Design Considerations When Rod Pumping Gas Wells

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Abstract

Many SPE papers have been written over the years on how to pump the deep and difficult wells. However, when it comes to rod pumping gas wells, there is negligible literature. In the past three decades, our industry has transitioned from manually calculating rod pump designs using the method found in API bulletin RP 11L[1] to fully computerized dynamic simulations. Most operators with limited engineering resources depend upon third parties to run these computer programs, with the direct result being a loss of a "feel" for the process. By optimizing every component for the lower fluid volumes required for gas well de-watering, installation costs can be minimized. More importantly, mistakes can be avoided that will assure a successful installation, and lowered future operating expenses. This paper will look at every component of the rod pumping system, including rod pump sizes, rod string size and grade; pros and cons of tubing anchors; and pumping unit and driver sizing. Wave equation calculations will be used to support the conclusions made, and the end result will be the presentation of several "Rules of Thumb." A comparison between two actual field installations will be made using dynamometer analysis, with one of the two utilizing these design concepts.

Introduction

"The complete design of a sucker rod pumping system is an involved trial and error process," according to Jennings.[2] In his paper, Jennings reviewed the information required to start the design procedure, and then compared three calculation methods: Mills,[3] API RP 11L, and Gibbs' wave equation method.[4] The results of these calculations were then to be compared to the desired performance, and the process reiterated until the design was deemed adequate.

It has been many years since this paper was written, and given the state of our industry, we find much of the design work has shifted from staff engineers to the manufacturers of rod pumping equipment. The depth of design knowledge and experience has been retired and downsized away over the past 20 years. We no longer see SPE papers such as Gott's[5] "Successful Rod Pumping at 14,500 Feet." The shift of domestic producers away from oil production to natural gas has also been responsible for this knowledge loss. The end result has been that design work is often simply a phone call to a vendor, with very little of the iterative process that Jennings mentioned actually occurring.

The proper design of a rod pumping application for a gas well is important in order to 1) maximize cost savings both in up-front installation costs and operating costs, and 2) insure a trouble-free installation. The objectives of this paper are to evaluate every component of the rod pumping system, including rod pump sizing, rod string size and grade; pros and cons of tubing anchors, pumping unit and driver issues; and to deliver a set recommended "Best Practices" that could be adopted for gas wells.

Comparison of Pump Sizes

In any rod pumping design, the first two questions are how much pump capacity is required and what depth is the pumping fluid level? For all the examples in this paper, the calculations are based on 100% pump capacity of 40 barrels per day with a fluid level at the pump intake. Since pumping units are usually installed later in the life of a loaded up gas well, this capacity should be ample for the majority of gas wells.

The Gibbs' Wave Equation was used to model three sizes of pumps at three different depths. Rod tapers and stroke lengths were 1) 3000 feet of ⅝-in. diameter API Grade C rods with a 54-in. surface stroke length, 2) 6000 feet of ¾-in. and ⅝-in. diameter API Grade C rods with a 64-in. surface stroke length, and 3) 9000 feet of ⅞-in. and ¾-in. diameter API Grade D rods with a 74-in. surface stroke length. The three pumps evaluated were 1.06-, 1.25-, and 1.50-in. diameter. (It should be pointed out that 1.06-in. diameter pumps are not usually stocked by pump shops, although they are readily available at similar pricing.)

Figure 1 depicts the Modified Goodman Rod stress for each pump at the various depths. Figure 2 depicts the Gearbox Torque requirement, and Figure 3 depicts the Motor Horsepower Requirement. Although the smaller pump requires slightly more horsepower and gearbox loading, the reduction in rod loading greatly eclipses the other increases. These slight increases are also less of a concern because of the common oilfield practice of oversizing motors and gearboxes.

To elaborate more on this, when a pumping unit is moved from an oil well to a gas well, the pumping depth is usually much deeper, and the fluid volume is much lower. The result of this is a heavier rod string, which means that the counterbalance weights usually need to be increased, and the structure rating of the unit (the middle number that nobody ever worries about) may not be sufficient. The electric motor size is normally going to be much larger than required to run the pumping unit at low speeds. (Refer to Figure 3.) An increase of a few horsepower is also moot if you have a motor that only operates several hours a day, hence requiring very little electricity.

