BEST PRACTICES OPERATING ELECTRICAL SUBMERSIBLE PUMPING (ESP) SYSTEMS IN UNCONVENTIONAL ENVIRONMENTS TO MAXIMIZE RUN LIFE GOALS

J. Fernandez, A. Adenuga.
ChampionX

ABSTRACT

Unconventional reservoirs bring new challenges for electrical submersible pumping (ESP) systems, such as rapid decline and high gas production. These conditions can create obstacles to efficiently produce wells and the industry is continuously looking to improve ESP performance. This study analyzes the performance of successful ESP applications installed to produce from unconventional wells and to increase run life in the Permian basin, Delaware basin, and Midland basin.

Unconventional wells present challenging conditions and prolonging the life of an ESP is critical. Correct sizing of the application, operating the system, and optimizing the well are key factors to maximize ESP run time.

This paper will present clear guidelines about how to operate the ESP equipment to maximize efficiency.

INTRODUCTION

Electrical submersible pumping (ESP) systems is a technology that requires serious commitments from the oil producer (operator) with their production engineers, artificial lift subject matter experts, field operators, the ESP company (provider), ESP applications engineers, optimization engineers, sales representatives, and everyone involved in the operation of the ESP to make it successful, especially when installing the system to produce unconventional wells. This paper is focused on the operation of ESPs in the Permian, Delaware, and Midland basins but also applies to any unconventional environment.

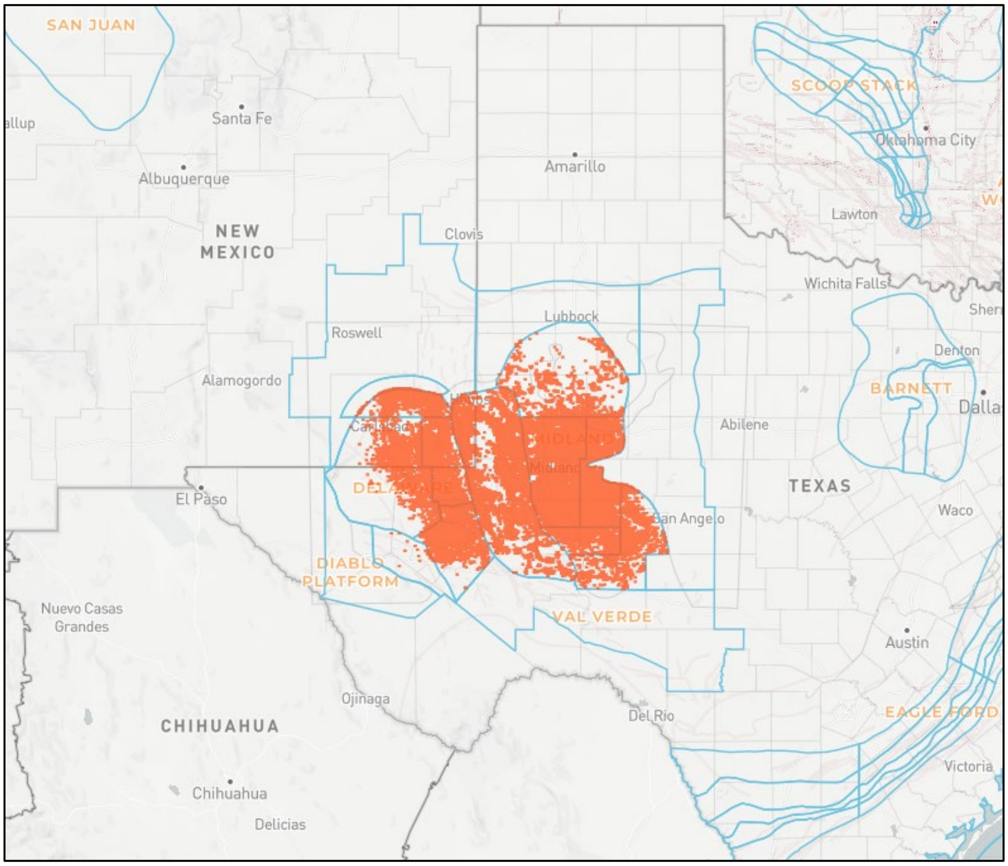

Figure 1- Permian basin

When operators evaluate an oil well to produce using an ESP and request a sizing for a unit, that is when this process and relationship begins, providing the most accurate information of the well history and expectations. Then, the unit needs to be sized fitting these expectations, reviewed by the operator, and agreed on the proposal to be deployed.

Once the unit is installed, the teams in charge of operating the unit from both the operator and the ESP provider need to be aligned on the production targets, how fast the well will be drawing down, optimizing the ESP, and actions to take during troubleshooting.

We will have a successful ESP application and improve the run life when we know the job doesn’t finish after installation. In fact, it is the opposite, the relationship and commitment between the parties starts with the design and installation of the equipment and continues during the whole life of the ESP equipment until the “run life cycle” is closed.

UNDERSTANDING THE ESP RUN LIFE CYCLE

The run life cycle starts with the design of the ESP system based on the given conditions. This is crucial for the success of the ESP application. Inaccurate well data or missing information needed when the ESP is being sized, could cause a potential early failure of the equipment. Preventing early failures is why it is very important to follow the proper steps to determine what the best equipment arrangement is for the well.

It is key to capture the following data when sizing an ESP system; completed well data sheet, historical production data, deviation survey report, wellbore diagram showing perforations depths, liner hangers, and any other relevant information that may obstruct or interfere with the ESP equipment, well history and challenges; well solids production, corrosion, power quality, etc.

Historical production and downhole pressure data helps determine and predict productivity declination.

