SUCKER-ROD PUMP SELECTION AND APPLICATION

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Abstract

The most common form of artificial lift is sucker-rod pumping. One of the main elements of rod lift system design is the selection of a downhole pump. This study examines the various factors that affect the selection and design of downhole rod pumps. This paper will examine the following five downhole pump components: barrel, plunger, cages, balls and seats, and seating assembly. Understanding the various well and system design factors that are examined when selecting each of these components is a crucial part in the design of the downhole pump. The dynamics that affect metallurgy, length, diameter, and pump configuration of the critical components are examined within this study. Once the aspects that affect material selection have been evaluated the different applications of API and specialty pumps are considered. By following the procedures and methodology outlined in this study, proper downhole pump selection can be implemented and the risk for premature pump failures is mitigated.

Introduction

In the oil and gas industry the most widely used form of artificial lift is sucker-rod pumping. Sucker-rod pumping typically consists of three main components: the surface unit, the rod string, and the downhole pump. Each of these main components are essential for total system efficiency and also consists of other subcomponents. This paper will discuss the factors and considerations that go into selecting an optimized design for the downhole pump.

Downhole Pump Overview

There are many factors to consider when designing a downhole pump. In the ideal scenario for artificial lift, the well has been drilled with artificial lift in mind, the fluid output of the well is known, pump capacity is equivalent to the reservoir inflow, and the sucker-rod system design is developed in the order of the downhole pump, then rods, and finally the surface unit. However, varying operational or financial circumstances usually prevent this. Oftentimes the wells are deviated during drilling or the pump must be designed around existing equipment which can limit the effectiveness of the pump application. Some of the benefits of a properly designed rod pump are that the fluid level can be reduced and sustained at a manageable level, free gas is directed away from the pump intake or effectively moved through the pump, and entrained gas remains in solution when flowing through the pump. The American Petroleum Institute (API) also has a standard in place that helps with the design of pump components, this is API Specification 11AX. This specification provides a standardization in component dimensions, labeling, and quality control practices. However, API 11AX does not go into the applications of each type of pump or the material selection process. This paper attempts to help readers better understand the application and selection process involved with designing a downhole pump. The main parts of the pump that will be discussed in this paper include the barrel, plunger, standing and traveling valve assemblies, and seating assemblies. Figure 1 shows these key components and where they are located on conventional pumps.

Key Factors of Components

Component selection is affected by a variety of factors including fluid and wellbore characteristics, desired setting depth, and overall bottom-hole assembly (BHA) design. For instance, the bore size of the pump is determined primarily by the desired fluid output. However, casing size, tubing size, pump type, and setting depth can all affect bore size selection as well. In addition, the bore size selected may affect other components of the BHA such as gas separating components, causing them to operate less efficiently. Such is the case with many of the most critical pump components, each of which require thorough analysis of the existing BHA design, if applicable, and the down-hole environment in order to ensure an effective pump design. The following section will examine the different metallurgies, lengths, and other options available when determining the design up the pump.

Barrels

Metallurgy

When determining which barrel to run there are several factors to consider. One of those considerations is which metallurgy to use for the base metal. The options include steel and brass. Steel is often used for pumping conditions where mild abrasion and corrosion are present. Brass barrels can be used in lightly abrasive conditions where there is average to severe corrosion present.

One of the other considerations that needs to be kept in mind when selecting a barrel metallurgy is the possible coatings that can be applied to the base metal to enhance longevity. The two main options are Nickel Carbide (NiCarb) and Chrome coatings. When using a NiCarb finish, the coated surface of the barrel has a smooth, opaque layer on the inner and outer surfaces that increases corrosion resistance. However, if solids are present within the well, there is an increased possibility for the plunger to become stuck in the barrel. The NiCarb coating consists of carbide particles suspended uniformly throughout a nickel matrix. The carbide particles, being very hard and irregularly shaped, create a much higher coefficient of friction than other coating options like chrome. When solids are introduced, the NiCarb coating has a tendency to "bite", leading to the plunger becoming stuck in the barrel. For pumps where corrosion is a severe issue or if the well is being acidized without pulling the pump, then a Brass NiCarb barrel is recommended for use. Chrome plating on barrels results in a hard, mirror like finish on the inner diameter of the barrel. This plating can greatly improve the run times of pumps in wells with moderate to severe abrasion problems. The limiting factor on chrome plating is the amount of corrosion present within the well. For wells with lower amounts of corrosion and high amounts of solids, a Steel Chrome barrel is recommended. A side-by-side comparison of the relative corrosion, abrasion, and burst ratings can be seen in Figure 2.

