Recommended Practice for Sizing and Selection of Electric Submersible Pump Installations

API RECOMMENDED PRACTICE 11S4
THIRD EDITION, JULY 2002

REAFFIRMED, OCTOBER 2013

energy API
AMERICAN PETROLEUM INSTITUTE

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Upstream Segment

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FOREWORD

This recommended practice is under the jurisdiction of the American Petroleum Institute (API) Subcommittee on Field Operating Equipment.

This document presents recommended practices for the design (sizing and selection) of electrical submersible pumps. The intent of this document is to provide a "checklist" of items that need to be considered when designing an ESP. It has been written for persons who possess knowledge in basic nodal analysis and petroleum terminology.

This document includes usage of the verbs shall and should, whichever is the more applicable to the function. For the purposes of this document:

Shall: Indicates the recommended practice is considered a minimum requirement that has universal applicability to the specific activity.

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Suggested revisions are invited and should be submitted to the standardization manager, American Petroleum Institute, 1220 L Street, N.W., Washington, D.C. 20005.

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Recommended Practice for Sizing and Selection of Electric Submersible Pump Installations

1 Scope

Each component of the ESP system (pump, motor, intake, seal or protector, cable, switchboard, etc.) is discussed in some detail as far as what must be considered for the best selection at a desired rate and well conditions. Examples are given to illustrate the basic design procedure and illustrate how PVT correlations, multiphase flow correlations, and inflow performance relationships are used.

Summary designs and computer examples using the detailed design principles are presented which show how design considerations fit together, and how tools such as computer programs allow faster solutions resulting in easier trial and error calculations for optimization of designs and study of existing installations.

Topics such as PVT correlations, multiphase flow correlations, and inflow performance relationships are discussed in the appendices.

2 References

This recommended practice includes by reference, either in total or in part, other standards and recommended practices listed below. The latest edition of these standards and recommended practices should be used unless otherwise noted:

API

RP 11S	*Recommended Practice for the Operation, Maintenance and Troubleshooting of Electrical Submersible Pump Installations*
RP 11S1	*Recommended Practice for Electrical Submersible Pump Tear Down Report*
RP 11S2	*Recommended Practice for Electric Submersible Pump Testing*
RP 11S3	*Recommended Practice for Electrical Submersible Pump Installations*
RP 11S5	*Recommended Practice for Application of Electric Submersible Cable Systems*
RP 11S6	*Recommended Practice for Testing of Electrical Submersible Pump Cable Systems*
RP 11S7	*Recommended Practice for Application and Testing of Electric Submersible Pump Seal Chamber Section*
RP 11S8	*Recommended Practice for Application and Testing of Electric Submersible Pump System Vibrations*
RP 500	*Recommended Practice for Classification of Locations for Electrical Installations at Petroleum Facilities*
RP 5C7	*Recommended Practice for Coiled Tubing Operations in Gas and Oil Well Services*

3 Definitions, Abbreviations and Conversions

This section provides an alphabetic listing of all the basic terminology and symbols used throughout API RP 11S4. In addition, the formulas to convert between English and metric units are given.

3.1 NOMENCLATURE

B_o	Oil formation volume factor (bbl/STB) [m^3/m^3]
B_w	Water formation volume factor (bbl/STB) [m^3/m^3]
f_w	Water cut (fraction range 0 – 1)
H_D	Vertical fluid head measured from the wellhead to the working fluid level (ft) [m]
H_F	Tubing head loss due to friction (ft) [m]
H_T	Head equivalent to wellhead pressure (ft) [m]
J	Productivity index (bbl/day/psi) [m^3/day/kPa]
KVA	Transformer power rating (kilowatts-volts-amperage)
MD_{pump}	Measured pump intake setting depth (ft) [m]
P_{bhs}	Bottomhole static pressure (psig) [kPa]
P_{wf}	Wellbore flowing pressure (psig) [kPag]
P_{wh}	Wellhead flowing pressure (psig) [kPag]
PIP	Pump intake pressure (psig) [kPa]
q	Desired flow rate of fluid into the wellbore (bbl/day) [m^3/day]
q_{intake}	flow rate at the pump intake (bbl/day) [m^3/day]
SCF	Standard cubic feet
SSU	Saybolt Seconds Universal viscosity
STB	Stock tank barrels
TDH	Total dynamic head needed to pump fluid at a certain rate (ft) [m]
VD_{pump}	Vertical pump intake setting depth (ft) [kPa]
VD_{res}	Vertical depth of reservoir (midpoint perforations), (ft) [m]
γ_{API}	Oil gravity term commonly used in the petroleum industry (API)
γ_f	Specific gravity of fluid (measured relative to pure water = 1.000)
γ_o	Specific gravity of oil (measured relative to water = 1.000)
γ_w	Specific gravity of brine (measured relative to pure water = 1.000)

3.2 CONVERSION FORMULAS

Length:
cm = 0.3937 in.
m = 3.281 ft

Volume:
bbl = 5.615 ft^3
m^3 = 6.289 bbl

Density:
kg/m^3 = 16.01846 lbm/ft^3

Gas-oil or gas-water ratio:
m^3/m^3 = (SCF/STB)/5.615

Pressure:
kPa(g) = 6.894757 psi(g)
bar(g) = 14.7 psi(g)

Temperature:
°C = (°F – 32)/1.8

4 Basic Design Application

The flow chart illustrated below is an overview of the entire design procedure. The diagram (see Figure 1) illustrates ESP design as a linear process, but it actually may require a few iterations since one particular piece of equipment may impact previously selected equipment. For example, the additional horsepower (HP) required for the seal section may require you to re-evaluate your previous motor selection. Also, you may want to make several design runs in order to optimize your equipment selection and see how sensitive your design is to key input parameters. The detail for each step is described in the noted section.

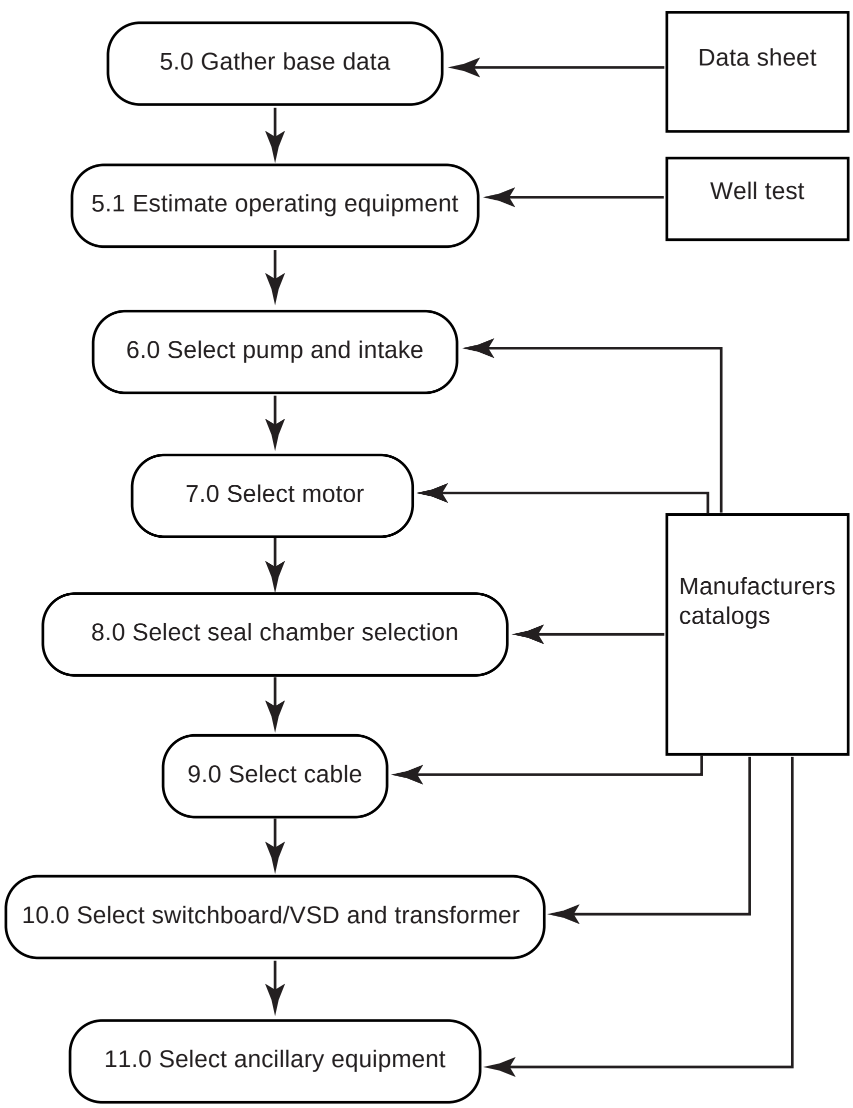

Figure 1—ESP Design Process

5 Gather Base Data

Data is used to describe the environment where the ESP must operate. Care must be taken to quality check data from all available sources. The primary quality limitation of an ESP design is the quality of the data used in the design. The performance characteristics of the pumping system, fluid flow through piping and fluid PVT properties are all reasonably well understood and can be mathematically modeled. If, however, inaccurate data is fed into these mathematical models, an incorrect answer will be produced. Inaccurate data can lead to improper sizing of the pump, motor, or other system components and ultimately lead to premature equipment failure, workovers and deferred production.

The data input sheet shown in the appendix can be used to gather the data required for an ESP installation design. The data elements required for an ESP design can be segregated into six categories:

1. General Information: Identifies the well and who collected the data on what date.
2. Wellbore Geometry: Describes well trajectory and completion equipment details.
3. Surface Information: Describes surface equipment and conditions.
4. Fluid Properties: Describes the fluid produced by the well and chemicals introduced for deposition prevention and corrosion.
5. Inflow Characteristics: Contains data elements that describe the well's productivity. This data is critically important in an ESP design. Care should be taken that this data is as accurate as possible.
6. Design Criteria specifies the desired performance from the ESP installation.

The first five categories define the environment in which the ESP will operate. The sixth category defines the operating parameters desired by the well operator.

The data input sheet contains the minimum data required for an ESP design. Additional information that may be of use to the ESP designer includes wellbore schematics, PVT reports, gas and oil composition reports, and water analysis reports. ESP failure analyses, amp charts, and workover reports on prior ESP installations from the well of interest or offset wells can also provide valuable design clues. If offset well information is included, make certain that the completion reservoir is specified for both the well of interest and the offset wells.

A description of the data elements that comprise each category can be found in the appendix.

5.1 ESTIMATE ESP OPERATING REQUIREMENTS

To properly select the pump, well performance must be estimated. Fundamentally, well performance estimates define what additional energy (i.e., volumetric flow rate and differential pressure or head) must be supplied by the pump to deliver a desired stock tank flow rate. Ideally, this behavior should be understood or estimated taking into account not only the current well data, but also for forecasted changes in reservoir or system performance over the expected life of the ESP (usually, considering a 3 – 5 year period is sufficient). Specific attention should be paid to expected changes in average reservoir pressure, water cut, producing gas-oil ratio, required wellhead pressure and inflow performance.

Nodal analysis techniques are recommended as the best process for defining well performance and considering sensitivity to changes over time or due to variations in available data. These techniques can be used both numerically and graphically to provide a good understanding of the differential pressure or head that the pump must provide at a broad range of surface flowrates and for a number of varying conditions.

To properly select a pump to produce at a specified stock tank production rate, the corresponding in-situ flow rate must be known and both inlet and required discharge pressures at the stock tank flow rate must be determined. Additionally, the fluid specific gravity must be known. Once the differential pressure requirement is known, this value can be converted to an equivalent head using the composite fluid specific gravity, which, together with the corresponding in-situ flow rate, can be used to select an appropriate pump design and number of stages required to deliver the additional energy required to lift the fluid at the desired stock tank rate. This same approach can be used for single-phase or multi-phase fluid applications. The use of computers to perform complicated inflow performance, fluid properties or tubing pressure traverse calculations is desirable in the latter case.

Single operating point calculations can be effective for defining operating requirements, provided data is good, well behavior is stable over time and the produced fluid is a single phase fluid.

For such applications, it is common to simplify the procedure by combining or summarizing the additional energy that the pump must supply into a single term, Total Dynamic Head (TDH). TDH is a summation of the of the net vertical distance fluid must be lifted from an operating fluid level in the well, the frictional pressure drop in the tubing and the desired wellhead pressure. The TDH and in-situ flow rate can be used directly to select an appropriate pump stage design and number of stages required.

5.1.1 Pump Intake Pressure

Pump intake pressure can be estimated through the use of Productivity Index calculations obtained from well tests or more complex Inflow Performance Relationships. Productivity Index calculations should only be used in single phase fluid applications or in multi-phase fluid applications when the flowing bottomhole pressure is greater than the fluid bubble point pressure. If there is free gas at the pump intake (i.e., pressure is below bubble point), emulsions present or the fluid is highly viscous (less than 40 SSU), use applicable computer software as hand calculations are not recommended.

Pump inlet pressure is dependent on pump setting depth. Pump inlet pressure is simply the flowing bottomhole pressure adjusted for change in pressure due the static gradient of the fluid (due to the vertical distance the pump inlet in placed above the reservoir or pressure datum location) and frictional pressure drop in the casing between the perforations and pump inlet (which is generally very small and is normally ignored).