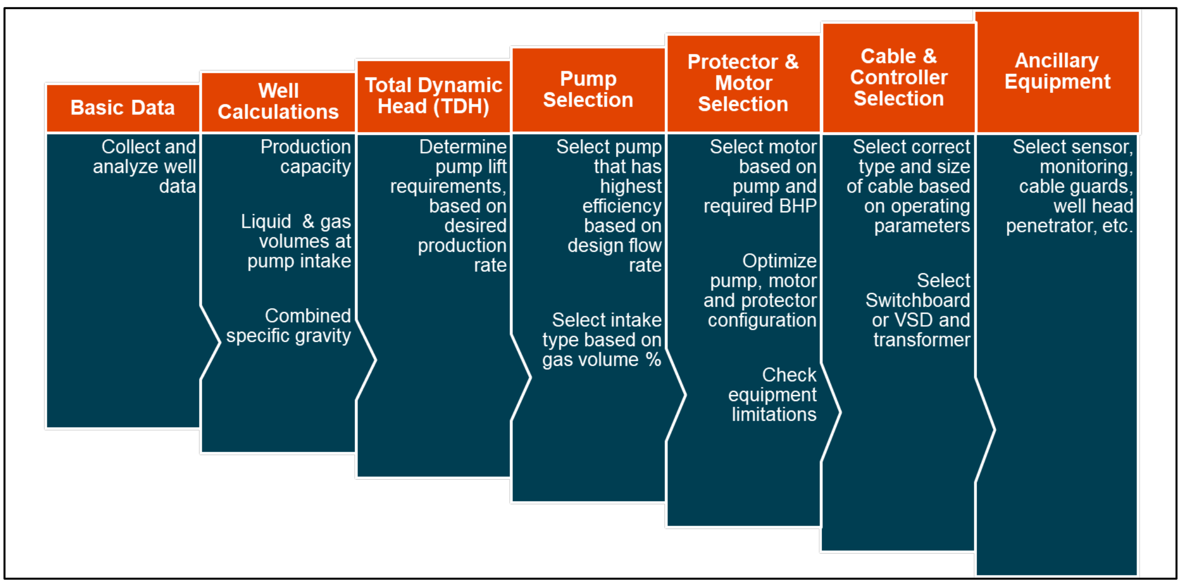

Figure 2- ESP application / sizing process

After the unit is sized to the given well conditions, it must be installed and started up following the ESP company procedures to ensure the equipment is safely landed at the desired pump setting depth. During the operation time of the ESP, the unit requires a lot of care and "babysitting" to ensure it operates smoothly and overcomes different challenges, such as, high gas production, gas slugs, and rapid production decline.

During the lifetime of the ESP equipment, important decisions need to be made; such as the most efficient operating mode, the monitoring and optimizing of the wells to prevent repetitive shutdowns, and the action plan if troubleshooting is needed. The challenges the equipment will encounter running in an unconventional environment may affect the run life. The most common challenges we have seen in the Permian basin are excessive gas production, gas slugs, well solids in the different forms, including but not limited to formation sand, frac sand, iron sulfide, scale and corrosive environment. We will discuss these challenges and how to solve them later in the paper.

After the ESP failure, the equipment is retrieved from the well and the biggest opportunity we have to learn more about the application and operation of the ESP equipment. A DIFA (Dismantle Inspection and Failure Analysis) is performed on the ESP, allowing the team to determine what caused the failure, implement corrective actions, and possible changes for the next ESP design before re-installing the new equipment.

Every subsequent installation will likely be more challenging for an unconventional ESP application as the well gets mature with lower production liquid rates, lower downhole pressure, and higher gas production. The team involved taking the decision to re-install the ESP unit will need to account for all these conditions before designing the new unit.

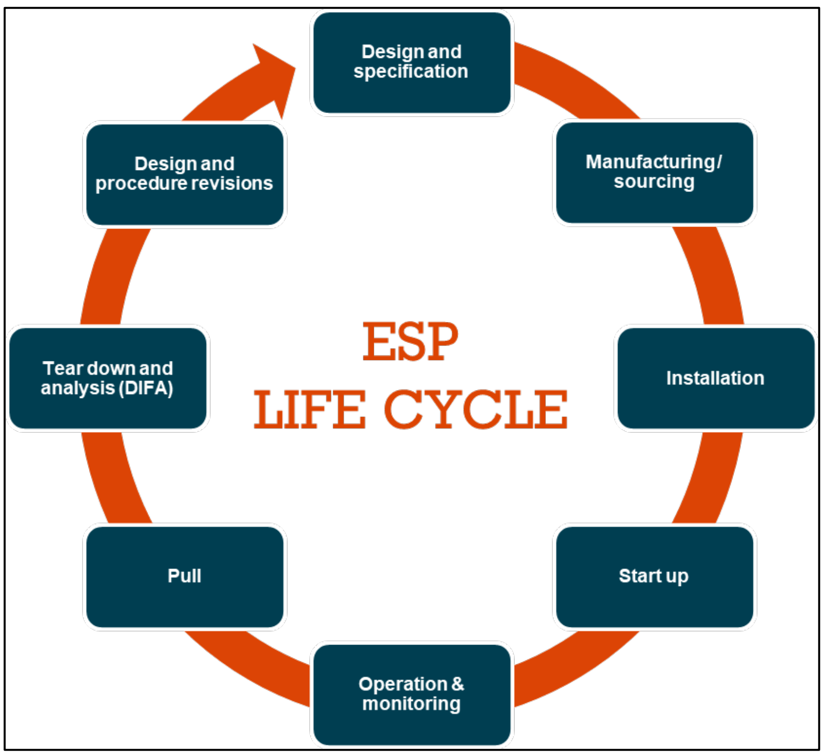

Figure 3- ESP life cycle

<u>CHALLENGES AND EFFECTIVE SOLUTIONS PRODUCING FROM UNCONVENTIONAL RESERVOIRS</u>

Rapid production declination

Wells producing from unconventional reservoirs decline the liquid rate very fast and this is important to consider when sizing the ESP equipment, it needs to be prepared to handle the initial production that will eventually be in a new drill, it will probably flow naturally thru the back side at the beginning. In the Permian basin, we can see wells producing from 3000 BPD to 4500 BPD or more at the beginning of their production life and later drop the liquid rate to 500 BPD – 700 BPD before the first 12 months.

If the pump is not ready for this fast-changing conditions, it will soon be "out of range" causing the pump to over head and can be oversized very quickly, requiring the team to downsize the equipment soon after the installation.

At the same time, with the rapid declination, we will see an increase on the gas rates and possibly slugging gas. The lower the downhole pressure with higher gas rates, the more difficult for the ESP system to handle gas and stay running. The equipment needs to be design and capable to handle high free gas percentages in the pumps.

Most ESP companies have developed their pump technology to have "extended" production ranges and be capable of handling these conditions.

