FACTORS AFFECTING ELECTRIC SUBMERSIBLE PUMP (ESP) RUN LIFE

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INTRODUCTION TO THE ESP SYSTEM[1,2,3,4]

Description of Components and their potential problems

The system (Figure 1) has the pump (a stack of centrifugal stages/diffusers) discharging up into the tubing. The intake or gas separator is below the pump. The seal section is under the intake to protect the motor and absorb thrust above the motor. The motor is on bottom so fluids can pass by the motor to keep temperatures down as the motor generates heat. The system illustrated is with a standard control panel and does not show very common use of a variable speed drive.

The pump (Figure 2) can be one or several housings where the pressure (and head) in the fluid is increased across each stage. Stages can be all radial vanes or mixed (axial and radial) for rates over about 1800 bpd. The stages can be free to slide up/down on the shaft or compressed so they are essentially fixed to the shaft. The deeper the well, the more stages are needed. Stages are cataloged with ranges of flow from low to high.

With little gas a standard intake can be used (Figure 3). If gas at the intake is excessive then a separator may be required to send as much as possible gas to the casing before fluids enter the pump intake.

The use of a gas separator may help mitigate potential problems inherent in wells where excessive free gas at the intake pressure may enter the pump and cause the pump performance to degrade or reach a low amps cutout. The effectiveness of the gas separator varies with each design, well conditions and differences between the gas bubble rise velocity and the liquid velocity at the intake of the pump.

The rotary gas separator will separate free gas with an efficiency of 75% to 98+%. However, some operators design for 50% separation for a conservative design. The rotary gas separator may be considered where the free gas into the intake begins to degrade pump performance. This condition can be warned against by calculation of an experimentally determined correlation (Dunbar factor) explained in the gas section below. If abrasives are present, then the vortex separator is preferred over the rotary separator and should include abrasive resistant (AR) bearings.

Rotary Gas Separators allow the entry of fluids and gas at the base of the separator into a rotating centrifuge with inducers and straight vanes. As the liquids and gas rotate in the centrifuge, the denser liquids (oil and water) move to the outside of the centrifuge and the lighter components (the free gas) move to the center. A crossover diffuser allows gas to be collected and sent to the annulus while liquid rich fluids enter the pump.

Since there is a large mass rotating, shaft stabilization is very critical. Seal failure and then motor failure due to excessive gas separator vibration can occur if the shaft is not stabilized with AR (hardened) bearings. Earlier models used only two bushings to stabilize the long shaft. Modern designs incorporate three bearings. Hardened bearings are an option that should be incorporated into the gas separator.

Even though the rotary separator is very efficient when operated in range, there can be cases where excessive gas enters the pump. If the pump intake pressure gets so low that a slug flow pattern develops, then there will be moments of time when only gas is present at the intake. During this interval, only gas will enter the pump. Gas in the pump usually triggers a low amps cut-out. Starting and stopping is highly undesirable when trying to achieve long run life.

The Vortex Gas Separator also uses centrifugal force to separate the fluids according to the fluid gravity. The denser, high specific gravity fluids are forced against the separator wall and lighter, low specific gravity fluids, are left around the shaft. The vortex separator creates a vortex in the separation chamber with a spinning paddle set above the inducer or high angle vane auger. The advantage is the separation does not require the additional weight of the spinning chamber. The vortex separator will also have a higher maximum through put rate than the rotary. Figure 4 gives a general idea of liquid through put vs. percent free gas that can be separated. Notice that the separation efficiency is 0% at the maximum liquid rate and at that point there is no room for free gas to enter the separator. If the total flow of oil, water, and gas is greater than the maximum liquid rate, then this will begin to cause a choking effect on flow through the ESP and the Pip will increase, reducing the free gas, until a stable operation point is found.

The Vortex separator will handle abrasives better than the rotary chamber separator and the rotary chamber separator will de-gas viscous oil better than the vortex separator. Figure 4 shows approximate operating ranges of rotary and vortex gas separators.

The seal (Figure 5) absorbs shaft thrust above the motor, seals wellbore fluids from the motor and equalizes the pressure in the seal and motor to that of the surrounding wellbore fluids. On the left a bag seal is shown to positively seal the motor form the wellbore. On the right a labyrinth section is shown to seal the motor from the wellbore

The motor (Figure 6) may be a two pole, three phase induction motor (IM) or a 4-pole, synchronous, permanent magnet motor (PMM). IM or PMM synchronous RPM is defined by equation 1;

$$RPM_{SYNC} = \frac{\text{Hertz} \times 120}{\text{Motor Poles}}$$ ………. Equation 1

The induction motor, when connected to a 60-hertz power system, or a variable frequency drive (VFD) operating at an output frequency of 60 hertz, has a synchronous RPM of 3600 but the actual RPM when loaded will be less. The induction motor rotor must slip or rotate slower than the rotating magnetic field produced by the stator windings, to induce current into the rotor, which develops the rotor's magnetic field. The induction motor RPM is defined in Equation 2;

$$RPM_{IM} = RPM_{SYNC} - RPM_{SLIP}$$ ……… Equation 2

The slip RPM can vary from 180 to 50 depending on the pump, seal and intake load, and the motor diameter. The Induction motor's full load RPM when 60 hertz power is applied will be approximately 3420 RPM. Computer programs (using motor performance curves and system performance data) will calculate the RPM and the resultant pump and system performance. Note that many catalog pump performance curves are published at 3500 RPM.

The 4-pole, synchronous PMM must be operated with a Variable Speed Drive (VSD), also called a Variable Frequency Drive (VFD), and when operated at 120 hertz, the motor will rotate at synchronous RPM, 3600 RPM. There is no RPM slip associated with the permanent magnet motor since the rotor magnetic field is supplied by the permanent magnets on the rotor. Since there are no rotor losses in the PMM, it is 10 to 12% more efficient than a comparable IM.

The permanent magnet motor uses rare earth magnets to generate a strong rotor magnetic field. This field is stronger than the electrically generated field of an induction motor. As a result, a PMM can generate three to five times the power of an equivalently sized induction motor. This translates into the horsepower density being increased 3 to 5 times.

The main power cable (Figure 7) is typically spliced to a pigtail under the wellhead and is banded to just above the pump where is it spliced to a flat thin motor lead extension cable (MLE) banded down to the pothead at the top of the motor. The main power cable can be flat or round (clearances dictate) with the larger diameter cables exhibiting lower losses and the smaller cables being less expensive per ft.

For further introduction and system details, there are several API Recommended Practices and IEEE documents that relate to the various components, test criterion, installation, operation and more[5-15].

It is desirable to extend the life of the installation and the individual components. If this can be done one can reduce the lease operating expenses (LOE) and downtime required repairs. An overall life of ESPs might be on the average about 2 years but with mild conditions it might be several more years. However with severe conditions such as excessive sand laden production, the failures might occur on the average in a matter of a few months. This paper will focus on what concerns run life regardless of conditions.

COMMON FAILURE MODES[8, 17-22]

Common failure modes of motors:

1) Excessive Motor Overload: Resulting from one or more of the following reasons:
   - Abnormally high specific gravity of the well fluid.
   - Bad design (undersized motor) resulting from poor data.
   - Worn out pump.
   - High, low, or unbalanced voltage.
   - However if motor is overloaded then then the high amps cutout can stop the unit. The high loads may lead to starts and stops which are bad in themselves as far as run life goes.
2) Seal Section Leak: A leaking seal section allows well fluids to enter the motor and usually results in a failure. Possible reasons for a Seal Section leak are:
   - Worn out pump causing seal damaging vibrations.
   - Broken mechanical seals from rough handling.
   - Defective seal section construction.
   - Bad installation methods and/or procedure.
   - Chemical attack on elastomeric bag
   - Burst elastomeric bag due to bad check valve.
   - Corrosion though the wall of the seal section
   - Presence of low grade metal shipping plugs that can corrode through if not replaced
   - Unbalanced voltage at the motor terminals which causes vibration, which can cause seal damage.

3) Motor winding operating temperature exceeding the temperature rating of the motor insulation. Motor winding operating temperature is determined by the following factors;
   - Ambient temperature of fluid passing the motor.
   - Temperature rise above the ambient temperature due to the motor operating load, with specific heat = 1.0 water as the cooling fluid at a velocity of one ft/sec.
   - Temperature rises should the velocity of the cooling fluids be less than 1 ft/sec.
   - Temperature rises should the average specific heat of the cooling fluids be less < 1.
   - Temperature rises due to incorrect motor voltage for the operating load.
   - Temperature rises due to any voltage unbalance at the motor terminals.
   - Temperature rises due to harmonics in the motor voltage from a VSD.
   - Temperature rises due to voltage unbalance at the motor terminals.

4) Errors when servicing the motor at time of installation.
   - Air not circulated out of the motor when pumping oil into the motor at installation time.
   - Contaminated motor oil used to service the motor into the well.
   - Jacks not used to connect tandem motors.

Common intake / gas separator failures:

1) Shaft
    - Excessive end play caused be wear / abrasives.
    - Shaft frozen
    - Side play caused be wear / abrasives.
    - Check the shaft for spline damage and abrasion wear.
    - Check the gas separator rotor for wear or mechanical damage.
    - Visually inspect the interior of the gas separator for accumulations of scale, abrasives or similar debris which can plug or damage the lower stages of the pump
    - Also inspect outside intake holes for plugging due to asphaltenes, corrosion, etc.
2) Abrasive or erosion in the intakes, and throughout.

Common Seal Section Failures:

1) Vibration – Shaft Seals
2) Sand – pump vibrates
3) Bag – chemical attack
4) Sand fill – excess sand in top of protector
5) Temperature – bag, excess venting of fluid
6) Excess starts/stops – bag/bellows helps
7) Thrust
8) Misalignment – mechanical seals, shaft, bushings
9) Bent housing , shaft,

Common Pump Failures

1) Down-thrust wear, due to producing below peak efficiency.
2) Up-thrust wear, due to producing above peak efficiency.
3) Grinding wear, due to producing abrasives.
4) Plugged or locked stages, due to scale build up.
5) Longevity wear.
6) Twisted shaft, due to locked pump, starting during backspin, or absence of VSC.
7) Spinning diffusers that can generate heat and corrosion
8) Corrosion.

Common Cable Failures

1) Mechanical damage during running or pulling operations caused by:
    - Crushing
    - Stretching
    - Crimping
    - Cutting
2) Cable deterioration due to:
    - High temperatures
    - High pressure gas
    - Corrosion
    - H2S when not properly protected against
    - Normal aging
3) Excessive current creates a high conductor temperature capable of breaking down the insulation… Surge of power... lightening

ESPS IN CONVENTIONAL AND UNCONVENTIONAL WELLS

Conventional Well - More constant or slowly declining rates[5]

In these wells design of equipment may last a lot longer as conditions do not change rapidly enough to move away from the equipment capabilities? The unit is usually landed above the near vertical perforations.

Unconventional Wells

Unconventional Wells have high initial rates and sharp declines (Figure 8 and 9). This can create a situation where the well is allowed to flow and then artificial lift may have to be staged from high rate AL to lower production as the well depletes. For ESPs a VSD is a must but even then AL must be staged to lower rate AL.

Figure 10 shows an example of an unconventional well with an initial high flow rates. Initially flow and then use of high rate (ESP) is used. Then as rates drop, SRP and then Plunger are indicated which may be more suitable for lower rates. Many choices exist for staging and well conditions can exclude some lift methods.

Note that most of the PVP (Present Value Profit, Figure 9) is from the initial first year of two for this particular example. For the initial high rates, high rate ESP can be used or if conditions warrant then initial high rate Gas Lift can be used after the flow period or even earlier.

In the past well below about 400 bpd were usually pumped with SRP's but more recently low rate ESPs have come along. Still ESPs are best from the standpoint of electrical power efficiency and operating motor temperature if at least a few hundred BPD is the target rate.

The high rate AL for unconventional wells can be ESP or Gas lift. Use ESPs if little sand and moderate gas. Use gas lift if large amounts of gas present or if sand production sufficient to frequently fail the ESP system. Both can work in deviated wells.