It is quite common in ESP applications to make pump setting depth somewhat arbitrary, providing a safe amount of submergence is available and depending on the well deviation. In other cases, a safe desired pump inlet pressure is specified and the pump depth is determined which will provide this inlet pressure at the operating stock tank flow rate.

In most single-phase fluid applications, 100 psi inlet pressure is sufficient. For unusual flow characteristics (such as high volume), pump Net Positive Suction Head requirements should be checked.

In gassy applications, it is common to set the pump inlet as deep as possible to keep pump inlet pressure as high as possible, so less gas evolves from the fluid before it reaches the pump inlet.

A simplified procedure for calculating pump inlet pressure is as follows:

Calculate Well Fluid Composite Gravity

$$[f_w \times \gamma_w] + [(1 - f_w) \times \gamma_0] = \gamma_f$$

Calculate Well Fluid Gradient

$$[\text{Fluid gradient}] = [\text{Water gradient} \times \gamma_f]$$

where

[Water gradient] = 0.433 psi/ft or 9.8 kPa/m

Calculate Well Flowing Pressure at Desired Flow Rate (P_{wf})

$$P_{wf} = P_{bhs} - [q/J]$$

Calculate Pump Intake Pressure (PIP)

$$\text{PIP} = P_{wf} - \{[\text{VD}_{res} - \text{VD}_{pump}] \times [\text{Fluid gradient}]\}$$

Calculate Intake volume at pump (q_{intake})

$$q_{intake} = [\text{Surface volume water} \times B_w \text{ at pump depth}] + [\text{Surface volume oil} \times B_o \text{ at pump depth}]$$

Note: The total intake volume when below the bubble point must include the free gas volume.

5.1.2 Total Dynamic Head

For applications pumping a ***single phase fluid***, the term Total Dynamic Head can be used to summarize the differential pressure or head the pump must supply to lift fluid at a desired flow rate from an operating fluid level in the well to the surface.

Calculate Net Vertical Dynamic Lift (H_D)

$$H_D = \text{VD}_{pump} - [\text{PIP/Fluid Gradient}]$$

Determine Friction Loss (H_F)—refer to Hazen-Williams chart in Appendix E.

$$H_F = \text{MD}_{pump}/1000 \times [\text{Friction loss for given tubing size and production rate}]$$

Calculate Wellhead Tubing Pressure Head (H_T)

$$H_T = \{P_{wh} \times [2.31 \text{ ft/psi}]\}/\gamma_f$$

Calculate Total Dynamic Head (TDH)

$$\text{TDH} = H_D + H_F + H_T$$

6 Select Pump and Intake (see API RP 11S2)

A pump with capacity matching desired well production should be selected based on a expectation of well performance based on pump performance data from a manufacturer's catalog. Additional operating constraints are taken into account during this selection. These constraints include casing size, housing burst pressure limit, shaft strength, corrosive, abrasive or gassy environments.

6.1 MATCH PUMP PERFORMANCE TO WELL PERFORMANCE

Submersible multistage centrifugal pumps consist of rotating impellers that are affixed to a shaft and stationary diffusers that are mechanically held within an outer housing. A matched set consisting of one impeller and one diffuser is commonly referred to as one stage. The pump functions by imparting kinetic energy to fluid as an impeller rotates. The stationary diffuser then rectifies the fluid back toward the shaft and inlet to the next impeller, converting the kinetic energy into potential energy in the form of increased head (or pressure). This process is continued from stage to stage. The amount of head increase due to an individual stage is independent of fluid density, although the pressure increase is proportional to density or specific gravity.

The geometry of a pump design (e.g., number of vanes, vane angle, vane height, diameter, vane length, etc.) controls the performance of the pump. This performance is normally summarized in a pump performance curve (on either a single stage or multistage basis, commonly 100 stages or a specific number corresponding to the number of stages in a specific pump) that relates head (differential pressure), power required and mechanical efficiency to volumetric flow rate. These curves are often drawn showing flow rate to be the independent variable with head, power and efficiency being the dependent variable. This is actually only one way of looking at pump performance. For purposes of sizing, it is often useful to understand that in fact the relationship works in the other direction as well. The flow that a specific pump with a specific number of stages can provide depends on the differential pressure imposed on the pump.

The task in pump selection is to select the appropriate pump stage design for the desired pump flow rate and then select the appropriate number of stages to deliver the desired flow rate given the necessary head or differential pressure required to cause the well to flow at the desired flow rate.

Care should be taken to insure that in-situ pump flow rates and not stock tank rates are used to properly select stage type and number of stages.

A simple process for pump selection consists of the following steps:

<u>Determine Stage Type</u>

Depending on casing size and desired flow rate, there may be several possible pump stage types available for a given application. The pump stage type should normally be selected primary on the basis of which pump will be most efficient at the desired operating flow rate. As a rule, a pump should be selected such that the desired operating flow rate is as near as possible to the best efficiency point and, as a minimum, within the recommended operating range stipulated by the manufacturer. Although many pumps can be operated outside this range, the pump performance is best within this range and it is within this range that pumps are commonly tested by those adhering to API RP11S2 *Recommended Practices for Submersible Pump Testing*.

<u>Determine Number of Stages Required</u>

Given a desired flow rate, Total Dynamic Head (TDH) required and pump stage type, read the head per stage corresponding to the desired pump flow rate. The number of stages required to achieve the desired flow rate will be the TDH divided by the head per stage at the desired pump flow rate.

Number of stages = TDH/[Head per stage from pump curve at pump flow rate]

Pumps are normally available with a discrete number of stages in predetermined pump section lengths (often referred to as housings). Multiple sections may be assembled together to obtain the total number of stages required. In some cases, the number of stages available may not exactly match that required. In most cases, this results in a very small error.

There are two configurations of pumps. In a floating stage design (most common), the impellers float axially on the shaft and the thrust of the individual impeller stage is absorbed on specially designed pads found on the diffuser. The fixed impeller or compression pump design has the impellers locked to the pump shaft in the axial direction and no thrust is absorbed by the impeller rubbing on the diffuser. In the compression pump, the thrust is transferred to the thrust bearing in the seal chamber. Please consult with your pump manufacturer to discuss which design is better for your application.

<u>Determine Power Required by Pump</u>

Read the horsepower per stage required by the pump from the curve at the desired pump flow rate. Calculate the total motor horsepower required to drive the pump by multiplying horsepower per stage by the number of stages and composite fluid specific gravity.

$$[\text{HP required}] = [\text{HP per stage}] \times [\text{Number of stages}] \times \gamma_f$$

This information should be used in selecting a proper motor HP size.

6.2 LIMITATIONS AND CONSIDERATIONS

Besides hydraulic performance, several other physical limitations must be considered, even in simple applications.

6.2.1 Shaft Strength

The amount of horsepower that the pump shaft can transmit (torque at a given speed) should be checked to insure it is within acceptable limits stated in the manufacturer's catalog. Exceeding this limitation can result in premature failure.

6.2.2 Housing Strength

The pump differential pressure under operating and shut-in conditions should be checked to insure it is does not exceed burst pressure limitations. Worst case pump head can be determined by obtaining shut-in head per stage from the zero flow rate point on the pump head capacity curve and multiplying it by the number of stages. In most cases, different designs are available for extremely high differential pressures. Exceeding this limit can result in premature failure. Please consult with your ESP manufacturer for equipment ratings.

$$[\text{Shut-in pump head}] = [\text{zero flow head per stage}] \times [\text{Number of stages}]$$

$$[\text{Differential pressure}] = [\text{Shut-in pump head}] \times [0.433 \times \gamma_f]$$

6.2.3 Pump Thrust

The pump shaft thrust should be calculated to use in seal chamber section thrust bearing design selection. While the limitation to be checked is a consideration of the seal chamber section, the source of the thrust is the pump. The magnitude of thrust depends on the number of stages employed and the mechanical configuration of the pumps being used. The most common form of pump is commonly referred to as a floating impeller pump, in which the pump impellers are free to travel axially somewhat. In being free to travel, the individual diffusers carry the thrust generated directly by each impeller. The differential pressure developed by the pump acting on the cross sectional area of the pump shaft causes a separate thrust load that must be accommodated for by the seal chamber section thrust bearing. Again, this load should be calculated for worst case, shut-in conditions.

[Floater pump thrust] = [Pump differential pressure] x
[Shaft area from manufacturers catalog]

Thrust calculations for fixed or compression type pumps should be based on data provided by pump manufacturers and worst case operation (e.g., shut-in).

6.2.4 Variable Speed Design

While variable speed drives provide additional flexibility and adjustability to ESP installations, they complicate pump selection. Variable speed drives capitalize on the behavior of centrifugal pumps at different speeds (where will affinity law equations be located). As a general rule, the design should begin at the highest frequency to be sure the equipment will be sufficient to handle situations such as lifting kill fluid upon start-up. However, the best efficiency rate should be targeted for the frequency at which the longest running time is expected in the application. While this can be calculated by hand, the use of computer software is recommended to handle the conversion of pump performance data at variable speeds.

6.2.5 Gassy Wells/High Vapor-liquid Ratios

As explained above, hand calculations are inadequate for applications with more than a few percent of vapor in the fluid flow stream at the inlet of the pump. In these applications, computer software should be used to handle the more complex inflow and multiphase flow calculations and multiphase pump performance calculations based on PVT data and correlations. Specific attention should be paid to avoid sizing pumps for normal operating conditions that are incapable of lifting heavy kill fluids or completion fluids during startup.

There are design options for handling the gas, either through the pump or separating it out of the flow stream prior to entering the pump. There are special pumps made to handle a high percentage of free gas. Please consult with your manufacturer to find out the free gas limitations on their equipment. Another design is the tapered pump, which uses several different volumetric stages (large flow capability on bottom, smaller flow capacity on top). As the fluid is compressible, the volume becomes smaller as it travels through the pump.

Gas separators are also available. Consult with your manufacturer to determine which type of separator is best for your application. The user will also need to determine if the separator requires additional horsepower to function. This value will be needed to properly size the motor.

6.2.6 Abrasives

Abrasion resistant pump trim and features should be selected for applications in which abrasive solids, such as sand (grain size and shape is essential data), scale, etc., are expected. While there are many different designs available, manufacturers are generally able to help specify an adequate level of bearing and material options to mitigate abrasive wear concerns. The type and volume of sand dictates the materials needed and its placement inside the pump.

6.3 CHECKLIST

a. Select the appropriate pump stage design for the desired pump flow rate.
b. Determine number of stages required.
c. Determine power required by pump (horsepower).
d. Ensure the pump shaft and housing strengths are within acceptable limits.
e. Ensure the proper metallurgy for produced well fluid is selected.

7 Select Motor

A motor must deliver the horsepower required to run the pump, seal chamber section, and gas and water separator, if required. Important considerations include temperature limitation, casing size, length and size of cable, motor terminal voltage, motor current and also the well operating conditions.

The horsepower requirements and the well conditions should be studied against the catalog listings to determine which catalog horsepower will satisfy his requirements, i.e., should he use a smaller catalog horsepower to meet his requirements or a de-rated larger horsepower or stick with the closest catalog horsepower. All possibilities will have different cost associations.

The motor nameplate voltage should be selected in conjunction with the cable selection, as the different motor voltage ratings will require different currents which will impact on the running costs as far as cable losses are concerned. A realistic of run time estimate should be made so that running costs and initial costs can be added together to give a cost comparison for each case considered.

Checks should be made for each case to ensure the motor will start and attain its proper running speed.

7.1 MATCH MOTOR PERFORMANCE TO PUMP/WELL PERFORMANCE

Submersible pump motors have many similarities and many differences from a “standard” surface motor. A detailed description can be found in Appendix C.

From the previous section, the required pump horsepower and gas separator (if needed) is known. In addition, you will need an estimate of the horsepower required for the seal section (refer to Section 8). Add these values together to determine the motor horsepower required. By taking into account the limitations and considerations in the following sections and by working with your ESP vendor, a proper motor can be selected for your particular application.

7.2 LIMITATIONS AND CONSIDERATIONS

7.2.1 Motor OD vs. Casing ID

Generally speaking, the motor outside diameter is limited by the casing I.D. or in some cases by the pump type selected. In other cases, consideration has to be made for well deviation radii (dogleg severity) when running the motor to the desired location, but this also entails consideration of the length of motor as well. In the case of deviated wells, a check should be made that the motor selected is capable of moving around the bend when being installed. The motor OD/casing ID ratio can help in establishing the required fluid rate around the motor. It is recommended to use a minimum fluid velocity of 1 ft/s to get proper motor cooling but a maximum value of 12 ft/s (in an abrasive environment, 7 ft/s) to prevent housing erosion. Consideration should be given to gassy or poorly conductive fluids. Having decided on the diameter of motor required, it is very unlikely that the horsepower required will match a horsepower listed in the manufacturer's catalog for the motor diameter selected. A decision has to be made whether to select a motor rated for a horsepower higher or lower than the horsepower required.

7.2.2 Well Temperature vs. Motor Cooling

Most submersible motor manufacturers list a bottom hole temperature (BHT) in which their motor can operate. The user should be very careful with this number. The BHT only defines the ambient or motor environmental temperature in which the motor operates. Probably the most important factor is the actual motor operating temperature or its internal temperature when the motor is operating. In other words, the temperature rise of the motor during load conditions plus the ambient temperature gives the operating temperature.