Size

Barrel size is an important detail to consider when designing a downhole pump. The barrel displacement is selected primarily based on the required production values and tubing size. The goal is to meet or exceed reservoir inflow to most efficiently lift what the formation provides. In order to meet this goal, two variables need to be determined: the pump bore diameter and the barrel length.

The pump bore diameter, or barrel ID, can be calculated using Equation 1 shown below. In order to determine the pump constant, use the maximum expected production divided by the product of the stroke speed and surface stroke length. This value is the pump constant. This pump constant directly correlates to the pump bore needed for the maximum expected production. Figure 3 shows the plunger constant for different pump bores. In the event the pump constant does not match with a plunger diameter, round the pump constant up to the next pump bore.

$$Pump\ Constant = \frac{Theoretical\ Production}{SPM * Downhole\ Stroke\ Length} \qquad Equation\ 1$$

Once the pump bore has been calculated, the length of the barrel and barrel extensions can be calculated. To calculate the length of the barrel, Equations 2 and 3 must be used. Equation 2 shows the relationship between the surface stroke length, rod stretch, and the downhole stroke length. Equation 3 takes the calculated downhole stroke length and shows the calculation needed for both the barrel length and overall pump length.

$$Surface\ stroke + Rod\ Stretch = Downhole\ Stroke\ Length \qquad Equation\ 2$$

$$\begin{aligned} &Downhole\ Stroke\ Length + Plunger\ Length = Barrel\ Length + Extension \\ &= Pump\ Length\ (rounded\ up\ to\ the\ next\ even\ numbered\ foot) \qquad Equation\ 3 \end{aligned}$$

Plungers

Metallurgies

Like barrels, plungers come in several different metallurgies that can be applied to different downhole conditions. The main metallurgies that are considered are carbon steel, spray metal, and chrome plated plungers. As can be seen in Figure 4, a carbon steel plunger is only recommended for mild well conditions where there is little corrosion or abrasion. Spray Metal plungers are recommended for wells with excessive amounts of solids and above average corrosion. The spray metal is a hardened material that is flame sprayed with a nickel base creating a hard coating on the plunger. Chrome plated plungers are very resistant to abrasion but are only recommend when there is little to no corrosion downhole. Additionally, consideration must be taken to ensure the plunger metallurgy is compatible with its barrel counterpart. Using the same coating on both the barrel and plunger can lead to a seized pump.

Lengths

Again, like barrels, the length of the plunger is a key factor that will be determined while designing the pump. Commonly the length will range between 3 and 6 feet, but plungers with lengths of 8 or more are also run in certain circumstances. The general rule of thumb for the plunger length is that for pump depths less than 3,000 feet, a three-foot plunger is recommended (Gabor, 2015). For wells with depths between 3,000 and 6,000 feet, the rule of thumb is one foot of plunger length per one thousand feet of depth (ie; 5,000-foot depth = five-foot plunger). For depths of greater than 6,000 feet, a plunger length of six feet is recommended unless conditions require a different length (Gabor, 2015).

Grooved, Smooth, or Pressure Actuated Plunger

The next factor to consider when determining the type of plunger to select is whether to run a grooved, smooth, or pressure actuated plunger. Grooved and smooth plungers are depicted in Figure 5. In wells with few to no solids, a smooth body plunger is recommended. The grooved body plunger has grooves machined every six inches along the plunger body. These grooves will allow for solids to be collected and deposited outside of the barrel preventing abrasion cutting throughout the length of the plunger. While abrasion cutting could still occur on the plunger, it will be limited to the first one or two grooved sections from the top extending the usage life. In a pressure actuated (PA) plunger, there are small rings placed into grooves on the plunger. On the upstroke, the rings will swell outward and reduce the clearance between the rings on the plunger and the barrel. This leads to a reduction of wearing and scoring on the barrel as well as preventing the plunger from seizing in the barrel. PA plungers are typically recommended to be run in wells that have recently been completed, are expecting an increase in solids from an offset frac, or have trash in the wellbore.

Fit and Slippage

Two more important terms when selecting a plunger are the clearance, or “fit,” and pump slippage. The fit of the plunger is the clearance between the OD of the plunger and the ID of the barrel. Pump slippage is the term used to describe when produced fluid falls (or slips) between the plunger and the barrel back down below the plunger. Pump slippage will directly affect the efficiency of the pump. 2-3% pump slippage is required to lubricate the action of the pump. Overall, in the Permian Basin, plungers typically fall between 4-6 feet in length with a standard fit between 0.005 to 0.008 inches.