Deviation

If ESPs can be introduced to a deviated well with no permanent damage they can run at any angle including the horizontal. However they need to be landed in a straight section (<~ ½ deg/100 ft). ESP's have and continue to be used in the horizontal but not so much in the USA. If a deviation survey is supplied most major ESP vendors can tell if the ESP can be run with no permanent damage. Special flanges and bolts can be recommended for severe dog legged wells after a deviation survey is analyzed to prevent damage or bending on run-in.

DEFINITION OF FAILURES

Failures

Definitions of failures

1. MTBF = (Total # of Units) x (Time Period of Test) / (# of Failures)
   - Running equipment included
   - All failures during time period included
   - Stands for Mean Time Between Failure
   - Also called MTTF (Mean Time To Failure)
   - One of the two common methods used in the oil industry
   - Simply stated, the calculation for MTBF involves the summing of the operating time for all ESP installations in a target group of wells and then dividing the total cumulative operating time by the number of failed ESP systems during that same period.

- In some cases, instead of a calculation based on equipment failures, the calculation will use ESPs pulled for any reason. Then MTBF becomes mean time before pulling (MTBP) and reflects the disruptions in production for any reason, and not just for failures**.**

$$MTBF = \frac{\sum_{t=1}^{t=tp} ESP\ run\ days\ for\ installed\ population}{\text{Number of failed ESPs}}$$

Where tp=time period of interest

2. Failure Frequency = (# of Failures) / (Time Period of Test) * (Total # of Units)
    - Inverse of number 1 (MTBF)
    - Running equipment included
    - All failures during time period included
    - Also called failure rate
    - The other common method used in the oil industry
    - Also called Failure Index. The failure index is the measure failure rate as expressed by the number of failure/well/year and is particularly useful in forecasting the total number of failures across the coming annual period for designated ESP population. This forecast can help in budgeting expenses and personnel required for the coming year associated with ESP workovers.

$$f(x) = \sum_{t=0}^{t=interals\ in\ a\ year} \left(\frac{ESP\ Faiures\ during\ interval\ period}{Number\ of\ ESP\ wells\ operating} \right)$$

3. C-FER (RIFTS data base)
    - Includes all ESP systems, including those running.
    - Uses similar calculations to MTBF
    - Recommends that all data be taken into account and the data comes from as large and consistent a database as possible.
    - Two of the three calculations are similar to the above-mentioned MTBF. One uses all pulls; regardless of reason while the other uses pulls that only include failed equipment.

4. Reliability

Reliability is an inherent feature of design. It is concerned with performance in the field as opposed to quality of production. Reliability if the probability that a system will perform in a satisfactory manner for a given period of time when used under specified operating conditions. Reliability is not commonly used by Operators but easily could be if failure rate data is available.

Failure Modes (definition)

The definition and identification of failure modes is as, if not more critical to meaningful run life calculations as the method of calculations used. What failure is and then how they will be categorized.
Definition of failure: An event in which any item or part of an item does not or would not perform to required operating specifications. Following is the list of different type of pulls/failures for example.

1) All Pulls
2) Non-Failure Pulls; Workover, Re-size, Conversion, Special Test
3) DH Failures (all equipment)
4) Non-ESP; Tubing, packer, casing, seating nipple, check valve, drain valve, etc.

5) ESP; Pump, Seal, Motor, Cable, MLE, Intakes, PSI

BASIC CHECKLIST FOR BEST OPERATION AND REDUCED FAILURE RATES

Although details follow, this check list is a quick reminder of important factors

1. Design and operate in recommended range.
2. For pump stages err on side of a few more in pump.
3. Design for presence of long flowlines that will increase tubing pressure when running.
4. Ground all cabinets to casing and have rod ground for each cabinet.
5. Protect surface cable from transformers to control panel or VSD, from control panel to junction vent box and from vent box to wellhead. Use trough or bury cable in a conduit.
6. Select cable size for a voltage drop of no more than 30 V/1000 ft. after using temperature correction factor.
7. No more than 2 splices in cable allowed (operator preference).
8. Do not band over splices. Do band on either side of splices.
9. Monitor cable banding. Hit band with palm of hand and if does not move to the side its tight enough. If armor on cable is indented it’s too tight.
10. Use more than 2 bands per joint for cable size of #2 or greater or for lead cable.
11. Make sure MLE cable splice is well above the pump.
12. When banding make sure buckle is between cable and tubing…not on either.
13. When pulling cut the bands do not pry bands off.
14. Check rotation on new unit.
15. Don’t increase Hz as such that more than name plate amps (NPA) is indicated. The best life and performance of ESPs with VSD’s occurs when the pump is designed so that the operational head/stage is less than the head/stage at the BEP flow on the 60 Hz pump curve.
16. Set high amps about 115% of running amps and low amps about 85% of running. For oversized motor, you may not be able to rely on low amps as shut down and may have to rely on production, motor temperature, pressures, or combinations of these parameters.
17. Monitor voltage imbalance (<2%) and current imbalance (<5%).
18. Don’t operate motor against closed valve, or with plugged intake, or with low amps reading set too low, and minimize starts and stops. Set motor temperature hi limit cut out.
19. If cycling consider choking back or reduce Hz if VSD present. Do not continue to operate in on/off mode.
20. Realize that low casing pressure may allow more drawdown and production and that high tubing pressure will reduce production and may add to motor load.
21. Monitor fluid level and not BHP.
22. Monitor chemical treatment and rates, test for residuals, and adjust accordingly.
23. Always verify that surface equipment and cable armor are not live before touching.
24. Ground all cabinets to the ground and to the casing.
25. When starting check for proper direction of rotation.
26. When motor is oversized, don’t use low amps cutout but instead use hi-temp motor cutout and discharge pressure or intake pressure cutout controls.

INSTALLATION BASICS[10,17]

Good installation gives longer run life. Items below listed are from API RP 11S3. Highlights are covered in below information.

Transportation, Handling, and Storage of Equipment

To ensure a cable will arrive at a well site in the “as manufactured” condition, the reels must be transported and stored with the reel axle horizontal to the ground, and the reels must be chocked to ensure they are immobile. Loading and unloading cable reels must be done in compliance with best practice and safety, as illustrated in Figure 11 (from Installation Practices, X-Tract Cables). Figure 12 shows orientation for spooling cable from reel.

1.0 Cable Spoolers or Reels[17]

During installation, a sheave should be supported above ground when preparing to feed the cable through it (Figure 13). After the cable has been fed through and has been securely banded to the tubing, the sheave shall be raised to the “running position”, approximately 25-45 ft above the slips (the electrical connections made through a rotating assembly). The sheave should then be secured such that the cable is as close as possible in line with the movement of the travelling blocks which support the drill column and “travel” up and down as it hoists the pipe in and out of the hole. *The cable should not be used to reposition the sheave. It is common practice to jerk the cable hanging down over to tie on to the basket to be tied on. DO NOT DO THIS! It will stretch the cable.* When flat pump cable is being run, a flat rimmed sheave is to be used.

Put sills or supports under the cable from the reel to the well keeping cable off ground, especially if rough rocky ground or muddy ground. Alternatively a tarp could be used. Metal or wooden support sills are used but often in lower numbers than required (Figures 14 & 15). One case history indicated dragging the cable over caliche resulting plugged pump stages.

Downhole Cable Protection
There are a number of protection systems for downhole cable including protection across the motor and various methods of protecting between the tubing and tubing collars and the casing. An example is shown (Figure 16) of a simple device used across the pump to protect the cable

Running Equipment into the Well
Use of a Gauging Tool to Eliminate Burrs, etc. Even in a new well, a gauge ring and scraper should be run to assure that no burrs or damaged collars protrude enough to damage the power cable and equipment.

Shipping caps
Components should be shipped with shipping caps on the ends which are removed during installation. Components when pulled should be sent to shop with shipping caps.

Insulation Resistance Test during Lifting
To gain access to the cable conductors, remove the shipping cap from the end of the dry. Using a Megohmmeter, connect the ground lead to the cable armor and then test each leg of the cable in rotation. Record all phase-to-phase and phase-to-ground readings. New cable should read close to infinity for both phase-to-phase and phase-to-ground. In adverse conditions (high humidity/wet), lower readings may be obtained; experienced operators report that readings of only 1500 Meg Ohms are obtainable and considered normal; this, however, is not general recommendation.

Cable Splicing
General Cable recommendation. See API 11S3.
The Motor Lead Extension (MLE) should be spliced to the Power Supply (PS) cable before being shipped to location. Splices should be made in the cable shop. Never band over a splice. Some operators specify a maximum number of splices or number of splices per 1000 ft.

Cable Banding
Banding is done using a banding tool. Figure 17 shows if you bend the “tang” under the cable it will hold the cable more securely. It is tight enough if you hit with palm of your hand to move It circumferentially and it does not move. It is too tight if the armor of the cable is indented.
Per API RP 11S3, no less than two bands are to be applied to secure (approx. 60 ft/18.29 m), as well as when running the tubing through a dogleg or other tight spots. This practice provides extra cable support in the area of “tubing cut-off” that might occur during a fishing operation

Running Practices
Running speed should not be too fast. IEEE says running speeds of 1000’-4000 per hour normal while installing ESP. The speed can be reduced for wells that have tight spots and that have historically

damaged cable on run-in. In general lower running speeds (~1000 ft/hr) may reduce failures and this factor should not be ignored, especially if high cable and connection failures persist.

Phase-to-Ground insulation resistance (IR) Test

Historical data (Pulling Equipment out of Wells)
Production records, down time, reasons for down time, stops/starts, SCADA records (PIP, motor temp, amps, etc.),

Downhole Pump Cables (Field Evaluation of Used Equipment)
Pulling requires as much attention to detail and caution as running new equipment. Once all the preparations have been made, including opening the bleeder valve to remove the fluid, begin lifting the pump string out of the well. A record of the number of bands that are missing should be kept, and the decision should be made whether to retrieve or push them to the bottom of the well. Remove the bands progressively by cutting and not by levering them away from the tube/cable, as that will damage the cable. If there is evidence of corrosion on the bands, it may be necessary to change them when re-establishing the well with bands of higher corrosion resistance. Observe the condition of the cable as it emerges from the well. Look for evidence of overheating, melted lead, scorch marks on the armor and corroded or separated armor. Check for swollen insulation, exposed conductors and excessive corrosion of cable splices, as well as the number of splices. If there is a reported motor failure, ask the owner/operator whether to leave a portion of the MLE attached (1-2 ft).[30-60 cm] above the pothead) or if it should be removed completely.

Motor Lead Extensions (Field Evaluation of Used Equipment)
See condition comments in previous section

Minimum high voltage (HV) IR Requirement
When running in, cable should have 2000 megohms phase to ground with a megohm meter. If cold and run in could be 500 megohms. Reading will begin to drop when the cable enters fluid. If damage probably less than 20 megohms

Startup parameters affecting run life
Starting under load. With a check valve the unit can start under load and have no thrust problems
Starting with no initial load. With no initial load the unit will go into up-thrust until the tubing becomes filled with fluid

Periods of high temperature
Produced fluid cools the motor. On startup the majority of the fluid is coming from casing - tubing annulus and very little is producing from the formation to cool the motor and this may cause an initial spike in the motor temperature. If the well is choked back on stat up then motor temperature could rise significantly.

MONITORING AND SCADA[24]
Parameters which may be commonly monitored
- Intake Pressure
- Intake Temperature
- Motor Temperature
- Vibration
- Motor fluid dielectric strength
- Discharge Pressure
- Amps
- Most common are Amps, PIP, and Temperature

Indications from Amps alone
- Low % of NPA on motor so motor not loaded (could be over sized for future conditions.
- `Amps > NPA on motor, then motor overloaded regardless of HZ.

Erratic Amps. Gas interference or gas slugging?

Other trends and changes occur. A few examples presented

Figure 18 shows amps, pip and WHT before/after shaft break.
Figure 19 shows events as tubing leak progresses
An amps trace for normal startup (Figure 20) is shown. Amps spike 2-5 times running amps. Rest of trace is uneventful.
Repeating reaching low amps (Figure 21) shut down as well pumps off is illustrated. Pumping at higher capacity than well can deliver. Reducing Hz or choking well back if no VSD are solutions. Do not let the pump cycle. Cycling can drastically reduce run life.

