing leak was recorded as a "positive" percentage of seating nipple depth.

THE RESULTS

A total of 67 Spraberry wells were weighed utilizing dynamometer equipment as a result of a downhole failure or a production related issue.

A total of 103 predictive surface cards were matched to measured "full pump" surface cards. Some of the 67 wells were weighed more than once.

A total of 97 of these 103 matched surface cards were measured as a result of a tubing leak. These 97 matched surface cards were used to adjust pump friction defaults and upstroke and down-stroke rod-tubing friction coefficients defaults in the Rodstar predictive program. Predictive runs recommended new rod string designs or changes in operating procedures. At the next tubing leak, the location of first buckling was compared to the location of the tubing leak. The scorecard was utilized to present the following results;

Location of tubing leaks:	458 feet (average) above the pump
Estimate of first buckling:	175 feet (average) above the pump
Location of Tubing leaks to first buckling:	283 feet above the estimate of first buckling
Estimate of first buckling error:	- 3.4 % (percentage of seating nipple depth)

Load cells operating under field conditions are estimated to be accurate within 3 to 5 % of actual measured loads.

Refer to Figure 6 which shows the location of measured downstroke compression in relation to the sinker bar section. This figure demonstrates that when downstroke compression can be isolated to within the sinker bar section you can expect a reduction in tubing leaks.

Figure 7 shows the performance of this same well since all downstroke compression was isolated to within the sinker bar section. This well has operated for 4 years without a tubing leak.

Figure 8 shows the reduction of tubing leaks in 339 wells utilizing this technique of designing the downstroke compression into the sinker bar section. The last 6 years indicate the impact of this technique.

CONCLUSIONS

Tubing leaks can easily result in the greatest well expense while operating rod pumped wells. Both the cost of repairing tubing leaks and the deferred revenue due to down-time contribute to expensive operating costs.

Abrasion, removal of inhibitor film and the resulting corrosion inside the tubing, are the result of rods buckling due to compressive loading during the down-stroke. Rod buckling can be minimized by installing sinker bars in the area of compressive loading.

Improving surface pumping parameters such as; pumping unit run times with pump off controllers, polished rod velocities through management of strokes per minute and / or surface stroke lengths, and chemical programs can be accomplished with relative ease and result in reduced operating expense.

Improving down-hole designs utilizing sinker bars, rod-string designs and other down-hole improvements can be accomplished with more effort and more expense.

This paper has shown that you can minimize rod buckling and reduce tubing wear by using down-hole failure data, measured dynamometer data and predictive design software.

Use of this improved predictive design process will provide you a more accurate model of actual rod buckling. This more accurate model will improve sinker bar section designs. Incorporating dynamometer survey data will reduce the number of "trial and error" designs required to reach your final sinker bar design. The final result should be reduced tubing failures caused by rod buckling effects.

REFERENCES

(1) "Total Downstroke Friction from Downhole Dynamometer Analysis", by Scott W. Long, P.E., SPE, Flexbar, Inc., Elton J. Smith, Kirk Mehaffey and Albert S. Garza, Pioneer Natural Resources, SPE #67274

(2) "Euler Loads and Measured Sucker Rod / Sinkerbar Buckling", by Scott W. Long, P.E., SPE and Donald W. Bennett, SPE, Flexbar, Inc., SPE #35214