Cages, Balls, and Seats

Cage Metallurgies

Once the barrel and the plunger have been selected, it is time to examine the cages, fittings, balls, and seats for the traveling and standing valves. The metallurgy of each is the main variable that is selected in the design for these components as the size will be based primarily on the pump bore. Cages can be either machined or insert guided and can be made up of other metallurgies than the cages themselves.

The metallurgies that are currently available for the cages are plain steel, stainless steel, Monel, brass, alloy, and hard-lined improved cages.

Plain steel cages will, most often, be the most inexpensive option. However, these cages should only be used in mild to average pumping conditions where abrasion and corrosion are not a problem. Stainless steel cages come in two separate materials. Stainless 304 and Stainless 316. Stainless 304 has increased corrosion resistance compared to plain steel cages as it provides more corrosion resistance than the plain steel due to the change in metallurgy composition. However, is there is an above average amount of chlorides present in the well, then Stainless 316 will be recommended for improved corrosion resistance due to the higher molybdenum concentrations present in the metallurgy. Brass cages are similar in corrosion resistance to their barrel counterparts and are also relatively susceptible to abrasive conditions. For special applications, specific steel alloy parts can be requested based on unique well conditions. The final option for cage metallurgies that will be discussed here is specifically for guided cages. This option is a hard-lined cage. A hard-lined cage will have a Stoodite 6 lining on the ball guide inside of the cage. This hard-lined guide is available in steel, stainless, and monel cages. By hard-lining the guides in the cage, there will be a higher tolerance to ball chatter as production occurs which in turn will reduce the amount of cage beat-out. A side-by-side comparison of cage metallurgies can be seen in Figure 6.

Ball and Seat Metallurgies

While cages make up one part of both valve assemblies, the ball and seat combination makes up the other part. There are several considerations that need to be taken in to account when deciding the metallurgy for the ball and seat. The first of which is making sure that the material is compatible with the cage and will not lead to impact damages like a beat out cage or a cracked seat. The other is ensuring that the ball and seat metallurgies are compatible with each other. There are scenarios where a certain metallurgy is recommended for the ball while another is used for the seat. One example of this is running a silicon nitride ball paired with a nickel carbide seat. With a more durable or heavier ball, it is recommended to use a more durable seat to prevent wear from occurring in the seat and extend the run life of the valve and also the entire pump. The different metallurgies that will be discussed are stainless steel, alloy, titanium carbide, tungsten carbide, silicon nitride, and nickel carbide. A side-by-side comparison of each of the metallurgies can be seen in Figure 7.

Stainless steel balls and seats are made from a series 400C stainless steel. These balls and seats are quenched and tempered to develop good abrasion and moderate corrosion resistance. Like cages, these are recommended only for less severe well conditions. Alloy ball and seats are a non-ferrous, non-magnetic cobalt-chromium tungsten alloy. This alloy is very hard and handles shock better than their stainless-steel counterparts. These balls and seats have high resistance to both abrasion and corrosion. The next option is a titanium carbide ball and seat. The titanium carbide ball is homogenous throughout due to it being made from a powdered metal material instead of a cast material as found in alloy. A Titanium carbide ball and seat will typically have a Rockwell hardness rating of 90 and is more abrasion and pitting resistant than alloy. Tungsten carbide balls and seats have excellent abrasion and corrosion resistance and are recommended when pumping wells with the most abrasive fluids. A silicon nitride ball is a much lighter alternative than the previously mentioned alternatives. It also has the highest mechanical strength, fracture toughness, and resistance to deformation either through corrosion or abrasion. This metallurgy is currently only available for the ball. The final option that will be discussed is the nickel carbide metallurgy. This material is best suited for wells where both corrosion and wear resistance are required. This material is suited for more impact resistance when compared to other nickel grades. It is also the recommended seat when using a silicon nitride ball due to its impact wear resistance.

Specialty Valve Sizes and Combinations

Another option to consider when determining the valve design are the sizes of the valve and whether to run a single or double valve assembly. The double-valve assembly is recommended for wells containing solids that may cause the pump to “miss a stroke”, meaning a valve is held open for one stroke and production is lost. The secondary valve in the double-valve assembly picks up any potentially lost strokes and maintains production levels. This configuration may not be appropriate for wells experiencing gas interference as the second traveling valve reduces the overall compression ratio of the pump.

Oversized cages are available for standing valves only. The larger flow area of these cages, particularly when used in conjunction with alternate pattern balls, reduces the pressure drop as the fluid passes through the standing valve. This helps to mitigate gas interference and increase pump efficiency in wells with entrained gas, or gas dissolved in the production fluid.