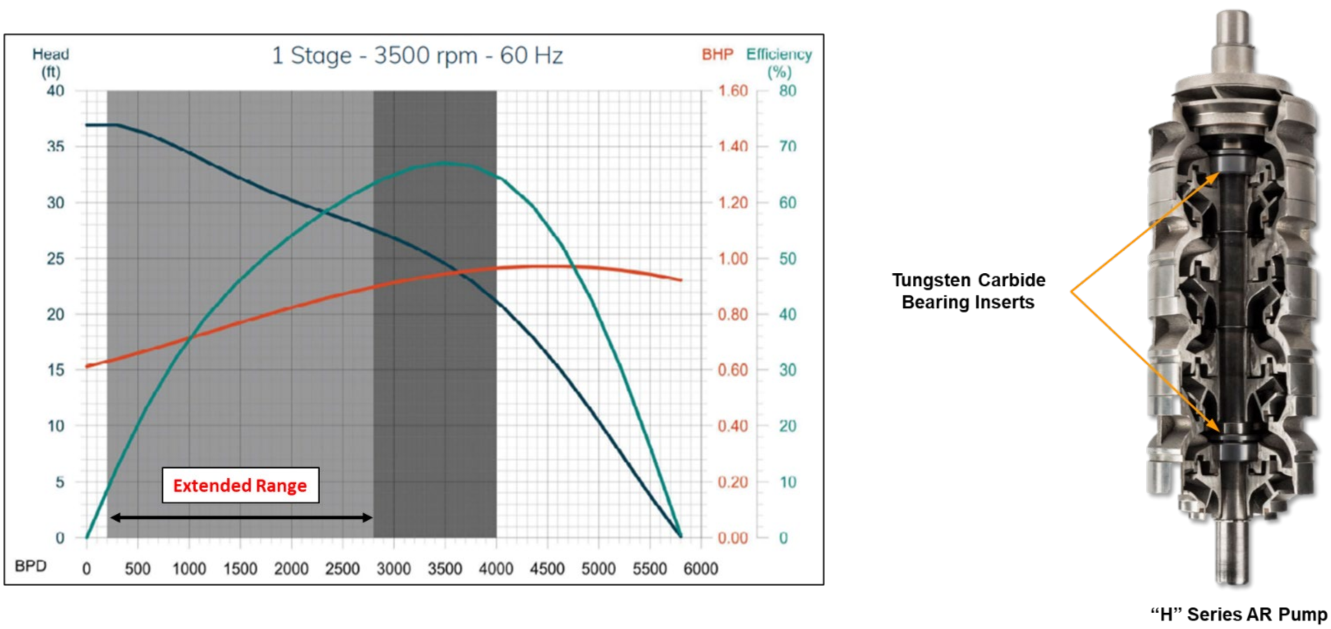

Figure 4- 3500 BPD pump at best efficient point 1:3 AR ratio, which is popular in the Permian

The following chart shows a typical decline in the Midland basin, this well dropped production from over 4500 BPD down to around 730 BPD in only 11 months, with only one ESP system.

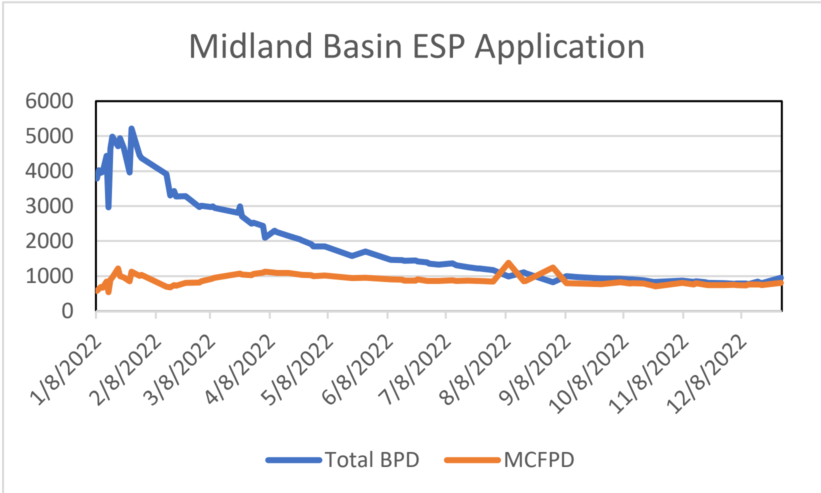

Figure 5- Typical well decline

Electrical submersible pumping system design for fast decline

In these types of reservoirs, when running an ESP for the first time in an unconventional well, we want to install a pump capable to handle a wide operating range, allowing for some room to keep the pump within range at the lower rates, that the equipment will be producing in the next few months. When sizing the equipment, at the beginning of the ESP life cycle, we want to have the pump running at the right of the tornado curve or the closest to the upper limit of the pump. This will keep the designed pump longer in the hole when producing the lower rates.

This example below shows the pump operating range in an ESP simulation using the tornado curve, with the same pump producing from 2200 BPD down to 550 BPD.