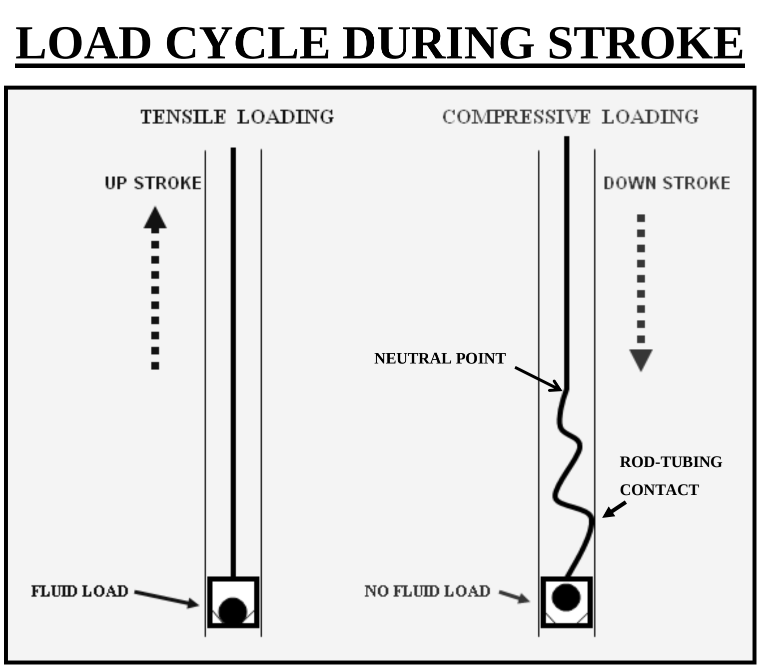


Fig.#1 Rods are in complete tensile loading on up-stroke. Compressive loading takes place in lower portion of rodstring during the down-stroke.

CORROSION /ABRASION RESULT

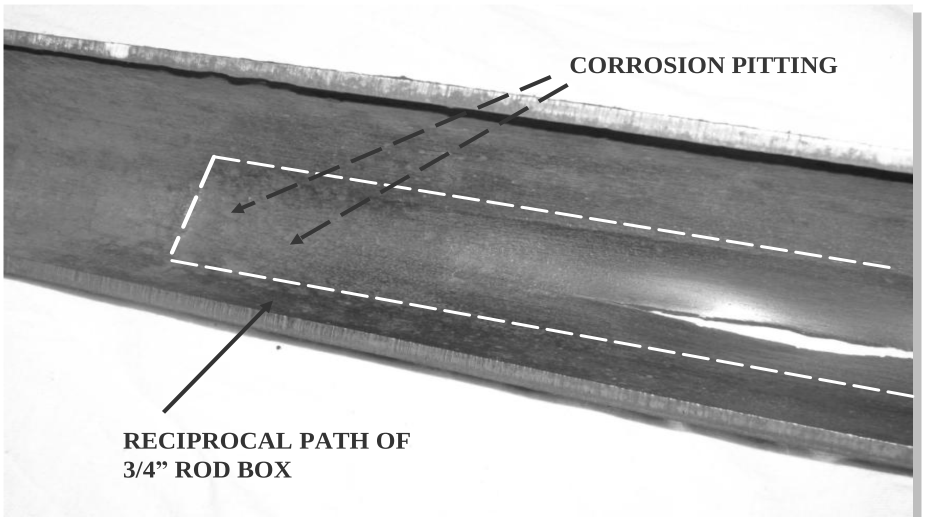


Figure 2 **-** Reciprocal wear removes corrosion inhibitor film and creates Corrosion/Abrasion affect.

