CHAPTER 5

ELECTRICAL SUBMERSIBLE PUMP DESIGN

The established nine step procedure can help to design the appropriate submersible pumping system for a particular well. Each of the nine steps are explained in the sections that follows, including gas calculations and variable speed operation.

5.1 STEP 1- BASIC DATA

The design of a submersible pumping unit, under most conditions, is not a difficult task, especially if reliable data are available. Although, if the information especially that pertaining to the well's capacity, is poor, the design will usually be marginal. Bad data often result in a misapplied pump and costly operation. A misapplied pump may operate outside the recommended range, overload or underload the motor, or draw the well at a rapid rate which may result in formation damage. On the other extreme, the pump may not be large enough to provide the desired production rate.

Too often, data from other wells in the same field or in a nearby area is used, assuming that wells from the same producing horizon will have similar characteristics. Unfortunately, for the engineer sizing the submersible installation, oil wells are much like fingerprints, that is, no two are quite alike.

The actual selection procedure can vary significantly depending upon the well fluid properties. The three major types of ESP applications are:

1. High water cut wells producing fresh water or brine.
2. Wells with multi- phase flow (high GOR).
3. Wells producing highly viscous fluids.

Following is a list of data required:

5.1.1 Well Data

a. Casing or liner size and weight

b. Tubing size, type and thread (condition)

c. Perforated or open hole interval

d. Pump setting depth (measured & vertical)

5.1.2 Production Data

a. Wellhead tubing pressure

b. Wellhead casing pressure

c. Present production rate

d. Producing fluid level and /or pump intake pressure

e. Static fluid level and /or static bottom-hole pressure

f. Datum point

g. Bottom-hole temperature

h. Desired production rate

i. Gas oil ratio

j. Water cut

5.1.3 Well Fluid Conditions

a. Specific gravity of water

b. Oil API or specific gravity

c. Specific gravity of gas

d. Bubble-point pressure

e. Viscosity of oil

f. PVT data

5.1.4 Power Sources

a. Available primary voltage

b. Frequency

c. Power source capabilities

5.1.5 Possible Problems

a. Sand

b. Deposition

c. Corrosion

d. Paraffin

e. Emulsion

f. Gas

g. Temperature

5.2 STEP 2- PRODUCTION CAPACITY

The following is a simplification of procedures for predicting well performance. This discussion assumes a flow efficiency of one. A damaged well or other factors will effect the flow efficiency and efficiency and could change the well's productivity.

5.2.1 Productivity Index

When the well flowing pressure (P_{wf}) is greater than bubble-point pressure (P_b), the fluid is similar to single phase flow, and the inflow performance curve is a straight line with slope $-\frac{1}{J}$, as given by the productivity index, PI:

$$\text{P.I.} = J = \frac{Q}{\overline{P}_r - P_{wf}} \tag{5.1}$$

where:

Q = the fluid test production rate

P_{wf} = the well flowing pressure @ test rate Q

P_r = reservoir pressure

Note:

P_r and P_{wf} are terms which are always referenced to the same specific vertical depth.

5.2.2 Inflow Performance Relationship

If P_{wf} is less than P_b, resulting in multi-phase flow, the Vogel method should be used. The relationship is given by the following equation:

$$Q_{o,MAX} = \frac{Q_o}{1 - 0.2\left(\frac{P_{wf}}{\overline{P}_r}\right) - 0.8\left(\frac{P_{wf}}{\overline{P}_r}\right)^2} \tag{5.2}$$

It's a dimensionless reference curve that can be used to determine the IPR curve for a particular well.

5.3 STEP 3- GAS CALCULATIONS

The presence of free gas at the pump intake and in the discharge tubing makes the process of equipment selection much more complicated and voluminous. As the fluid (liquid and gas mixture) flows through the pump stages from intake to the discharge and through the discharge tubing, the pressure increases and consequently, fluid properties (such as volume, density, etc.) continuously go on changing. Also, the presence of free gas in the discharging tubing may create significant "gas-lift" effect and considerably reduce the required discharge pressure.