It is interesting to look at the low motor horsepower and gearbox torque requirements and the high structure load in Figure 4. For the smaller 1.06-in. pump size, the following pumping unit sizes and motors would suffice:

Depth	Gearbox Rating	Structure Rating	Stroke Length	Motor Horsepower	Closest Available Size
3000	48	51	54	3	C57-76-54
6000	92	109	64	7.5	C114-143-64
9000	143	202	74	10	C228-213-86

To the experienced oil well pumping unit design engineer, these pumping units probably appear very small for the pump depth shown. However, for each case, pumping unit size was primarily dictated not by gearbox torque requirement, but rather by the structure load, and, to a degree, stroke length. Due to rod stretch being significant, a short stroke pumping unit can end up with minimal downhole pump stroke. For our 6000-ft pump depth case, a

1.06-in. diameter pump with 64-in. surface stroke had only 45.1 in. of net pump stroke, whereas the 1.50-in. diameter pump had only 25.4 in.

We have two goals with any rod pumping installation: avoid expensive well servicing, and minimize original installation costs. By keeping rod loading as low as possible, we can often use less expensive Grade C rods, which are a softer metal and more corrosion resistant by nature, which supports both of these goals. By not oversizing our surface pumping equipment, we can minimize equipping costs.

Tubing Anchors—Friend or Foe?

The 3000- and 6000-ft computer design runs on the previous page were made without tubing anchors. The addition of a tubing anchor (a best practice in the oilfield) can be a detriment to a gas well. During the rod pumping cycle, the weight of the fluid in the tubing will shift from the rod string to the tubing and back every stroke. A tubing anchor will prevent the tubing from stretching when these load shifts occur. In gas wells, where the load shift is somewhat minimal thanks to smaller pumps and lighter produced fluids, tubing stretch may be acceptable. The result of removing a tubing anchor will also be slightly lower pump capacity, but equipment loading will be lower. Figure 5 depicts the effect of adding an anchor to rod loading, keeping all surface parameters to those calculated previously in the pump-size evaluation, except the speed was increased slightly to maintain the pump capacity at 40 BPD. Figures 6 and 7 depict the effect of a tubing anchor to gearbox loading, and motor horsepower requirement. The observation is that gearbox loading increases appreciably due to the presence of a tubing anchor; rod loading increases slightly; and motor horsepower is slightly reduced.

The standard tubing anchor design will occupy approximately 78% of the annular area, leaving a limited area available for the flow of gas. For production casing sizes greater than 4.5-in. outside diameter, there are modified tubing anchors available that offer additional clearance, and only reduce the annular area by 55%. As pertains to gas wells, the tubing anchor should be viewed as a downhole choke. Whether there will be a pressure drop across this choke or not is dependent on well deliverability. Considering that lowest flowing bottomhole pressure is the goal for every gas well, the paradigm should be to never run anchors unless their necessity has been proven. Combining rod guides, a properly designed rod string and an effective corrosion program usually offset the wear issues that can be of concern. Another option is raising or lowering the tubing by the amount of tubing stretch when servicing the downhole pump, which is less than 10 in. when pumping shallower than 8000 ft. This will move the wear to a different point in the casing.

Evaluation of Two Gas Well De-watering Applications

The premise of this paper was that proper design of rod pumping installations for de-watering gas wells would provide up front cost savings as well as ongoing operational cost savings. To support this supposition, two actual installations in Panola County, Texas, were evaluated. Both wells pump intermittently on pumpoff control, producing less than 20 BPD of total fluid from similar depths.

Although both wells are pumping similar volumes from similar depths, the equipment for Well B is approximately twice as large as Well A. Table 1 compares the pumping setup of both. Complete diagnostic analyses were performed by Lufkin Automation for each well, and are presented in Table 2.

To summarize this information, Well A equipment loading was very light, running from a low of 33% on the gearbox to a high of 69% on the structure rating. A case could easily be made that this pumping unit was oversized, and a C-80-109-48 with a 7.5-HP motor would have been a better choice. However, Well B equipment loading was relatively high, ranging from a low of 75% on the structure to a high of 114% (overloaded) on the gearbox. The rod string is also operating at 94.8% load if no safety factor is used, which is a harbinger of rod problems.

The conclusion drawn from this data is that Well B was poorly designed, being overdesigned as far a pump capacity. This additional pump capacity caused higher loads, resulting in higher initial equipping costs and higher operating expenses. The use of 1.06-in. diameter pumps and ⅝-in. diameter rods were the key factors that resulted in Well A's superior design. If your company has an "Engineering Edict" that no rods smaller than ¾-in. diameter will be utilized, this policy should be revisited.