SINKER BARS INSTALLED BELOW NEUTRAL POINT REDUCE ROD BUCKLING

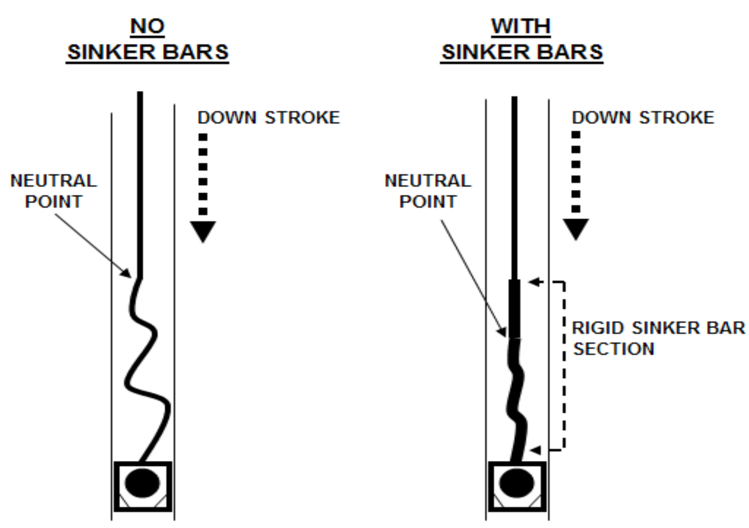


