DOG LEG SERVERITY (DLS) AND SIDE LOAD (SL) RECOMMENDATIONS TO DRILLING

Norman W. Hein, Jr., Oil & Gas Optimization Specialists, Ltd.
O. Lynn Rowlan, Echometer Company

ABSTRACT

Dog Leg Severity (DLS) had been used for many decades as recommendations to drill oil and gas wells and to provide "trouble free" operating conditions. Many of these recommendations were historically based on vertical, shallow (<5000 ft.) deep wells. But as wells continued to be drilled deeper, the recommendations were still applied. With the current drilling and operating practices of deviated and/or horizontal wells, these recommendations may no longer be applicable. Additionally, the deviation measurement interval (degrees/100 ft.) also may no longer be accurate when trying to match downhole problems using existing rod string design software. Furthermore, as wells have become deeper and many now also exclusively are drilled as deviated/ horizontal, side loading (SL) may be a more appropriate condition to be used to determine problems. This paper will review the historic DLS recommendations, provide insight on deviation measurement interval, discuss the importance of SL, and provide new recommendations for drilling wells that should provide better, longer term, less problematic operating wells. This paper also should be considered a compendium of knowledge, experiences, operating and testing results that have been presented at various industry workshops, schools, papers, presentations, and schools conducted by the authors over the past 10 + years specifically related to DLS, SL, Drilling and operating Sucker Rod Lifted (SRL) vertical, deviated and horizontal wells.

Introduction

For many years it was recommended that the Drilling Department try to drill vertical wells with limited Dog Leg Severity (DLS) or deviation per a typical 100-foot interval of well depth. This deviation was recommended to be less than 1 degree/100ft. However, it was not always possible to obtain this limited well bore deviation, especially as well depths increased from a few thousand feet (shallow wells) to at moderate depth of 5,000 to 7,000 feet. These depths also reflect the continued industry change to drill deeper wells with time which became more difficult to hold these wellbore deviation tolerances.

Guidelines were then developed to provide more practical well bore deviations. The following rules of thumb (ROT) guidelines have been recommended for many decades for drilling vertical wells. An added comment associated with operating the well over the producing sucker rod lifted well's life within the deviation limits is also shown.

- Deviation 0 to 3 degrees/100 ft. – _no "problem"_
- Deviation 3 to 5 degrees/100 ft. – increased wear & friction
- Deviation   >5 degrees/100 ft. – will have problems

While these higher deviations may cause or have caused problems, this does not mean that these wells cannot be operated. In fact, there have been wells that have been rod pumped with local wellbore deviations more than 30 degrees/100 ft. But to operate these higher deviated wells required extra precautions may be necessary such as the use of centralizers or that there will probably be increased operating cost due to increased failures, decreased run time/life, etc. Additionally, while these deviation conditions have been associated with the Sucker Rod Lift artificial lift technique, these ROT have practical effects for other forms of artificial lift.

Drilling Considerations

Over the past few years as deeper and deeper wells have been drilled and drilling has been or will be typically done from pads, these ROT wellbore deviation guidelines may not be the only considerations

(see **Figure 1**). While there have been many wellbore trajectories developed to reach deeper depths and different producing zones from the same well pad, these plans should be discussed with the whole well team since mock up drilling deviation plans could be checked by computer programs to see if there could be improved drilling plans that may reduce deviations and associated side loads, especially at or near the surface where the highest sucker rod string loads are applied. These higher loads will naturally cause increased side loads for the same wellbore deviation as the same deviation occurring deeper in the well with less rod string load. Instead the SL may be a more appropriate condition to consider once the well has been drilled and the wellbore deviation has been developed.

Wear Considerations
Most operators have used normal casing deviation surveys conducted with the deviation point at an interval of 100-feet. Operating practices, especially downhole wear of the tubing (hole in tubing – HIT), rod wear and possibly related failure and/or coupling wear have been used to determine actual operating conditions versus just relying on the deviation survey. However, over time, a number of computer design programs, primarily for sucker rod string designs, have been developed that allowed the deviation survey and resulting DLS to be estimated. More recently, a number of computer program have also added the capability to calculate and estimated side load based on the downhole deviation times the applied rod string load.