Excessive motor operating temperatures can shorten motor insulation life, shorten the bearing life and result in mechanical problems from thermal expansion of components.

Normally, the manufacturer knows what the motor temperature rise will be from tests done in a controlled environment at the factory. In most cases, this controlled environment will have little resemblance to the real well conditions.

Some of the conditions that will affect the operating temperature of the motor in the well are: horsepower required, bottom hole temperature (flowing and static), water cut, Oil API gravity, rate of fluid flow by the motor, amount of gas flow by the motor, whether a variable speed drive is used (and at what frequency), presence of scale, existence of special motor housing coatings, voltage unbalance and the motor efficiency at the operating load point.

The user needs to work with the manufacturer to ensure these conditions are incorporated into the ESP design, through the application of correction factors. In some cases, the manufacturer might well suggest a smaller catalog horsepower rating than what is calculated, generally for benign well conditions. However, for more severe well conditions or uncertainty of the well conditions, the manufacturer might recommend a higher catalog horsepower rating to operate the motor in a derated condition.

7.2.3 Motor Terminal Voltage (Nameplate Voltage) and Cable Size

The submersible motors are connected to the surface by a length of cable. However, the motor is designed to run at its nameplate voltage. It is necessary to determine the voltage drop in the cable for the motor rating using the nameplate amps and add the cable drop to the motor terminal voltage to determine the surface voltage. The question then arises as to what cable size to use. The selection of the cable size is determined by cost and the ability of the motor to come up to speed.

The user has to do a cost study based on the cost of the cable losses for the expected life of the system for the different cable sizes and the initial cost of the different cable sizes as well as the cost differential or premium for higher voltage motors, switch gear or transformers. When the selection has been made, the ability of the motor to come up to speed has to be checked.

The current when starting the motor can be several times larger than when it is running fully loaded. The result of this phenomenon is that the cable voltage drop when starting the motor is quite a bit larger than when normally running. The motor terminal voltage can be so low that the motor is unable to generate enough torque to start the motor or run up to speed. As a rule of thumb, 50% of nameplate voltage at motor terminal is required for starting. This is more apt to happen with high amperage motors, or motors with long lengths of cable. In any event, the starting capabilities under the real conditions should be verified with the motor manufacturer.

The starting limitations can be overcome in the following three ways:

a. Use a larger diameter cable. Reduce the cable voltage drop during starting. May mean higher cost for cable.
b. Use a higher voltage motor. For the same horsepower, the current will be lower.
c. Use a VSD with sufficient voltage boost to get a higher starting torque for less current at a lower frequency.

When determining the motor starting capability, it is recommended that an electrical system study be done, especially including the surface transformer and the generator (if used) to determine limitations.

One of the benefits of the long cable, assuming the motor is able to start, is that it acts similar to a "soft start" in that it reduces the inrush or starting current, and since the motor and pump have low inertia, the motor gets up to speed very quickly. Often, utility companies will accept the cable as a "soft start" alternative in lieu of installing a standard soft start package.

7.3 CHECKLIST

a. Determine the motor horsepower by adding the required horsepower for the pump, gas separator and seal sections.
b. Determine diameter of motor required.
c. Check fluid flow velocity for motor cooling.
d. Ensure that the estimated motor winding temperature is within manufacturer's limits.
e. Determine motor starting capability.

8 Select Seal Chamber Section (see API RPs 11S, 11S7 and 11S8)

The seal chamber section is selected from the manufacturer's catalog. Major considerations include: compatibility with pump and motor, casing clearance when cable is installed, use of labyrinth or bladder type design, fluid expansion capacity, ratings for temperature and exposure to chemicals.

In a conventional ESP configuration, where the motor is located below the assembly, the seal chamber section is mounted between the motor and pump. The pressure equalization and volume change accommodation may be located elsewhere if desired, for instance at the bottom of the motor as in a "water well" type motor.

In an inverted ESP system with the motor on top, it is still necessary for the seal section to be located between the motor and pump. However, it may be more desirable to accommodate volume change and pressure equalization with a device located above the motor. These types of systems require special installation procedures to prevent loss of motor oil during installation.

Generally, the seal chamber section will be selected in the same nominal diameter as the pump. An alternate diameter seal chamber section may be used if the shaft, thrust, and oil expansion capacity are adequate.

8.1 MATCH SEAL CHAMBER TO PUMP/MOTOR/WELL PERFORMANCE

The seal chamber section can only be selected after the pump and motor have been specified. The seal chamber section must be matched to the application. The successful seal chamber section will include the following requirements.

a. Have proper head and base flange designs for connection to the pump and motor, or select adapter kit to make the connection.
b. Allow clearance for the motor flat cable.
c. Have sufficient shaft strength to withstand maximum torque for the application.
d. Have sufficient expansion volume in chambers to allow motor thermal cycling.
e. House a thrust bearing rated to handle the pump shaft axial thrust and maximum operating temperature.
f. Contain desired number of shaft seals able to function for an extended time in the application.
g. If a bag type seal, contains elastomers able to withstand the applications temperature and chemicals.
h. Be filled with proper motor oil.
i. Be of a design style that is compatible with the application and offers desired redundancy of protection according to application cost and severity.

8.2 LIMITATIONS/CONSIDERATIONS

8.2.1 Temperature Rating vs. Well Temperature

Operating temperature is an important consideration; the material should be matched to its intended operating temperature. There are several factors that affect the actual operating temperature of the seal chamber section: bottom hole temperature, actual motor temperature rise, heat transfer properties of the well fluid, speed of the well fluid as it passes the seal chamber section, and temperature rise of the well fluid as it passes the motor. Operation temperature of the seal chamber section (except the thrust bearing) is typically 25°F – 50°F greater than the well temperature.

Applications with heavy crude, high oil cuts, low velocity of fluid flow past the motor, or very long motors increase the operating temperature of the seal chamber section. Consult the ESP manufacturer for an approximate operating temperature for each specific application.

Consider all temperatures (high and low) that the material will see in all aspects of unit life, i.e., storage, shipping, testing, and installation. Also be aware that a "high temperature" elastomer may not be the best selection for a low temperature application.

There are many different formulations with widely divergent properties and performance. Generally, ESP manufacturers specify the elastomer formulation used in various components and offer several choices for varying well conditions. Typical maximum service temperatures for several elastomers are shown below:

Nitrile: 250°F (121°C)

Highly Saturated Nitrile (HSN): 275°F (135°C)

Fluoroelastomer compounds: 325°F (163°C)

Tetrafluoroethylene/propylene copolymer (TFE/P): 350°F (177°C)

It is important to ensure that the specific formulations selected are compatible with the operating environment. Each application should be reviewed with the ESP manufacturer for specific recommendations.

Operating temperature should also be considered when selecting the type of oil to be used in the seal chamber. In general, oil viscosity decreases as temperature increases. At operating temperature, the oil viscosity must be sufficient to provide lubrication for the seal chamber section bearings. Selection of oil types used to accommodate a range of operating temperatures should be based on the ESP manufacturer's recommendations to ensure proper bearing operation.

8.2.2 Shaft Strength

All phases of operation must be considered when evaluating the required shaft torque capacity. Maximum torque may occur during start-up or when pumping heavy fluids.

Shaft strength is dependent on the smallest cross-section (usually the spline root) and material yield strength. Select a seal chamber section with a shaft design according to manufacturers' recommendations.

8.2.3 Thrust Bearing Load Rating vs. Thrust Developed

The required thrust bearing capacity will be determined primarily from the thrust characteristics of the pump, which is unique to each application.

The thrust load rating for the seal chamber section should be greater than the highest possible thrust load for the application.

Typical pumps use floating impeller designs. The primary thrust load produced which the seal chamber section must carry is given below.

<u>Floating Impeller Pumps</u>

Down Thrust = [pump discharge pressure – PIP] x pump shaft cross-sectional area

Evaluate the worst case scenario when the flow rate is zero to simulate producing against a closed production valve.

Note: The shaft thrust load will be greatly increased if impellers seize to the shaft.

<u>Fixed Impeller Pumps</u>

Consult ESP manufacturer for down thrust values.

All phases of operation that directly impact thrust should be considered, including the pumping of heavy fluids. Thrust bearings are typically available in several configurations and materials (see API RP 11S). Bearing surfaces are made from a wide range of materials. Babbitt is commonly used and is rated for operating temperatures up to 300°F (149°C). Bronze alloys may be used for high temperature applications (greater than 250°F). A number of plastic formulations have been developed for use in thrust bearings and are rated for high loads and high temperatures. The capacity of a thrust bearing may be reduced at elevated temperatures or by rotating opposite to the design direction. Consult with the manufacturer for recommendations.

8.2.4 Protecting Against Corrosion and Erosion

Water, oil, gas and brine are among the many fluids to be considered when selecting materials for the "wetted" (in contact with well fluid) components of the seal chamber section. The wetted parts of the seal chamber section include housings, head, base, shaft and shaft seal. Generally, housings, heads, and bases are available in carbon steel or high chrome alloys for added corrosion resistance. Special coatings can also be applied to these components for additional corrosion protection. Corrosion resistant materials such as monel and stainless steel are commonly used for shafts. Metallic components of mechanical face seals are typically stainless and bronze with monel available for additional corrosion resistance.

Generally, stainless steel is used for ancillary components like bladder clamps and relief valves. Inconel® provides good corrosion resistance and is often used for actuating springs of relief/check valves or rotating seals.

The metal components of the seal chamber section should be selected so that destructive galvanic corrosion cells are not formed between adjacent components.

It is important to consider the effect of produced and treating fluids, such as corrosion inhibitors and acids, when selecting materials. For example, amines used in some inhibitors will greatly accelerate the deterioration of some elastomers.

If solids are present in the well fluid, hard mechanical seal faces may be required to avoid excessive face wear. Tungsten carbide and silicon carbide seal faces are generally used in more abrasive well conditions.

8.2.5 Bladder and Labyrinth Seal Sections

Tandem seal chamber sections are units where two or more seal chamber sections are stacked in series for the purpose of increasing the number of protection chambers, thereby increasing the motor protection. These units have been used in very hostile environments, in applications with expensive installation and pulling costs or where experience indicates longer run times can be obtained. In most cases, if each section has a thrust bearing, the upper unit will carry the pump thrust unless special consideration is given to shaft spacing or shimming.

The number of starts and stops (cycles) during operation of an ESP determines the number of thermal cycles the seal chamber section must support. Bladder type seal chamber sections should be considered for applications where frequent cycling is anticipated.

In some applications, bladder and labyrinth seal chamber sections are used in tandem. In deviated wells, the bladder seal chamber section should be installed on top to prevent contamination of the labyrinth seal chamber motor oil. In vertical wells, the bladder seal chamber section may be installed on the bottom for increased protection of the bladder from chemical attack by the well fluid.

Seal chamber section designs are available that use multiple chambers in a single unit to achieve the functions of tandem seal chamber sections. In these designs, the criterion for arrangement of labyrinth and bladder chambers is the same as for tandem seal chamber sections.

8.2.6 Fluid Expansion Capacity

The effective oil expansion capacity of a labyrinth seal chamber section will be reduced in deviated wells. Bladder-type seal chamber sections should be considered for wells with any deviated section over 30 degrees from vertical.

The required oil expansion capacity of the seal chamber section is a function of the total oil volume in the motor and seal chamber section and the maximum thermal cycle the unit experiences during installation and operation. Usually, the motor/seal chamber section assembly is at the lowest temperature during installation. The highest temperature will typically occur when the motor has reached operating temperature down hole. Provided with the thermal cycle, the manufacturer can select a seal chamber section with adequate oil expansion capacity.

Interchangeability of equipment offered by various manufacturers may be limited by flange and coupling incompatibility which may be overcome with the use of adapters. However, consideration should also be given to thrust requirements of the pump (both magnitude and direction) and oil volume requirements of the motor.

Actual motor loading should be considered when evaluating the required oil expansion capacity in the seal chamber section. The seal chamber section should be selected with sufficient oil capacity to accommodate the maximum probable motor load condition.

8.2.7 Seal Chamber Section OD vs. Casing ID

The resultant diameter of the seal chamber section with the motor flat cable on one side should be smaller than the casing drift diameter to avoid damage when installing the equipment. Refer to 6.2 for additional considerations.

Sufficient clearance is required between the seal chamber section OD and Casing ID to allow flow of well fluid without excessive pressure drop or erosion of the motor body or well casing. The recommended maximum fluid velocity past the ESP assembly is 7 ft/s (abrasive fluids) and 12 ft/s (solid-free fluids).

8.2.8 Speed Effects

Operating at speeds other than 3500 RPM will affect the seal chamber section performance. Generally, if you are operating from 30 – 70 Hz this is not a critical issue; however, the manufacturer should address any special bearing needs.

Operating an ESP system on a variable speed drive may cause increased motor temperature rise, which results in additional oil expansion. The seal chamber section must have adequate capacity to accommodate motor oil expansion at the highest anticipated operating speed. Shaft torque and thrust bearing capacity should also be checked at the highest operating speed since pump torque and thrust increase with speed. Mechanical shaft seals have a speed limit, which should not be exceeded. The ESP manufacturer can recommend safe operating speed ranges.