The performance of a centrifugal pump is also considerably affected by the gas. As long as the gas remains in solution, the pump behaves normally as if pumping a liquid of low density. However, the pump starts producing lower than normal head as the gas-to-liquid ratio (at pumping conditions) increases beyond a certain "critical" value (usually about 10-15%). It is mainly due to separation of the liquid and gas phases in the pump stage and due to a slippage between these two phases. This phenomenon has not been well studied and there is no general correlation describing the effect of free gas on pump performance. A submersible pump is usually selected by assuming no slippage between the two phases or by correcting stage performance based on actual filed test data and past experience.

Ideally, a well would produce with a submergence pressure above the bubble point pressure to keep the gases in the solution at the pump intake. This is typically not possible, so the gases must be separated from the other fluids prior to the pump intake to achieve the maximum system efficiency.

There are numerous combinations of equipment configurations and well bore completions which are available for enhancing the performance of ESP's in gassy applications. Many of these are identified in the "Gas Handling Guideline". Specifically, many manufacturing companies offer several optional components used for separating gas from the fluid going to the pump intake. These are listed according to increasing efficiency. The first is a reverse flow intake, which uses the natural buoyancy of the fluids for separation. The second is a vertex type intake, which uses the fluid velocity to set-up a rotational flow to induce radial separation of the gas. The last is a rotary gas separator intake, which utilizes a mechanical, rotating chamber to impart a high, centrifugal force on the fluid to separate the gas.

It is essential to determine the effect of the gas on the fluid volume in order to select the proper pump and separator.

If the solution gas/oil ratio (R_s), the gas volume factor (B_g), and the formation volume factor (B_o) are not available from reservoir data, they must be calculated, and there are a number of correlations to select from. The correlation you select will affect your design, so select the one that best matches your conditions. The following are Standings correlations for solution gas/oil, and formation volume factor:

5.3.1 Solution Gas/ Oil Ratio

$$R_s = Y_g \left(\frac{P_b}{18} x \frac{10^{0.0125 \times ^\circ API}}{10^{0.00091 \times T(^\circ F)}} \right)^{1.2048} \qquad (5.3)$$

where: Y_g = Specific Gravity Gas

P_b = Bubble-Point Pressure, psi

T = Bottom-hole Temperature, $^\circ$ F

Note: Pump Intake Pressure (PIP) should be substituted for Bubble Point Pressure when calculating intake conditions.

5.3.2 Gas Formation Volume Factor

$$B_g = 0.00502 \frac{ZT}{P} \text{ or in metric, } B_g = 0.003377 \frac{ZT}{P} \qquad (5.4)$$

where: Z = Gas compressibility factor (0.81 to 0.91)

T = Bottom-hole temperature degrees Rankin (460 +°F), or in metric Kelvin (273 +°C)

P = Submergence pressure psi, or (kg/cm^2)

5.3.3 Oil Formation Volume Factor

The oil formation volume factor B_o, represents the increased volume a barrel of oil occupies in the formation as compared to a stock barrel.

$$B_o = 0.972 + 0.000147\,F^{1.175} \tag{5.5}$$

where: $F = R_s \left(\dfrac{Y_g}{Y_o}\right)^{0.5} + 1.25\,T$

T = Bottom-hole temperature, "F or in metric.

5.3.4 Total Volume of Fluids

When these three variables, R_s, B_o and B_g are known, the volumes of oil, water and free gas can be determined and percentages of each can be calculated. The total volume of gas (both free and in solution) can be determined as follows:

$$\text{Total Gas} = \frac{Producing\ GOR \times BOPD}{1{,}000} = \text{MCF} \tag{5.6}$$

Total Gas= Producing GOR x $M^3PD = M^3$

The gas in solution at submergence pressure can be determined as follows:

$$\text{Solution Gas} = \frac{R_s \times BOPD}{1{,}000} = \text{MCF} \tag{5.7}$$

The Free Gas equals the Total Gas minus the Solution Gas.

The volume of oil (V_o) at the pump intake equals stock tank barrels times B_o, the formation volume factor.

The volume of gas (V_g) at the pump intake equals the amount of free gas times B_g, the gas volume factor.

The volume of water (V_w) in the formation is the same as stock tank barrels.