This progression in technology is further evidenced by a recent paper from ConocoPhillips coal bed methane gas wells operated in the San Juan Basin (**ref. 1**). These were relatively shallow (<4000 ft) but many S-shaped drilled. **Figures 2 to 5** show many different aspects from their operational experience. These showed a comparison of DLS and SL from the deviation survey, rod pumping speed versus side load, run-time (years) versus side load and the resulting HIT failure at a depth of approximated 1650 ft in a constant build section of the well where SL was <50 pounds. Conventional practices indicated that rod guides should not be required with this amount of SL, but this ROT was based on vertical wellbores where rod on tubing wear would be minimal. However, in the constant build section, the rods were always in contact with the tubing and even with this low SL, caused a HIT for the unguided portion. Subsequently, guides were installed on these sections. These results also provided that with SL of approximately 200 pounds, adequate (~10 year run times) were possible. However, the wells could still be operated with over three to four year run times with side loads of approximately 400 to 450 pounds.

The conventional design recommended practices of assuming 50 pounds of SL could be accommodated per each rod guide would then anticipate the normal practice of four guides per rod (for up to the 200 pound of load) and up to eight or possibly nine or ten guides per rod for the highest SL (depending on the rod guide design recommendations).

The published results combined with many years of operating experience and some unpublished wear testing results have developed the following recommendations on DLS and SL wear for sucker rod lifted wells
- Design assuming 50 pound of side load per guide can be accommodated and provide adequate runtime
- Wells drilled with 100 to 200 pounds of SL can operate for relatively long time (10 years or more) using four guides per rod
- This amount of SL (and the original DLS) could be considered a Drilling well design recommendation and the wellbore plan should be checked using rod design programs before the well is drilled
- DLS and resulting SL higher than 200 pound can still be operated but runtime will be decreased with increasing side load
- Selection of the rod guide materials and guide design are also critical to run time and reducing downhole problems
- Materials that worked at shallower wells and lower downhole temperatures may not work at deeper wells with higher bottom hole temperatures
- Additionally, the produced fluids, including gases that might be present (H_2S, for example) and having different concentrations may affect the guide material

- So, what "worked" to provide adequate runtime in one well may not necessarily work in a different well, even in the same field

Deviation Survey Considerations

Since the calculations for DSL and related SL are dependent on the downhole wellbore deviation survey, the questions that must be asked are: how accurate were prior drilling surveys and can improvements be made to obtain better results? Related to these then are the questions as to when, during/after drilling or when the well is in production, and where, in casing or tubing, should the survey be obtained? Finally, there is the question, is there an optimum sample spacing interval?

A field example on the importance of answering these questions can be seen in the following data. The background is a well had multiple failures at a depth of approximately 475 feet. A DLS and related SL calculation was obtained using the "in-casing" gyro survey conducted with the normal 100-foot spacing interval. The problem that occurred was that there was not a good match between the actual downhole location of the failures versus the calculated, maximum SL.

Newer technology digital deviation survey was obtained with a one-foot deviation interval but then the DLS/SL were calculated using different deviation intervals. **Table I** shows the calculated SL comparing the well depth using a commercially available rod string design program where side loads exceeded the minimum of 50 pounds for the various intervals. It is interesting to note that the maximum SL was obtained for the interval of 25 ft at the approximate depth of 475 ft. This is the approximate location where the failures were occurring. It should also be noted that as data spacing interval was increased, the well depth where the maximum occurred was shifted downward. Additionally, the maximum SL value was reduced. Finally, if too wide an interval was used, the change in DLS/SL was shown not to be significant.

A more recent investigation of the deviation interval compared the location of SL with well depth and the magnitude of the calculated resulting side load when both low- and high-resolution deviation survey intervals were used. It should be noted that the location of the various peaks of SL were in the approximate same location however the magnitudes and the maximum SL at approximately 500 feet was missed for the 100-foot spacing compared to over 350 pounds of SL when 1 foot intervals were used. A precaution should be considered is that the computer program must be able to allow the various data intervals to be incorporated into the program calculations. For this well example, when 100-foot spacing was provided for the 10,000-foot deep well, only 100 data points were entered but for the 1-foot interval, 10,000 points of data had to be entered. Thus, the rod string design program needed to be able to make the calculation using this high number of points.

The following summarizes the various observations of the deviation survey data collection intervals.
- Deviation intervals using degrees per 100 ft. do not appear to provide the most accurate effect of the local deviation
- The best match to where the actual well failures were occurring using higher resolution data intervals
- It may be best to obtain a detailed digital deviation survey at 1-foot intervals then process the resulting deviation data at 30-foot intervals (depending on the allow deviation points for the rod string design program)
- There also may be relaxation in the SL maximum magnitude effect since the tubing string will temper some of the casing deviation and should reduce the maximum SL. (However, field examples should be obtained to verify if this occurs.)