Figure 3 **-** Rigid sinker bar section minimizes rod buckling

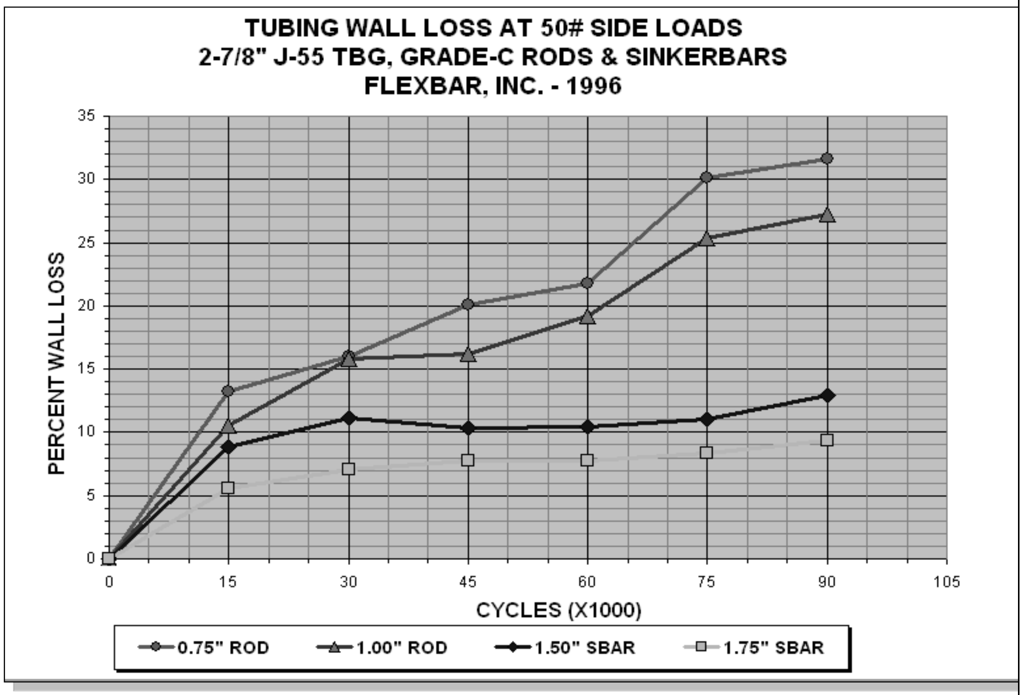