Rules of Thumb

Anyone reading a technical paper is interested in gleaning something useful to assist in their engineering tasks. The case has already been made for smaller pumps and rod strings, as well as foregoing tubing anchors. Can we go a step further into the design realm?

A multitude of computer design runs were made for gas well rod pumping installations at depths to 10,000 ft in 1000-ft increments. The only given parameters were 100% pump displacement of 40 barrels per day, and 1.05 fluid gravity. Often the fluid pumped from a gas well is primarily condensed fresh water and (hydrocarbon) drip, since condensation occurs as warm gas contacts the cool production casing while it rises to the top of the well. In these cases, the 1.05 fluid gravity will yield a conservative design. If there is a mix of oil and salt water, the 1.05 gravity will be close. For heavy saltwater production, it is likely that 40 BPD pump capacity would be insufficient anyway, making these rules of thumb inapplicable.

The results of the many Gibbs' Wave equation-based computer runs have been assembled in Table 3. Six design variables form the columns in this table. The first six columns are the stroke length, recommended pump size, API rod string, motor size, pumping unit geometry, pumping speed and calculated tubing stretch. The last column is a suggestion on whether the pumpoff control method should be based on the surface or downhole pump card.

This table is meant to be used as a starting point to design work, and perhaps as a check to see if final design is close. Significant differences in final design to this table should be scrutinized.

Pumpoff Control

Percentage timers have been used for pumping gas wells, but the cost/benefit ratio of pumpoff controllers make them too valuable not to include on every rod pumped gas well. The primary benefit is the ability to accommodate fluctuating fluid volumes, which is standard for gas wells. Two examples are corrosion treatments (with flush water) and pipeline pressure changes. A compressor shutdown or other event raising line pressure can cut gas flow immediately, and will likewise cut fluid flow. A percentage timer would simply over-pump the well, causing mechanical wear and other problems. Another overlooked benefit is the ability to diagnose downhole pumping problems by having the real time dynamometer information.

In Table 3, there is a column regarding pumpoff control based upon surface or downhole pump card. The shape of a surface dynamometer card undergoes drastic shape changes as pumping depth and pumping speed increases. This is due to the dynamic nature of the load changes combined with the elasticity of the rod string. Accurate identification of incomplete pump fillage from the surface dynamometer card becomes difficult, at which point an evaluation of the downhole pump card is preferred.

The use of a variable speed drive in conjunction with a pumpoff controller offers the ability to exactly match pump displacement with wellbore fluid entry. Continuous operation is better for all components of the system as opposed to cycling, provided accommodations for proper gearbox lubrication are taken. Wear on belts, gears and electrical contacts is minimized when this occurs. As pointed out by Elmer and King,[6] decreasing pumping speed by 50% instead of cycling 50% can reduce rod stress, gearbox torque requirement and energy required per barrel by 16 to 19%.

Summary and Conclusions

1. Utilization of 1.06-in. diameter rod pumps provides for significant reductions in rod loading, with insignificant increases in horsepower and gearbox loading.

2. Utilization of ⅝-in. diameter rods is a best practice at depths to at least 7000 ft.

3. Tubing anchors should not be run unless other methods of negating wear have not proven effective.

4. Pumpoff control based on realtime dynamometer analysis is a "Best Practice."

References

1. API Recommended Practice 11L, "Recommended Practice For Design Calculations For Sucker Rod Pumping Systems," Fourth Edition, June 1, 1988.

2. Jennings, J.W.: "The Design of Sucker Rod Pump Systems," paper SPE 20152 presented at the 1989 Petroleum Technology into the Second Century Symposium at New Mexico Tech, Socorro, NM, October 16–19.

3. Mills, K.N., "Factors Influencing Well Loads Combined in a New Formula," *Petroleum Engineering* (April 1939).

4. Gibbs, S.G., "Predicting the Behavior of a Sucker Rod Pumping System," *JPT*, (1963) 769–778

5. Gott, C.I., "Successful Rod Pumping at 14,500 Feet," *SPE Production Engineering* (November 1986)

6. Elmer, W.G. and King, J.D., "New Oilfield Applications for Electronic Phase Converters/ VSD's," paper SPE 24833 presented at the 1992 SPE Annual Technical Conference and Exhibition, Oct. 4–7.