Excessive Downhole Friction

Dynamometer analyses[3] considering excessive downhole friction that sufficiently impacted pump action are shown in **Figures 7 to 10**. These analyses provided an equivalent match of rod stretch spring constant, Kr - lbs/in, employing a procedure to reduce the length of the sucker rod string to account for the depth rods from the surface to the down hole location where the dog-leg created mechanical friction is applied to a point in the rod string. Reducing the rod string length increases the rod stretch spring constant, a greater Kr indicates a stiffer rod string as the rod string length from the surface to a point becomes shorter and the force required to stretch the rod string 1 inch increases.

Fig. 7 is an example surface and pump dynamometer card for a well having excessive downhole mechanical friction applied to the rod string. The diagnostic wave equation calculated 15,715 lbs pump card load range is 48% greater than the expected pump load of 10,610 lbs due to the differential pressure acting across the pump plunger. A 142 lbs/in composite Kr for the entire rod string is calculated based on the rod string taper, shown for the **Rod String in the Well Table II**:

	Top Taper	Taper 2	Taper 3	Taper 4	Taper 5
Rod Type	EL	EL	EL	SB	SB
Length	3162.00	4125.00	3025.00	32.50	300.00
Diameter	1.000	0.875	0.750	1.000	1.500
Weight	9145.1	9124.4	4910.9	94.0	1958.9

Fig. 8 is the same well's surface and pump dynamometer card shown in **Fig. 7** except the pull rod for the pump parted and no load is being applied to the rod string by the pump (even though the diagnostic calculated pump card load on the upstroke is +5000 lbs and the diagnostic calculated pump card load on the down stroke is -5000 lbs). In this well the measured surface loads are created due to excessive down hole mechanical friction force being applied to the rod string at some unknown distance from the surface. The pull rod at the pump parted. Based on the measured surface loads the rod string part appears to be at the pump with the entire rod string still attached because the average of the horse shoe load cell measured surface dynamometer loads is equal to the weight of rods in fluid. The Kr slope on the right and left side of the surface dynamometer card is equal to 1470 lbs/inch ((27430-16670)/7.27) and is shown by a line drawn between the two points circled on the left side of the surface dynamometer card load versus position plot. The depth along the rod string to the point of the application of the excessive down hole mechanical friction force is where the measured surface Kr equals the Kr calculated from the surface down the rod string (Measured Kr = Rod Kr). The Rod Kr is determined by removing a portion of the rod string from the bottom and re-calculating Rod Kr for the remaining rod string from the surface to the new end of the rod string. The step by step removal of rod segments from the bottom toward the top is a quick technique to determine the depth to the point of the application of the excessive down hole mechanical friction force. **Fig. 9** shows the calculated rod spring constant of 1479 lbs/in at a depth of 1350 feet from the surface in the 1 inch sucker rod string section and Rod Kr closely matches the 1470 lbs/in Measured Kr determined from the surface dynamometer loads versus position plot. At the 1350 foot calculated depth from the surface where the Rod Kr equals the Measured Kr represents the location of the down hole severe mechanical force application in the tubing and the location of a severe dog-leg in wellbore profile should be expected near this depth. **Fig. 10** shows a diagnostic calculated pump card load of 12,000 lb mechanical force is being applied to the rod string at a depth 1350 feet from the surface. This 12,000 lbs friction force is much larger than expected and the total load applied at the 1350 depth is the weight of the rods in fluid plus the mechanical friction force due to the dog-leg. Inspection of the deviation survey **Fig. 11** on 100 foot intervals shows at a measured depth of 1371 feet the dogleg severity to be 1.96 deg/100 ft. The location of the severe mechanical force being applied to the rod string can be accurately determined by finding the depth to where the measured Kr is equal to the Kr calculated.

When the pump card sides slopes "backwards" (**Fig. 8**) then that "backwards" slope is the indication of a mechanical static friction force acting on the sucker rods, but not at the pump. The "backwards" slope is result of the wave equation calculating what the up hole mechanical friction force should look like if the mechanical static friction force were applied at the pump. If the sucker rod string (**Fig. 10**) used in the wave equation to calculate the pump card are removed from the bottom of the rod string, then the "backwards" slope of the pump card will become a vertical load at the length of rods where the mechanical friction force is applied. As the rod string length is shortened, the Rod Kr line will become steeper and match the slope of the surface dynamometer card when the length of rods are shortened to equal the depth to the point where the mechanical static friction force is applied.