Other Amp patterns exist and are used for diagnosis of pumping operation.

Problems that can be detected using sensor outputs from Petroleum Development, Oman, IPTC 17413 2014 are shown in Table 1. These trends can be used to identify or eliminate occurring problems. The arrows indicate the rate of change of the variables. The best "trip" parameters are indicated by "TRIP". The colored boxes indicate the unique characteristics of the response.

Alarms

Protection philosophy (some operators may set differently)

Shutdowns

a. Traditional underload and overload
b. Stable motor temperature +15 deg F

Alarms = key to initiate analysis

a. Stable discharge pressure ± 50 psi
b. Stable intake pressure ± 20 psi
c. Motor temperature + 10 deg F
d. Stable current ± 10%

Surveillance Process: (questions to consider)[25]

- Is the pump on?
  - How is downtime captured?
- Is it producing?
- Is the system protected?
  - alarms and trips
- Has it lost production?
  - suddenly
  - gradually
- Do we understand the well inflow?
  - flowrate / watercut / PI validation
- Can we gain production (existing / new system)?
- Do we need remedial action?

<u>PULLING DUE TO FAILURE OR OPTIONAL PULL</u>

It is important to witness the pull. This is one time data and the condition of the unit when pulled can give important information on how the unit operated and what contributed to the failure.

Important decisions concerning future installations may also be based on this historical data.

Following is a breakdown of some aspects of electric submersible pump operation and the respective operator guidelines for each.

A "best guess" should be made at the wellsite as to the cause of failure

Record the pull with pictures, notes and sample of well material in/on the ESP when appropriate

Pulling Procedure

Care should be exercised pulling an ESP. For whatever the reason for pulling the ESP, the equipment is still valuable and should be treated the same as new equipment

Wellsite Pulling Observations:

Examine the wellhead feed through mandrel and cable connections to the mandrel (mechanical and electrical condition). Typically, not a problem area.

Look over the cable for mechanical (especially near clamps or bands) or electrical induced damage (burns or shorts).

Pull slowly if cable overserved to be outgassing and bubbling insulation.

Confirm number of retrieved cable clamps (i.e. Cannon or Lasalle if used) and bands is same # as installed. Inspect all splices in the cable, including the motor lead extension (MLE) to main power cable splice.

If any splice is suspected of being a problem, the point of the splice should be noted on the pull of the report. Most likely no repair splices should be tolerated in the cable body in offshore environment.

If the MLE to cable splice appears to have problems, the cable shall be cut approximately 3-4' above the splice and captured for further inspection and analysis.

Record the condition of Pothead Entry Point. NOTE: The pothead should NOT be disconnected in the field. The MLE should be cut 1-3 feet (~ 0.5-1 meter) above the pothead connection. Note possible corrosion of pump/motor other housings

Look for:

Plugged intake with debris or collapsed intake screen. (Take samples if debris is found and look for pugged stages near intake at shop dismantle)
Corrosion of cable armor
Condition of clamps/bands WRT to corrosion or mechanical damage
Impact damage to housings or cable
Signs of "drag marks on housings"
Signs of vibration between casing/housings with cable in between leaving cable indentations
Signs that the housings are bent
Note and/all electrical burns or arcing damage and location.

<u>TEARDOWN AND INSPECTION</u>[8,17-28]

Prepare for teardown

Set a date. It is possible to arrange teardowns of more than one unit on a given date. Prior to commencing dismantle operations, identification cards shall be prepared. These cards shall contain the following information for each component and should be visible to caption any photographs taken of the component:

1. Well Identification
2. Component Identification
3. Serial Number
4. Date of dismantle

Bring a notebook, camera (if allowed) and sample bags
Follow instructions of vendor on procedures, safety, etc.
Identify equipment by serial number/s or you may teardown wrong equipment.

Check lists for what to examine for each component when doing a teardown in the below mentioned API Practice:

Recommended Practice for Electrical Submersible Pump Teardown Report API RECOMMENDED PRACTICE 11S1

Below examples of what to look for when examining each component are given but the API checks lists (or company lists) can be more detailed.
Teardown Inspection by Components

Exterior (All components)
Is housing bent, corroded, is coating (if present) flaking off due to handling/well conditions, show signs of vibration between casing/pump, have dents, drag marks, other damage?

Visually inspect the head and intake for erosion, abrasives and foreign material.

Motor Inspection

Review the electrical readings from the pull report and reconfirm. Complete an electrical check on the motor prior to removing the MLE connection at the pothead if possible. At a minimum, the motor should be:

1. Megger test
2. Resistance readings taken
3. KV (dielectric) test on an oil sample taken from the base of the motor

Refer the specific manufacturer for minimum acceptable readings.
Check motor thrust bearing condition
Look in windings for burn
Inspect rotor for burns, hot spots (discoloration)
Check stator for phase balance and resistance to ground
And more… Have inspection sheet to remind what to check (API for instance)

The motor is shown in the shop with the head and rotor stack remove (Figure 22). An example motor winding burn (Figure 23) and an overheated motor radial thrust bearing are also shown (Figure 24).

Gas Separator Inspection
Check shaft play and exterior condition
Check rotor and internals, for erosional wear
Check bushings, shaft for wear. See components in Figure 25.

Protector Inspection (Seal Section, or Equalizer)
In general, following checks are made: condition of exterior interior for water, corrosion, foreign material, erosion, solids shaft play, all joints for leakage, bag (if present) for cracks, leakage etc. condition of shaft seals
Condition of shaft, bushings
Look for blockages or corrosion in labyrinth seal mechanism/s, all thrust bearing surfaces for steaking, wear, grooving, etc. Again, a check sheet should be used to insure all inspections are completed.

Check bag for leaks, tears, inappropriate assembly, chemical attack. See split bag in Figure 26

Figure 27 pictures a worn thrust bearing and a worn thrust ring from a protector

Check (Figure 28) the condition of the shaft seal. Shown here is seal on the shaft and spring and surfaces of the equipment. The shaft surfaces can be brittle so the seal or protector must be handled with care.

Next for example the tube/s in the labyrinth section of the seal or protector are shown in new and corroded condition (Figure 29).

Pump Teardown Inspection

Housing/Head/Intake

Remove joint lock plates if present Check equipment for lock-plate weld air leaks

Rotate Shaft and Check End Play

Using the appropriate spline wrench rotate the shaft (in the same direction as normal rotation, CCW for Reda as viewed from bottom of unit and CW for other makes).

The shaft should rotate freely and require very little effort as shown.

If the shaft rotates freely check the end-play gap and movement of the shaft. Push the shaft to the down position and take measurements; repeat in the up position. This will determine the shaft's axial movement. Compare to the manufacturer's factory settings.

Reda indicates normal axial shaft movement is about 1/16 in. on 3.38 in. – 540 series pumps and 1/16-1/8 in. on longer series pumps.

Using a dial indicator on the inside of the shaft spline, or on a coupling, measure run-out when the shaft is rotated. Repeat this procedure on either-end of the pump. Compare to the manufacturer's factory settings.

Remove the pump stages form the housing.

Inspect the stages nearest the intake for signs of plugging, erosion and similar mechanical damage. Visually check the impellers and diffusers for scoring due to upthrust or downthrust. Then check stages in middle and towards discharge to determine if wear is uniform throughout. With gas, for instance, more volume at intake might become apparent near discharge.
Check for hub radial wear.
Check for bushing-bearing wear in pump head which can be the cause of radial wear in the pump stages.
Also sand falling form the tubing back into the top end of the pump during frequent shutdowns could accelerate wear of stages near the pump discharge.
Radial and mixed flow impellers and diffusers with up and downthrust surfaces are shown below.
Remember the type of pump being inspected; i.e., fixed or floater, before making conclusion on the thrust wear.
Also take a sample of any foreign particle present.

Impeller Skirt Dimension

Check the skirt on both impellers and diffusers with a go-no go gauge.
(If the gauge can be slipped onto the skirt, the stages are worn beyond standard dimensions.)
If abrasive or erosional wear with time is a concern, a complete check of impeller and diffuser dimensions would include a measurement of:

impeller hubs (OD and ID)
impeller skirt OD
depth from reference to down-thrust surfaces;
diffuser hub ID
depth from reference to down-thrust wear surface;
diffuser ID where impeller skirt rides.

Inspect the shaft spline on both ends. Observe the splines for straightness and coupling engagement. If a coupling is only partially engaged damage may be noted at the upper end of the spline. Refer to guidelines for checking shaft straightness.

Place the shaft on a bench with the keyway facing up. Observe the shaft for straightness or twisting.
If the shaft utilizes shim nuts – remove and measure with a caliper.
Inspect the shaft surface for possible pitting, galling, erosion beneath the shaft sleeves, one-sided wear, etc.

Examples of Damage
Figure 30 shows an impeller and diffuser being checked for wear with go/no go gages.
Example severe sand wear for a diffuser/impeller is shown in Figure 30.
If the diffuser spins (Figure 31) inside the housing, a lot of heat is generated. Spots exposed to intense heat will be evident on the outside of the pump housing.

Teardown Inspection of Cable

Much of cable inspection may be made at the pull. A short piece of the MLE can be inspected still connected to the Pothead in the shop;

Check for:

1) Mechanical damage during running or pulling operations caused by:
- Crushing
- Stretching
- Crimping
- Cutting

2) Cable deterioration due to:
- High temperatures
- High pressure gas
- Corrosion
- Normal aging

3) Excessive current creates a high conductor temperature capable of breaking down the insulation.

Some example views of damaged cable and bands show the damage that can occur running in a well with small clearances present (Figure 32).

<u>RCFA (ROOT CAUSE FAILURE ANALYSIS)</u>

A process that determines: (after J Patterson, SWPSC)

What happened?
How did it happen?
Why it happened?
What will prevent it from happening again?
How will the solution be implemented?
How will the performance be measured?

Goal: To prevent reoccurrence of the failure

RCA Report guidelines

Investigation details:

Event description
Related documents
Sequence of Events
Critical event & Contributing factors

Root causes
Corrective action plan
Verification of effectiveness
Conclusions
Logic Chart & Tables & Figures

All of this should be included in the DIFA report at some level. (DIFA: Dismantle Inspection & Failure Analysis)

Once the immediate cause of failure is determined (teardown) then ask questions to get to root cause. The question and answer method is recommended for lower risk failures. High risk failures that perhaps involve loss of life have more detailed approaches.

Example possible Q&A related to ESP failure to determine the root cause of failure:

Motor failed:
Why? Burn
Why? Water in motor
Why? Seals on protector/seal/equalizer shafts failed
Why? Vibration
Why? Pump worn with sand wear and induced vibration
Why? Sand handling or elimination methods ineffective

So root cause could be current method of sand handling or sand elimination is ineffective. The ACTION item is to improve current methods for ESP with sand or go to another method to handle or eliminate sand. The effectiveness of any proposed solution method must be monitored.

Many (most?) teardown reports list the immediate cause of failure but due to time constraints, etc. the failure root cause is not determined as well as it could be.

<u>DESIGN FOR LONGER LIFE</u>

Design so pump conditions are in the recommended range to avoid up/down thrust for rates that are too high/too low and efficiency is higher.

Even if thrust rated OK at low rates, if you get to low rates where velocity of fluids pas the motor is less than 1 ft/sec, the motor temperature may spike. Areas of concern on the pump performance curve are shown in Figure 33.

For best life and performance design with the downhole or in-situ rate through the pump between the BEP and the right limit of the recommended range on the pump performance curve (Figure 34).

To avoid some instability and maintain better control, do not design on near flat portion of the head curve (if any). See Figure 35.

When moving to higher rate with VSD, design so that operational head/stage is less than the head per stage at the BEP on the 60 Hz pump curve (Figure 36).

When the tubing unloads because of slug flow and gas in the tubing, the pressure across the pump is reduced which places the pump in a low head and high flow point on the pump curve. This can lead to pump off which is to be avoided for longer life. See Figure 37.