8.3 CHECKLIST

a. Determine seal chamber section OD/flange size based on pump and motor requirements.

b. Determine expansion volume requirements based on motor HP and well conditions (primarily temperature).

c. Evaluate the required shaft torque capacity.

d. Determine approximate operating temperature.

e. Evaluate special conditions and operating temperature and select elastomers, shaft seals, and material.

f. Calculate operating and no flow thrust loads and then select thrust bearing.

g. Select design style and configuration based on application and level of protection redundancy desired.

9 Select Cable (See API RPs 11S5 and 11S6)

Cable conductor size is selected based on the voltage and amperage requirements of the down hole motor, voltage losses over the length of the cable and clearance in the wellbore. In addition, cable insulation is chosen to survive in the well conditions and armor is selected to protect and contain the cable core.

The type of cable to be used primarily depends on specific well conditions so it is critical to have accurate well information. Bottom hole temperature is needed to calculate the cable operating temperature, which determines the basic type of insulation and jacket materials required. Fluid and gas composition determines corrosiveness of the well. For example, the presence of H_2S may require the use of leaded cable, special alloys may be needed in wells with highly corrosive fluids and cables in wells with a high GOR may need special containment to keep the cable insulation or jacket from decompression failure due to well pressure changes.

An economic comparison should be made between the cable conductor size and the cost of the cable power losses. This analysis should evaluate whether lower power costs over the life of the cable will offset the higher initial purchase price of a cable with larger conductors.

9.1 MATCH CABLE TO PUMP/MOTOR/ WELL PERFORMANCE

Due to the many different parameters required to match the cable, pump and motor when sizing a unit, programs have been designed to make this process easier, and are provided by the pump manufacturers and some third party vendors. API RPs 11S5 and 11S6 also provide detailed information to help select cables, with explanations, tables and charts to guide a person through the basic steps of cable selection.

9.2 LIMITATIONS/CONSIDERATIONS

9.2.1 Well Temperature vs. Conductor Temperature

Well temperature is the bottom hole ambient temperature surrounding the cable at any point. Conductor temperature is the temperature on the surface of the current carrying conductors. Cable operating temperature is a function of the well temperature and the conductor temperature. Cable operating temperatures can exceed bottom hole temperature by more than 30°F. When selecting cable, the conductor temperature or cable operating temperature should not be above the manufacturer's established temperature rating of the cable.

Section 7.2.3 dealt with cable size from the point of view of the power loss in the cable as an operating cost and the voltage drop in the cable being small enough to allow sufficient voltage across the motor terminals for starting. In addition to a voltage limitation on cables, there is also a temperature limitation. As with motors, this temperature limitation depends on the operating temperature of the cable and the type of insulating material. The operating temperature of the cable is a function of the ambient or bottom hole temperature and the temperature rise of the cable. Cable manufacturers can supply curves showing the relationship between current in the cable, bottom hole temperature and the operating temperature of the cable that is a result of the copper losses in the cable. Depending on the limitations, this may force the user to a larger cable size than a cost analysis would otherwise indicate.

9.2.2 Cable Size vs. Voltage Loss

Generally, the smaller the conductor size, the greater the voltage drop per unit length and the more electrical power is lost to heat rise in the cable. These power losses can increase operational costs significantly, especially if cost per kilowatt are high. If voltage drop is excessive, the motor may not start. These concerns must be balanced against the increased initial cost of larger conductor sizes and whether there is room within the drift diameter of the casing for the larger cable.

9.2.3 Cable Dimensions vs. Diametrical Clearances

Additional clearance should be considered if the well is highly deviated. The use of protective cable clamps should also be considered, especially when there has been a history of cable damage. There are two cable configurations available, flat and round. Round cable has the better electrical balance; however, flat cable is primarily used in wellbores with limited diametrical clearances.

9.2.4 General Cable Material Limitations

Cable life will decrease as the temperature increases. The two most common insulation types are thermoplastic and thermoset materials. The most commonly used thermoplastic material is polypropylene which is usually limited to an operating temperature of 205°F. When protected by a lead extrusion, the limit can be increased to 225°F. Most thermosetting insulation compounds are based on EPDM (ethylene propylene diene monomer) and are capable of withstanding 400°F or more depending on specific compound properties. Jacket materials based on nitrile rubber are limited to 280°F and those based on EPDM can handle temperatures up to 400°F.

If the cable is exposed to gaseous fluids, decompression damage can occur when there are rapid pressure changes in the well, such as when the pump is started or pulled from the well. Decompression occurs when gasses dissolve into the insulation and jacket and then expand rapidly when the pressure is reduced, causing tears and micro-voids in the insulation and jacket materials. Special containment with braids, tapes or armor is required to prevent decompression damage.

Polypropylene: Several detrimental well conditions are known to affect polypropylene insulation. Light ends of crude oil and aromatic treatment chemicals tend to soften polypropylene, making it more susceptible to further degradation at elevated temperatures and pressures. The combination of carbon dioxide, temperature and other hydrocarbon gases can lead to premature stress cracking. Such conditions are found in CO_2 floods where the GOR and carbon dioxide concentrations are high. External forces from clamps, bands or tight well conditions when operating near the upper temperature limits can cause deformation and premature failure. Polypropylene should be protected against accelerated aging due to contact with copper. This is typically done by addition of stabilizers in the insulation and by tin coating the copper.

Thermoset Cables: EPDM is the most common thermoset insulating compound used in ESP cables. EPDM materials provide a broad service temperature range, remaining flexible in sub-zero installations and performing in geothermal applications. While gases do not degrade EPDM, proper containment is necessary to prevent explosive decompression. EPDM, in general, has good chemical resistance; however, oil and aromatic hydrocarbons will cause softening and swelling. The life of an EPDM cable is dependent on how well it is protected from the environment.

Cable Jackets: Jackets are protective coverings used to mechanically shield the insulation from the downhole environment. The most common cable jacketing compounds are Nitrile and EPDM. These materials have been used based on economics and performance. Nitrile compounds offer excellent oil resistance, but are subject to embrittlement (age hardening). EPDM retains its integrity and remains flexible in both subzero and geothermal applications; however, it is less resistant to oil and other chemicals than Nitrile.

Tapes, Braids and Barriers: Tapes and/or braids are supplemental layers of material that are used to provide additional strength and protection to the underlying cable components. In round cables, the tape and/or braid is applied directly over the insulation. Flat cables typically have this material applied over the jacket material. Barrier materials such as extruded PVDF and FEP extruded over the insulation provides a fluid barrier, chemical resistance, decompression resistance and added electrical strength. Lead sheathing is another type of barrier that is an excellent fluid and gas barrier and it protects copper in H_2S applications. Lead sheathing is heavy and can work-harden, causing cracking. It is also susceptible to mechanical damage. For more detailed information on these materials, refer to API RP 11S5.

Armor: Armor is the outer covering that provides mechanical protection during installation and removal of the cable from the well. In round cable construction, armor provides mechanical strength to confine swelling of the cable during decompression as the cable is pulled. Galvanized steel, stainless steel and monel armor are the most common types of armor used on cables for oil well environments.

In severe environments where large amounts of CO_2, H_2S, and large amounts of brine may be present, Monel armor should be used. While 316L stainless steel armor is a good choice for many corrosive well applications, stress cracking can be a problem in chlorides (greater than 30,000 ppm) where the temperature is over 160°F. Because of its cost, galvanized steel is normally the first armor of choice. Before using more expensive armors in corrosive applications, thicker galvanized metal should be considered. API RP 11S5 Section 7, provides detailed information on cable armor.

9.2.5 Motor Lead Extension and Pothead

Potheads are electrical connectors to the motor, which isolate the motor oil from the well fluid. The motor lead extension is a special power cable extending from the pothead on the motor to above the end of the pump where it connects with the power cable. A low-profile cable (flat configuration) is usually needed in this area due to limited clearance between the pump housing and the well casing.

9.3 CHECKLIST

a. Determine cable configuration needed (flat or round).

b. Determine jacket materials required.

c. Work with ESP vendor to determine optimal and economical conductor size.

d. Ensure voltage and temperature limitations in cable not exceeded.

e. Ensure that voltage drop in cable does not prevent motor starting capability.

10 Select Switchboard/VSD and Transformer (see API RPs 500 and 11S3)

Surface equipment, such as the switchboard or VSD, transformer, and surface cable must be selected to deliver electrical energy at the voltage and amperage required by the downhole motor. Additional considerations, like operating offshore or in desert environments, will influence equipment selection.

10.1 MATCH SURFACE ELECTRICAL EQUIPMENT TO MOTOR/PUMP/WELL PERFORMANCE

Primary power received at the well site will be in the form of high voltage (i.e., 7200, 12470, 14400, 24950, etc.) or low voltage (380, 440, 460, 480, etc.) A constant frequency of 60 Hz (50 Hz in some countries) is also provided. Although the voltage and fixed frequency may vary from region to region, it is important that the power source and surface equipment provide the ESP motor three-phase power and the required surface voltage (see Equation 10.1a). When proper voltage is supplied to the motor, the required current (amperage) will be made available to the motor. Proper voltage, and therefore amperage, is essential to maintain a high efficiency of the motor.

$$\text{Surface Voltage} = \text{Motor Voltage} + \text{Cable Voltage Drop}$$

When high voltage power is supplied, a step-down transformer is required to provide the proper voltage at the motor. A low voltage power supply requires transformers be installed that will increase the primary voltage to match the surface voltage needs. Transformers are predominately sized by Kilowatts-Volts-Amperage (KVA). The calculated KVA value must not exceed the transformer's rating. Three single-phase transformers have a total KVA rating of the sum of their individual ratings.

$$KVA = \frac{1.732(\text{Surface volts})(\text{Actual Motor AmpLoad})}{1000}$$

10.2 LIMITATIONS/CONSIDERATIONS AND DEFINITIONS

10.2.1 Step-down Transformer

When high voltage power is supplied, a step-down transformer is required for supplying the proper voltage to the motor. There are three different configurations available for a transformer. The three single-phase and one three-phase standard are both dual wound transfers used for "step-down" applications. Overloading of transformers is not advised and special ratings are required for desert applications. Offshore applications may require special non-flammable oil to meet Class 1 Division 2 requirements for transformers. Dry type transformers are sometimes used in offshore applications.

10.2.2 Step-up Transformer

Low voltage power requires transformers that will increase the primary voltage to match the surface voltage requirement. This may occur if the primary power is low voltage (480) and the control panel is also low voltage but the motor voltage required is greater. In this case a step up transformer may be placed between the control panel and the downhole motor. In the case of a variable speed controller, the input and output to the controller is low voltage (480 V, for example) and a special step up transformer is used between the controller and motor to bring the voltage up to that required by the motor (see Figure 2). The three-phase autotransformer is used to step up when the distribution voltage is 440 or 480 V, with the limitation to applications requiring 1000 V or less that do not use downhole monitoring systems. Overloading of transformers is not advised and special ratings are required for desert applications. Offshore applications may require special non-flammable oil to meet Class 1 Division 2 requirements for transformers. Dry type transformers are sometimes used in offshore applications.

10.2.3 Fixed Speed Controller, "Control Panel" or "Switchboard"

All applications, except where variable speed drives are used, will require a control panel. Control panels provide four basic functions:

1. Switchgear to start and stop the motor.
2. Current overload and underload motor shut-down protection.
3. Current monitoring for predicting downhole conditions.
4. Transient surge protection.

High voltage applications require the control panel be on the secondary side of the step-down transformer with a rating that meets or exceeds the calculated surface voltage and amperage required by the motor (see Figure 3).

Where low voltage power is supplied, the control panel is often placed on the primary side of a step-up transformer. In this case, care must be taken to select a control panel that is rated for the higher amperage, which will be required.

When using a generator with a switchboard, the generator KVA rating selected is equal to or greater than the motor full load KVA plus any surface load KVA plus transformer loss KVA plus cable loss KVA. However, a generator that is capable of carrying the full load continuously will not necessarily supply the required starting KVA to start and accelerate the motor to full speed. Historically, rule of thumb multipliers were used on the motor horsepower rating to determine the generator kW rating required for motor starting. With the many generator manufacturers today, each with different design characteristics, the use of thumb rules are not a reliable method. The ESP manufacturer should be consulted for an evaluation, as generator selection needs to be based on its individual electrical characteristics.

There are two construction types: electromechanical and solid state. The electromechanical switchboard provides a manual disconnect switch, magnetically operated motor controller, magnetic-oil dashpot overcurrent relays, and undercurrent relay for pump off and gas lock protection. A Bristol recording ammeter, with mechanical lock, records running time, downtime and amount of current being used during operation. The solid state controlled switchboard provides a greater level of protective functions plus selected operating parameters and status indicators. The electromechanical is the only one that offers a DC control scheme, which for some applications could mean sizing a smaller generator. On the other hand, the solid state is the only one that offers SCADA capability. Both types, when maintained properly, provide equal reliability. There are various optional accessory packages that can be included with a switchboard.