Total fluid volume (V_t) can now be determined.

$$V_t = V_o + V_g + V_w \tag{5.8}$$

The percentage of free gas to total volume of fluids can now be calculated:

$$\% \text{ Free Gas} = \frac{V_g}{V_t}$$

5.4 STEP- 4 TOTAL DYNAMIC HEAD

The next step is to determine the total dynamic head required to pump the desired capacity. The total pump head refers to feet (meters) of liquid being pumped and is calculated to be the sum of: 1) net well lift (dynamic lift); 2) well tubing friction loss; and 3) wellhead discharge pressure. The simplified equation is as follows:

$$TDH = H_d + F_t + P_d \tag{5.9}$$

where:

TDH= total dynamic head in feet (meters) delivered by the pump when pumping the desired volume.

H_d = vertical distance in feet (meters) between the wellhead and the estimated producing fluid level at the expected capacity.

F_t= the head required to overcome friction loss in tubing measured in feet (meters).

P_d= the head required to overcome friction in the surface pipe, valves and fittings, and to overcome elevation changes between wellhead and tank battery. Normally, this is measured in gauge pressure psi (kh/cm^2) at the wellhead and can be converted to head, in feet (meters) as follows:

$$P_d = \frac{psi \ x \ 2.31 ft / psi}{Specific \ Gravity} \quad \text{or;} \tag{5.10}$$

$$P_d = \frac{psi}{0.433 \ psi / ft \ x \ sp.gr.}$$

In Metric:

$$P_d = \frac{kg/cm^2 \; x \, 10.01 \; m/kg/cm^2}{Specific \; Gravity} \quad \text{or;} \qquad (5.11)$$

$$P_d = \frac{kg/cm^2}{0.0999 \; x \; Sp.Gr.}$$

5.5 STEP 5- PUMP TYPE

Based on expected fluid production rate and casing size, select the pump type which will, at the expected operating range and nearest to the pump's peak efficiency. Where two or more pump types have similar efficiencies at the desired volume, the following conditions determine the pump choice:

1. Pump prices and corresponding motor sizes and prices may differ somewhat. Normally, the larger-diameter pump and motor are less expensive and operate at higher efficiencies.
2. When the wells capacity is not known, or cannot be closely estimated, a pump with a "steep" characteristic curve should be chosen. If the desired volume falls at a point where two pump types have approximately equal efficiency, choose the pump type which requires the greatest number of stages. Such a pump will produce a capacity nearest the desired volume even if the well lift is substantially more or less than expected.
3. If gas is present in the produced fluid, a gas separator may be required to achieve efficient operation. Refer to Step 3 to determine the effect of gas on the produced volume. The adjusted volume affects pump selection and the size of the other system components.
4. In wells where the fluid is quite viscous and/or tends to emulsify, or in other extraordinary circumstances, some pump corrections may be necessary to ensure a more efficient operation.

5.5.1 The VSSP System and Pump Selection

Under the above, or other pumping conditions, also consider the Variable Speed Submersible Pumping (VSSP) system. For instance, in item 2 above, if a well is not accurately known, a VSSP system is ideal. An Electro-speed variable speed controller effectively converts a single pump into a family of pumps. So, a pump can be selected for an estimated range and adjusted for the desired production level, once more data is collected.

The VSSP system with the Electro-speed improves pump operation under other conditions as well, including gassy wells, abrasive wells, low volume wells, etc. It provides soft starts, eliminates intermittent from power transients, minimizes down-hole heating, and more.

Review Step 9 when considering the VSSP system. The VSSP System with Electro-speed may provide additional economies of capital expenditure and operating expenses, and should be considered in Step 6, "Optimum Size of Components." The Electro-speed variable speed controller and transformers for the VSSP system are discussed in Step 8 and 9.

5.6 STEP- 6 OPTIMUM SIZES OF COMPONENTS

Many components are built in a number of sizes and can be assembled in a variety of combinations. These combinations must be carefully determined to operate the submersible pumping system within production requirements, material strength and temperature limits.

A fluid velocity of 1 foot per second (0.305 meters per second) is recommended to ensure adequate motor cooling. In cases where this velocity is not achieved, a motor jacket may be required to increase the velocity.