Conclusions and Recommendations
Severe doglegs in the upper sections of any well should be avoided because the increased mechanical friction forces due to the dogleg severity will result in increased failures and high operating cost. Mechanical forces applied to the rod string by a severe dog-leg are normally large, if the sticking/drag occurs near the surface where the rod loadings are large. It should be noted that the excessive friction

example showed that a DLS of less than 2 degrees/100-ft could be sufficient for much deeper wells that fluid production would not occur. Thus, a new **Table III** has been developed providing DLS recommendations for current generation, deeper, vertical and/or deviated/horizontal wells. However, these numbers still reflect the need to have better drilling control shallower in the well where the applied rod string loads would be greater.

- Drilling design/wellbore profile have a major impact on Sucker Rod Lift systems
- Normal consideration includes:
  - pump depth vs. reservoir depth,
  - production rate,
  - casing – tubing size and downhole separation
  - pump type
  - pumping parameters, S, N, Fo/SKr, No/No'
- Added considerations includes:
  - impact of side loads, friction, dynamic effects on up and down stroke, buckling, wear, etc.
- It is best that the natural work team (drilling, completions, reservoir, production and facilities) are all involved in the determination of the well drilling profile and the resulting expectation for the various fluids production rates
- This may require running computerized rod string design programs with multiple well configurations to determine best drilling time, cost, and layout to provide the best downhole separation and least production problems over the entire time in production
  - But, remember, software programs are only a tool (see SWPSC papers on Sandia work), may not be highly accurate, and require weighing the well after installation
- While new recommended DLS are less than (pre)historic, it must be remembered that these ROTs originally were developed based on the "shallow" and "Vertical" wells drilled at that time and did not consider the effect of well/string depth and rod loads
- SL recommendations for drilling based on rod string design program are to keep SL less than 200 pounds per rod
- Based on field example from **Ref. 1**, this may result in runtime of >10 years
- However, these results were obtained from the use of rod guides assuming 50 pounds per rod
- The amount of load per guide is different for various guide designs, materials, but typically for 200-pound SL, then a minimum of 4 guides per rod should be used
- While we can't necessarily limit the amount of DLS and/or SL based on actual drilling, higher resulting side loads may require more guides per rod (up to about 8 or 10 depending on manufacture and guide design)
- While very high SL (~ >450 pounds) may be encountered, then resulting higher SL per guide may be greater than 50 pounds
- Some unpublished guide wear testing was obtained with applied load as much as ~450 pounds per guide but resulted in less than 4-year runtime

References
1. Cochrane, T., Colley, J, and Kane, E., "Sucker Rod Side Load and Wear in Deviated Coalbed Methane Gas Wells," SWPSC, Lubbock, 2013
2. "Rod-guide Placement Based on High-Resolution Tortuosity Analysis of Production Tubing," ALRDC Sucker Rod Pumping Workshop, Oklahoma City, 2018.
3. O. Lynn Rowlan, Clint Haskins, Carrie Anne Taylor, Ken Skinner, "Examples of Forces not Accounted for by the Wave Equation", SWPSC, Lubbock, 2018

Table I. Side Loads Greater than 50# At Various Depths & Data Stations/Intervals

Depth	25'	50'	75'	100'	150'	200'
475'	68.0	58.7	-----	-----	-----	-----
500'	57.6	57.4	59.2	62.2	-----	-----
525'	-----	-----	59.2	62.2	-----	-----

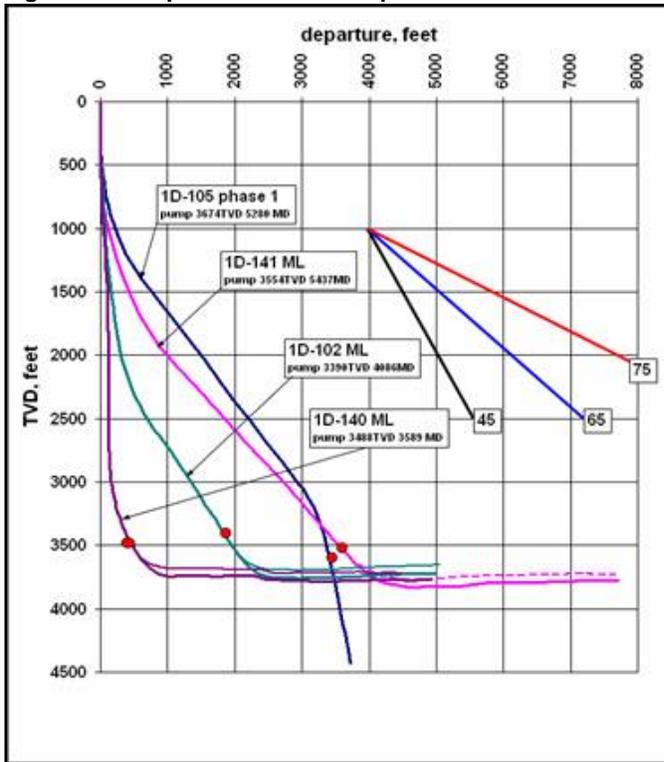**Figure 1 Example of various well plans considered for drilling from one pad.**