Alternate pattern balls are simply balls that are slightly smaller in diameter than their API counterparts. They are intended for use on the same size seat as the appropriate API ball. The primary purpose of this design is to increase the flow area through the cage and decrease the likelihood of gas interference.

<u>Seating Assemblies</u>

One of the other choices that needs to be made when designing a downhole pump is what style seating assembly (or hold-down) to use. There are two locations on the pump that the seating assembly can be placed, either the top or the bottom. The other option when selecting a seating assembly style is whether to run a cup or mechanical type hold-down. This section will discuss the factors that are used when determining what style seating assembly needs to be selected.

Mechanical or Cup Type

Seating assemblies commonly come in one of two forms, either mechanical or cup type. Figure 8 shows both styles side-by-side. The cup type seating assembly is the most versatile option for any pump design. This design holds 2-6 (traditionally) seating cups tightened onto a mandrel. The seating cups provide the seal against the seating nipple while the upper portion of the mandrel contains an area known as the “no-go” which prevents the assembly from passing all the way through the seating nipple. Cups are available in many materials from hard plastic, which are most common, to the more specialized high temperature and composite cups. Both the material and fit of the cups can be customized to the appropriate application.

The mechanical seating assembly is specifically used for downhole conditions with excess temperatures. The use of a metal seating ring rather than cups on the hold-down allows for use in high temperature environments which otherwise would deteriorate plastic cups used with standard cup type hold-downs. A mechanical seating nipple is required when running a mechanical seating assembly.

Seating Assembly Location

The second decision to be made when selecting a seating assembly is where to locate it on the pump. Standardly, this can be run either at the top of the pump or on the bottom. A top hold-down pump is typically recommended for wells with higher amounts of sand and other solids. When the hold-down seals at the top of the pump directly below the pump discharge there is less risk of solids settling causing the pump to stick in the tubing. Also, stagnant fluid around the barrel is eliminated reducing the risk of corrosion. The main limitation of the top seating assembly is depth. When the seating assembly is placed at the top of the pump, the pressure inside the barrel during operation can far exceed the pressure outside the barrel. This can lead to a burst barrel in deep wells and wells that are pumped off. It is recommended to run this configuration in shallow to medium depth wells with automation in place to mitigate fluid pound. The second location that a seating assembly can be placed is on the bottom of the pump. This allows for an increase in the range of depths that the pump can be run as the operating pressures inside and outside the barrel are essentially equal. This drastically reduces the likelihood of a burst barrel under favorable operating conditions. The drawback to a bottom seating assembly is that if there are increased amounts of solids, there is a higher possibility of the pump becoming stuck in the tubing and the well intervention crew not being able to unseat the pump. However, pump accessories like brushes or rubber seals exist to place at the top of the pump below the discharge to mitigate solids accumulation around the pump.

API and Specialty Pumps

The previous section of this paper discussed several of the options for each of the components that make up downhole pumps. This next section will discuss both API style pumps as well as provide examples of specialty pumps that can be used when more specific applications are required for wells. The various metallurgies, hold-downs, and other options are still available when determining which style of pump to use. This section will first walk through the API style pumps and explain the nomenclature used in the API naming convention. It will then explain several examples of non-API pumps and how they can be applied to specific well conditions to extend a wells average run-time.

API Pumps

Before describing each of the six main API style pumps, it is important to understand the API pump naming convention. When naming a pump there are 10 numbers used broken down into seven sections. Figure 9 shows the different options for each of the sections and Equation 1 shows an example of an API pump designation.

$$25 - 150 - RHBC - 24 - 5 - 2 - 2 \qquad Eq. 4$$

The first section (25) describes the tubing size that will be used downhole. In this case the designation shows that 2.875" tubing is being used. The second section describes the pump bore. There is no limit to the number of options that can be used but it will describe the diameter of the pump. In this case the number shows 150 which means it is a 1.50" pump. The third section is subdivided into four subsections, one for each letter. The first letter explains which type of pump is being used. R is used for a rod (or insert) pump and T is for tubing pump. The second letter explains the type of barrel being used. The three most commonly used types are H, W, and X. The third letter explains the location of the seating assembly. The fourth and final letter explains the type of seating assembly used. In this example, there is an insert style pump with a heavy walled barrel and a bottom cup-style seating assembly. The fourth and fifth sections are the length of the barrel and plunger (in feet) respectively. The sixth and seventh sections denote the lengths of the upper and lower extensions in feet respectively. In summary, this example shows that this pump is in 2.875" tubing with a 1.50" bore. It is an insert style pump with a heavy walled barrel and a bottom cup type seating assembly. The barrel and plunger are 24 and 5 feet respectively with a two-foot extension on both the top and bottom of the pump. The six types of pumps that will be discussed in the following section are RWAC, RHAC, RWBC, RHBC, RWTC, and THBC type pumps. The discussion will focus on the type of pump being used rather than the length, tubing size, and pump bore as those will vary and require more specific discussion based on the well conditions present.