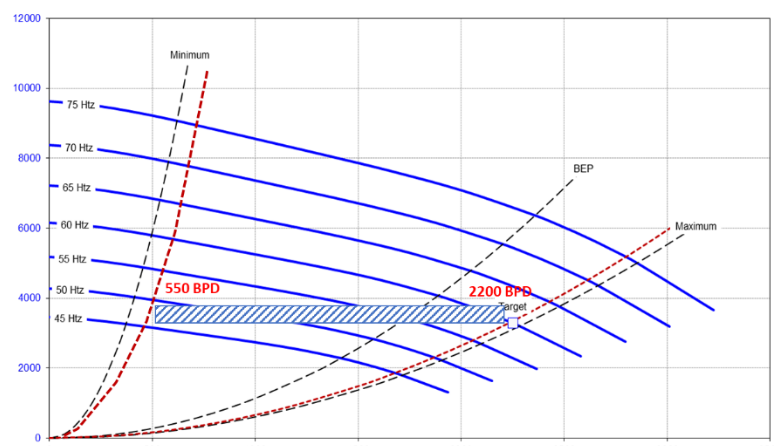

Figure 6- Operating range 1750 pump

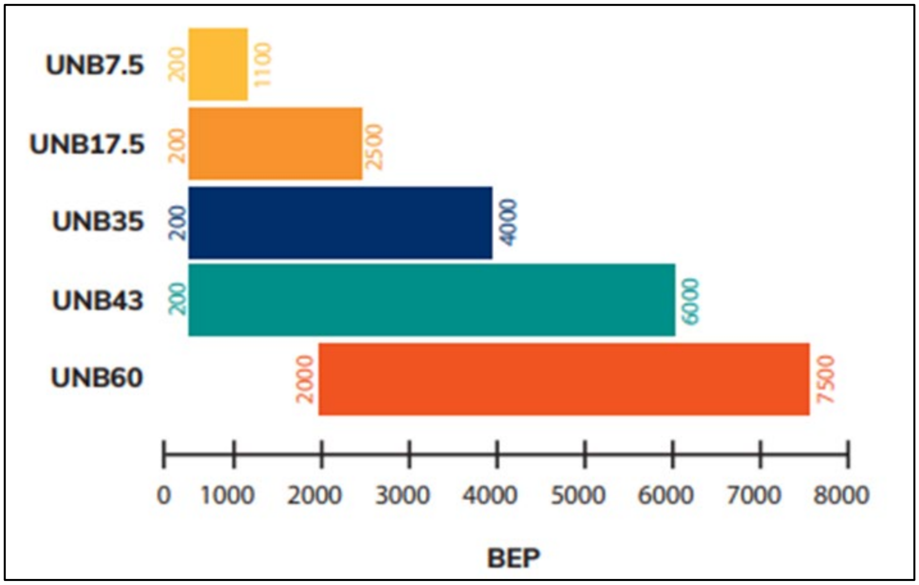

Figure 7- Pump models with wide operating range for unconventional wells

Here are some examples of how these pumps with the extended range for the unconventional wells are beneficial for these changing conditions.

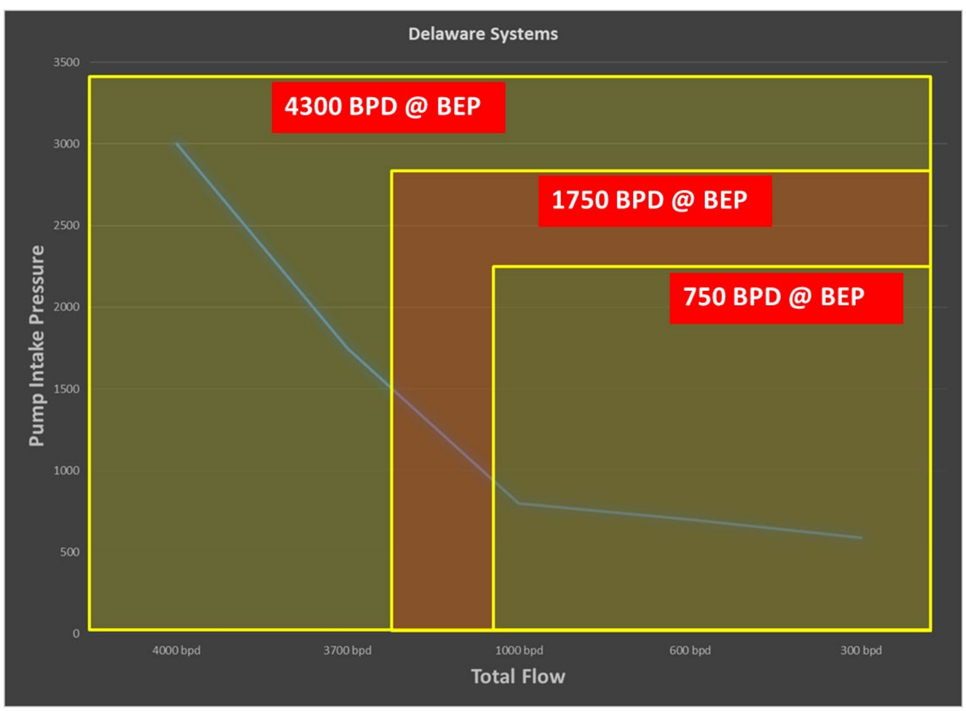

Figure 8- Declination and pump ranges commonly used in the Delaware basin

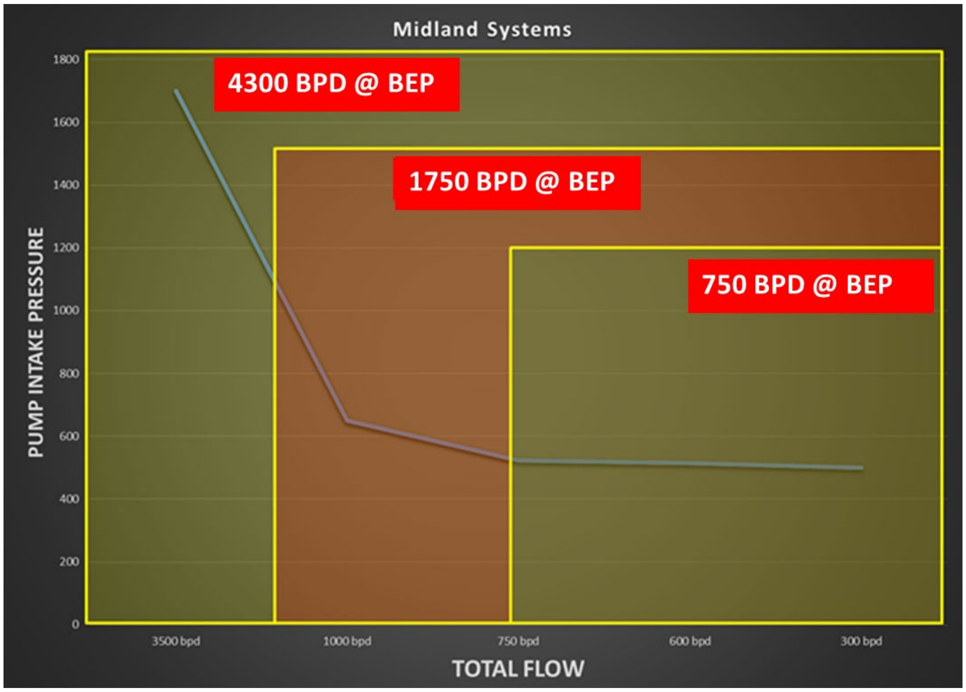

Figure 9- Declination and pump ranges commonly used in the Midland basin

Selecting the most suitable system will reduce change outs of the equipment and can keep the wide range pump running longer.