10.2.4 Variable Speed Control Panels or "VSD"

Flexibility in flow and lift can be realized through the use of a variable speed motor controller. When a variable speed controller is used, a fixed speed controller is not required. A 460 – 480 V input at 60 Hz is normally required for variable speed controllers (380 – 400 V at 50 Hz). Varying the Hz has a direct ratio effect on the voltage output and thus the motor revolutions per minute. The capacity of the pump is changed also (see Appendix D for more detail on the affinity laws). A Variable Speed Drive (VSD) is used to change the fixed frequency of the incoming AC power wave to other frequencies (usually in the 30 – 90 Hz range). By changing the frequency of the AC power being supplied to the ESP, the pump performance is changed. Higher frequency translates to higher

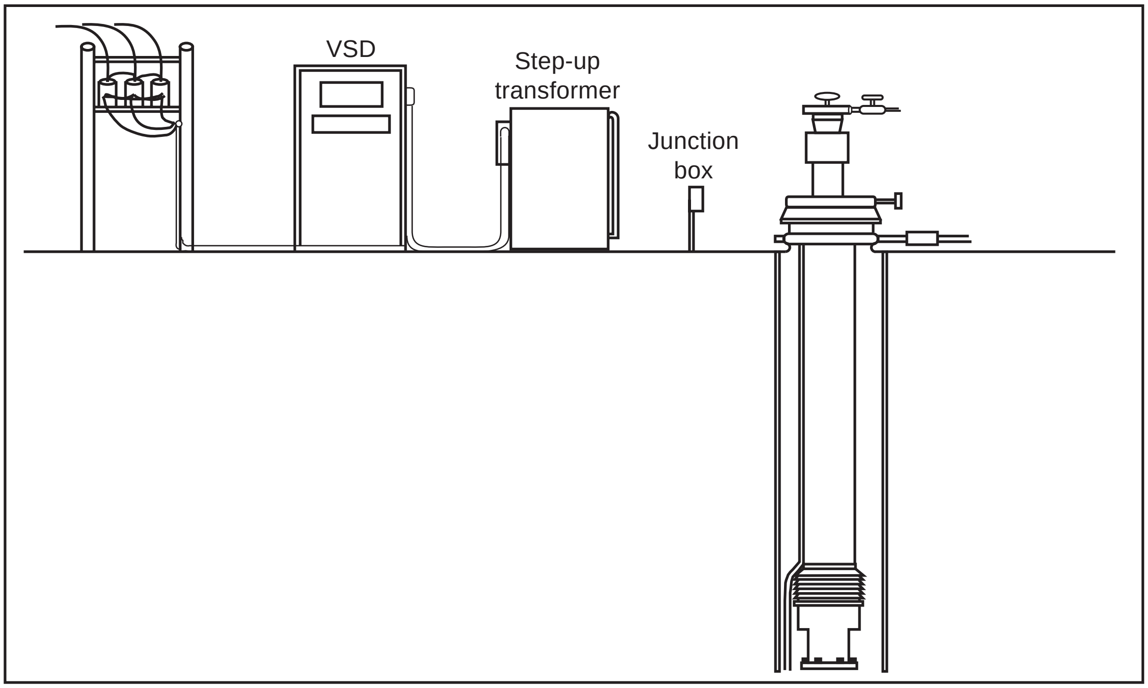

Figure 2—Electrical Configuration Using a Step-up Transformer

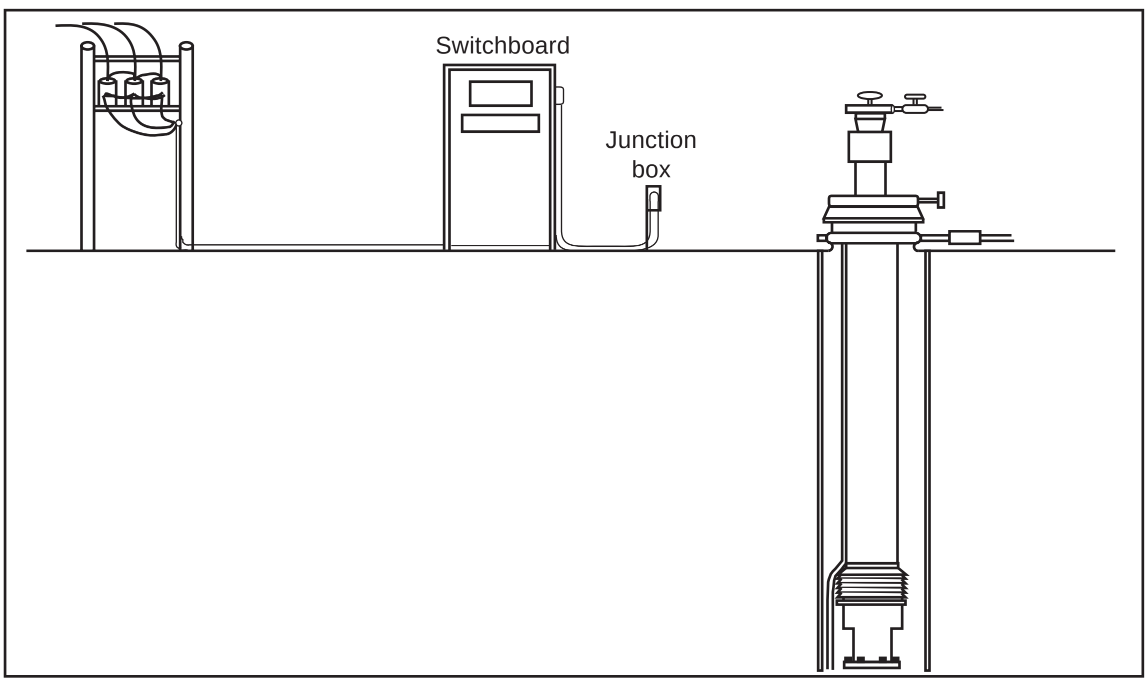

Figure 3—Electrical Configuration Using a Fixed Speed Controller

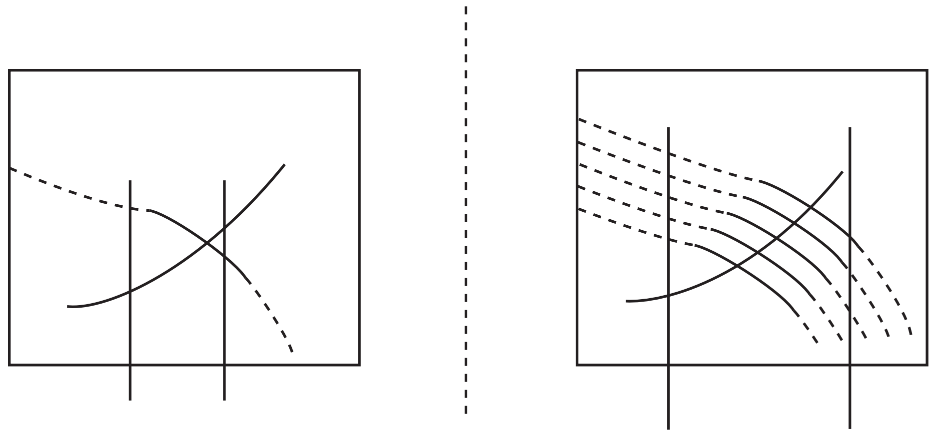

Figure 4—Fixed Frequency and Variable Frequency Pump Performance Curves

pump speed, which generates greater flow and head, but the horsepower required will be higher as well. The performance changes in centrifugal pumps are estimated using the "affinity laws" where RPM represents revolutions per minute:

FLOW: $Q_{\mathrm{RPM2}} = Q_{\mathrm{RPM1}} \times (\mathrm{RPM}_2 / \mathrm{RPM}_1)$

HEAD: $H_{\mathrm{RPM2}} = H_{\mathrm{RPM1}} \times (\mathrm{RPM}_2 / \mathrm{RPM}_1)^2$

BHP: $\mathrm{BHP}_{\mathrm{RPM2}} = \mathrm{BHP}_{\mathrm{RPM1}} \times (\mathrm{RPM}_2 / \mathrm{RPM}_1)^3$

Since the ratio of the RPM is the same as the ratio of the frequency,

$$\frac{\mathrm{RPM}_2}{\mathrm{RPM}_1} = \frac{\mathrm{Hz}_2}{\mathrm{Hz}_1}$$

The "affinity laws" can be expressed directly as a function of an electrical parameter such as the frequency in Hertz. If the pump performance at 60 Hz is known, it can be corrected to another frequency:

FLOW: $Q_{\mathrm{Hz}} = Q_{60} \times (\mathrm{Hz}/60)$

HEAD: $H_{\mathrm{Hz}} = H_{60} \times (\mathrm{Hz}/60)^2$

BHP: $\mathrm{BHP}_{\mathrm{Hz}} = \mathrm{BHP}_{60} \times (\mathrm{Hz}/60)^3$

VSDs allow a great deal of flexibility in applying the ESP to a well. As can be seen graphically in Figure 4, simply changing the frequency (or speed of the pump) can greatly affect its performance. This means that with a VSD, one size of pump and motor is capable of handling a wider range of application conditions.

VSDs may be beneficial in cases where the well productivity is unknown or to handle the changes in well condition or performance over time. Operating the ESP with a VSD in conjunction with a downhole pressure sensor will allow optimization of the well production by operating in a closed loop pressure control, set up to maintain a fixed pump intake pressure.

Changing the frequency also affects the horsepower output of the ESP motor. The motor horsepower increases directly with the ratio of the frequency, as depicted in Figure 5. Higher frequency means the motor turns faster and the motor is capable of generating higher horsepower.

This happens because the *VSD output maintains a constant volts-to-hertz ratio.*

$$\frac{\mathrm{HP}_2}{\mathrm{HP}_1} = \frac{\mathrm{Hz}_2}{\mathrm{Hz}_1}$$

Graphically it would look like this for a 200-HP, 60-Hz motor:

Since the BHP required by the pump increases with the cube of the frequency ratio, there will be a frequency where the pump required BHP will exceed the HP delivered by the motor. This point is the maximum limiting frequency ($F_{\max}$) and is depicted in Figure 6.

Operating the ESP above $F_{\max}$ will overload the motor and cause it to overheat, shortening its life.

Unfortunately in the conversion process from AC to DC and back to AC, a VSD can introduce voltage and current signal distortions called "harmonics" and "ringing" or noise into the system. Ringing is form of voltage overshoot. Sine wave power gives a smooth curve for the voltage to follow; however, the output of the VSD is not necessarily a smooth curve. There are models on the market with filters that emulate sine wave output, which eliminates the harmonics.

Special considerations should be made when running a VSD on a generator set because harmonics can damage the

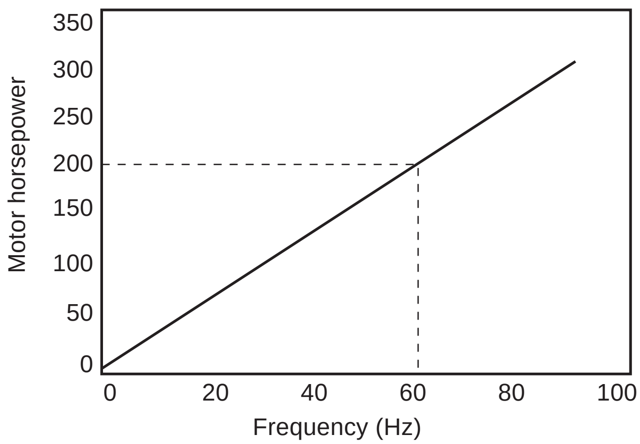

Figure 5—Motor Horsepower Output vs. Frequency

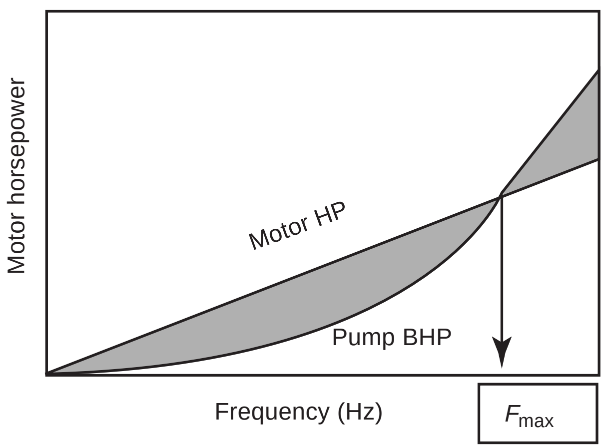

Figure 6—Motor Horsepower Output and Pump Required BHP vs. Frequency

control circuit and overload the generator. Normally, power systems are strong enough to handle the excess current but generators are sized much closer to actual load requirements. The generator will need special filters on the control circuit to eliminate the harmonics from being seen. The gen-set should also be oversized by 25% – 50% of the actual drive load to be able to handle the commutating current.

As with the switchboard, there is more than one type of VSD, and there are optional accessory packages that can enable better monitoring, control and diagnostic capability for the well.

10.2.5 Vents and Junction Boxes

API RP 11S3, 4.3 recommends that a vent be installed between the wellhead and the motor control panel. This vent should limit the pressure on the sealing fitting between the vent and the motor control panel to 6 in. (15.2 cm) of water column (illustrations available in API RP 11S3). A properly designed vented junction box is one method of achieving this. The junction box connects the power cable from the controller to the well power cable. Where free or liberated gas is present, there is the possibility for gas migration up the cable and into the control panel. The vented junction box provides a means for venting off the gas and away from the control panel eliminating a possible explosive situation. A vented junction box should be located more than 5 m (15 ft) from the wellhead or other provisions should be made to allow access for well servicing units.