RWAC & RHAC

The first two types of pumps that will be discussed are the insert style pumps using both thin and heavy walled barrels with top cup type seating assemblies. The purpose of this section is to highlight the applications of seating assemblies located on the top of the pump. The RWAC and RHAC pumps are typically best suited for sandier wells because it prevents sand from building up around the barrel resulting in potential for a pump stuck in tubing. It is not recommended to use these pumps in deep wells.

RWBC & RHBC

The next two pumps that will be discussed are the RWBC and RHBC API pumps. These focus of this section is to examine the advantages of the bottom cup-style seating assemblies. These pumps are suitable for wells of any depth. With the entirety of the pump located above the seating nipple and inside the tubing string, the pressures inside and outside the barrel are approximately the same. This reduces the likelihood of a burst barrel during operation. There are several disadvantages to these types of pumps however. The main disadvantage of a bottom hold-down pump is that the barrel is subject to corrosive attacks. It is recommended to use on of the more corrosive resistant metallurgies in wells where this may become an issue. The second disadvantage is that tubing erosion may occur as the pump will be located above the seating nipple inside of the tubing. Finally, the barrel of the pump may also be subject to corrosive attacks. It is recommended to use one of the more corrosive resistant metallurgies discussed earlier in wells where this may become an issue.

RWTC

The fifth type of pump that will be discussed is the RWTC pump. This pump is a rod (or insert) style pump with a thin walled barrel and bottom cup style seating assembly. The difference between this pump and the RWBC is that the barrel moves around the plunger while the plunger remains stationary. This type of pump is recommended for sandy wells or in wells where intermittent pumping is occurring. With the barrel moving instead of the plunger, any trash or solids in the well are kept in suspension allowing the pump to move them more efficiently. The main limitation to this pump is that it is not recommended for gassy wells, wells with low fluid levels, or deep wells. Due to the barrel moving, the unswept area of the pump increases. As the unswept area increases in the pump, the compression ratio decreases and possibility for gas interference increases. This may lead to more extensive damage to the pump, rod string, and tubing. In wells with low fluid levels, the same concept applies with fluid pound occurring in place of gas interference. Finally, these pumps are not recommended for deep well applications due to the thin walled barrel.

THBC

The final type of API pump that will be discussed is the THBC pump. This is a tubing style, heavy walled pump with a bottom cup-style seating assembly. The primary difference between a tubing and insert style pump is that the barrel of a tubing pump is considered another joint of tubing and is connected directly to the tubing string. The travel assembly is run directly on the rod string. These pumps are good for high fluid production because of their much larger displacement compared to an insert pump. These pumps are primarily recommended for use only in shallow to medium depth wells. The THBC pump has two primary limitations. It is not recommended for gassy wells due to the design of the pump allowing for more gas expansion in the pump. This in turn can lead to severe gas interference within the pump. The second limitation to the tubing pump is that they are more costly to service than a rod pump. This expense comes from workover costs as the entire tubing string needs to be pulled instead of just the rods for an insert pump.

Specialty Pumps

The previous section highlighted six of the API standard pumps. While the applications for these pumps extend over most situations, there are other well conditions that may require additional measures to be used to keep the well producing. This section will provide two examples of other styles of pumps that can also be used.

Sand Diverter

The first example of a specialty pump is the sand diverter pump. A sand diverter pump is used in wells with excessive amounts of solids that may be pumping intermittently. Another benefit of sand diverter pumps is that they are not limited by the depth of the well. The concept behind this style of pump is that the clearance is reduced due to a beveled leading edge between the plunger and the barrel directing solids away from this area. This mitigates scoring which leads to lost production. An example of the top plunger adapter that is used and an external seat plug can be seen in Figure 10. This concept also applies to intermittently pumping wells as the reduced clearance prevents solids from settling out of the fluid and between the barrel and the plunger when the well is idle.

Like the API style pumps, there are limitations to this design. The external seat plug that reduces the clearance on the bottom of the plunger increases the spacing between the bottom of the traveling valve and the top of the standing valve reducing the compression ratio. This leads to an increased possibility of gas interference occurring within the pump.