At the same time, as we will see later, the equipment needs to be prepared to handle free gas. However, in most cases, gas production is not very high with the initial production, but the equipment needs to be ready for worse conditions once the gas rates increase.

Reservoir solids production

It is common to find solids in these types of environments. The failure of the ESP equipment under these conditions is mainly related to abrasives wear, cutting wear due to erosion, and in a way, excessive volume of formation sand or frac sand that can cause plugging of the pumps.

What causes sand production? The faster we drawdown the well, we cause depletion of the reservoir pressure and increase the risk to move solids from the formation to the intake of the pump (Figure 10). This is why one of the best practices after letting the well to flow before installing the ESP equipment, is to operate at a low speed/frequency (40-42hz) for the first few days and avoid frequency increases until we see stabilization of the pump intake pressure.

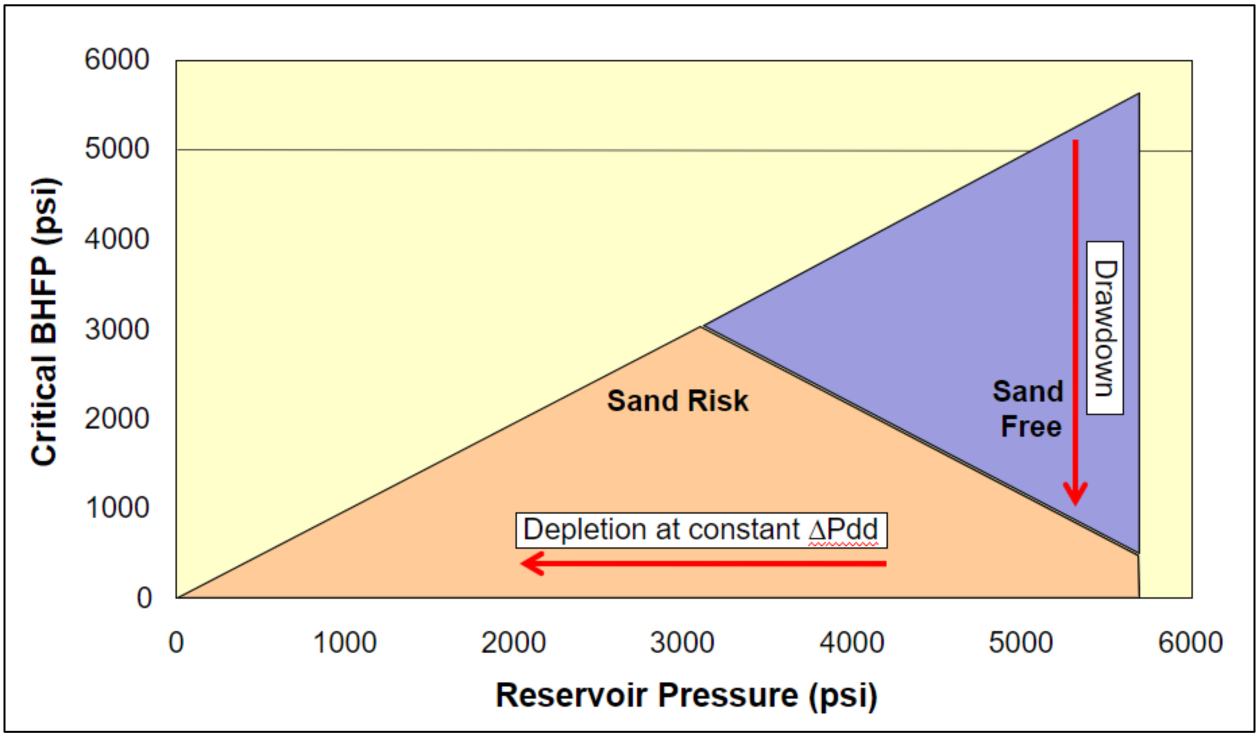

Figure 10- Sand production

When the ESP system is handling solids, first, depending on how sharp the sand particles are (quality), it will cause wear in the stages. This creates vibration, that may damage the mechanical seals in the protectors and cause the well fluids to contaminate the dielectric oil causing the electrical failure of the system. If the amount of solids is excessive (quantity), when the ESP shuts down, solids will fall back from the tubing and eventually could completely plug the pump causing a broken shaft or make the equipment unable to start (high amps). On another hand, solids erosion and solids deposits accelerate corrosion.

These are the most common types of wear patterns we find in the pumps when handling solids.

- Erosive wear in the flow path area of the stages due to the high velocity and abrasive fluid
- Radial wear in the bushings, as well as the stage shaft supports
- Upthrust or downthrust wear on the stage thrust surfaces

In pumps, the primary wear first occurs on the thrust surfaces of the impeller and diffuser. Severe wear in this area will damage the thrust washers, causing metal to metal contact, which generates high temperatures in the pump that will destroy the stages and lock up the pump. This excessive heat in the pump will also eventually be transferred to the MLE cable and potentially cause an electrical failure. An indication that some solids may be entering the pump is an increase on the vibration readings from the downhole sensor.

If the thrust surface wear does not cause the failure, then the vibration caused by radial wear will ultimately result in fluid leakage by the mechanical seals in the protectors and the motor will experience an insulation breakdown.

Figure 11- Pump plugged with solids

Solids mitigation and operation

There are options to avoid the produced solids that effect the life of the ESP equipment. The most popular are:

- Desanders

Desanders are a popular tool in the Permian basin to avoid solids (sand / frac sand) produced by the pump. The operating principle of a desander is based on utilizing cyclonic motion to provide separation of solids from well fluids. These are highly recommended when solids are expected.