Table 1. Comparison of Two Gas Well De-Watering Applications

Parameter	Well A	Well B
Pump	1.06 in.	1.25 in.
Pump Depth	5900 ft	6575 ft
Pumping Unit	C114-133-54	C228-213-120
Motor Size	10 HP	20 HP
Rod String	API 55 Grade D	API 66 Grade D
Pumping Speed	9.2 SPM	6.9 SPM
Stroke Length	48 in.	102 in.
Tubing Anchor	None	Present
Tubing Diameter	2.063 in.	2.375 in.
Casing Diameter	4.5 in.	4.5 in.

Table 2. Results of Diagnostic (Dynamometer) Analysis

Observations	Well A	Well B	Difference
Downhole Stroke	28.8 in.	79.8 in.	51 in. (177%)
Pump Capacity	34.7 BPD	100.3 BPD	65.6 BPD (189%)
Motor Load	4.1 HP (41%)	14 HP (70%)	9.9 HP (241%)
Gearbox Load (Bal)	38 M in.-lbs (33%)	259 M in.-lbs (114%)	221 M in.-lbs (581%)
Structure Load	9176 lbs (69%)	15996 lbs (75%)	6820 lbs (74%)
Rod Stress (1.0 SF)	64.9%	94.8%	46%

Table 3. Predicted Acceptable Designs that Provide Minimized Rod Pumping Configurations

Depth	Stroke Length	Pump Size	Rod Taper	Motor Size	Closest Lufkin Pumping Unit	Speed SPM	Tubing Stretch	Surface or Downhole
3000	33	1.06	55 C	3	C-40D-76-42	11.3	1.3	Surface
4000	33	1.06	55 C	5	C-40D-76-42	14.1	2.4	Surface
5000	37	1.06	65 C	5	C-57D-95-48	13.3	3.8	Surface
6000	48	1.06	65 C	7.5	C-80D-109-48	10.8	5.4	Surface
7000	54	1.06	65 C	7.5	C-80D-133-54	10.1	7.4	Downhole
8000	64	1.06	65 D	10	C114D-143-64	9.3	9.7	Downhole
9000	74	1.06	76 D	15	C160D-200-74	7.3	12.3	Downhole
10,000	86	1.06	76 D	15	C228D-246-86	6.8	15.2	Downhole
Minimize SPM to reduce wear cycles								
9000	100	1.06	76 D	15	C228D-213-100	4.7	12.3	Downhole
10,000	100	1.06	76 D	15	C228D-256-100	5.5	15.2	Downhole
Anchor Tubing to stop tubing movement								
9000	86	1.06	76 D	15	C228D-213-86	6.5	0	Downhole
10,000	86	1.06	76 D	15	C228D-246-86	5.9	0	Downhole