2-stage HVR

The 2-stage HVR pumps has become widely used across many regions because of its unique differences from a conventional valve rod pump. The 2-stage HVR pump has improved gas and solids handling capabilities compared to most of the standard API pumps due to two key components. Instead of using a solid valve rod, a hollow valve rod, or pull tube, is used. This pull tube allows for solids to flow through the pump instead of being released in an area where it can fall back in between the plunger and the barrel. The second key design change to this pump is that there is a three-wing open cage located at the top of the pull tube. An example of a three-wing cage can be seen in Figure 11. This three-wing cage reduces the hydrostatic load on the lower traveling valve allowing for the ball to unseat more easily, reducing gas interference. The upper traveling valve creates a second compression chamber which compresses on the upstroke further improving gas handling capabilities.

Conclusions

The downhole pump is one of the three main components that makes up a rod-lift system. In understanding how the different components work together and selecting the proper design, the operator can better optimize rod-lift systems for enhanced performance. This paper examined the different key factors that are used in the selection of pump components and their metallurgies as well as the standard API and specialty pumps.

References

Gabor, T. (2015, May 2). Sucker-Rod Pumping Handbook: Production Engineering Fundamentals and Long-Stroke Rod Pumping. Gulf Professional Publishing. Print.

Figures

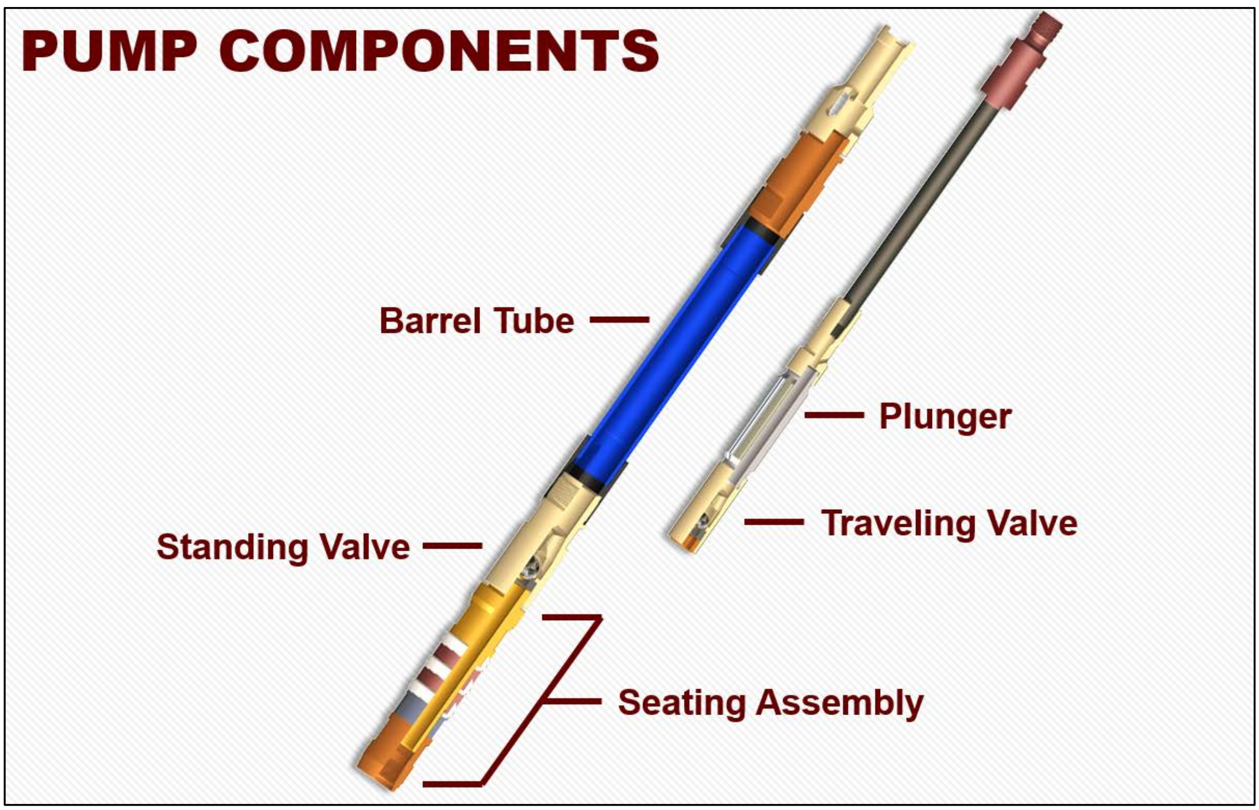

Figure 1 shows the five key pump components and where they are located on some pumps