Other factors:

Use a VSD for voltage balance and soft start, adjusting the voltage to optimize the motor efficiency, Large enough VSD, SUT, and Cable to increase starting torque, but limited so not to apply starting torque that is higher than the torque limits for the equipment shafts. Size unit so it does not continue to pump the well off. This is easily corrected when a VSD present.

Design so gas separator/s (if needed) can handle gas to prevent stops due to gas lock and/or underloads.

<u>OPERATIONAL PROBLEMS</u>
Starting/stopping. Starting and stopping is considered a critical factor leading to shorter run life.
Electrical surges, Electrical protections; A good grounding program (and use of VSD) can go a long way to prevent failures related to power surges or lightening (Figure 38). This figure includes a TVSS (Transient Voltage Surge Suppressor)

High Surface tubing or wellhead pressure:
High surface pressure is like pumping a deeper well and wastes electricity. However, if some gas is escaping a gas separator and flowing up the tubing then tubing back pressure can lead to more stable production. If high pressure occurs after design, it can lead to motor overload.
Poor quality power
Electrical filters, keeping ESP cable balanced, can help. Imbalance can be due to other electrical installations going on and off close by.
Reservoir Related Problems

- Declining reservoir
- Shut downs related to reservoir weakening
- Unconsolidated reservoir
- Slow starting to reduce solids influx
- Slugging from lateral

Severe Conditions
Sand
For sand , sand can be pumped or be pumped with pumps that have hardened sleeve bushings around the shaft or pumps that are “fixed” to the shaft to take thrust away between the stages and the diffusers. To better handle sand there are carbide inserts that put axial and vertical thrust on carbide for life These can be placed every few stages or on every stage.
To keep sand away from the pump, the Cavins sand separator swirls the fluids and sand, separates the sand and drops it into a closed end tubular below the pump intake. When the tubular fills with sand the separation no longer works.
Filters: (Odessa, Stren, Stanley, others) Filters can plug with time and probably should not be considered if there is scale formation in the well.
Gravel packs are sometimes used in wells to prevent the entry of solids into the well.
If run lives are still very short after evaluating the above, then another method of lift such as gas lift should perhaps be considered
Crystal or vibration sensors (Figure 39) exist to monitor sand production. They presumably could be used to diagnose the operation of sand eliminators such as the Cavins or filters.
Gas
Figure 40 shows that as intake pressure lowered that liquids follow the Vogel IPR but gas is present (from the GOR) represented by the dash line and the gas volume increases sharply at low pressures. The Red Dot (Figure 40) is where the ESP stages are predicted to no longer be able to handle the gas at lower pressure and higher gas volume fraction. Rotary and Vortex gas separators can separate high percentages of gas but for conservatism, one operator will analyze gas separation considering about 50% separation efficiency for rotary type separators.

Gas and liquid volumes at intake as pressure decreases
The ESP is predicted to no longer be able to handle the gas when the Dunbar factor drops below one. The conditions in the formula are all at pump intake conditions.

The Dunbar correlation uses the following correlation

$$\Phi_{Dunbar} = \frac{935}{Pip}\left(\frac{BGPD}{BLPD}\right)^{\frac{1}{1.724}}$$

Even with no gas separator, as long as the casing is vented at surface some of the gas will travel up the casing and not into the tubing. This phenomenon is said to be “natural separation”. The efficiency of natural separation can be approximated by:

$$Eff, natural = Vb/ (Vb+Vsl)$$

There are more sophisticated models for gas separator performance.
Vsl is the superficial liquid velocity using the casing as the flow path before the gas separation takes place. Vb is the terminal rise velocity of gas bubbles and is approximately ½ ft/sec although data is available that shows it to be a function of bubble size and also viscosity of the liquid. If the natural separation is around 50% then no additional separator may be needed. If it is lower, then a separator (probably some rotating separator, Vortex or Rotary) can be used to get better separation.

Packer Separators with a dip tube:
The completion on the left (Figure 41) is for horizontal well and the pump is set at the packer. The completion on the right (UPS system) shows a packer separator with a dip tube to take fluids a lower point in the well. The UPS system was designed and primarily used for Beam Pumps but can work for ESP’s (up to 3000 bpd).The UPS system is limited to about 50 bpd for each sq.in. of area between the tubing OD and casing ID so for higher rates this method would not.
Of course, for any downflow area the max rate is limited by the area which affects the downflow velocity of fluids which must be less than the bubble rise velocity. This system has been used for ESP applications.

ESP’s can be set below the perfs or in a sump as below. But the rate is limited for gas separation and a shroud or recirculating ESP must be used to insure fluids go to the bottom of the motor and then rise for motor cooling. Drilling a sump is possible in a horizontal well so the pump intake can be immersed in fluid but this is a very expensive addition to the completion.

Summary
A holistic approach to reduce failure frequency requires attention to many details to enhance run lives. If there is one overriding problem causing failures such as sand production, it probably wise to try to resolve this issue before looking extensively at the many additional contributing details that can cause failures.

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Case	Q	WHP	Amps	$P_{discharge}$	P_{intake}	ΔP_{pump}	T_{motor}
Broken shaft	↓	↓	TRIP ↓↓	↓	↑	TRIP ↓↓	TRIP ↗
Hole in tubing	↘	↘	→	↘	↗	TRIP ↘	TRIP ↗
Blockage at pump intake	↘	↘	↘	↘	↗	↘	TRIP ↗
Blockage at perforations	↘	↘	↘	↘	↘	TRIP ↗	TRIP ↗
Increase in water cut	↘	↘	↗	↗	↗	↗	→
Shut-in at surface	↓	TRIP ↑↑	TRIP ↓	TRIP ↑↑	↑	TRIP ↑↑	TRIP ↗
Blockage in pump stages	↘	↘	SPIKEY →	↘	↗	↘	TRIP ↗
Increase in reservoir pressure	↗	↗	→	↗	↗	↘	→
Incr. of free gas at pump intake	↘	↘	ERATIC TRIP ↘	↘	ERATIC ↗	↘	→
Wearing stages	↘	↘	SMOOTH TRIP ↘	↘	↗	TRIP ↘	TRIP ↗
Increase in frequency	↑	↑	↑	↑	↓	↑	↑
Open choke	↑	↓	→	↓	↓	↓	→

By Petroleum Development Oman, IPTC 17413 2014
Pattern Reconition Analysis Checklist: Using physical relationships, specific combinations of surface and downhole parameters can be used to describe any change of reservoir, well or ESP performance. The arrows indicate the rate of change of the variable. The colored boxes indicate the unique characteristics of the response.
The best trip parameters are indicated by 'TRIP'.

Table 1: Problems that can be detected from sensor outputs[24]