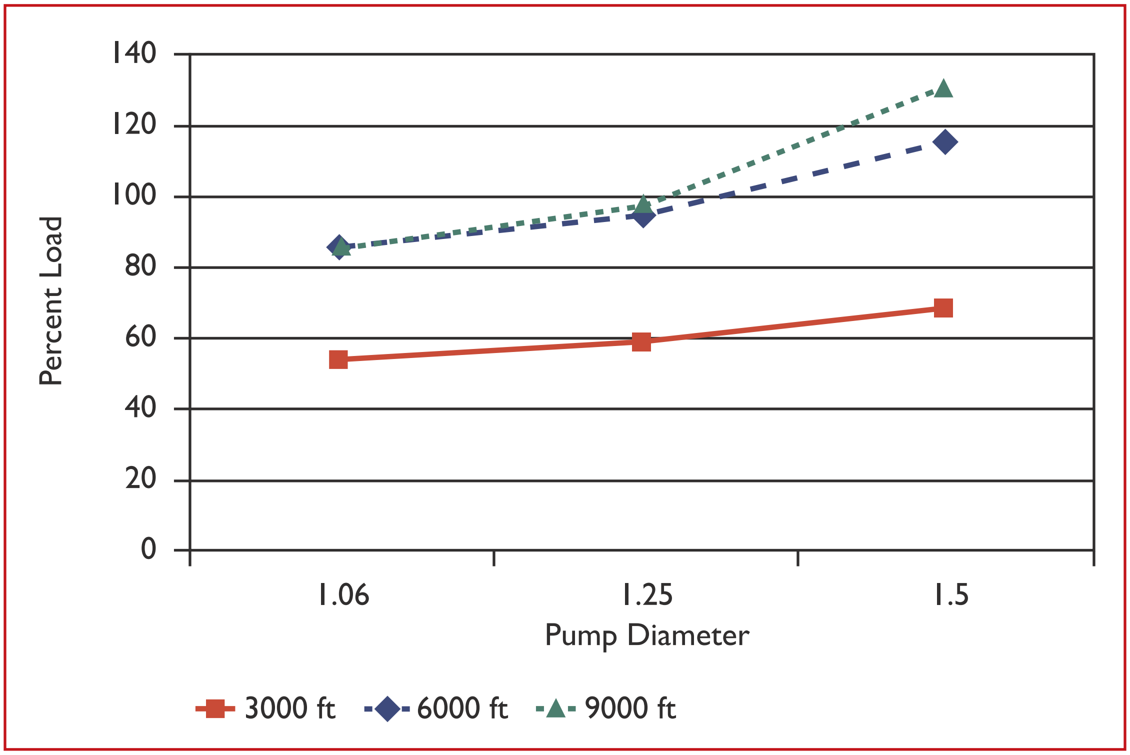

Figure 1. Rod Loading

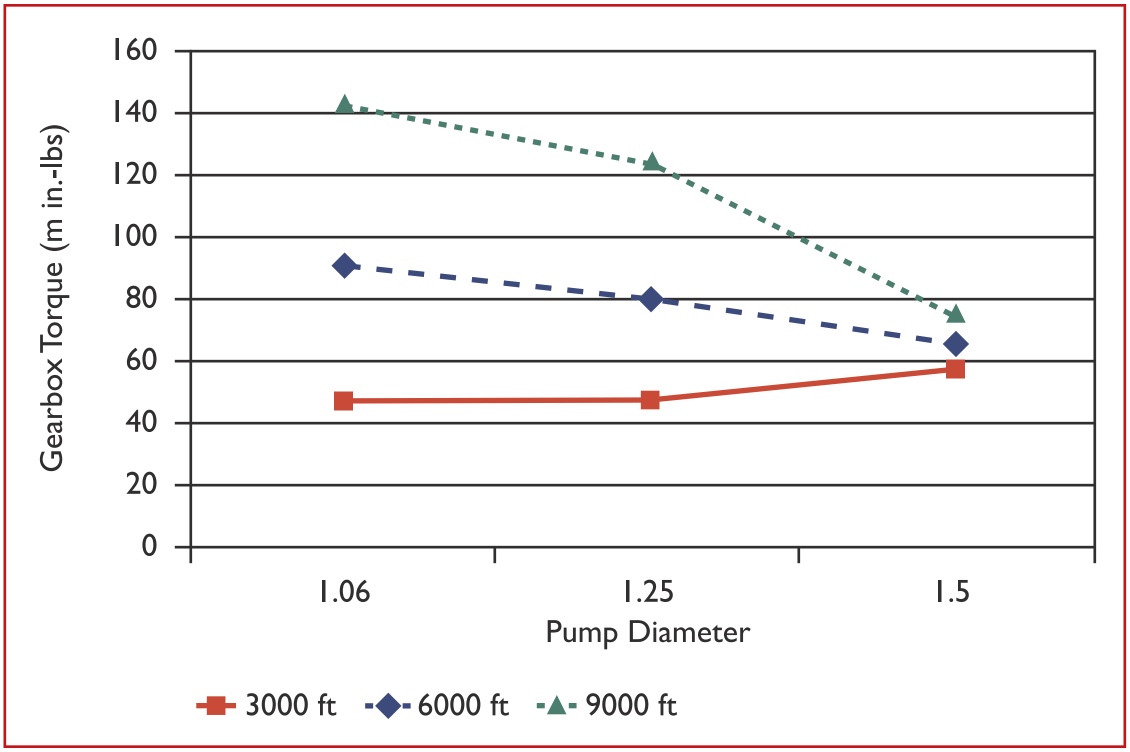

Figure 2. Gearbox Torque Requirement