5.6.1 Pump Number of Stages

Refer to the performance curve of the pump selected for use and determine the number of stages required to produce the anticipated capacity against the previously calculated total dynamic head. Performance curves for 60 Hz, 50 Hz and variable frequency performance are located in the pump plot. Note that the pump characteristic curves are single stage performance curves based on water with (specific gravity of 1.00).

An example of a pump plot is shown in Figure 5.1.

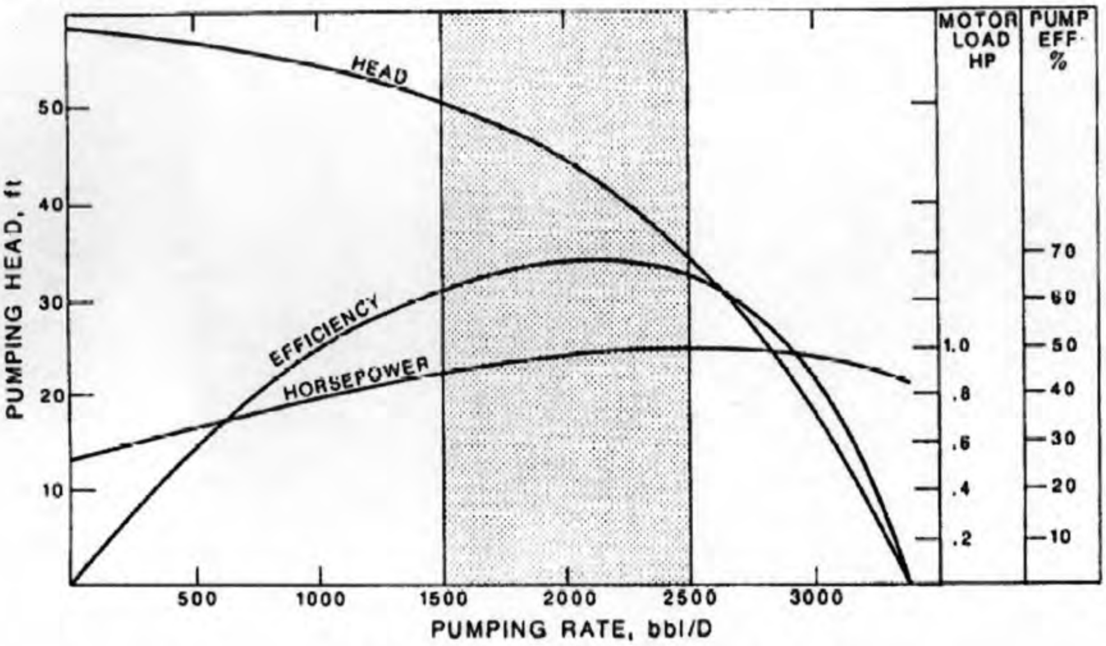

Figure 5.1 Typical pump plot for ESP[5]

At the intersection of the desired productions rate (bottom scale) and the head-capacity curve (vertical scale), read the head value on the left scale. Divide this value into the total dynamic head to determine the number of stages.

$$\text{Total Stages} = \frac{\textit{Total Dynamic Head}}{\textit{Head / Stage}} \tag{5.12}$$

5.6.2 Separator

Refer to gas separator information for gas separation capabilities. Make the necessary adjustments in horse power requirements and housing length.

5.6.3 Motor

To select the proper motor size for a predetermined pump size, you must first determine the brake horsepower required by the pump. The horsepower per stage is obtained be again referring to the performance curve for the selected pump and reading the value on the right scale. The brake horsepower required to drive a given pump is easily calculated by the following formula:

$$\text{BHP} = \text{Total Stages x BHP/Stage x Sp. Gr.} \tag{5.13}$$

5.7 STEP 7- ELECTRIC CABLE

Electric cables are normally available from stock in conductor sizes 1, 2, 4, and 6. These sizes are offered in both round and flat configurations.

Several types of ARMOUR and insulation are available for protecting against fluids and severe environments. Cable selection involves the determination of:

1) Cable size;
2) Cable type;
3) Cable length.