The desander goes at the bottom of the downhole sensor and usually with “mud joints” that consist of 3 to 10 joints for solids collections. The following illustration shows the sand separation process before the producing fluids enter the pump:

As we can see in the Figure 12, well fluids and solids enter the tool thru the slots bellow the cup packer (1), the fluid velocity increases, using cyclonic motion as it moves down (2), thanks to the centrifugal forces (3), solids will fall to be collected by the mud joints

(6), clean fluids will move upward to the ported assembly (4) above the cup packer to later enter the pump (5);

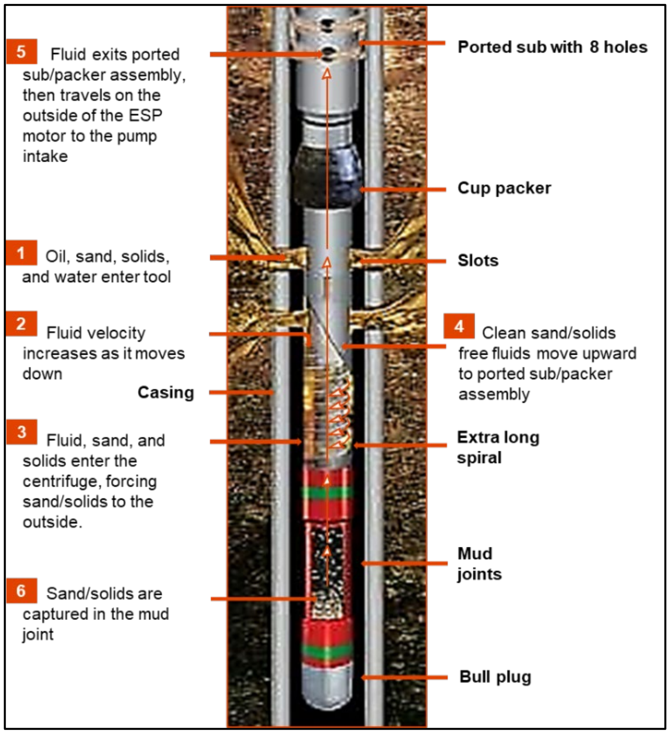

Figure 12- Desander operation

- Chemical Treatments

When we reference solids in the pump, the issue is not always related to sand (formation sand or frac sand). In the Permian, there are other common elements that create challenges and can affect the run life of an ESP.

By running an ESP downhole, we are causing some changes in the reservoir including drawdown to produce the fluids wanted, pressure changes, and adding temperature increasing the heat generated in ESP equipment. Because of this new environment downhole, in the Permian, it is very common to see scale deposition such as $CaCO_3$ (Calcium Carbonate), $CaSO_4$ (Calcium Sulfate) and FeS (Iron Sulfide). Paraffin is also possible in some applications.

For a successful ESP run life, the team needs to closely monitor the operating conditions, looking for elements that effect ESP performance. Below is a reference table to help identify possible “plugging issues”.

CONDITION	PARAMETER											
	Flow Rate		Wellhead Pressure		Operating Amps		Pump Discharge Pressure		Pump Intake Pressure		Motor Temperature	
Broken Shaft	↘	Reduced or No Flow	↘	Low or Facility Pressure Only	↘	Low or Idle Motor Amps	↘	Low or Equal to Intake Pressure	↗	Increasing	↗	Increasing or High Temp Trips
Hole in Tubing	↘	Reduced or No Flow	↘	Low or Facility Pressure Only	↗	Steady or Increasing	↘	Decreasing	↗	Increasing	↗	Increasing or High Temp Trips
Blockage at Pump Intake	↘	Reduced or No Flow	↘	Low or Facility Pressure Only	↘	Low or Idle Motor Amps	↘	Low or Equal to Intake Pressure	↗	Increasing	↗	Increasing or High Temp Trips
Blockage at Perforations	↘	Reduced Flow	↘	Decreasing	↘	Decreasing	↗	Steady or Increasing	↘	Steady or Decreasing	↗	Increasing
Start-up with Kill Fluid	→	Steady or Increasing	↘	Reduced	↗	Elevated	↗	Elevated	→	Steady	↗	Elevated
Shut in at Surface	↓	No Flow	↑	Excessive	↘	Low or Idle Motor Amps	↗	Elevated	↗	Increasing	↑	Increasing or High Temp Trips
Blockage in Pump Stage	↘	Reduced or No Flow	↘	Reduced	↘	Reduced	↘	Reduced	↗	Increasing	↗	Increasing or High Temp Trips
Increase in Reservoir Pressure	↗	Steady or Increasing	↗	Elevated	↗	Elevated	→	Steady or Reduced	↗	Increasing	→	Steady or Reduced
Increase of Free Gas at Pump Intake	↘	Reduced or No Flow	↘	Reduced	↕	Eratic	↕	Eratic	↗	Increasing	↗	Increasing or High Temp Trips
Stage Wear	↘	Reduced Flow	↘	Decreasing	↗	Elevated	↘	Reduced	↗	Elevated	↗	Increasing
Increase in Frequency	↗	Increasing	↗	Elevated	↗	Elevated	↗	Elevated	↘	Reduced	↗	Elevated

Figure 13- ESP troubleshooting guide

If the presence of any type of scale or paraffin is suspected, contact your chemical provider representative for a chemical treatment for the well. For unconventional applications, the use of capillary tube lines for continuous chemical injection is very important for a more efficient chemical treatment. In some cases, a scale squeeze before installing the ESP equipment may be necessary to prevent future plugging issues in the pump.

- ESP operation to mitigate formation and frac sand

Besides preventing solids to be produced by the pumps, using different tools, like sand screens, sand fall mitigation devices, diverter valves or desanders; desanders being the most popular option in the Permian Basin because of its simplicity and effectiveness to prevent solids entering the pump. During the operation of the equipment, we can also try to avoid the solids and mitigate the effects and damage they cause in the pumps.

We have seen the way we operate the equipment makes a big difference improving the system run life and avoiding solids. These are some of the recommended practices.

- Start the ESP at the lowest frequency that allows the equipment to surface fluid, experience shows frequencies between 42-45Hz have worked well.

- After the ESP has been started/commissioned following installation, operate a VSD at a determined startup frequency by the operator and ESP company. The dynamic fluid level/ PIP should be allowed to stabilize at the startup frequency prior to any increase in the frequency.

- A production test should be taken within 48 hours of startup, then again once the PIP has stabilized or weekly until stabilized. When stabilization has occurred, another frequency increase can be considered.

- A new target frequency should be agreed upon and generally should be between 1 to 2 Hz increments. Caution should be taken if solids are suspected to be present. If, this is the case PIP/ fluid level should be drawn down slowly to prevent the solids getting into the pumps.