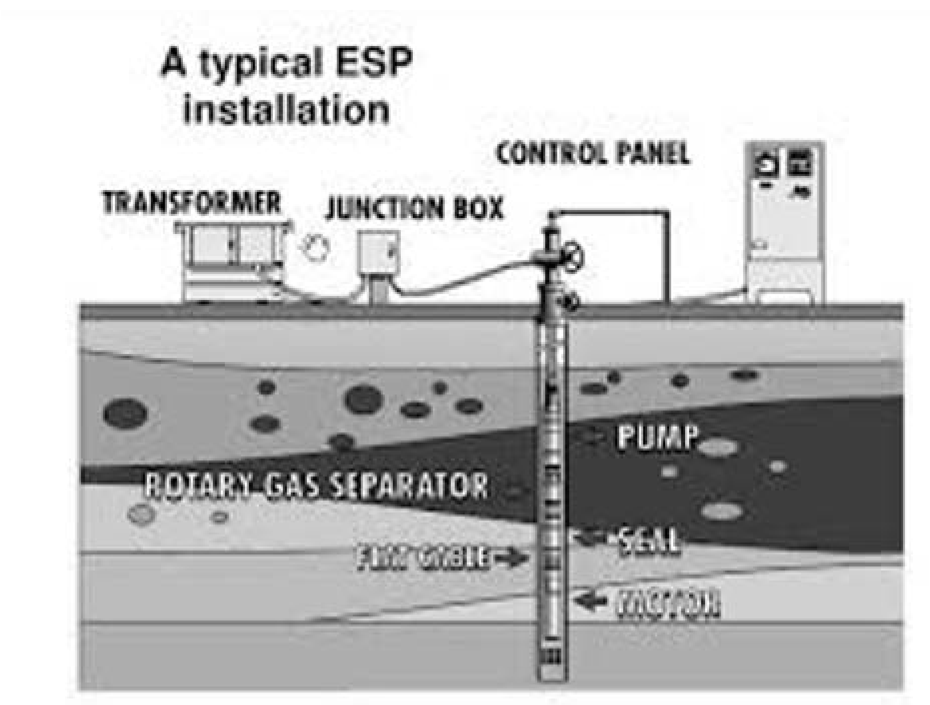


Figure 1: ESP System

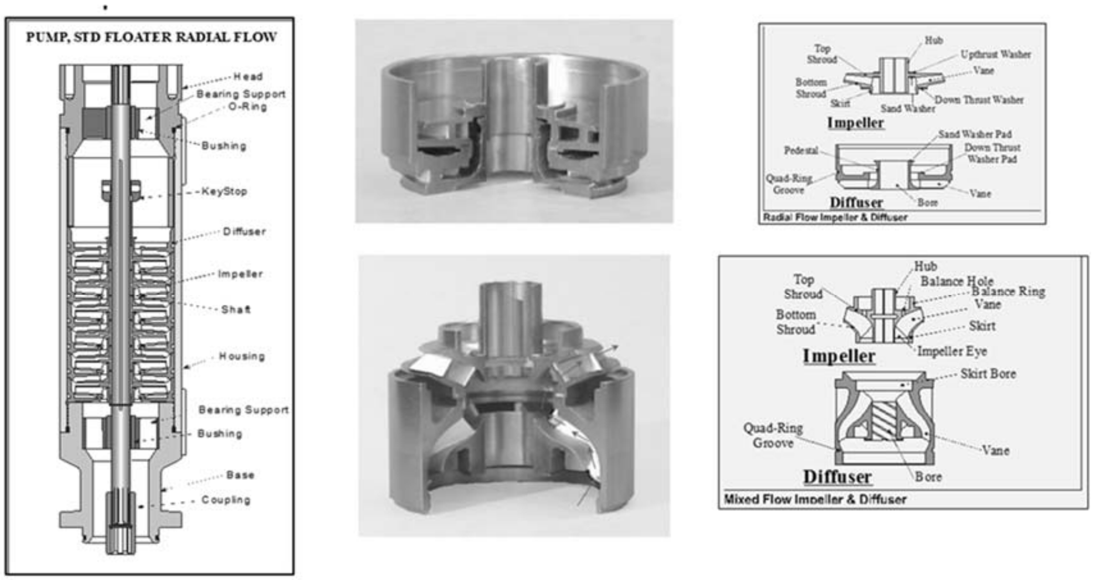


Figure 2: The ESP system pump

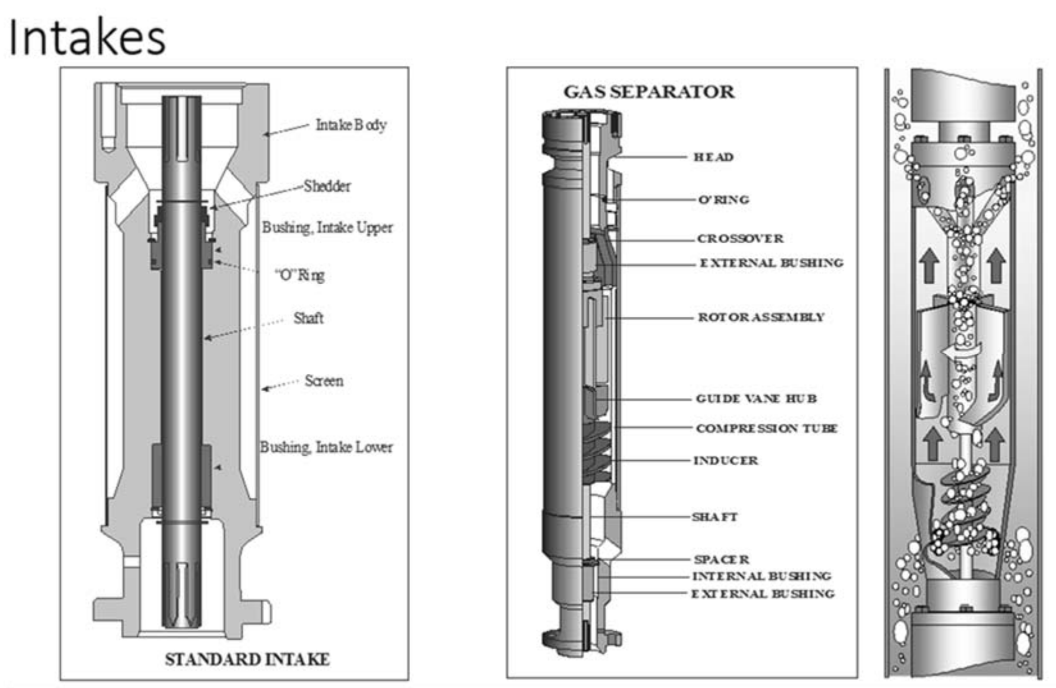


Figure 3: ESP Intake

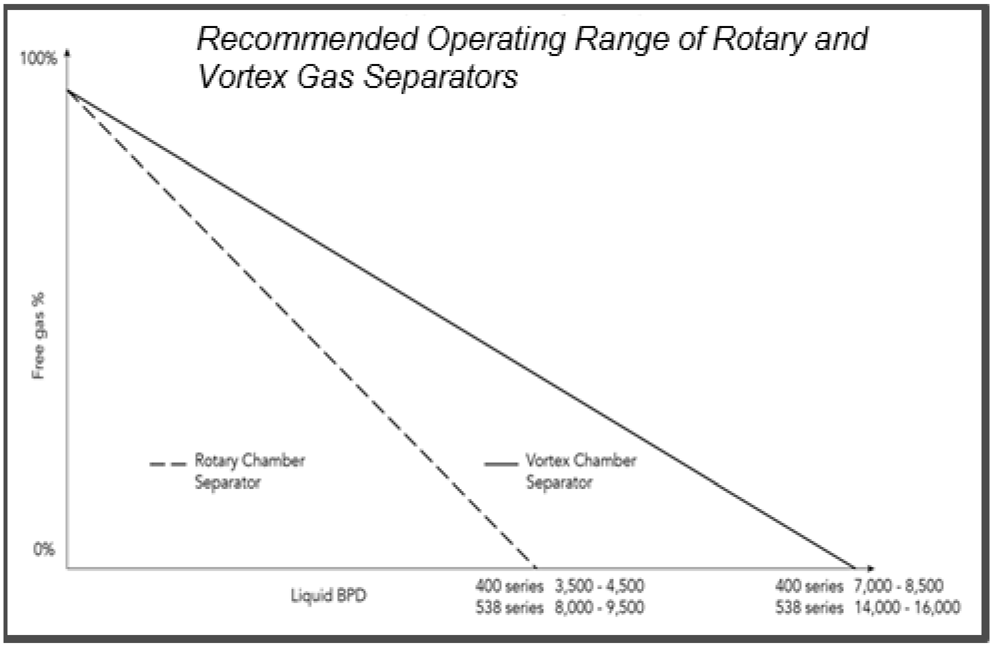


Figure 4. Range of Operation of Separators

Motor Protector (Seal Section)