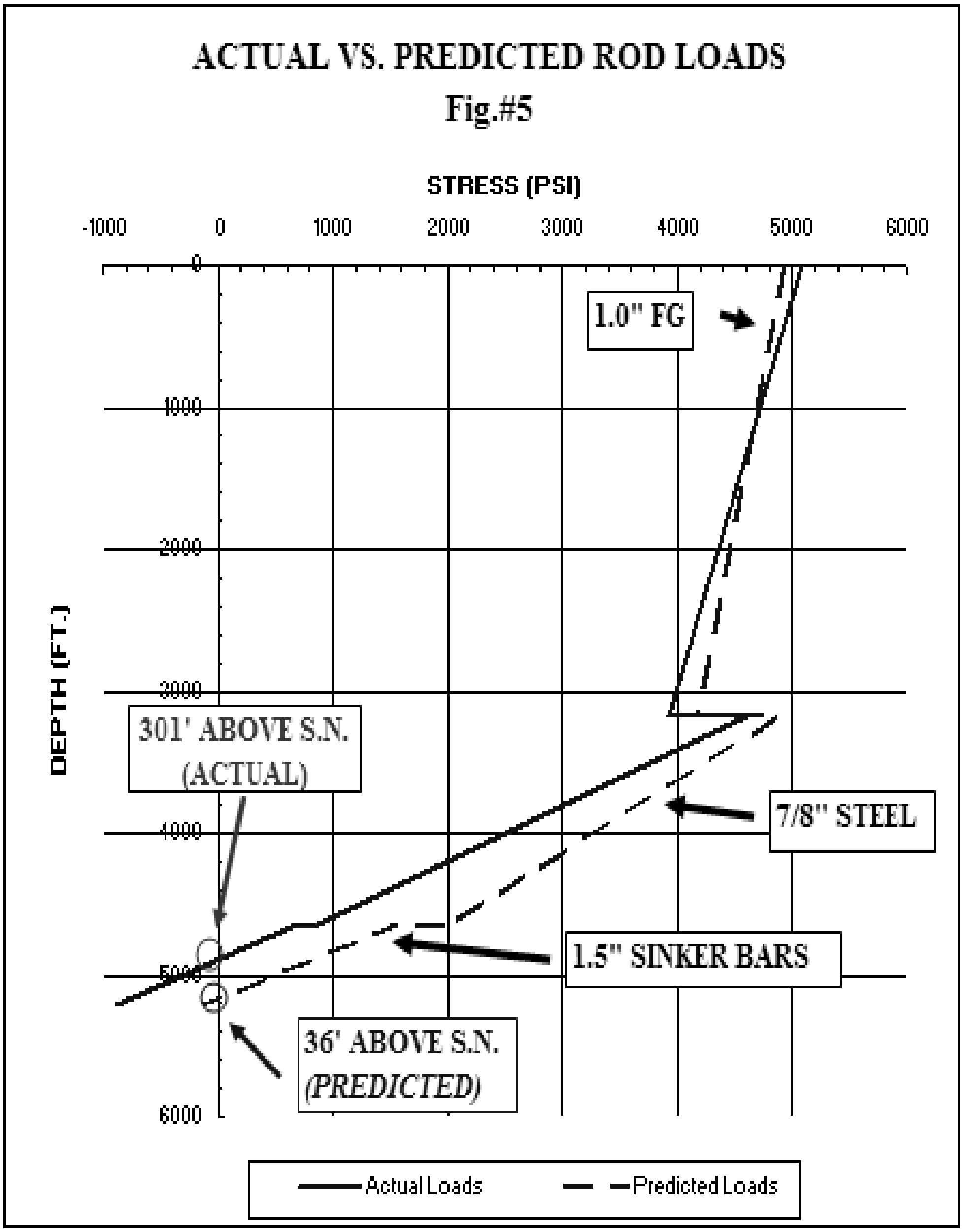
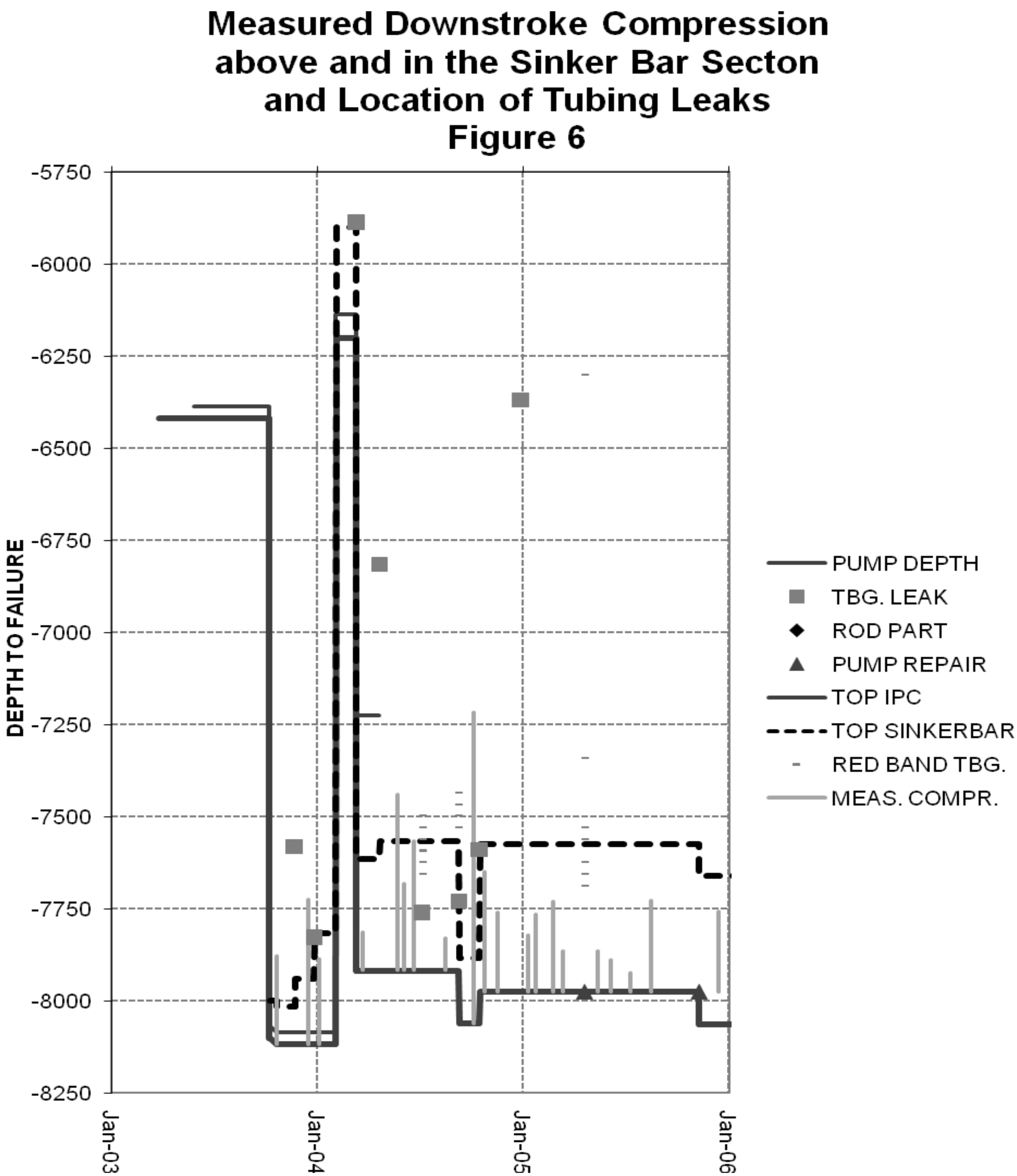
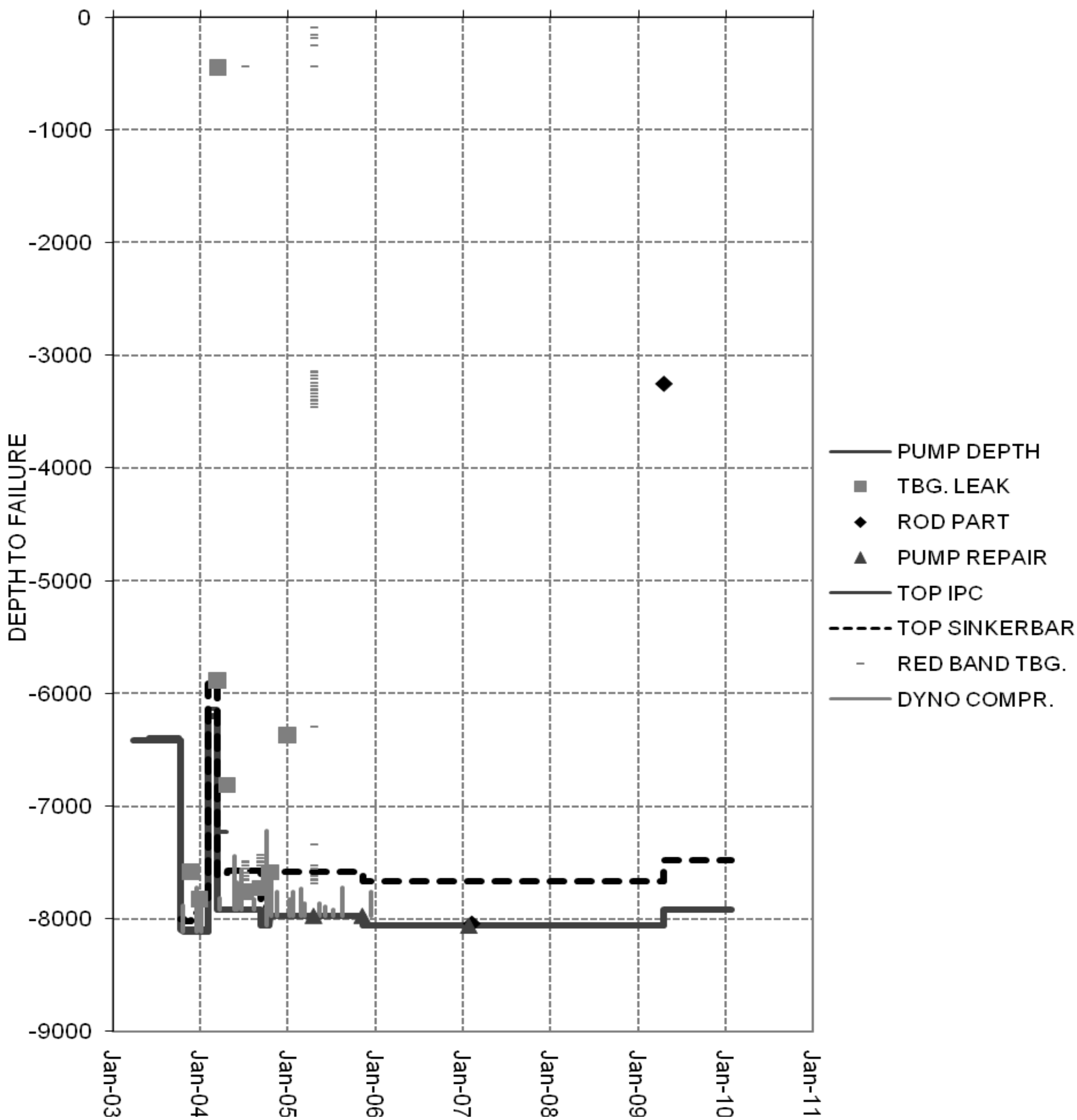