Figure 2. Well plan, deviation survey and associated side load for example, shallow CBM well. Ref. 1 – fig. 3
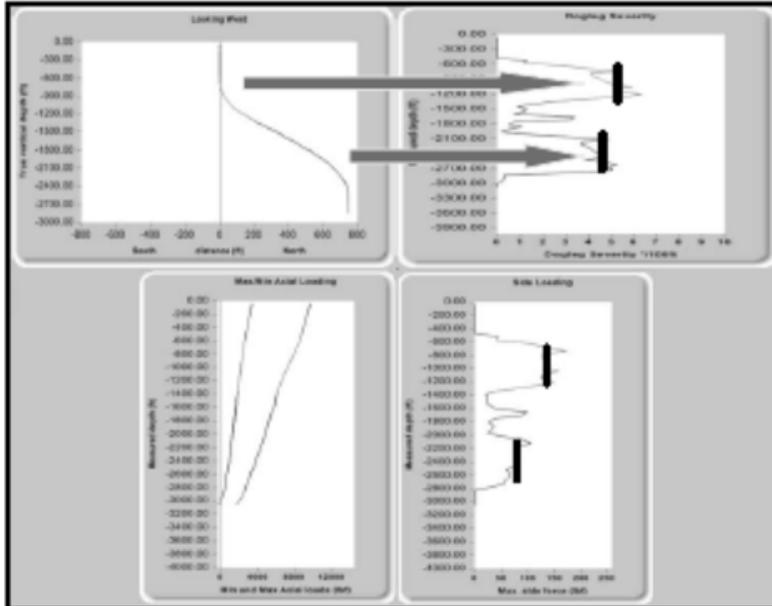

Figure 3

Figure 3 Effect of rod pumping speed and obtained side load in studied deviated CBM wells. Ref. 1 – fig. 4
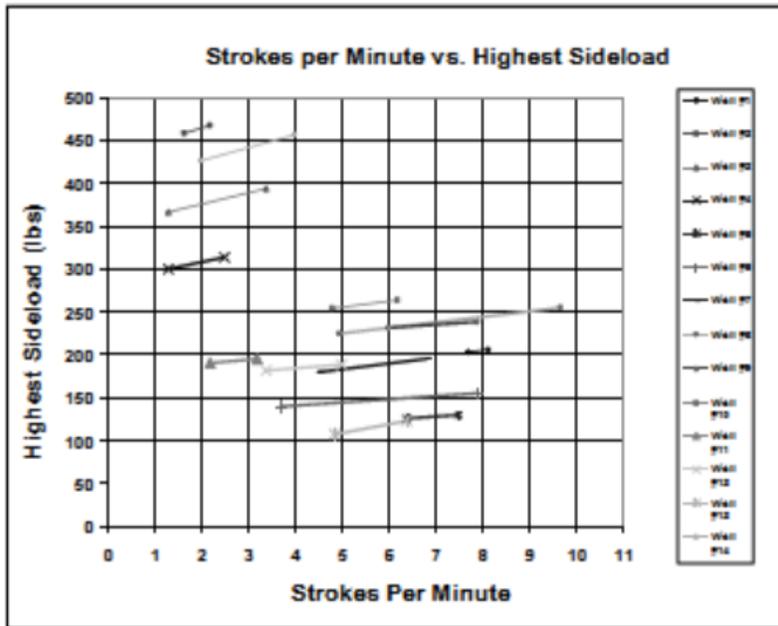