10.2.6 Soft Starting

There is a difference in the starting characteristics of a VSD and a direct-on-line (DOL) switchboard. Power requirements are reduced by using a VSD because it “ramps up,” or comes up to speed, more slowly compared to a DOL or switchboard start. A typical DOL start will bring the motor up to speed in less than 1/4 of a second. The VSD can slow this to around 7 seconds, reducing in-rush current on start-up and possibly reducing the high torque transients present in a DOL “hard start”. A special soft start mechanism can be added to a switchboard and is used mainly to relieve torque stress on the pump shaft at start-up for high horsepower applications.

10.3 OPTIMIZATION AND ECONOMICS

Table 1—Comparison of VSDs vs. Fixed Controllers

	VSD	SWITCHBOARD/DOL
Flexibility	It provides the means to match the well inflow within a wider operating range by changing the operating frequency.	It operates at the fixed frequency of the power supply grid (no flexibility).
Optimizing Well Production	It allows optimizing the well production by operating in a closed loop pressure control, maintaining the pump intake pressure at a minimum value—also, frequency and current operating modes are available.	No optimization capabilities.
Starting Characteristics	It starts more smoothly, ramping up to the set operating frequency. The ramp speed rate can be set by the operator for each application. It is a soft start system.	It is a DOL start which can place more stress on the motor, power system and cable during start-up.
Electrical Disturbances	It generates electrical disturbances called harmonics and ringing in the current and voltage signal. These disturbances move both upstream to the power supply and downstream to the downhole system. Operating the ESP with a VSD will generate these disturbances even when it operates at 60 Hz or at the normal grid frequency. Harmonic heating due to VSD operation is a component in the total internal motor operating temperature rise.	It does not generate electrical disturbances except during starts and stops. Power system disturbances (sags, surges and voltage imbalances) are passed on to the motor.
Power Operating Requirements	Under normal operating conditions, the operating power consumption is higher in a system operated with a permanent VSD for two reasons. The VSD is less efficient than a switchboard (VSD converts the input AC power to DC and then to AC at the new frequency) and the VSD disturbances create additional harmonics which produce heat. If the power supply for the ESP is an isolated gen-set, it needs to be oversized for VSD operation. All the energy lost against a choke can be reclaimed by a VSD.	The switchboard would normally be the lower operating cost option. However, in special operating conditions, such as choked or back-pressured tubing at the surface, the operating cost of a switchboard may be higher than with a VSD. If the power supply for the ESP is an isolated gen-set, it needs to be oversized for VSD operation.
Personnel Required for Operation	Personnel from both the Operating Company and the Service Company require special training in VSD operation. Only qualified technicians should perform maintenance of VSDs.	Most Operating Company Electrical Technicians are generally accustomed to switchboards. Only qualified technicians should perform maintenence of switchboards.
Initial Cost	The initial cost of a VSD is much higher than a switchboard. If high voltage power supply grid is available at a well site, which will be operated by a VSD, a step-down transformer and a step-up transformer will be required. Furthermore, the step-up transformer must be VSD rated. If the design frequency is greater than 60 Hz, the cost of the pump and oversized motor (for equal flow and head) will be less than that required for a 60 Hz switchboard.	Initial cost of a switchboard is less than the cost of a VSD. When using a switchboard, only one set of transformers will be required, except where local codes such as California law require low voltage switchboards and a second set of transformers.

If the well site is not supplied with grid power, the power will be supplied by a gen-set, which must be oversized for either VSD or switchboard, but for different reasons.

Selection of a switchboard or VSD as the permanent starter and control system of the ESP depends on several factors, including location of the wells, Operating Company operating policies, the available power supply, operating environment, well information (PI) availability, etc.

10.4 CHECKLIST

a. Calculate the surface voltage requirement (at highest frequency of application for VSD).

b. Calculate the KVA requirement (at highest frequency of application for VSD).

c. If the primary power source requires a step-down transformer, select the appropriate transformer to feed the controller the required voltage.

d. If using a fixed speed controller, select the appropriate voltage/amperage unit to feed directly to the motor or to feed to a step up transformer that will increase the voltage to that required by the motor (plus cable losses).

e. If using a variable speed controller, select the appropriate unit based on KVA requirements at the highest frequency of the application.

f. If using a variable speed controller, select the step-up transformer rated for VSD application that will provide the required voltage to the motor.

g. At all phases of the selection process, consider equipment efficiency losses.

11 Ancillary Equipment

This equipment includes downhole sensors, Y-tools, drain valves, check valves, packers, centralizers, penetrators, etc. These items are used for specific operating needs. Use of some ancillary equipment (e.g., Y-tool and packer) needs to be decided early in the design process because it may affect the selection of other ESP equipment. For special applications or equipment configurations, design should be referred to the equipment manufacturer.

11.1 CHECK VALVE AND BLEEDER OR DRAIN VALVES

A check valve is used to maintain a column of fluid in the tubing when the pump is shut down. It should be located a minimum of 6 – 8 joints above the pump to allow gas to be purged from the pump on startup. The check valve prevents the fluid column from flowing back through the pump, causing reverse rotation, when the motor is off.

A check valve is not a necessary component, but if not installed, all the fluid must be allowed to drain through the pump before restarting. If the unit is started while the pump is in reverse rotation, the result can be a broken shaft or motor/cable burn. There are several methods to ensure that the fluid has passed:

a. Wait a period of time (at least 30 minutes).

b. Install a backspin relay in the control panel.

c. Monitor the amperage generated by the motor while it is acting as a generator.

If a check valve is installed, a bleeder or drain valve should also be installed. It should be located one or two joints above the check valve. The drain valve is designed to allow for pulling of the tubing string and pumping system without the well fluids.

11.2 BACKSPIN RELAY

The backspin relay is located in the controller and is connected to the power cable. This relay detects when the pump is rotating in reverse and prevents startup until the pump is no longer spinning.

11.3 DOWNHOLE MONITORING SENSOR

To get a more accurate description of downhole conditions at the pump, there are a variety of sensor packages and installation methods available. Pressure (intake/discharge), temperature (fluid/motor windings), current leakage, flowrate, dielectric strength of motor oil, and vibration are parameters that can be measured with downhole sensors.

It is recommended that the user decide upon which variables need to be monitored downhole and how accurately those measurements must be. By working with the ESP and/or sensor vendors, a suitable sensor package can be installed to meet the user's needs.

11.4 CENTRALIZERS AND MOTORGUIDES

Centralizers and motor guides are designed to center the pumping system in the well, especially in deviated applications. Often, centralizers will be attached to the bottom of the motor to serve as a guide for the pumping system when running into the well or liner. Motor head and base centralizers (motor guides) are designed to protect the materials sprayed on the motor to protect it from corrosion from being scarred during installation. For deviated applications, the centralizer allows for 360° flow around the equipment and better heat transfer around the motor.

11.5 ANODES

Typically anodes are attached to the bottom of the motor and are sacrificial to the corrosive fluids. Anodes usually made of aluminum or zinc materials, are consumed as they corrode away while protecting the motor.

11.6 PENETRATORS

Penetrators (feed-through mandrels) are pressure/fluid barriers around electrical conductors that allow the flow of electrical power through the packer and/or wellhead. The electrical connection may be by connectors or cable leads. A connector will be located on both sides of the packer/wellhead, thereby connecting the power cables.

11.7 Y-TOOLS

Y-tools are used when it is desired to treat or work over the well without pulling the pumping system or for multiple ESP installations in a single wellbore. A Y-tool allows for continuation of the tubing string as it is attached along side the pumping system. The extended tubing serves as a passageway for logging tools and/or coiled tubing. A plug is run in the tubing when the well is operating to prevent recirculation of pumped well fluids. Bypass tubing size may affect pump/motor selection. For this reason, all elements planned through the bypass tubing need to be identified.

11.8 WELLHEADS

The wellhead must be equipped with a tubing hanger/pack-off which provides for a fluid and pressure seal around the tubing and power feed-through. To ensure safe operations, piping and valves of adequate pressure ratings should be installed to connect the wellhead to the flowline. Consideration should be given to pump discharge pressure, wellbore pressure, maximum shut-in pressure and other applicable parameters.

During ESP operations when free gas is present, the casing valve must stay open (vented or piped to flowline) to allow the gas to exit the annulus.

11.9 PACKERS

Packers are designed to direct and control the well fluids by isolating the well annulus. The packer may be installed with the production tubing and set above the pumping system. This requires that all fluid passes through the pump and a feed thru and power cable connectors will be required. Packers can also be set prior to running the submersible pump system. In this case, the pump intake is normally stung into the packer and special cable feedthrough systems are not necessary. This “below the pump” packer arrangement usually allows reservoir to be isolated during pump changeouts.

11.10 CABLE BANDS OR CLAMPS

Cable bands or clamps are used to attach the power cable to the outside of the tubing string because the cable cannot support its own weight. For most applications, cable bands made from carbon steel, stainless steel or Monel, are used. The minimum banding recommendation is two bands per tubing joint, with one band in the middle of the joint and the other band 2 ft – 3 ft above the collar. The widths of the bands are dependent on cable weight. Heavier cable (lead-sheathed) requires a wider band.

When the application presents the possibility of cable damage, such as deviated wellbores, special banding equipment should be considered. Re-usable, over-the-coupling protectors (cable clamps) are designed to prevent the power cable from making contact with the well casing while not allowing the cable to slip down the tubing. Re-usable bolting or pin clamps are also available for the mid-point of the tubing where additional cable support is desired

11.11 SHROUD OR MOTOR JACKET

A motor shroud is used in applications where the pumping unit is set in or below the production perforations primarily when the speed of fluid past motor is less than 1 ft/s. The shroud surrounds the motor housing up to just above the pump intake. The produced fluid travels from the perforations downward to the base of the shroud, up through the annular space between the motor and shroud to the pump intake. This fluid path allows sufficient motor cooling to prevent failures.

The shroud has also been used for other applications, such as a gas separator and for installation multiple ESPs in series in a single wellbore.

11.12 CABLE-DEPLOYED PUMPING SYSTEMS

The tension cable is used for cable-deployed ESP systems. The specially designed tension cable, which must support the weight of the downhole equipment, is used to raise and lower the ESP system in and out of a seating or landing nipple in the wellbore. The cable-deployed system requires special handling equipment and is relatively expensive. The tension cable termination point, called the rope socket, is the weak point of the system (due to the shear pins) if the ESP becomes lodged or stuck in the landing nipple.

11.13 COILED TUBING DEPLOYED SYSTEMS

The coiled tubing is used to supply strength to run, set and operate coiled tubing deployed ESP systems. There are several configurations depending on whether the power cable is banded externally to the coil, placed inside the coil and if the ESP is conventional or inverted. Only the internal power coil system allows the possibility of workovers on a live well using a lubricator and stripper for well control (see API RP 5C7).

12 Example Problem

Detailed discussion on design of ESP systems has been presented in other sections. From these presentations, it can be seen that much detailed computation must be completed for a typical design, considering multiphase flow, reservoir inflow performance and pump and motor performance under various loading, and well conditions.

Most ESP designs are completed on the computer today. However, the following example problem will outline the steps and equations needed to complete a basic design by hand for a high water cut well (no gas). It is still recommended to work with the manufacturer to refine the design further.

Target production rate:	q	=	1500 bpd
Fluid properties:	$\gamma_f \sim$		1.0
IPR:	P_{bhs}	=	2000 psi
	J	=	2.0 bpd/psi
Depth:	VD_{pump}	$= V_{Dres} =$	6353 ft
Surface tubing pressure:	P_{wh}	=	100 psi
Tubing size:		=	$2^7/8$"

For this problem, the following single stage pump curve will be used for the calculations:

The procedure is as follows (formulae found in 5.1):

1. Well fluid gradient = water gradient x γ_f = 0.433 psi/ft x 1.0 = 0.433.
2. Well flowing pressure at q = P_{bhs} – [q/J] = 2000 – [1500/2] = 1250 psi.
3. Pump intake pressure = P_{wf} – {[V_{Dres} – VD_{pump}] x [fluid gradient]} = 1250 – [0 x 0.433] = 1250 psi
4. Intake volume of pump: since $\gamma_f \sim 1.0$, assume that the volume at intake = q
5. Net Vertical Dynamic Lift = VD_{pump} – [PIP/Fluid gradient] = 6353 – [1250/0.433] = 3466 ft
6. Friction Loss = [MD_{pump}/1000 ft] x [ft of loss/1000 ft tubing] = 6.353 x 10 = 64 ft
7. Wellhead Tubing Pressure Head = [P_{wh} x 2.31]/γ_f = 100 x 2.31/1.0 = 231 ft
8. Total Dynamic Head = $H_D + H_F + H_T$ = 3466 + 64 + 231 = 3761 ft

Entering the above chart at 1500 bpd, we see that the pump generates about 39.5 ft of head per stage. Therefore the number of stages is:

9. Number of stages = Total Dynamic Head/(Head/stage) = 3761/39.5 ~ 95 stages.

For this particular pump curve, the HP/stage is 0.705 HP/stage.