Figure 4 - Increased rod diameter results in reduced tubing wall loss


ACTUAL VS. PREDICTED ROD LOADS
Fig.#5
STRESS (PSI)
-1000
0
1000
2000
3000
4000
5000
6000
DEPTH (FT.)
0
1000
2000
3000
4000
5000
6000
1.0" FG
7/8" STEEL
1.5" SINKER BARS
301' ABOVE S.N. (ACTUAL)
36' ABOVE S.N. (PREDICTED)
Actual Loads
Predicted Loads


Measured Downstroke Compression
above and in the Sinker Bar Secton
and Location of Tubing Leaks
Figure 6
DEPTH TO FAILURE
-5750
-6000
-6250
-6500
-6750
-7000
-7250
-7500
-7750
-8000
-8250
Jan-03
Jan-04
Jan-05
Jan-06
PUMP DEPTH
TBG. LEAK
ROD PART
PUMP REPAIR
TOP IPC
TOP SINKERBAR
RED BAND TBG.
MEAS. COMPR.

Reduction of Tubing Leaks after Isolating Downstroke Compression in Sinkerbar Section
Figure 7



TUBING LEAKS (FPWPY) - 339 WELLS (272 NEW WELLS & 67 OLD WELLS)
DESIGNING DOWNSTROKE COMPRESSION INTO SINKER BAR SECTION
FIGURE 8