Figure 4

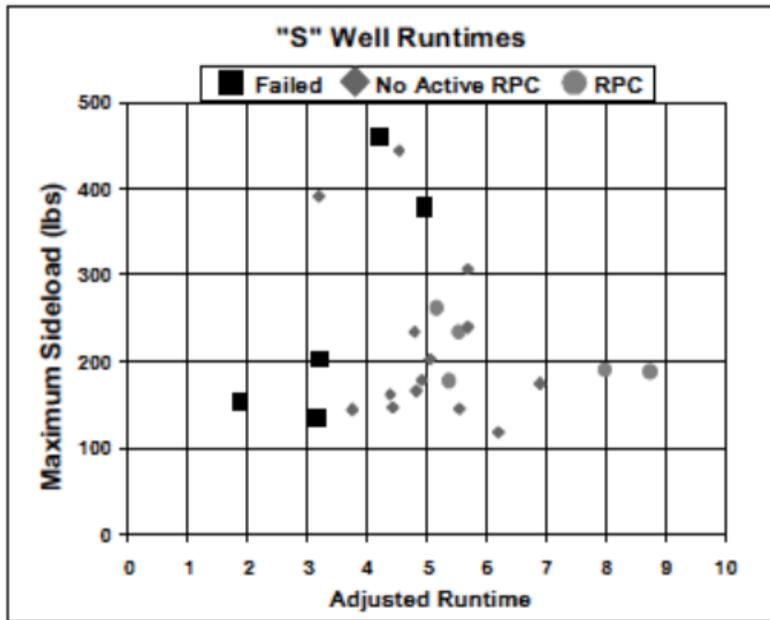**Figure 4. Effect of side load on runtime and/or well failure for example CBM wells. Ref 1 – fig 5**

Figure 5

Figure 5. DLS, resulting side load and noted hole in tubing failure at approx. 1650 ft were constant build was developed but rod guides were not considered since SL was approx. 50 pounds.
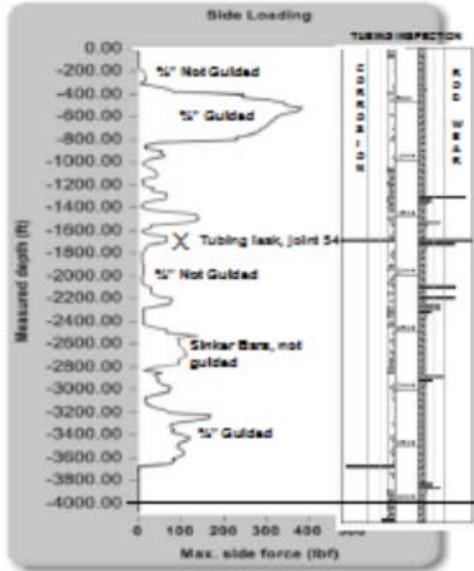

Figure 7

Figure 6. Gyro survey spacing interval and calculated side load comparing low resolution data collected at 100-foot interval to the high resolution data obtained with a 1 foot spacing. Ref. 2
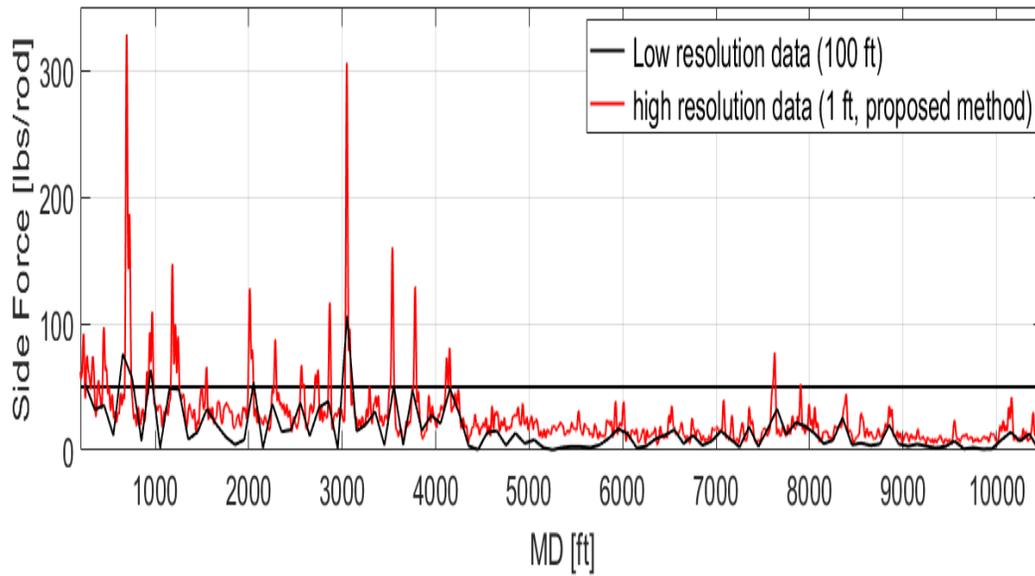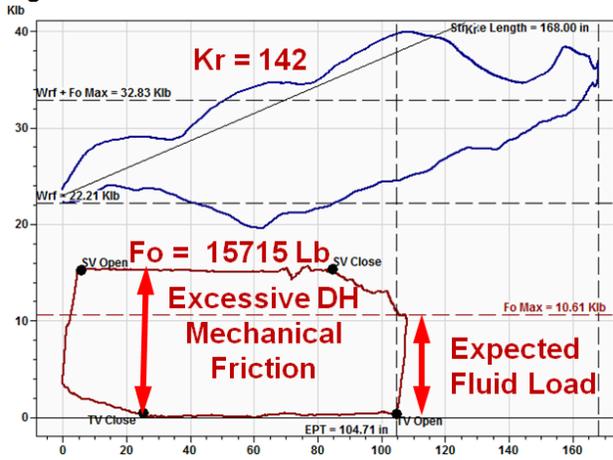
Figure 7 – Excessive Mechanical Friction Force