10. Power required by pump = HP/stage x # of stages x γ_f = 0.705 x 95 x 1.0 = 67 HP.
11. Production rate at 75 Hz (if VSD present) = q_{rpm1} x (RPM_2/RPM_1) = 1500 (75/60) = 1875 bfpd

For this problem, the following single stage pump curve (see Figure 7) will be used for the calculations:

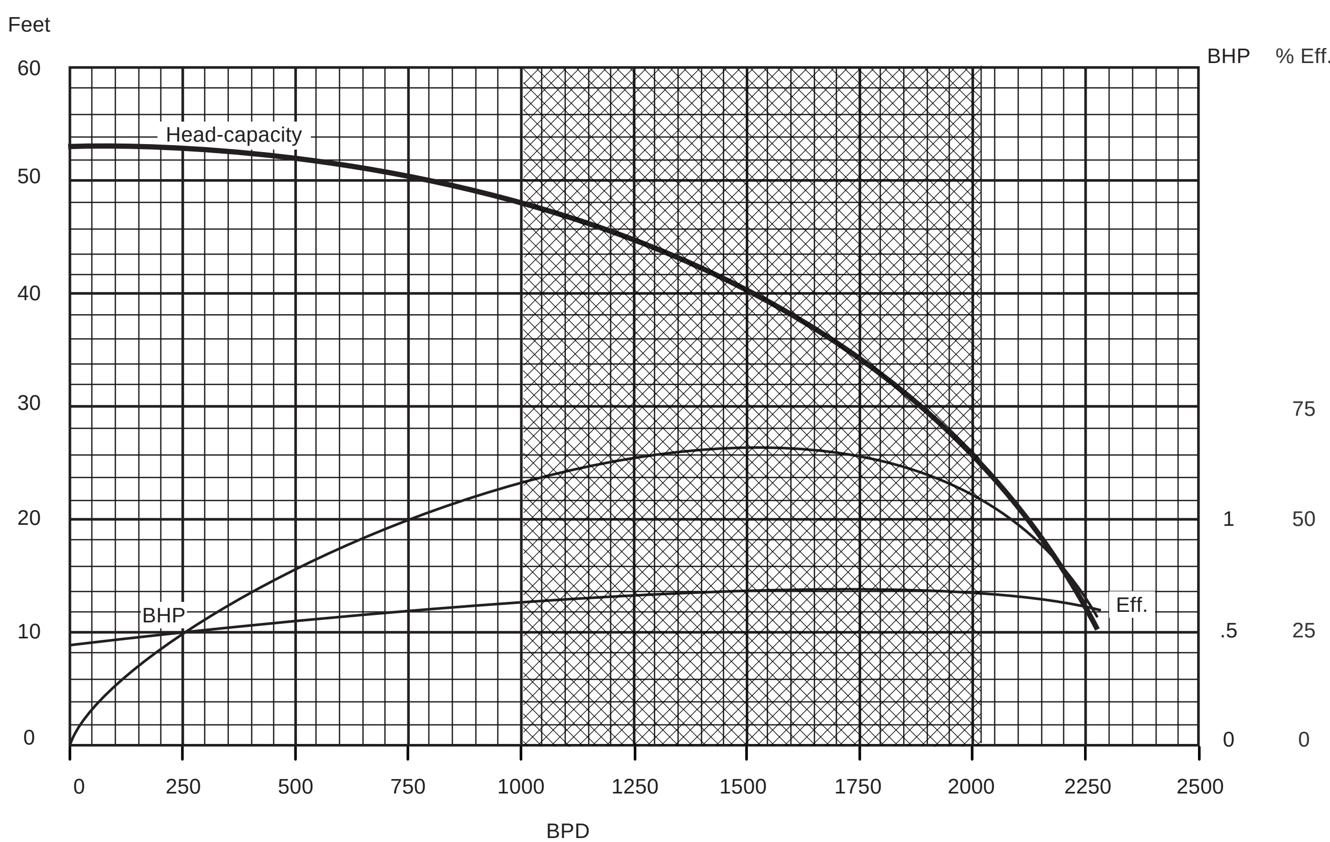

Figure 7—Example of a 60Hz—Single Stage Pump Performance Curve

APPENDIX A—DATA SHEET DEFINITIONS

Note: In the data sheet, both English and SI units follow each data item. It is very important to indicate which units are being used. Unit conventions change over time and the ESP designer might not use the same unit conventions as the data collector.

Operator is the company that operates the well. Identifying the operator helps identify the well. It might also indicate to the ESP designer that certain design specifications should be followed.

Lease is the property on which the well is located. Identifying the lease helps identify the well.

Well is the well identifier. Usually, this is a number used in conjunction with the lease or property name to identify the well for a particular operator.

Location is the geographical location of the well. Identifying the locations helps identify the well. In addition, knowing the location helps the ESP designer know what type of support services and equipment inventories are available.

Field is the name of the field where the well is located. Identifying the field helps identify the well. In addition, knowing the field might help the ESP designer identify potential operational problems.

Resvr is the name of the reservoir from which the well is producing. Include a tag that indicates the type of reservoir (sand, limestone, etc.) Knowing the reservoir can help the ESP designer identify potential operational problems.

Prepared by is the name of the person who collected the data. A telephone number or e-mail address at which the data collector can be contacted should be included. This information is needed in case the person designing the ESP installation has questions about the input data.

Company is the name of the company the data collector works for. This information is needed to help locate the data collector. A telephone number or address could be useful here.

Date is the date the data was collected. By dating the data the ESP designer has an indication of the timeliness of the data.

Perf interval is the section of the wellbore where fluids enter the well. It is needed as a guide in determining the pump setting depth. This is a measured depth.

Casing min. ID is the smallest internal diameter in the production casing through which the ESP assembly must be run. This will determine what size equipment can be run in the well.

PBTD is the plugged back depth of the well. This is needed only if some part of the ESP assembly will be run below the perforations. Checking this value in all cases is a good idea as it can help avoid surprises when installing the ESP.

Liner ID is the minimum liner diameter in which any part of the ESP assembly (such as a tailpipe) will be run. TOL is the measured depth to the top of the liner. Determining this value can also help avoid surprises when installing the ESP.

Tubing OD is the outer diameter of the tubing string. Wt is the nominal weight of the tubing. Grade is the material grade of the tubing. Thread is the type of threads on the tubing string. These values are used to determine what type of discharge head or crossover is needed for the ESP. From these values one can also determine the tubing ID and Burst strength. ID is used to calculate frictional pressure losses in the tubing string. Burst is used as a check to make sure the ESP does not generate enough pressure to burst the tubing.

Deviation profile describes the trajectory of the wellbore and dogleg severity.

Flowline ID is the internal diameter of the flowline linking the well to its associated production facility. Length is the measured length from the wellhead to the facility.

Elevation is the elevation difference between the well and production facility. These values are used to calculate the lift required to move the produced fluids from the well to its production facility. Many ESP designs routinely ignore this calculation and instead simply specify a wellhead pressure. This is not recommended because the production flowline can be a production bottleneck.

Separator/wellhead pressure and temperature: Depending upon the gathering system, if the ESP produces directly into a dedicated separator, enter the separator data. If not, enter the wellhead information.

Wellhead choke indicate whether a wellhead choke is present in the system and its location.

Casing pressure is the amount of pressure held on the wellhead casing. Vented specifies whether or not the casing is vented. If the casing is vented, either to atmosphere or a gathering system, much of the produced gas will flow up the casing/tubing annulus. If the casing is not vented, the ESP has to pump all produced gas.

Primary power is the voltage available at the well site. Frequency is the power frequency at the well site. This will be either 50 Hz or 60 Hz. These values determine surface electrical equipment requirements and the pump operating speed, if it runs from a switchbox.

Oil specific gravity is a measure of the density of the oil produced from the well. If you specify API gravity or density instead, make certain you indicate this on the data sheet. Oil gravity is used to determine fluid properties and in calculating the amount of lift needed to produce the well at desired flow rates. Oil gravity is strongly influenced by temperature. The value recorded in the data sheet should be corrected to standard conditions.

Paraffin/Asphaltenes/Scaling: Indicates whether or not these problems are expected. Answer none, light, moderate or heavy. If answer is other than “none”, needs to be quantified (location of deposition, type of scale, treatment program).

Chemical treatments: Used to describe types of chemicals being used (corrosion, diluents, demulsifiers, deposition), frequency and method of treatment.

Water specific gravity is a measure of the density of the water produced form the well. It is one of the variables used to calculate the amount of lift needed to produce the well at desired flow rates. It is may also be used to determine fluid properties. The value recorded in the data sheet should be for standard conditions.

Gas specific gravity is a measure of the density of the gas produced by the well. It is one of the variables used to determine fluid properties and to calculate the amount of lift needed to produce the well at desired flow rates. The value recorded on the data sheet should be at standard conditions, referenced to air.

H_2S content is a measure of the hydrogen sulfide present in the produced fluid. The ESP designer uses this value to determine whether or not H_2S resistant materials are needed.

CO_2 content is a measure of the carbon dioxide present in the produced fluid. The ESP designer uses this value to determine whether or not CO_2 resistant materials are needed.

Water cut is the percentage of produced liquid that is water. This value should be calculated using stock tank volumes. Water cut is an element used to determine the amount of lift required to produce the well at the desired production rate.

GLR/GOR is the ratio of gas to liquid or gas to oil in the produced fluid. Either value can be used. Circle the value you have entered. These ratios should be calculated at standard conditions. The gas volume includes both free and dissolved gas. Note the gas volume measured at separator conditions does not include the dissolved gas remaining in the oil and water phases. This volume can be accounted for with black oil correlations or PVT data. The GLR and/or GOR are elements used to determine the amount of lift require to produce the well and the amount of free gas entering the pump.

Sand content is the amount of sand in the production stream. The grain description of "round or angular" will indicate the abrasiveness of the sand. The ESP designer uses these values to determine whether or not sand resistant materials are needed. A sieve analysis of the produced sand should be attached to the data sheet if available.

Bubble pt pressure is the pressure at which gas begins to come out of the oil phase of the produced fluid. This value is used to determine fluid properties and the amount of free gas entering the pump.

The appropriate columns in the PVT and Viscosity data table should be filled out for high GLR or high viscosity wells.

P* and *T are the pressure and temperature at which the corresponding PVT or viscosity value was taken. Obvious needed values are pump intake (most important), pump discharge, wellhead and separator conditions.

B_o is the oil phase formation volume factor. This corresponds to the volume a stock tank bbl of oil occupies at the specified pressure and temperature. It will normally be larger than one because of the volume of dissolved gas it contains.

B_g is the gas phase formation volume factor. This corresponds to the volume a standard cubic foot of produced gas occupies at the specified pressure and temperature. It is normally much smaller than one because the pressure encountered down hole.

Rs is the solution gas ratio. This is the volume of gas dissolved in a stock tank barrel of oil at the specified temperature and pressure.

μ_{od} is the dead oil viscosity. Dead oil is oil that does not contain dissolved gas. μ_{od} is used with correlations to estimate a value for μ_o.

μ_o is the live oil viscosity. Live oil is gas-saturated. μ_o will be lower that μ_{od}. μ_o is used to calculate frictional losses within the piping associated with the well.

Test datum is the depth the test data is referenced. For bottom hole tests, this is the depth the pressure sensor is located. For surface tests this could be calculated at the pump intake, the top of the productive interval or the midpoint of the productive interval. It is from this depth, not the productive interval, from which any pressure differential calculations to the pump intake should be made. MD is needed for friction loss calculations. TVD is needed for head differential calculations.

Static pressure is the stabilized shut-in pressure at the test datum. Do not use reservoir pressure unless the test datum is at the reservoir. Temperature is the fluid temperature at the test datum.

Test rate is the most recent flow rate at the test datum during a flow test. Specify whether this is an oil or liquid rate. The rate should be converted to standard conditions. Test pressure is the pressure corresponding to the test rate. Test rate and pressure are used to construct an IPR curve for a well. If the productivity index and static pressure are known values, the test points are not needed.

Productivity index is the ratio between production rate and total pressure drawdown. This value is used to determine either the expected production rate or the pump intake pressure, depending upon which parameter is defined in the Design Criteria section.

The Design Criteria section also contains some parameters that may influence the ESP design.

Desired flow rate is the rate at which the operator wishes to produce the well. In many cases, the operator will wish to operate the well at the highest rate possible. In those cases, this value will not be specified.

Desired pump intake pressure is the pressure at which the operator wishes to operate the well. This value is used in conjunction with the IPR curve to determine the production rate. This field can also be used to specify a minimum allowed pump intake pressure (see 5.1.1).

Minimum fluid over pump is the minimum amount of fluid allowed above the pump intake. Most operators require 200 ft – 500 ft.

Desired pump setting depth is the depth at which the operator wishes to place the pump. This would normally be the greatest depth possible in order to maximize the production rate, if there is no gas or sand present. If the well is deviated, the pump depth will be determined by location of tangential section.

Switch gear/trans. rating KVA is the minimum KVA rating of the existing or specified power cable, wellhead power feed-through, transformers and switchbox or variable speed drive associated with the well. Min Hz and Max Hz are the minimum and maximum speeds the operator is willing to operate a VSD.

Available voltage taps are the output voltages available on the step-up transformer. This could influence motor selection.