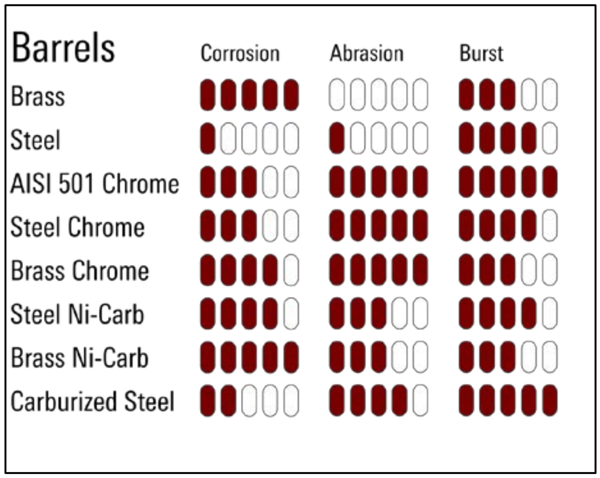

Figure 2 shows the various metallurgies and their overall corrosion, abrasion, and burst rating comparisons

PLUNGER DIAMETER	CONSTANT "C"
1 1/16"	0.132
1 1/4"	0.182
1 1/2"	0.262
1 3/4"	0.357
2"	0.468
2 1/4"	0.590
2 1/2"	0.728
2 3/4"	0.881
3 1/4"	1.231
3 3/4"	1.639

Figure 3 shows the plunger diameter for each pump constant calculated

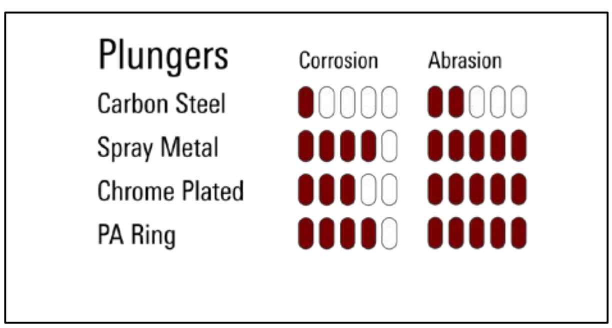

Figure 4 shows the different metallurgies available for plungers

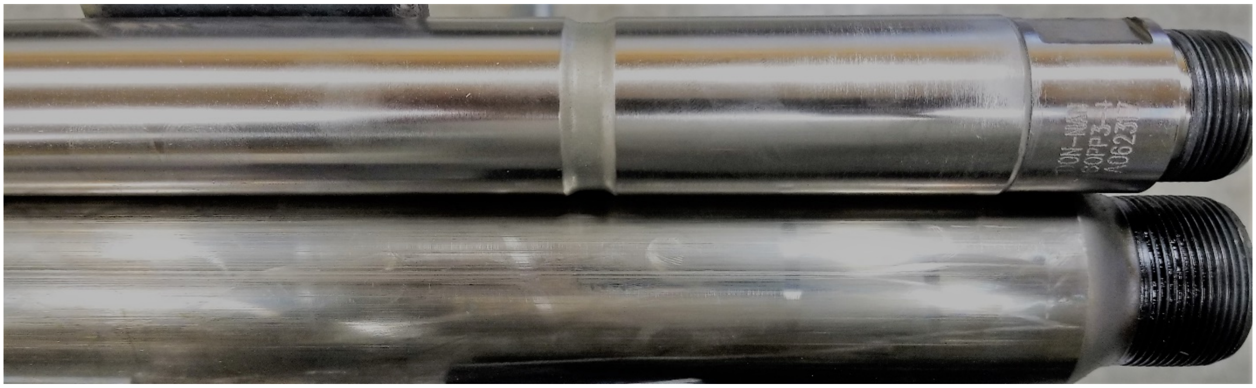

Figure 5 shows the difference between a grooved (Top) and smooth body plunger.