- Once again production tests should continue to be monitored and discussed between both the operator and the ESP company, prior to any increase in frequency for decreasing the PIP.

High gas production

ESPs work lifting the column of fluid to the surface imparting velocity to the fluid at the required flow rate. Each stage produces a certain amount of lift (head) in feet and that determines how many stages we need in the pump (diffusers and impellers), but this is based on a full liquid fluid regime.

These are centrifugal pumps, and the liquid, which is the heavier fluid part of this Multiphasic flow, during operation, tends to “escape” the center of the impeller to be taken later and redirected by the diffuser. Gas, since it is the lighter fluid, will stay closer to the eye of the impeller, which is the low-pressure area. Figure 14 shows an example of the impeller geometry, and the red bubbles represent the free gas at the low-pressure zone of the impeller:

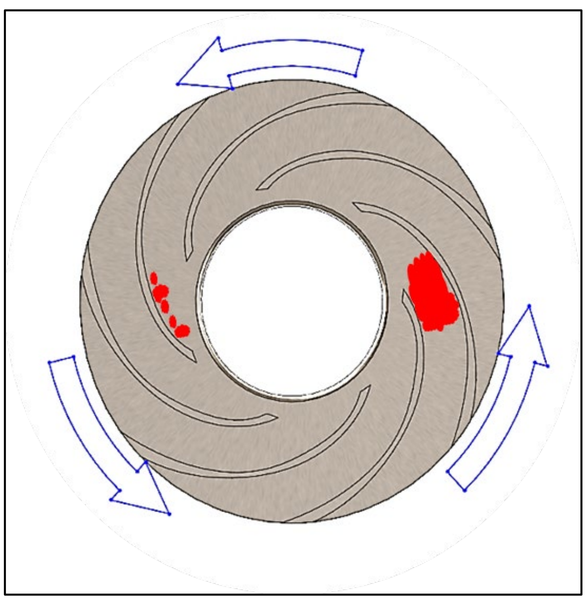

Figure 14- Pump Impeller affected by gas blocking / locking

Knowing how the gas occupies the spaces in the pump stages, once free gas enters the pump with the liquid, we can see the following effects:

Head reduction: The volume the free gas occupies in the stage will reduce the head per stage of the pump and the total production of liquid will also drop. Under this condition, efficiency is also reduced. An increase in the frequency can help compensate the loss.

Gas blocking: As described previously in Figure 14, the gas bubbles will tend to stay and concentrate in the low-pressure zone of the impeller, this pocket of gas will start creating a restriction for the fluid coming from the rest of the stages below. When monitoring the well, we will see this effect affecting the load (amps) of the system, lower density fluid, like free gas in the pump will cause the amps to swing.

Gas lock: Gas locking will occur when the flow is completely restricted at the eye of an impeller. This is the most severe case of excessive gas entering the impeller faster than it goes out. During a gas lock, all gas will be trapped in the center blocking all flow. The pump has not stopped spinning; it has just stopped moving fluid. Once gas locking has occurred, production at the surface has stopped because there is not enough pressure generated to lift the fluid column. The biggest problem with gas locking is the substantial temperature increase in the pump, protectors, cable, and motor. Because no fluid is moving through the pump and / or past the OD of the ESP, the heat transfer from the equipment to the fluid that allows the ESP components to cool down is severely reduced or eliminated. As a result, increased operating temperatures can severely damage system components and cause premature failure. What we have seen in the Permian, is when several of these gas lock events happen, the pumps and the MLE cable are the components suffering the most damage, in some cases causing an electrical failure.

Gas slugs: If the gas is concentrated in large slugs coming from the wellbore rather than being evenly dispersed in bubbles, the pump will be severely affected. The slug hits the intake, and the pump loses all capacity to move and surface fluid. Slugging is more commonly seen in horizontal wells because the shape and run of the well bore is prone to large gas pocket accumulation. Consequently, the pump will cycle between producing and gas locking, causing the same problems described with the gas lock events. The ESP will shut down from underload fault or high motor temperature.

Operation and best practices producing with high gas volumes

We have learned a lot about handling free gas with the ESP equipment, using different tools, from the selecting the most suitable equipment for the application to different gas control modes that we can setup in the drive. Here some of the best options to handle the free gas in ESP applications:

Use tapered designs: higher capacity pumps in the bottom and followed by smaller capacity pumps on top, like shown in Figure 15. This arrangement helps to compress any free gas in the stages.

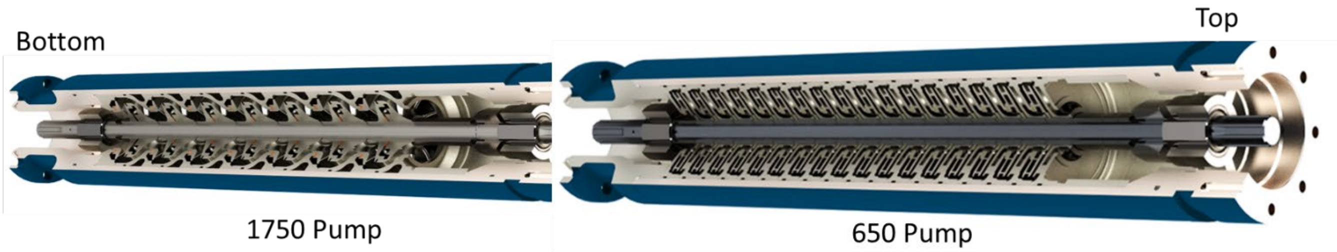

Figure 15- Example of tapered pumps

Always use mix flow stages: Mix flow stages offer more capacity to handle gas and its impeller configuration with the balancing holes close to the center in the low-pressure zone, which helps move free gas out of the pumps easier than radial flow stages, which don't have this configuration.