5.7.1 Cable Size

The proper cable size is dependent on combined factors of voltage drop, amperage and available space between tubing collars and casing. Refer to the Cable Voltage Drop curve of the specific pump for voltage drop in cable. At the selected motor amperage and the given down-hole temperature, the selection of a cable size that will give a voltage drop of less than 30 volts per 1,000 ft.(305 meters) or less than 15% of motor nameplate volts is recommended. This curve will also enable us to determine this necessary surface voltage (motor voltage plus voltage drop in the cable) required to operate the motor.

Finally, refer to the Equipment Combination table of the specific pump to determine of the size selected can be used with the proposed tubing and well casing size. Cable diameter plus tubing collar diameter will need to be less than the inside diameter (I.D.) of the casing.

In determining the optimum cable size, consider future equipment requirements that may require the use of a larger size cable.

If power cost is a major concern, the Kilowatt Hour Loss Curve can be used to justify the cable selection. Although power rates very widely, this data are valuable in determining the economies of various cable sizes.

5.7.2 Cable Type

Selection of the cable type is primarily based on fluid conditions, bottom-hole temperature and space limitations within the casing annulus. Where there is not sufficient space to run round cable, use electric cable of flat configuration.

5.7.3 Cable Length

The total cable length should be at least 100 ft. (30 M) longer than the measured pump setting depth in order to make surface connections a safe distance from the wellhead. Refer to curve on Recommended Maximum Cable Length to avoid the possibility of low voltage starts.

5.7.4 Cable Venting

In all wells, it is necessary to vent gases from the cable prior to the motor controller to avoid explosive conditions. A cable venting box is available to protect the motor controller from such gases.

5.8 STEP 8- ACCESSORY & OPTIONAL EQUIPMENT

5.8.1 DOWNHOLE ACCESSORY EQUIPMENT

5.8.1.1 Flat cable (motor lead extension)

Select a length at least 6 ft. (1.8m) longer than pump, intake (standard or gas separator) and seal selection for the motor series chosen.

5.8.1.2 Flat cable guard

Choose the required number of 6 ft.(1.8m) guard sections to at least equal that flat cable length.

5.8.1.3 Cable bands

Use one 30 in. (76 cm) cable band every 2ft. (60 cm) for clamping flat cable to pump. The 22 in. (56cm) length can be used for all tubing-cable combinations through 3-1/2" O.D. tubing. For 4-1/2" and 5-1/2" O.D. tubing, use 30 in.(76 cm) bands. One band is required for each 15 ft. (5m) of setting depth.

Selection of swaged nipple, check valve and drain valve is based on required outside diameters and type of threads.

5.8.2 MOTOR CONTROLLERS

The digital control consisting of two components:

- System Unit

  This unit performs all the shutdown and restart operations. It is mounted in the low- voltage compartment of the control panel.

- Display Unit(Optional)

  This unit displays readings, set points and alarms. It is normally mounted in the arm chart enclosure for easy access.

It provides all the basic functions, such as under-load, overload, phase imbalance, phase rotation, etc. and over 90 other parameters including communication protocols.

5.8.3 SINGLE- PHASE AND THREE-PHASE TRANSFORMERS

The type of transformer selected depends on the size of the primary power system and the required secondary voltage. Three-phase isolation step-up transformers are generally selected for increasing voltage from a low voltage system, while a bank of three single-phase transformers is usually selected for reducing a high-voltage primary power source to the required surface voltage.

For new installation of units with higher voltages, it is usually less expensive to install three single-phase transformers, connected wye, to eliminate the auto-transformer.

In choosing the size of a step-up transformer or a bank of three single-phase transformers the following equation is used to calculate total KVA required:

$$KVA = \frac{V_s \times A_m \times 1.73}{1{,}000} \qquad (5.14)$$

where:

KVA = Kilo-Volt-Amp or 1,000 Volt-Amp

V_s = Surface Voltage

A_m = Motor nameplate current in amps

5.8.4 SURFACE CABLE

Choose approximate length required for connecting controller to primary power system or to transformer. Two pieces are generally required for installations using an auto-transformer. Size should equal the well cable size except in the case of step-up- or auto-transformer, where the primary and secondary currents are not the same.