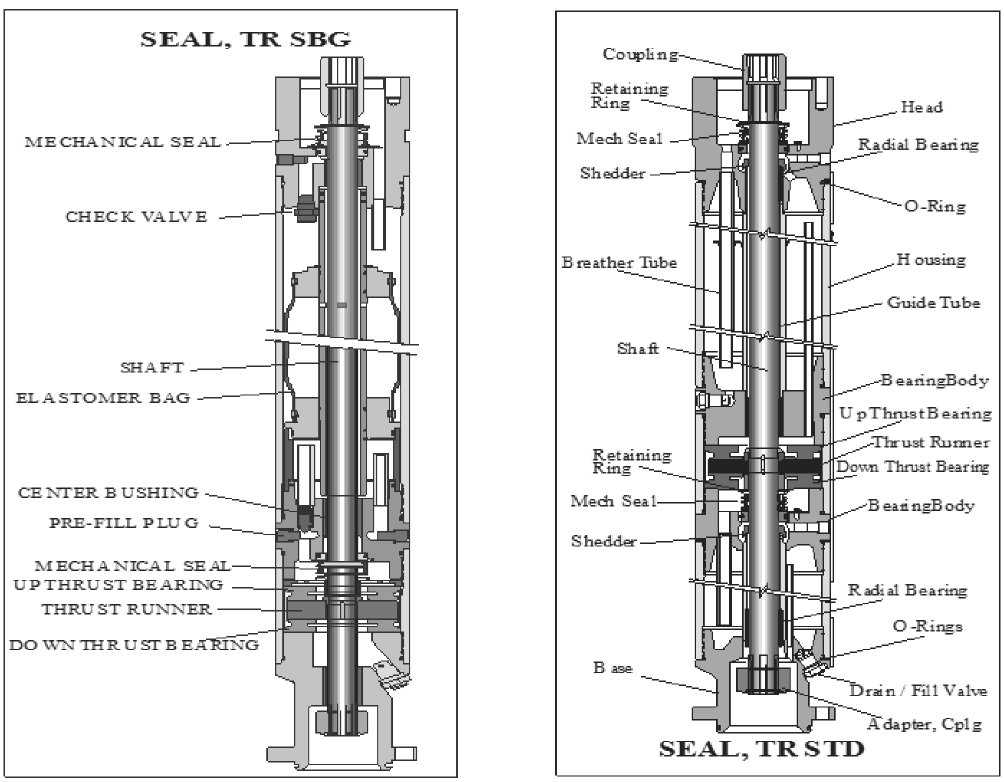


Figure 5: ESP Seal or Protector or Equalizer

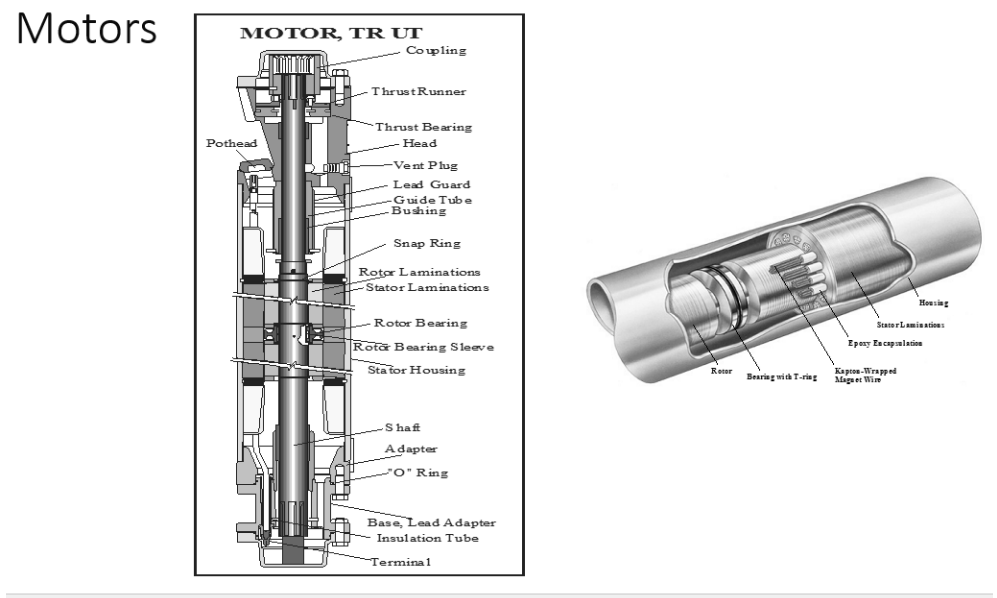


Figure 6: ESP Motor

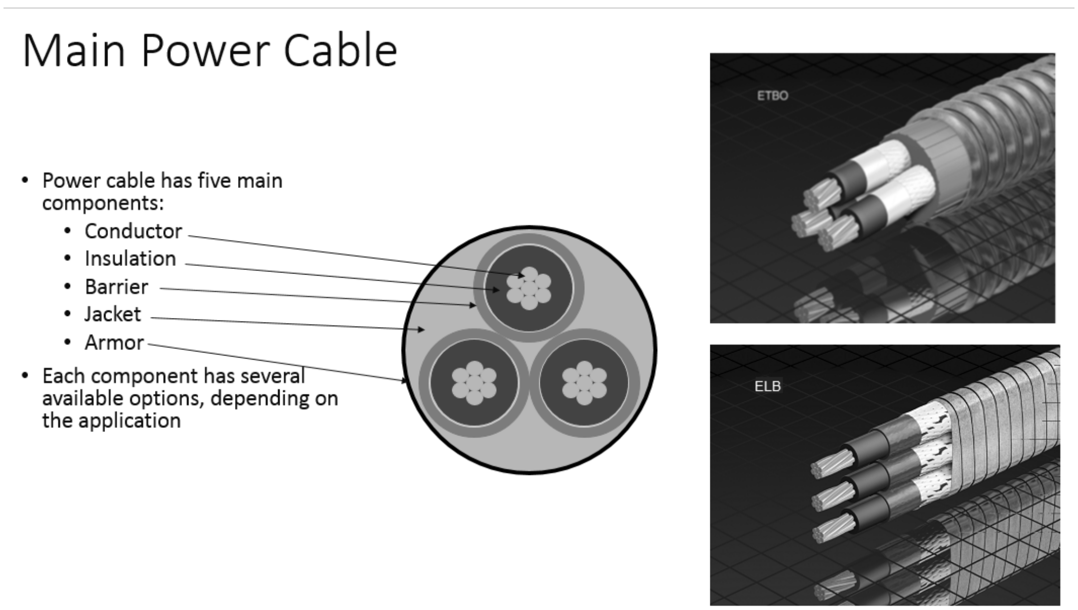


Figure 7: ESP Power Cable

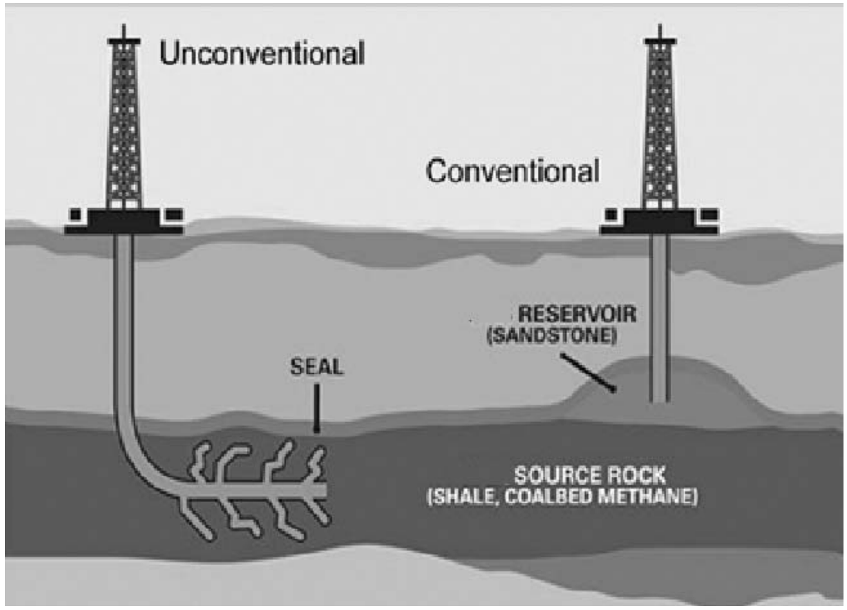


Figure 8: Conventional vs Unconventional Wells

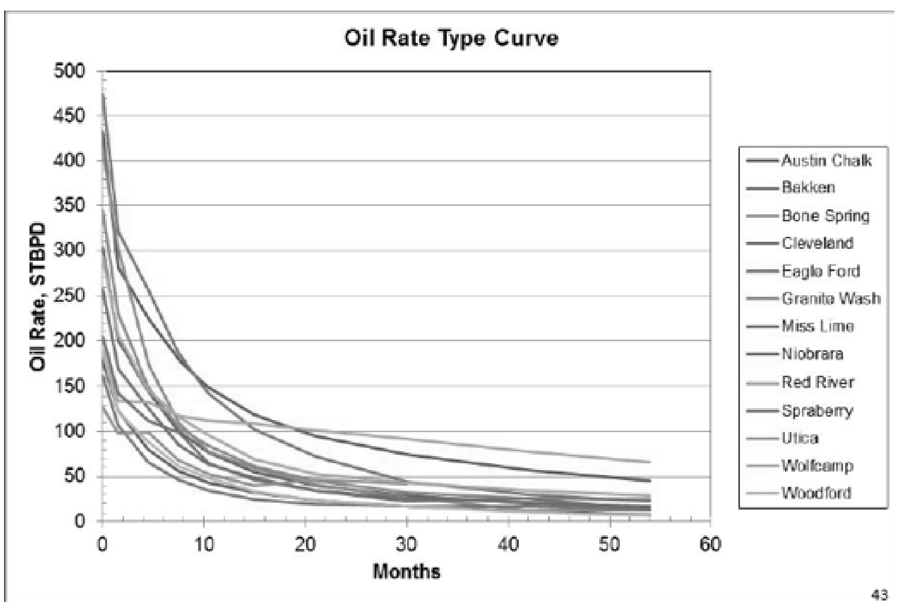


Figure 9: Various Decline Profiles

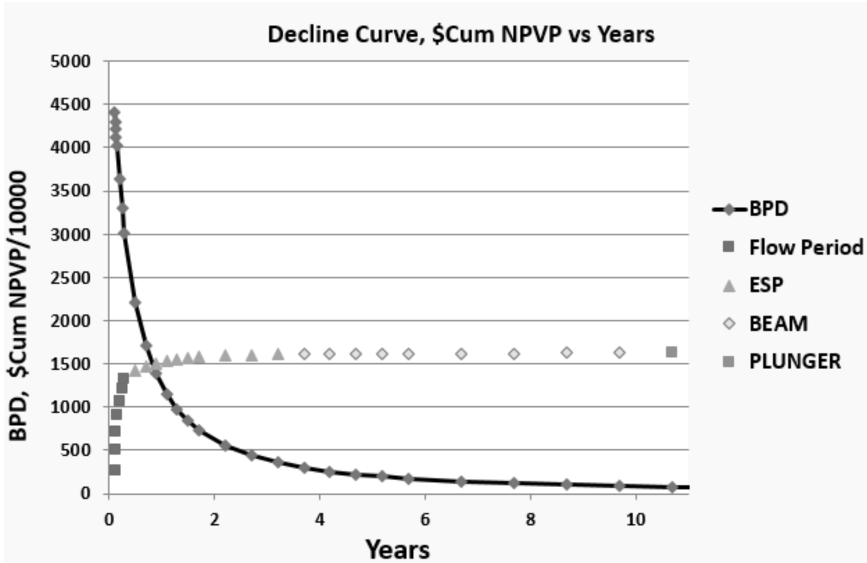


Figure 10: Results of PVP Analysis

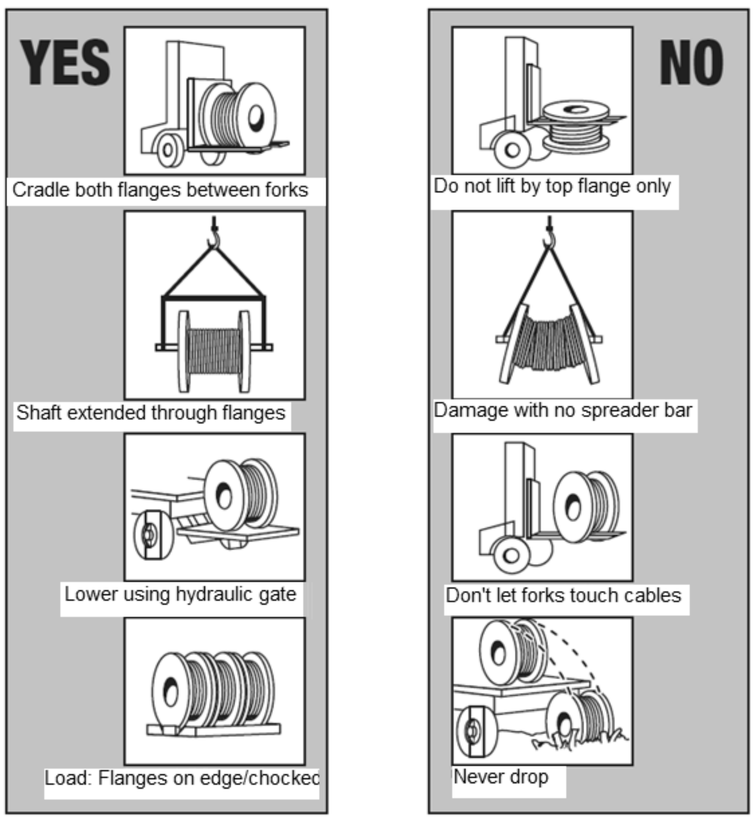


Figure 11: Handling Cable Spools[17]

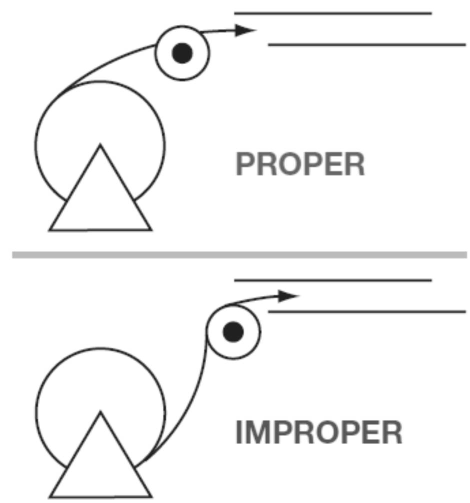


Figure 12: Spooling off Reels[17]

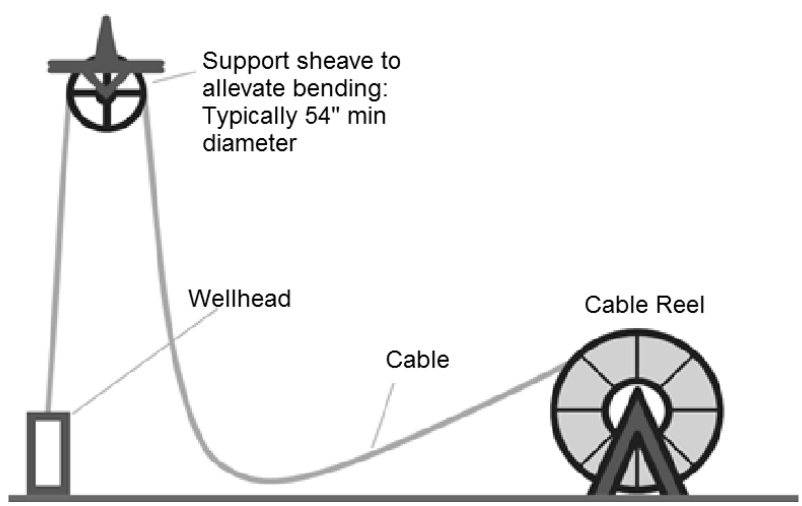


Figure 13: Support sheave above to alleviate bending[17]

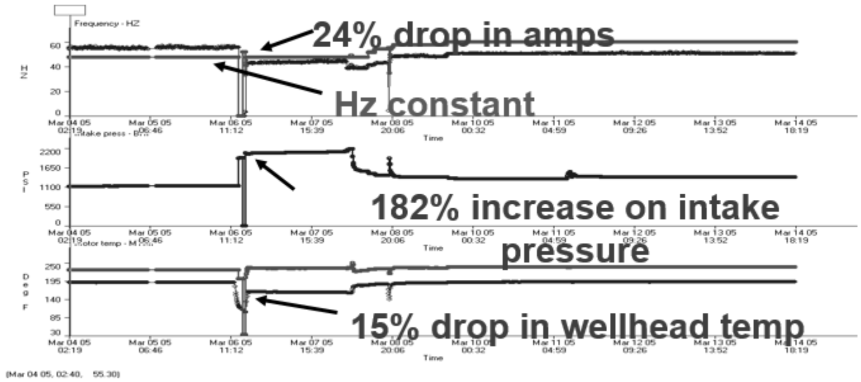
Figure 14: Cable sills/supports (adequate number)

Figure 15: Too few cable supports

Figure 16: A simple protective trough being banded across the pump

Figure 17: Banding tip. Bend “tang” such it will be under the cable

- Pump restarted - wrong rotation and broken shaft
- 2 days to realize – 12000 barrels oil lost



- Alarms catch this kind of thing!

Figure 18: Amps dropped (above) when shaft broke and no longer load on motor

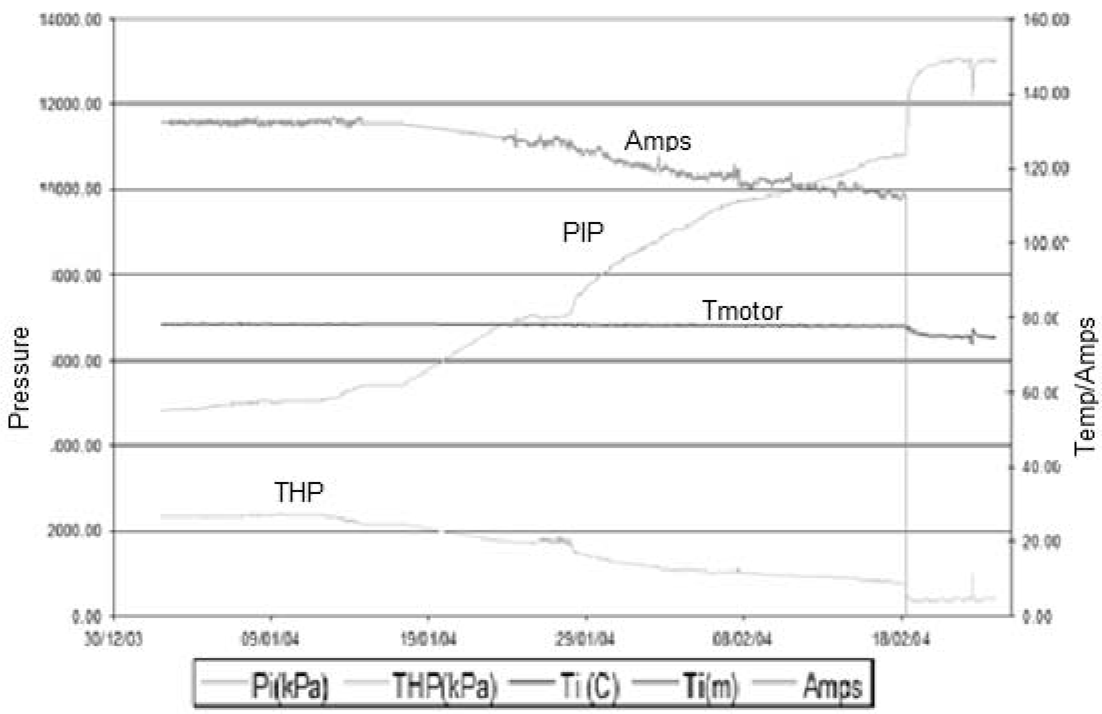


Figure 19: Amps gradually dropping with Tubing Leak

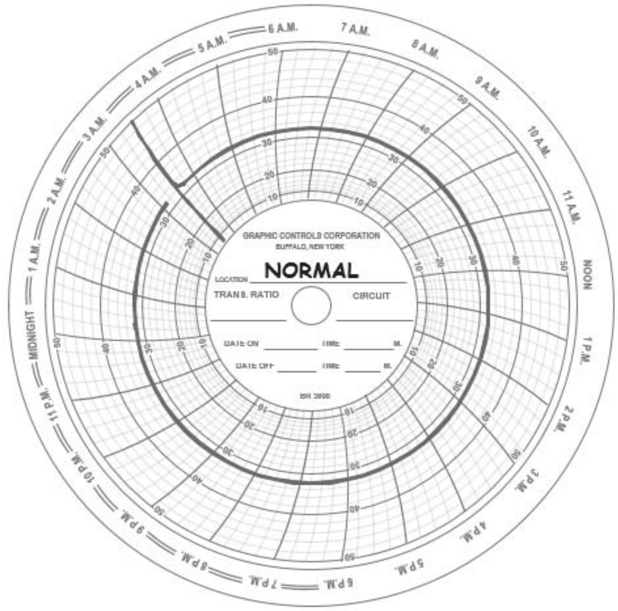


Figure 20: Normal Operation: Spike of Amps on start-up and then near constant amps