APPENDIX B—ESP DESIGN DATA SHEET

Operator: ____________ Lease: ____________ Well: ____________
Location: ____________ Field: ____________ Resvr: ____________
Prepared by: ____________ Company: ____________
Date: ____________

WELLBORE GEOMETRY

Deviation: Yes | No (if yes, include deviation survey and indicate following depths as TD or MD)
Prod. interval Top: ________ ft | m Bottom: ________ ft | m
Casing min. ID: ________ in. | cm Wt: ________ lb/ft | kg/m PBTD: ________ ft | m
Liner min. ID: ________ in. | cm Grade: ________ lb/ft | kg/m TOL: ________ ft | m
Tubing OK: ________ in. | cm Wt: ________ lb/ft | kg/m
Grade: ________ Thread: ________
Tubing ID: ________ in. | cm Burst: ________ psi | bar | kPa
Limiting factors in wellbore (y-tools, packers, etc)?

SURFACE INFORMATION

Flowline ID: ________ in. | cm Length: ________ ft | m Elevation: ______ ft | m
Separator/Wellhead pressure: ______ psig | bar | kPa Temperature: ______ °F | °C
Casing pressure: ________ psig | bar | kPa Vented? ________ Yes | No
Primary power: ________ Volts Frequency ________ Hz
Amperage Limitations? ________

FLUID PROPERTIES

Oil specific gravity: ________ Water specific gravity: ________
Paraffin? ________ Asphaltenes? ________ Scaling? ________
Detailed information on above: ________

Gas specific gravity: ________ H_2S content: ______ ppm CO_2 content: ________ ppm
Water cut: ______ % CLR | GOR: ______ scf/bbl | m^3/m^3
Sand? ________ Yes | No Shape of sand grains: Round | Angular
Bubble pt pressure: ________ psia | bar | kPa

PVT & Viscosity Data

P (psia | bar | kPa)	T (°F | °C)	B_o (bbl/stb | m^3/m^3)	B_g (bbl/stb | m^3/m^3)	R_s (cf/scf | m^3/m^3)	μ_{od} (cP | SSU)	μ_o (cP | SSU)

Emulsion Viscosity Correction Factors ________ Inversion point ________ % water
Water cut: ________ ________ ________ ________ ________
Factor: ________ ________ ________ ________ ________

INFLOW CHARACTERISTICS

Test datum MD: ________ ft | m TVD: ________ ft | m
Static pressure: ________ psig | bar | kPa Temperature: ________ °F | °C
Test rate (oil | liq): ________ ________ ________ ________ bpd | m^3/d
Test pressure: ________ ________ ________ ________ psig | bar | kPa
Productivity Index ________ bpd/psi | m^3/d/kPa

DESIGN CRITERIA

Desired flow rate (oil | liq): ________ bpd | m^3/d
Desired pump intake pressure: ________ psig | bar | kPa
Minimum fluid over pump: ________
Desired pump setting depth MD: ________ ft | m TVD: ________ ft | m
Switch gear/trans. rating: ________ KVA Min Hz: ________ Max Hz: ________
Available voltage taps: ________
Comments: ________

APPENDIX C—COMPARISON OF DOWNHOLE VERSUS SURFACE MOTORS

C.1 Similarities

The stator is composed of iron laminations with slots around the bore to accommodate the winding. The winding is made of insulated copper wire and wound in a manner to form a 3-phase winding to give a sinusoidal current distribution around the stator bore (ID). The rotating member (rotor) is made of iron laminations around whose OD are distributed slots to hold electrical conducting bars, usually copper. The electrical conductors are shorted at the ends by attaching an electrical conducting ring referred to as an end-ring, or resistance ring or shorting ring (short circuit ring).

The rotors are keyed to a shaft. Radial bearings are also placed on the shaft as well as a thrust bearing at the top end of the rotor to support the weight of the motor.

The whole assembly, stator and rotor is enclosed in a housing and the ends sealed with what is termed a head and base, analogous to the brackets or end-bells of the surface motors. The head and base also contain radial bearings and the thrust bearing, but more importantly, they allow the shaft to penetrate through to be connected to the load or additional motors.

C.2 Differences

The first noticeable difference is that whereas a surface motor may have a ratio of stator stack length of laminations to lamination OD of 0.8 – 1.2, the ratio for submersibles can be in excess of 100:1.

Surface motors normally have one rotor per motor, whereas, submersible motors can have in excess of 20 rotors per motor, each rotor being separated by a radial bearing.

The radial bearings are commonly sleeve bearings as opposed to ball bearings used in surface motors of comparable horsepower.

Shaft diameters for comparable horsepower are usually of much smaller diameter in submersible motors.

Submersible motors are usually filled with oil, which acts as a lubricant for the bearings as well as an insulating media and for distributing heat throughout the motor.

The submersible motor shafts are usually hollow to allow the motor oil to be circulated throughout the motor.

Some of the submersible motors can be connected via their shafts and the stator windings are connected electrically in series. This type of connection is referred to as a tandem motor, with the component motors referred to as an upper and lower tandem motor.

When the motors are connected in tandem, communication between the two motors allows the motor oil to move from one motor to the other.

Because submersible motors are filled with oil and operate at such diverse temperatures, it is necessary to add a seal or protector for purposes of being an expansion chamber to allow the oil to flow out of the motors when hot and back into the motor when it cools. This expansion chamber is designed to keep the well fluid out of the motor.

Motor cooling is achieved by allowing the pumped fluid to pass over the surface of the motor. In the event there is no movement of fluid or insufficient movement of fluid by the motor, the motor will overheat causing it to break-down (burn) or shorten the motor run life. In cases where there is low flow rate or the motor is situated below the perforations, it is not uncommon to fit a shroud around the motor so that the pumped fluid is forced over the surface of the motor. Surface motors, on the other hand, draw the cooling media (air) into the motor itself or by causing the cooling media to cool the motor surface. This is accomplished usually by having one or more fans attached to the motor shaft.

Surface motors are usually connected to a power source by a short length of cable. This means that the motor nameplate voltage and the power supply voltage are the same value. Submersible motors are connected to the power source via a long non-standard length of cables. The result is that the motor nameplate voltages are quite varied in magnitude, and the surface transformer is usually a multi-tapped variety so that a surface voltage can be set to offset the cable voltage drop at the motor operating conditions. Surface motors have higher inertia resulting in longer acceleration times when starting. Typical ESP motors start and accelerate up to full speed in approximately 0.2 seconds. Surface motors can normally withstand thermal overloads for a longer period of time than ESP motors. This must be considered when selecting overload protection devices and protection schemes.

APPENDIX D—VARIABLE SPEED DRIVE AFFINITY LAWS

The following equations may be useful when sizing and operating ESP systems with a VSD:

If the pump performance at 60 Hz is known, it can be corrected to another frequency by the affinity laws:

FLOW: $$Q_{\text{Hz}} = Q_{60} * (\text{Hz}/60)$$

HEAD: $$H_{\text{Hz}} = H_{60} * (\text{Hz}/60)^2$$

BHP: $$\text{BHP}_{\text{Hz}} = \text{BHP}_{60} * (\text{Hz}/60)^3$$

If the motor 60 Hz nameplate rating is known, the output horsepower rating at any other frequency can be calculated with:

$$\frac{\text{HP}_2}{\text{HP}_{60}} = \frac{\text{Hz}_2}{60}$$

If the pump BHP at 60 Hz is known and the maximum frequency desired is known, the minimum permissible 60 Hz motor HP rating can be determined as:

$$\text{MHP}_{60} = \text{BHP}_{60} \times \left(\frac{\text{Hz}}{60}\right)^2$$

If the pump BHP and motor size at 60 Hz is known, the maximum allowable frequency before overloading the motor can be calculated as:

$$F_{\text{max}} = 60 \times \sqrt{\frac{\text{MHP}_{60}}{\text{BHP}_{60}}}$$

If the voltage at 60 Hz is known, it can be calculated at another frequency as:

$$\text{Volts} = \text{Volts}_{60} \times \left(\frac{\text{Hz}}{60}\right)$$

If the pump BHP at 60 Hz and the motor rated HP at 60 Hz are known, the percentage of motor load at any frequency can be determined as:

$$\%\ \text{Load} = \frac{\text{BHP}_{60}}{\text{MHP}_{60}} \times \left(\frac{\text{Hz}}{60}\right)^2$$

At any frequency, if the volts and amps are known, the KVA can be calculated as:

$$\text{KVA} = \frac{\text{Volts} \times \text{Amps} \times 1.732}{1000}$$

Knowing the drive KVA rating at one input voltage, it can be converted to another input voltage as:

$$\text{Drive Output KVA} = \text{KVA}_{480} \times \frac{X\ \text{Volts}}{480\ \text{Volts}}$$

If the pump shaft HP rating at 60 Hz is known, it can be converted to another frequency as:

$$\text{HP Limit}_{\text{Hz}} = \text{HP Limit}_{60} \times \left(\frac{\text{Hz}}{60}\right)$$

If the pump shaft HP rating at 60 Hz and the pump BHP requirement at 60 Hz are known, the maximum frequency allowable before the shaft capability is exceeded can be determined as:

$$\text{Hz} = 60 \times \sqrt{\frac{\text{SHP}_{60}}{\text{BHP}_{60}}}$$

APPENDIX E—FRICTION LOSS IN API TUBING (HAZEN-WILLIAMS CHARTS)

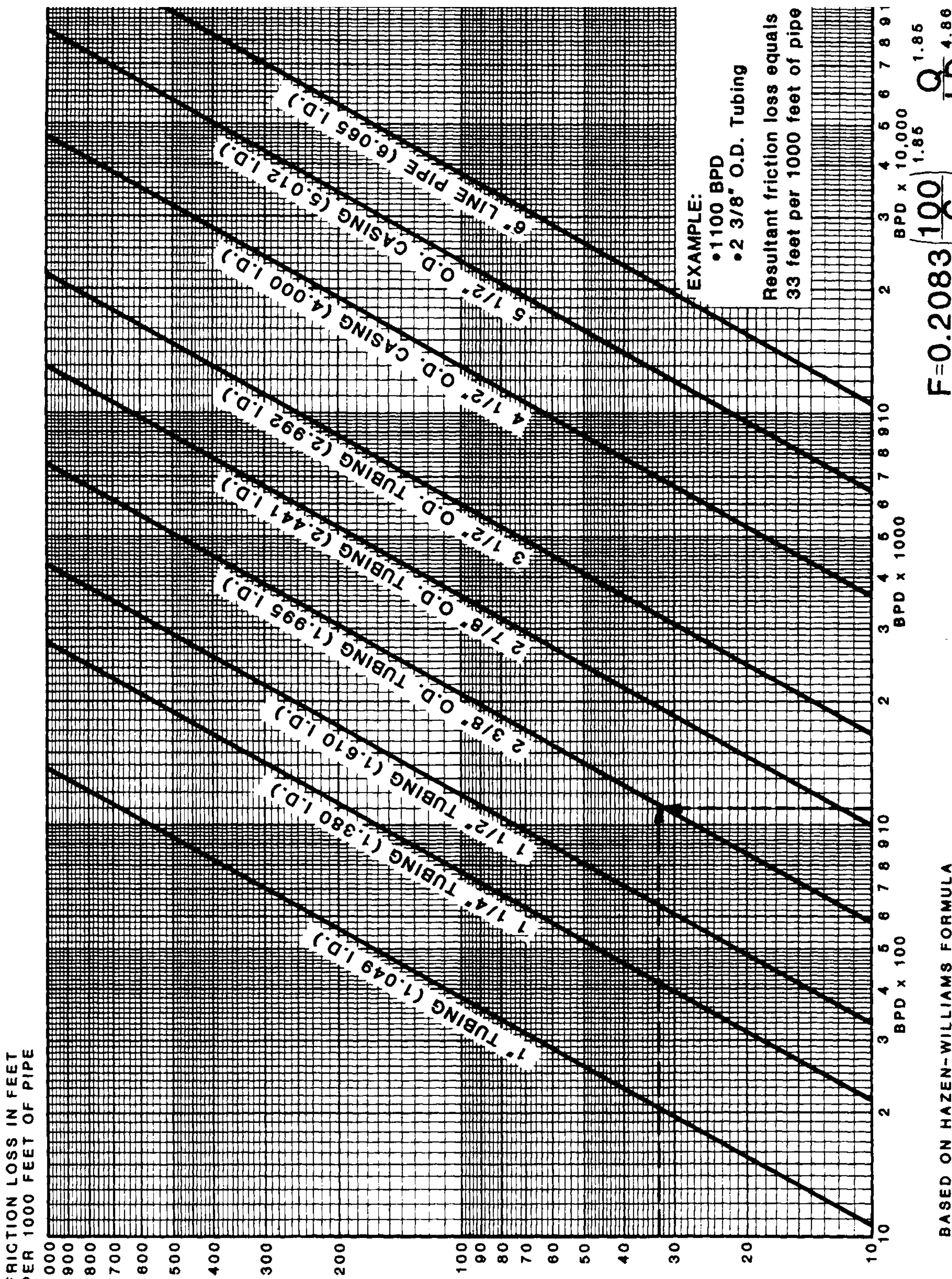

Figure E-1—Flow Losses Due to Friction in API Pipe

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