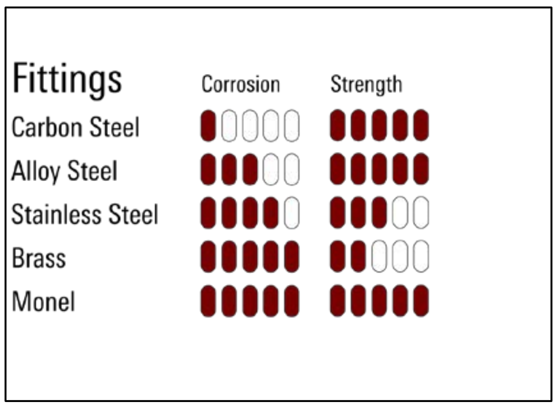

Figure 6 shows the different metallurgies available for fittings that are used on the pumps. These fitting metallurgies also include cages for the standing and traveling valves

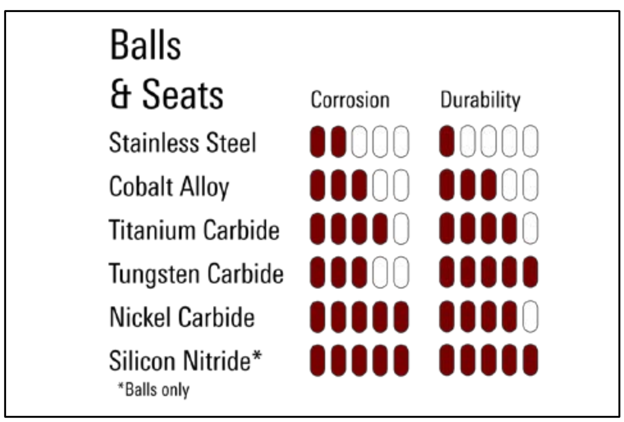

Figure 7 shows the metallurgies available for balls and seats

Figure 8 shows a side-by-side comparison of seating assemblies. The mechanical style seating assembly (top) is for high temperature applications while the cup style assembly (bottom) is the more common selection

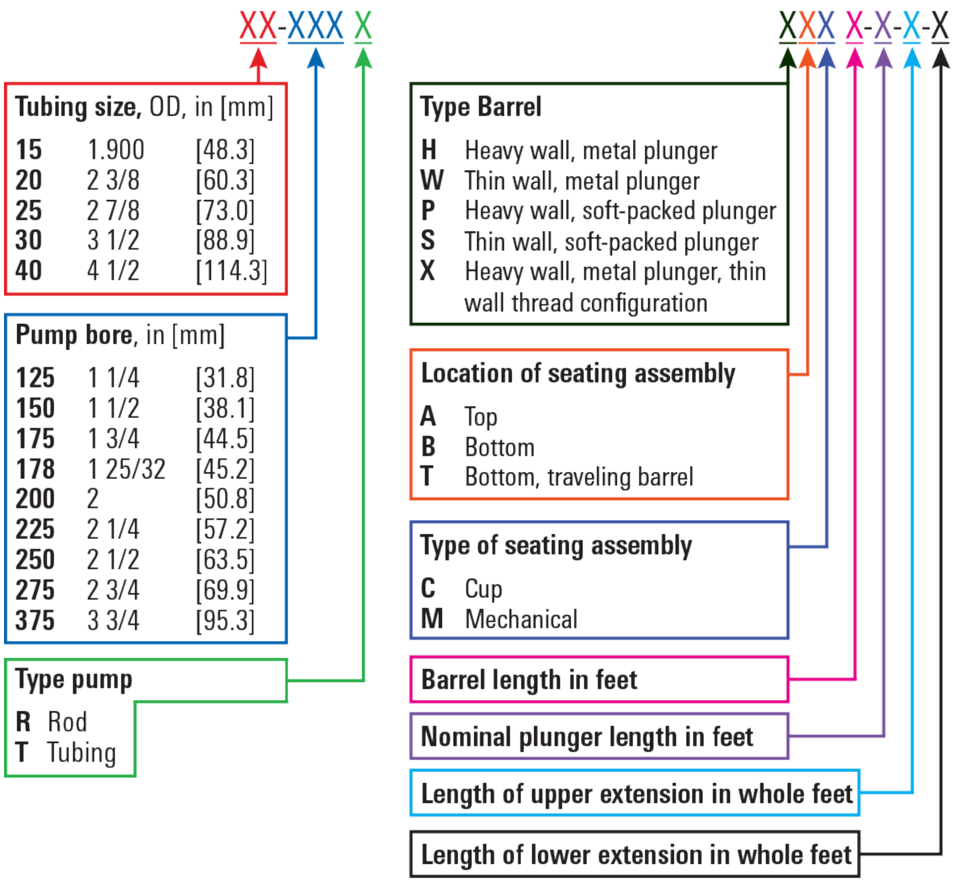

Figure 9 shows each of the API sections and details for each

Figure 10 shows an example of the external seat plug and top plunger adapter used in Sand Diverter pump applications

Figure 11 shows a three-wing cage used in both sand diverter and 2-stage HVR designs