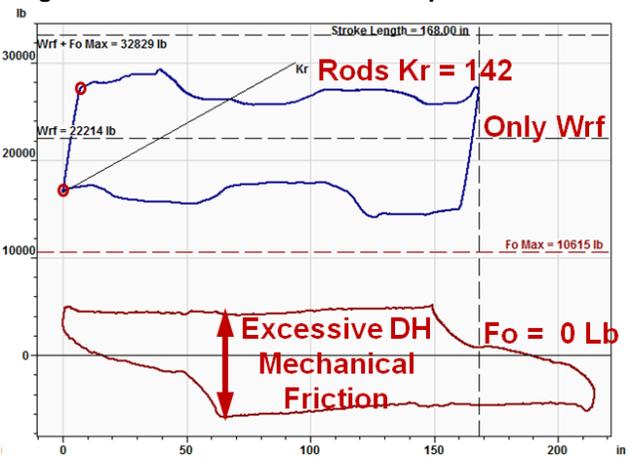**Figure 8 – Pull Rod Parts at the Pump**
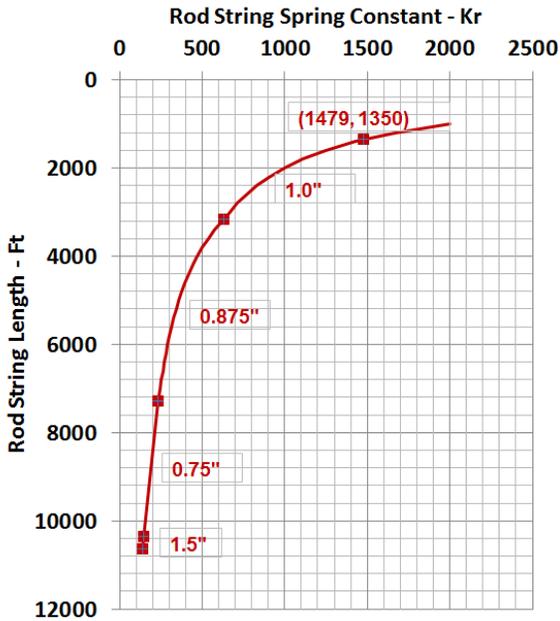

Figure 9 – Kr Measured Equals Kr Calculated
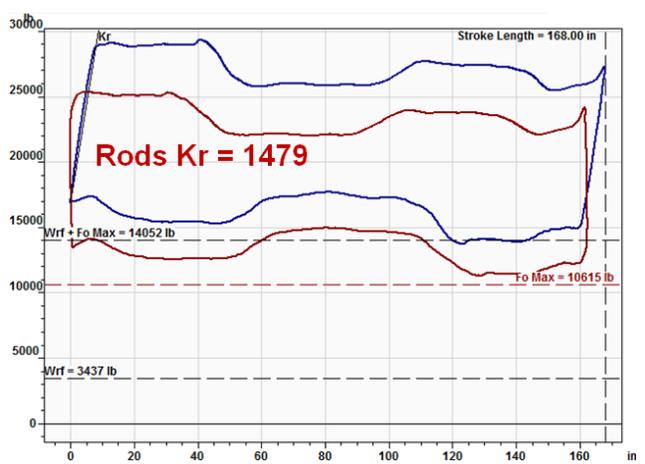

Figure 10 – Rod Load at Depth of 1350 Feet

Figure 11. Deviation survey and resulting DLS at the depth providing excessive friction