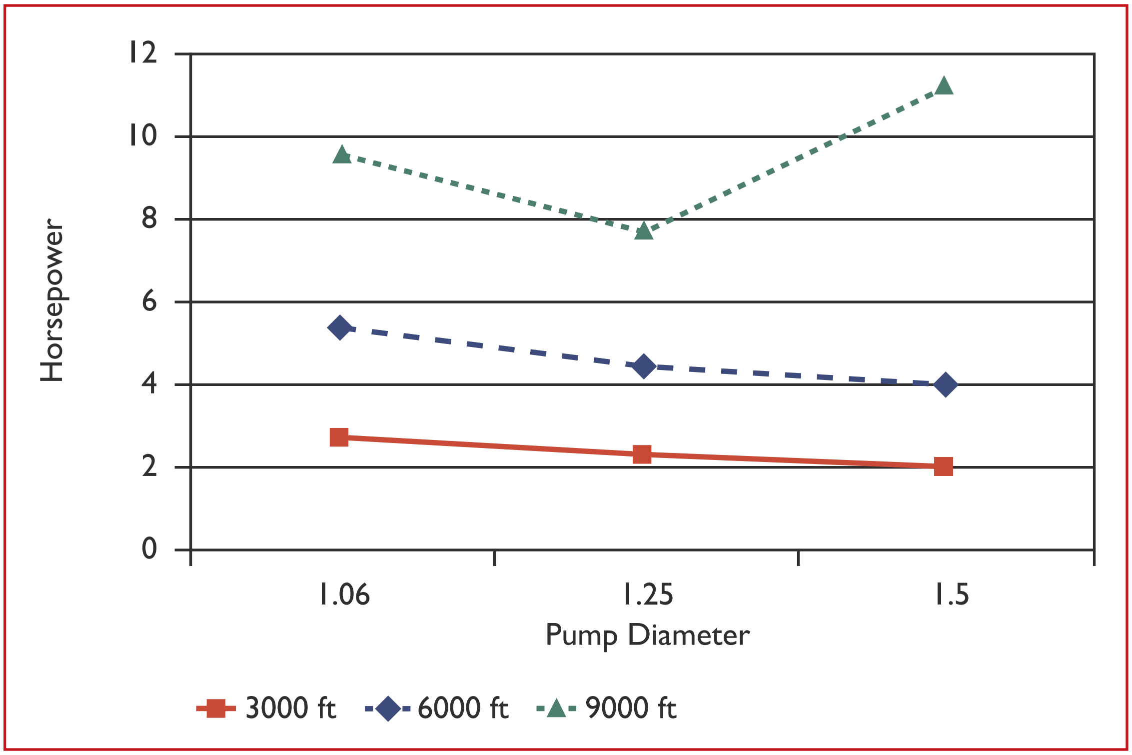

Figure 3. Horsepower Requirement

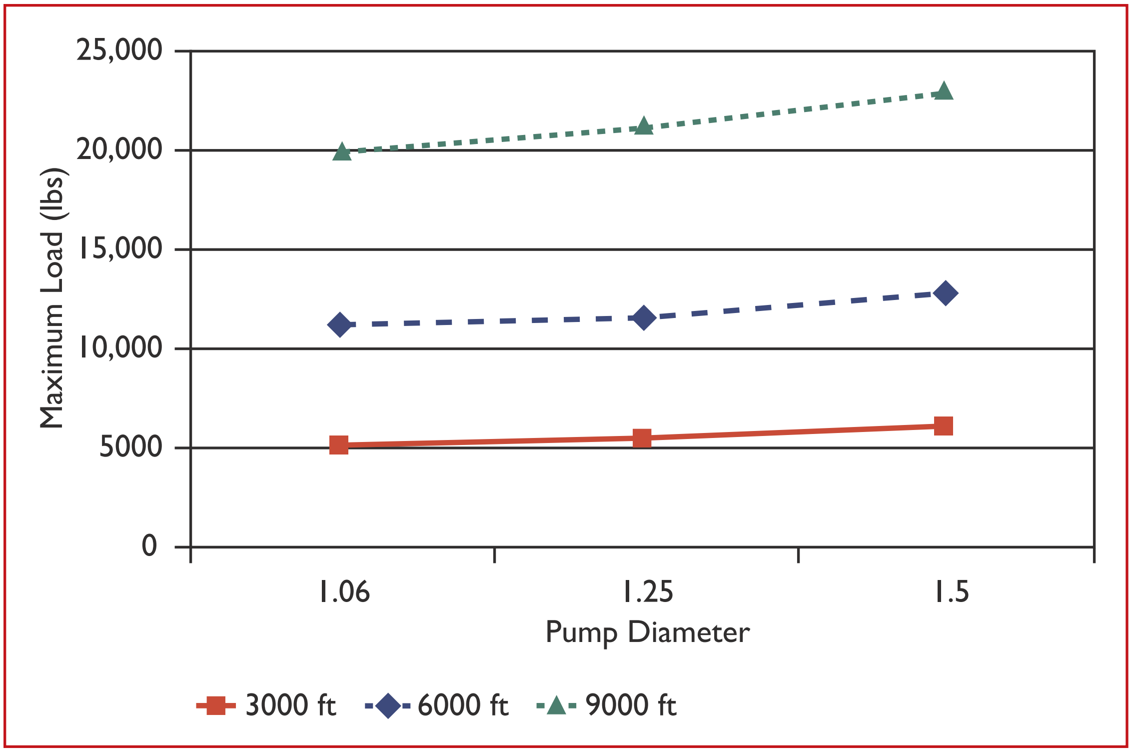

Figure 4. Maximum Surface Load

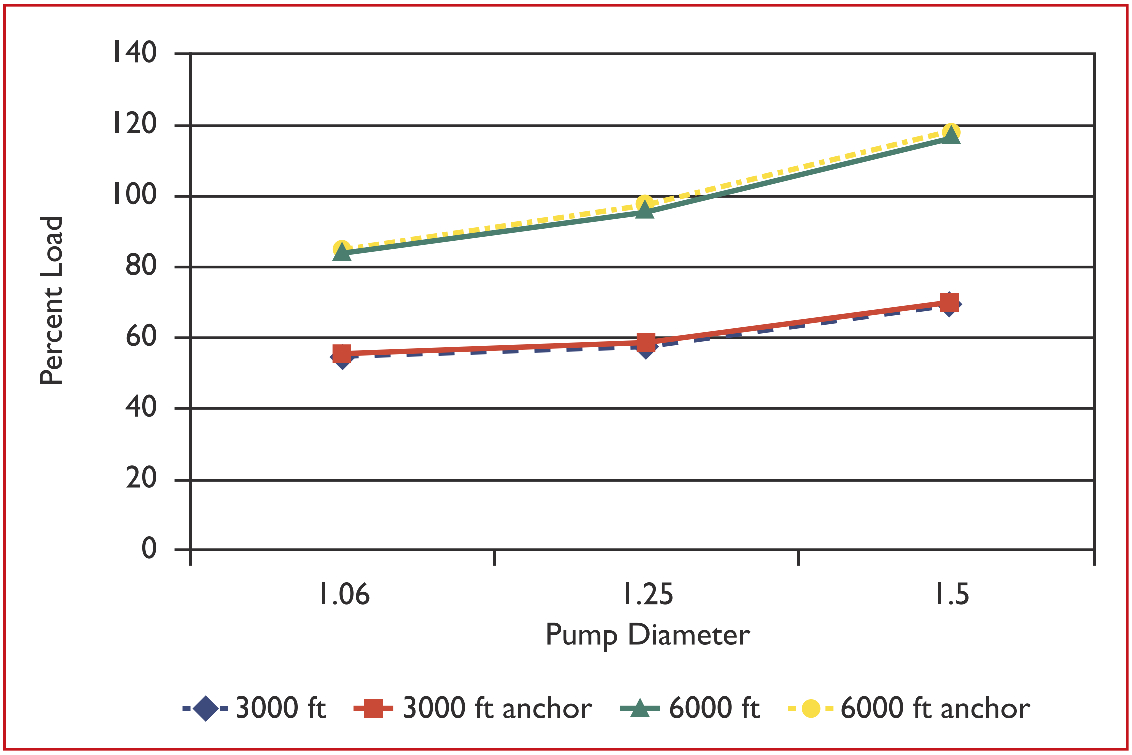