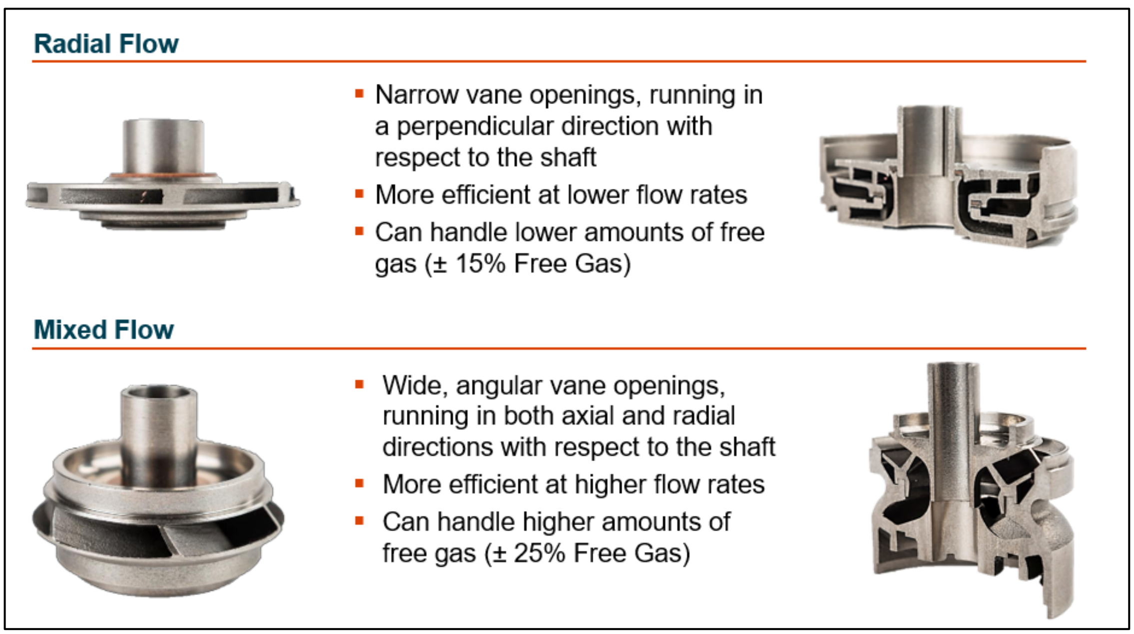

Figure 16- Types of pump stages

-Consider adding back pressure at the tubing line: We have learned that keeping the tubing head pressure between 350 – 500 psi, helps to compress the gas in the tubing. This restriction will increase the density of the fluid along the production tubing, increasing the pressure in the pump, and at the same time restricting the free gas to enter the pump. Note, this requires verification with the ESP company to make sure the tubing pressure added is still safe for the ESP equipment, and the pump is still able to surface fluid. Always keep the casing pressure low and casing valve open to production.

Gas accumulation in the back side will force all the free gas to be produced by the pump.

-Operating gas mitigation modes:

There are popular options to help ESP equipment fight gas interference using some special drive settings.

PID amperage control: The drive will follow the target amps setting and the frequency will change between the low and high-speed limits keeping the load. As we saw before, when there is free gas causing gas interference, the amps will drop. Using this mode, the unit will speed up to catch some load and try to keep consistent fluid produced to cool the equipment.

Gas lock recovery mode: In the event of a gas lock, the drive will slow down to a desired frequency and run slower for a certain period of time, then the unit will speed up again to the desired frequency so that the unit can catch the load again. This will help cool down the equipment by slowing down the frequency and rapidly increasing the equipment, picking up some load with more fluid to cool down the equipment.

Be mindful when setting up these control modes. They require some evaluation and analysis to determine the proper settings as wrong settings may cause severe damage to the equipment and opposite results. Please contact your optimization or ESP applications engineer for help.

-Over-staging the pump:

During the design process, when working on sizing the ESP equipment for gassy applications, it is important to account how the free gas will reduce the lift (head per stage) in the pump. It is important to be careful and take into consideration this loss and add additional stages. In the Permian, we typically need to increase the stage count around 15-20% to compensate the head loss from gas interference.

Considerations running the ESP equipment in down hole (installation)

High dog leg severity: While installing the ESP equipment in 5 ½” casing, which is the most popular casing size in the Permian Basin, the maximum dog leg severity recommended is 6°/100ft and land the equipment not to exceed 2°/100ft.

ESP setting depth and high deviation: It is recommended to land the bottom of the equipment at least 100ft (MD) over the Kickoff Point (KOP), including any tail pipe (mud joints).

CONCLUSIONS

-Accurate information for sizing the ESP equipment is the key for a successful ESP application. Failing to consider all the important data to select the proper equipment for the well, may result in a short run life.

-Monitoring and optimizing the operation of the ESP equipment is important, as mentioned at the beginning of this paper, making sure the correct decisions are taken during the ESP operation, avoiding shutdowns, and choosing the correct operating mode for gas handling since excessive free gas is very common in this type of ESP application.

-After the ESP failure, it is important to analyze what can be improved so that we can increase the run life for the subsequent ESP installations.

- Always be mindful of how the free gas will affect the lift per stage and the overall performance of the pump (lower efficiency) and not always more frequency (speed) means more production. In some cases, the ESP unit can be sped up with no more extra barrels or additional pressure drawdown. This decision will cause the equipment to work harder, generating more temperature in the pump with no additional positive results.

-Especially in new drilled wells; starting up the unit at low frequency and slowly speed up and optimize the unit will help to prevent solids, frac sand, or formation sand that potentially can cause erosion or plug the pumps.

-Sand is not always the solid found in pumps. Some type of scales, like Calcium Carbonate or Iron Sulfide are very common in the Permian. Always confirm what type of solids are affecting the ESP system and contact your chemical company to make sure the proper chemical program is in place.

-Temperature readings from the sensor show the winding temperature or dielectric oil temperature in the motor. It is important to keep in mind that the rest of the equipment, mainly the pumps, may be seeing very high temperatures when the pumps are not moving a consistent flow rate to keep them cool. Excessive heat in the pumps may be transferred to the MLE cable and cause an electrical failure. Always set the high motor temperature alarm based on operating temperature, considering around 20 to 30F above the operating temperature and not the maximum temperature allowable for the components. Also, in combination with the underload setting based on running amps.

-Good communication between all the parties involved operating the ESP equipment and taking decision during the life cycle is essential for the success of the ESP application. Following all the best practices in this document will help to maximize production, run life and reduce pumps change outs.

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- ESP Best Practices (Frac Sand / Formation Sand / Debris), Juan Fernandez, July 2013.
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FIGURE SOURCES

- Figure 1: ChampionX and Enverus
- Figures 2-16: ChampionX