No.	MD (ft.)	Incl (°)	Azm (°)	TVD (ft.)	VS (ft.)	N-S (ft.)	E-W (ft.)	Closure Dist. (ft.)	Ang. (°)	DLS °/100'	Build Rate °/100'	Walk Rate °/100'
Tie In (0)	0	0	0	0	0	0	0	0	0	0	0	0
1	140	0.7	218.2	139.9965	-0.66929	-0.67207 S	-0.52886 W	0.855201	218.2	0.5	0.5	155.8571
2	233	0.6	231.3	232.9905	-1.55375	-1.42296 S	-1.2602 W	1.900764	221.5287	0.191927	-0.10753	14.08602
3	326	0.3	127.8	325.9886	-1.84073	-1.87664 S	-1.44784 W	2.370239	217.6503	0.785783	-0.32258	-111.29
4	419	0.3	68.2	418.9875	-1.44704	-1.93545 S	-1.0294 W	2.192176	208.0069	0.320627	0	-64.086
5	513	0.3	46.1	512.9862	-0.99183	-1.67342 S	-0.62358 W	1.785834	200.4374	0.122339	0	-23.5106
6	608	0.4	53.1	607.9844	-0.47388	-1.30186 S	-0.17919 W	1.314137	187.8372	0.114291	0.105263	7.368421
7	703	0.1	99.5	702.9835	-0.09358	-1.11644 S	0.167756 E	1.128973	171.4547	0.356701	-0.31579	48.84211
8	798	0.4	21	797.9826	0.169717	-0.82054 S	0.368361 E	0.899428	155.8234	0.41315	0.315789	-82.6316
9	894	0.4	201.4	893.9818	0.167789	-0.81969 S	0.36618 E	0.897765	155.9283	0.833328	0	187.9167
10	990	0.6	165.2	989.9783	-0.00982	-1.61766 S	0.372308 E	1.659952	167.0389	0.379397	0.208333	-37.7083
11	1086	0.4	132.5	1085.975	0.191693	-2.33002 S	0.74777 E	2.447073	162.2071	0.354891	-0.20833	-34.0625
12	1180	0.3	128	1179.973	0.529989	-2.70321 S	1.183607 E	2.950974	156.3536	0.110248	-0.10638	-4.78723
13	1277	0.5	99.7	1276.971	1.078359	-2.93086 S	1.800905 E	3.439942	148.4308	0.283938	0.206186	-29.1753
14	1371	2.3	79.2	1370.939	3.340495	-2.6465 S	4.058167 E	4.844864	123.1101	1.957458	1.914894	-21.8085
15	1466	2.1	80.2	1465.869	6.98227	-1.99304 S	7.64584 E	7.901334	104.6102	0.214591	-0.21053	1.052632
16	1561	1.8	79.9	1560.814	10.20929	-1.43513 S	10.82991 E	10.92459	97.5486	0.315971	-0.31579	-0.31579
17	1656	1.7	83.6	1655.769	13.09792	-1.01641 S	13.69917 E	13.73682	94.24327	0.158778	-0.10526	3.894737
18	1710	1.6	77.9	1709.747	14.64682	-0.76909 S	15.2323 E	15.2517	92.89046	0.355682	-0.18519	-10.5556
19	1803	1.8	85.7	1802.706	17.38752	-0.38742 S	17.95831 E	17.96249	91.23586	0.328401	0.215054	8.387097
20	1899	1.8	83.3	1898.659	20.3744	-0.09846 S	20.9592 E	20.95943	90.26917	0.078521	0	-2.5
21	1995	1.1	82.1	1994.628	22.78954	0.204097 N	23.36938 E	23.37027	89.49962	0.729812	-0.72917	-1.25
22	2091	0.1	289.3	2090.622	23.63638	0.358444 N	24.20307 E	24.20573	89.15152	1.239396	-1.04167	215.8333

Table III. Recommended DLS limits for deeper vertical and deviated/horizontal wells showing more restrictive DLS than historic that varies with well depth to avoid excessive friction and inadequate pump action.

Recommended Dogleg Severity Limits to Control Drilling a Wellbore

Dogleg Severity (Deg)	Wellbore Location Above Kickoff
< 0.50	0 to 1,500 feet
< 1.00	1,500 feet to 25% of distance to Kickoff
< 1.25	25 to 50% of distance to Kickoff
< 1.50	50 to 75% of distance to Kickoff
< 2.50	75% to 50 feet above top of pump
< 1.00	50 feet above top pump to Kickoff

Use predictive rod design software to limit the degree of Dogleg Severity to calculated side loading acting on a 25 foot rod will be less than 200 lbs.