Figure 5. Effect of Tubing Anchor to Rod Load

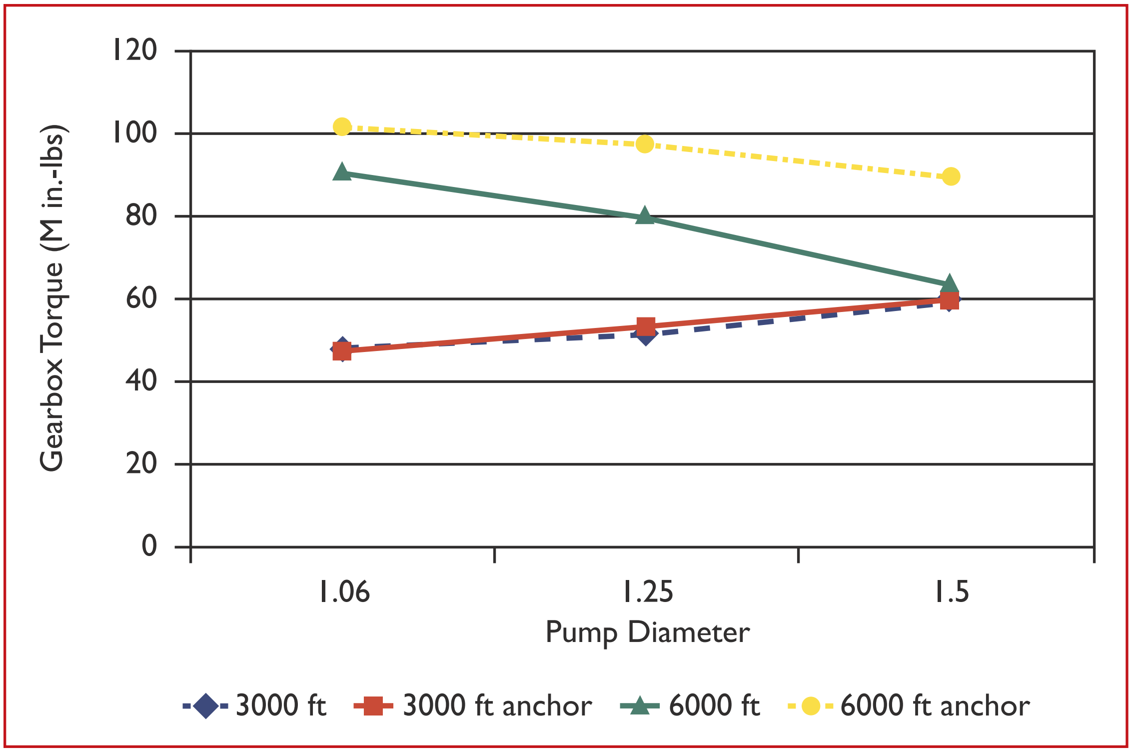

Figure 6. Effect of Tubing Anchor to Gearbox Torque Requirement