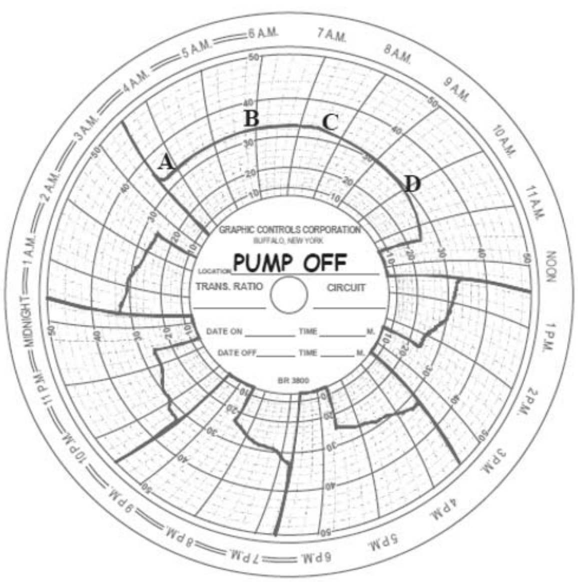


Figure 21: Well continuing to pump off.

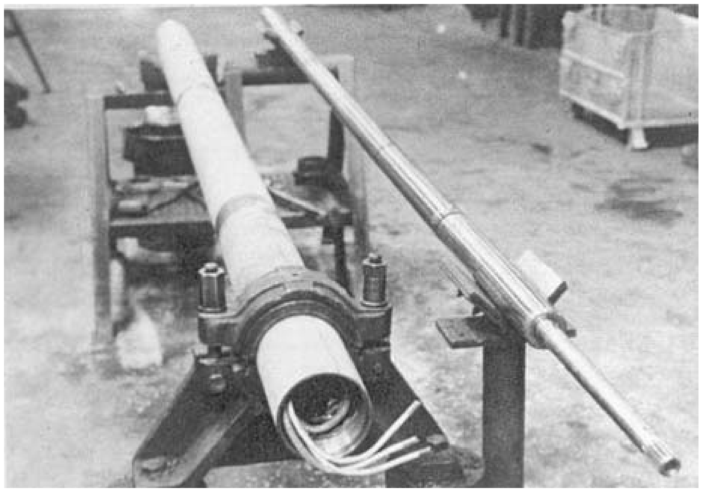


Figure 22: Motor in Shop: Head and rotor stack removed

Figure 23: Motor Slot burn

Figure 24: Motor Radial Thrust Bearing: White out, blue in – heating

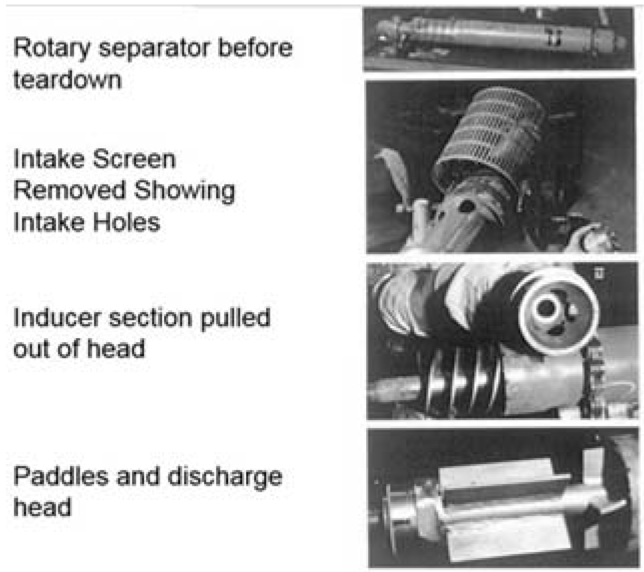


Figure 25: Miscellaneous Rotary Separator Components

Figure 26: Seal Split Bag

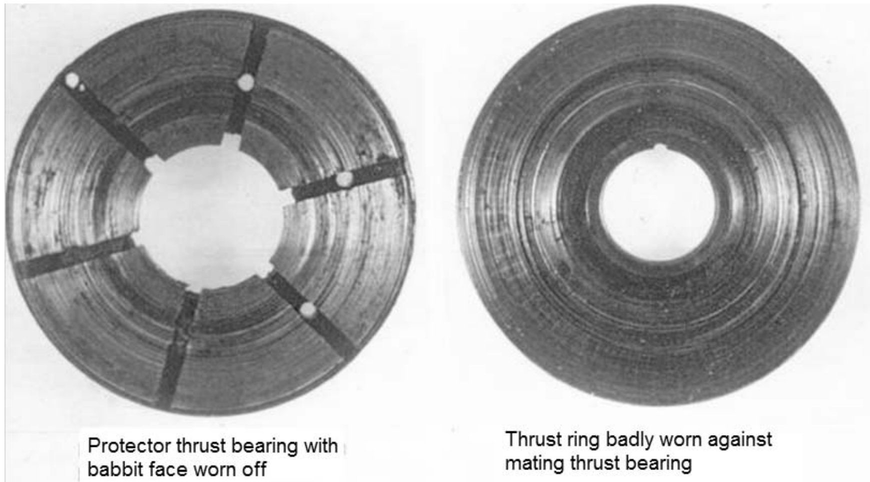


Figure 27: Protector thrust bearing and thrust ring both worn

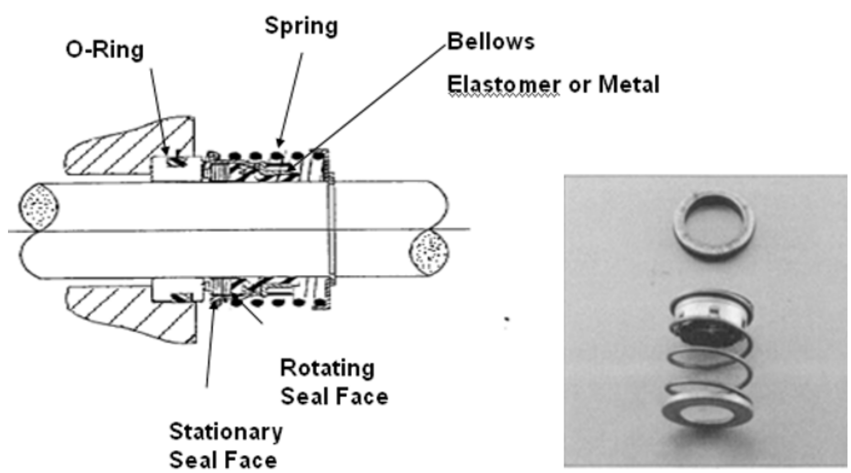


Figure 28: Shaft seal for protector

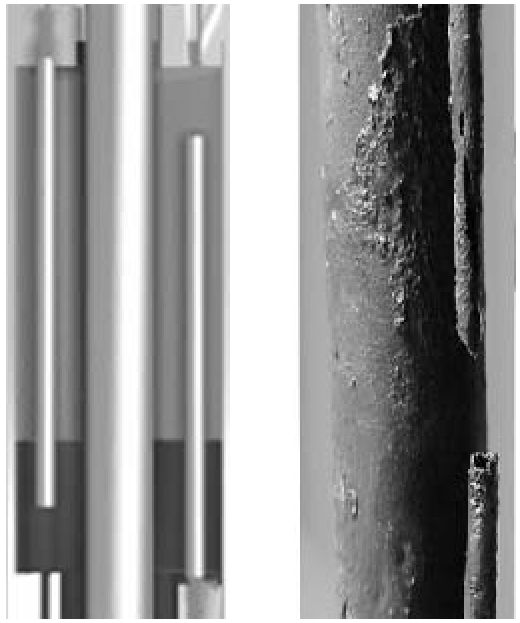


Figure 29: New Seal tube assembly (left) and Corroded Seal Tube (right)