5.8.5 WELLHEADS AND ACCESSORIES

Select the wellhead on the basis of casing size, tubing size, maximum recommended load, surface pressure, and maximum setting depth. Electric cable passes through the wellhead where pressure fittings are not required.

Electric Feed Through (EFT) mandrels are also available. The electric cable is sliced to pig tails. The EFT wellheads seal against down-hole pressure and prevent gas leaks at the surface.

5.8.6 SERVICE EQUIPMENT

Cable reels, reel supports and cable guides:

Select size of cable reel required to handle previously selected cable size. Select set of cable reel supports based on cable reel size. Cable guides are designed to handle cable sizes 1 through 6.

5.8.7 OPTIONAL EQUIPMENT

Bottom-hole pressure (PHD) sensing device:

The PHD provides continuous measurement of bottom-hole pressures.

Automatic well monitoring:

Motor controllers are available for continuous monitoring of pump operation from a central location.

5.9 STEP 9- VARIABLES SPEED SUBMERSIBLE PUMPING SYSTEM

The ESP system can be modified to include an Electro-speed variables frequency controller so that it operates over a much broader range of capacity, head, and efficiency. Since a submersible pump motor is an induction motor, its speed is proportional to the frequency of the electrical power supply. By adjusting the frequency, the variables speed submersible pump (VSSP) system offers extraordinary potential for boosting production, reducing downtime, and increasing profits. The VSSP can be used to boost efficiency in many cases, including highly viscous wells, water-flood wells etc. It extends the range of submersible artificial lift to less than 100 BPD (16 M^3PD) and up to 100,000 BPD (16,000 M^3PD)

It is necessary to understand the effects of varying the speed of a submersible pump, in order to apply the VSSP system. The VSSP system can be analyzed in terms of varying frequency or in terms of maintaining constant head. What follows is a basic explanation of the principles involved.

Variable Frequency

The effects of varying frequency can be seen by preparing new head-capacity curves for the desired frequencies, based on the pump's known 60 Hz performance curve data. The Electro-speed controller is commonly used to generate any frequency between 30 and 90 Hz.

Curves for frequencies other than 60 Hz can be generated by using the centrifugal pump affinity laws. The equations derived from these laws are:

$$\text{New Rate} = \frac{NewFrequency}{60Hz} \text{ x 60 Hz rate} \tag{5.15}$$

$$\text{New Head} = \left(\frac{NewFrequency}{60Hz}\right)^2 \text{ x 60 Hz head} \tag{5.16}$$

$$\text{New BHP} = \left(\frac{NewFrequency}{60Hz}\right)^3 \text{ x 60 Hz BHP} \tag{5.17}$$

where:

BHP= Brake Horsepower

New Efficiency= 60 Hz efficiency (there is negligible loss)

A set of curves can be developed for an arbitrary series of frequencies with these equations, as shown in the variable frequency performance curves at the end of this step. Each curve represents a series of points derived from the 60 Hz curve for flow and corresponding head points, transformed using the equations above.

Suppose we are given the following data at a frequency of 60 Hz:

Rate= 1,200 BPD

Head = 24.5 ft.(from FC-1200 curve @ 1,200 BPD)

BHP= 0.34 BHP (from FC-1200 curve @ 1,200 BPD)

If a new frequency of 50 Hz is chosen:

$$\text{New Rate} = \left(\frac{50}{60}\right) \text{X } 1200 \text{ BPD} = 1000 \text{ BPD}$$

$$\text{New Head} = \left(\frac{50}{60}\right)^2 \text{X } 24.\ 5' = 17\ '$$

$$\text{New BHP} = \left(\frac{50}{60}\right)^3 \text{x } 0.34 \text{ BHP} = 0.20 \text{ BHP}$$

The pump design details above have been very specific in order to design the pump thoroughly and some of the design factors are of high importance which can determine the life of the ESP. Most of the time, these designs can be made easier by the help of Softwares like Autograph (by Centrilift) and Integrated Production Model (IPM) by PetEx. However, the IPM software does not have all the pump models available but are updated every time new versions are released.