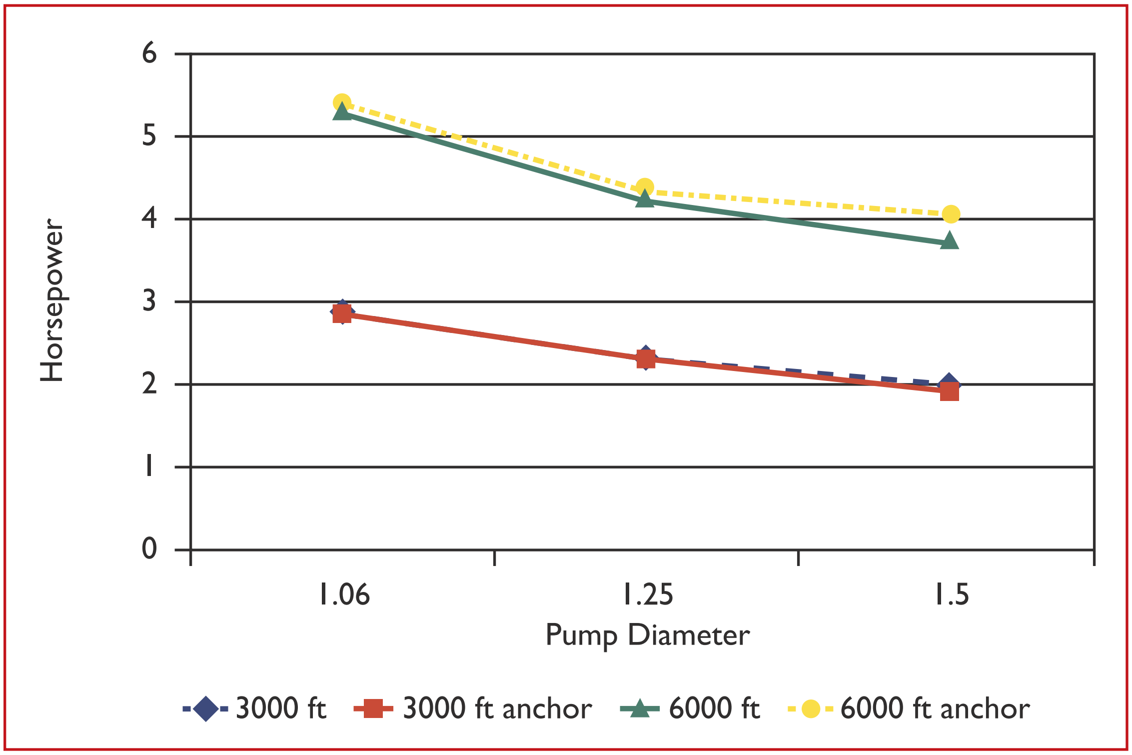

Figure 7. Effect of Tubing Anchor to Horsepower Requirement

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