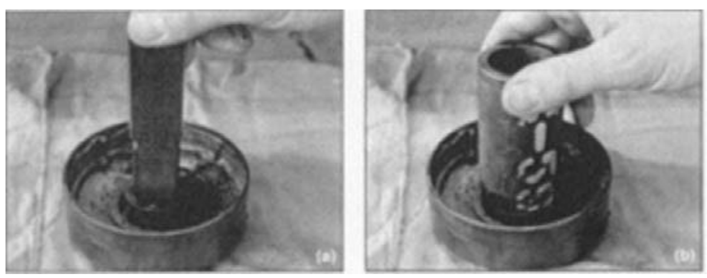


Figure 30: Check impeller/diffuser with go/no go gages

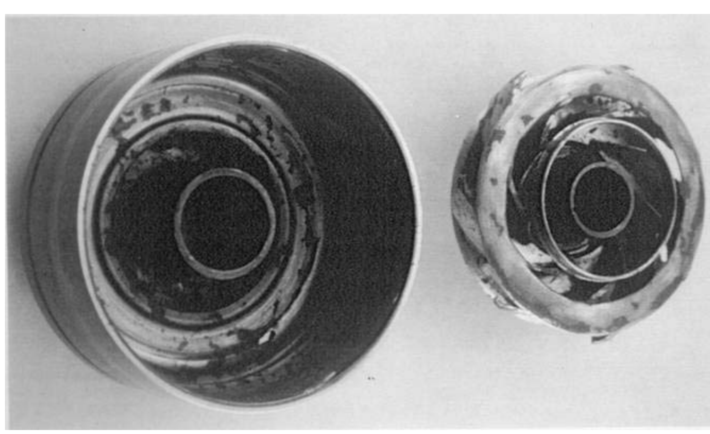


Figure 30: Diffuser/Impeller with sand wear

Figure 31: Diffuser Worn and Heated from Spinning

Figure 32: Views of cable from tight crooked hole showing band and cable damage

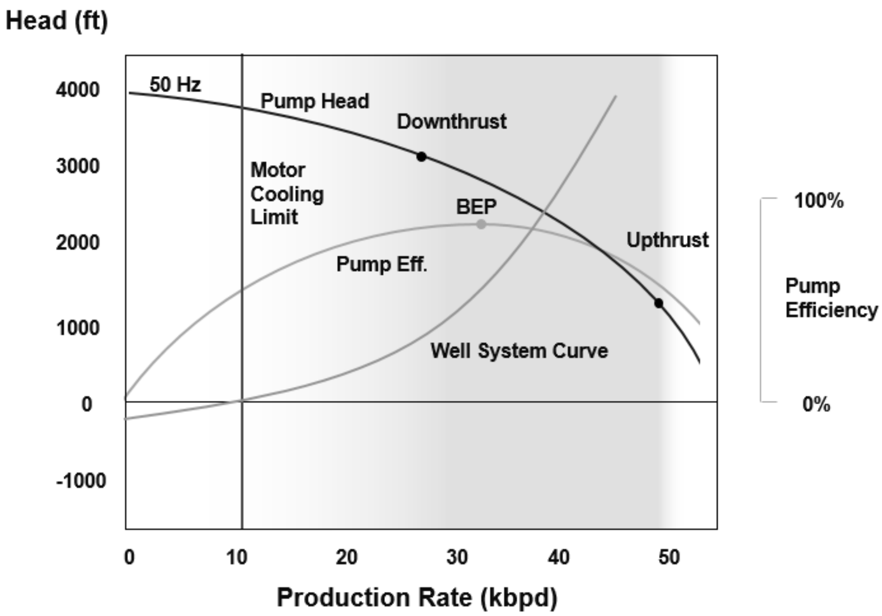


Figure 33: Areas of concern on pump performance design curve

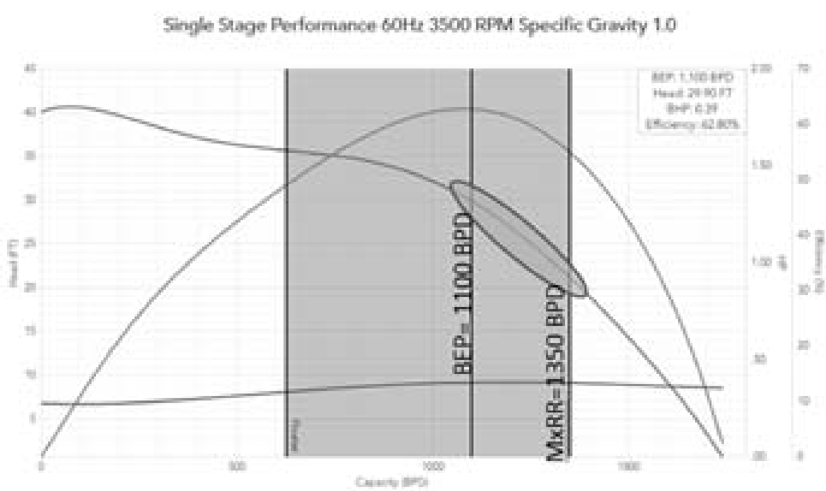


Figure 34: Best performance between BEP and right limit of recommended range

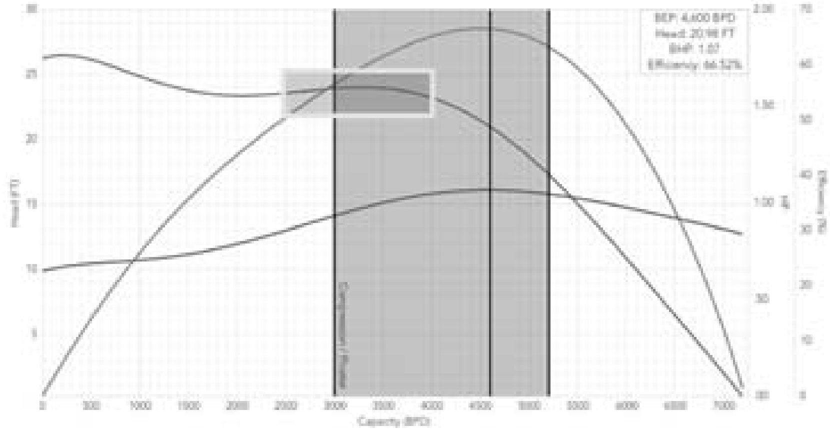


Figure 35: For stability do not design on a flat portion of Head curve

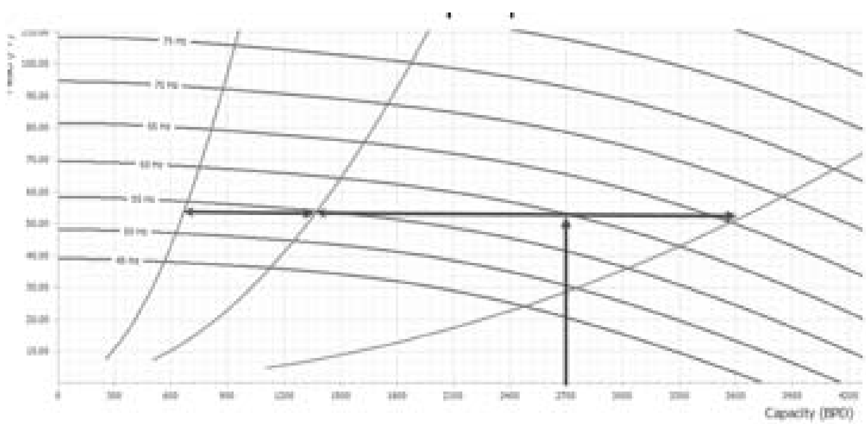


Figure 36; With VSD design so that the head/stage is less than head per stage at the BEP on the 60 Hz head curve

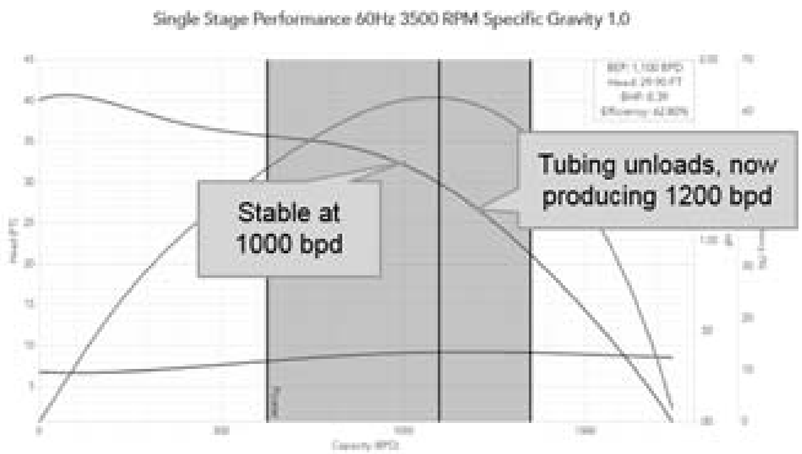


Figure 37: If gas in tubing causes tubing to unload, the pressure across the pump
Is reduced which generates low head and high flow which can lead to pump off

Transient Voltage Surge Suppressor (TVSS) devices (Variable Speed Drive)

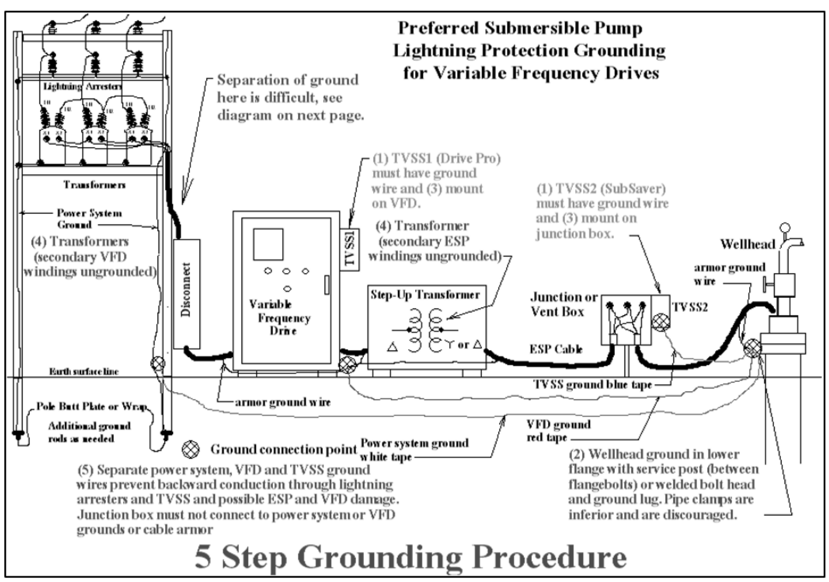


Figure 38: Grounding Systems (from T R Brinner)

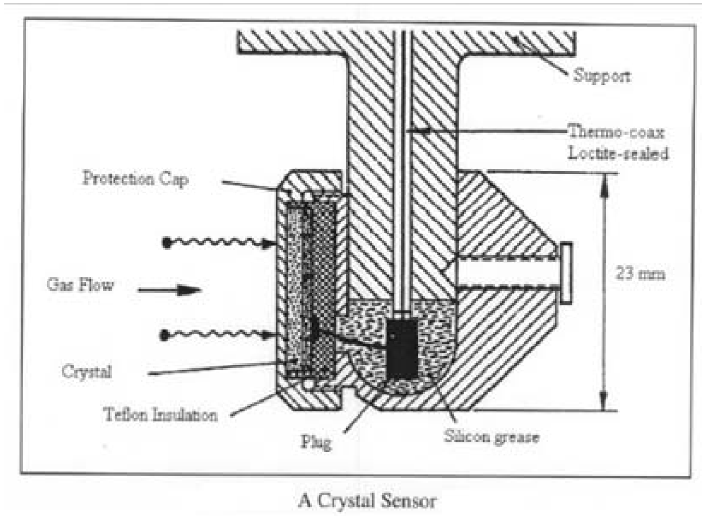


Figure 39: Crystal sensor that could pick up vibration from sand

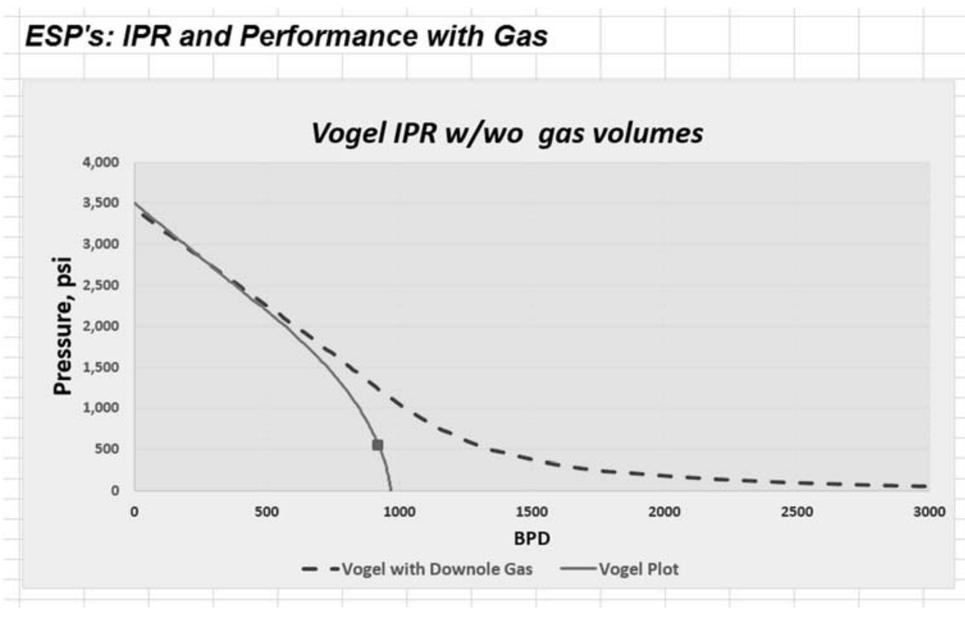


Figure 40: IPR with liquid & gas rates and min for ESP operation with gas

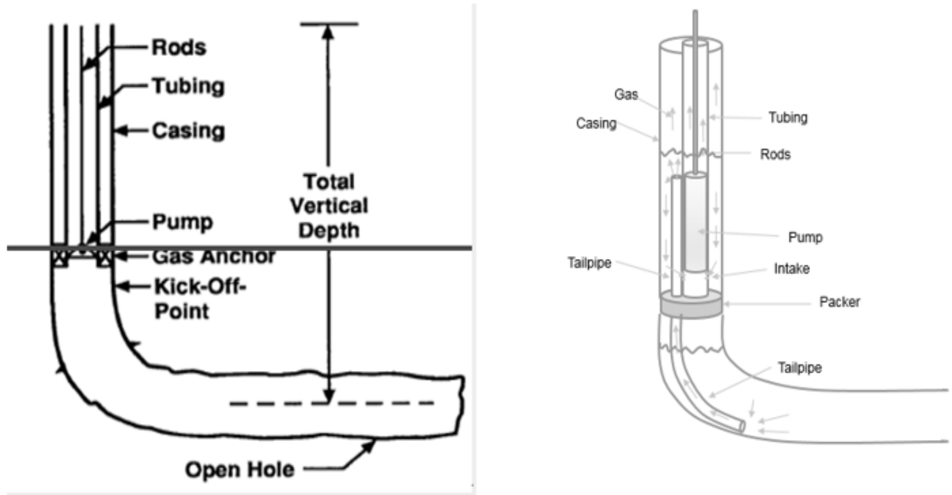


Figure 41: Packer separator on left and packer separator with dip tube on right