BASIC ELECTRICAL SUBMERGIBLE PUMP SIZING

John L. Logi
TRW Reda Pump

INTRODUCTION: SUBMERGIBLE PUMPING UNIT COMPONENTS

A typical submergible electric pumping unit is composed of seven basic components: electric motor, multi-stage centrifugal pump, protector, power cable, motor flat cable, switchboard and an auto transformer, single three phase or a bank of three single phase transformers.

All of the above equipment is manufactured in numerous sizes and types to fit the well specifications, such as casing size, desired producing volume, total lift, electrical power supply and environment.

In addition to these basic components, various auxiliary items are used. Some are required, while others are optional. The most common required items to complete an installation are: Cable clamps, cable reel, reel supports, shock absorber, shipping boxes, tubing support and, in many cases, a swage nipple. Other optional items not required for an installation, but recommended where applicable are: Flat cable guards, check valve, bleeder valve, centralizers, motor jackets and downhole pressure sentries.

In some instances, usually in remote areas, engine generator sets are used instead of purchased utility power. Such generator sets may power multi-well installations or individual wells. In the latter case, transformers can usually be eliminated by supplying an alternator which is wound to supply the proper input voltage (required surface voltage).

A standard submergible installation is shown in Fig. 1.

DESCRIPTION OF EQUIPMENT

The major components of a submergible pumping system are motor, protector, pump, cable, and switchboard.

Pump

Submergible pumps are multi-staged centrifugal pumps. Each stage consists of a rotating impeller and a stationary diffuser. The type of stage used determines the volumes of fluid to be produced. The number of stages determine the total head generated and the horsepower required.

Submergible pumps are manufactured in a broad range of capacities for custom application to virtually all well conditions.

The basic concepts of sizing of submergible pumps will be covered in this paper.

Applying a submergible pump to an application is much easier with a good understanding of what type pumps and volume ranges are available. Many times several pump types will work for the same application. Selecting the right pump for the application will come from experience and knowledge of each pump type's operation.

Protector

The protector performs 4 basic functions:

1. Connects the pump housing to the motor housing by connecting the drive shaft of the motor to the pump shaft.

2. Houses the pump thrust bearing.

3. Seals the power end of the motor housing from the wellbore fluids while allowing pressure communications between the oil-filled unit and wellbore fluids.

4. Provides the area necessary for the expansion of the unit's oil due to heat generated when the motor starts.

The protector's primary purpose is to isolate the motor from the well fluid. The protector design will allow pressure equalization between the intake pressure (annulus) and the motor's internal pressure permitting expansion or contraction of the motor oil due to thermal expansion. Two mechanical seals provide dual protection as a barrier against fluid migration along the shaft. The protector also houses a marine type thrust bearing which absorbs axial loading from the pump.

Motor

The motor is the driving force (prime mover) which turns the pump. Submergible motors are two pole, three-phase, squirrel cage induction type. These motors run at a relatively constant speed of 3500 rpm on 60 Hertz frequency. The motors are filled with a highly refined mineral oil that must provide dielectric strength, lubrication for bearings, and good thermal conductivity. The thrust bearing of the motor carries the load of the motor's rotors. The nonconductive oil in the motor housing lubricates the motor bearings and transfers heat generated in the motor to the motor housing. Heat from the motor housing is in turn carried away by the well fluids moving past the exterior surface of the motor; therefore, a pumping units' motor should never be set below the point of fluid entry unless some means of directing the fluid by the motor is utilized.

Gas Separator

The gas separator is an aid in preventing gas lock and provides more efficient pumping of gassy wells.

PUMP SIZING

General

The sizing of a submergible pump, in most applications, is not a difficult or mysterious chore if the basic fundamentals of submergible equipment and well data are understood. Each application is an individual situation due to varying well conditions and type fluids that are to be pumped.

In this section, we will cover the sizing procedures and methods incorporated with the most common type application. We will not get involved with extremely high gas-oil ratio wells where the computer is best suited to do the complex calculations required.

Required Well Data

The initial data used for sizing a submergible unit is very important and must be reliable to insure the proper sized unit. Bad data will result in a misapplied pump and costly operations. This is especially true where the data pertains to the well's capacity.

Well Data

The minimum data required to initially size a submergible and the reason for that data is as follows:

1. Data: Casing size, weight, and setting depth

   Reason: Submergible pumps are manufactured with different outside diameters. The casing sizes, along with the internal diameter of the casing, must be known to insure the pumping unit will fit inside the casing.

2. Data: Perforated intervals or open hole depth

   Reason: A submergible is cooled by the fluid passing it on its way to the pump's intake. If a unit is set in the perfs or below the fluid entry point, then a method to direct the fluid by the motor must be included. This is most commonly done with a motor shroud if the casing's internal diameter will accommodate both pumping unit and shroud diameter.

3. Data: Tubing size and thread

   Reason: The size tubing used determines how much friction loss must be included in the total head design. Tubing size should be evaluated for most economical size to use with the anticipated volume to be pumped.

   The tubing thread size and type must be known so check valves, bleeder valves, pump head, and well head can be accommodated with proper threads or crossovers.

4. Data: API Gravity Oil

   Reason: This data, along with temperature, water cut, GOR and other data from existing graphs and tables are used to determine the viscosity of the fluid that will be pumped.

5. Data: Specific gravity of liquids and gas to be produced

Reason: Specific gravity of fluid must be known as it has a definite bearing on what the horsepower requirements will be.

6. Data: Bottom hole temperature (BHT)

   Reason: To determine what cables, etc. should be used due to temperature.

7. Data: Productivity Index (P.I.), or Inflow Performance Relationship (IPR) Data, or Producing and Static Fluid Levels, or Flowing and Static Bottom Hole Pressures

   Reason: For determining well capabilities so unit can be sized for proper volume at selected pump setting depth.

8. Data: Produced Gas (MCF/Day) or Gas Fluid Ratio (GFR)

   Reason: Required for properly sizing unit to handle the reservoir volume necessary to provide the proper stock tank barrels at the surface. Also required to determine what pump intake pressure (PIP) will be required for operations.

9. Data: Discharge pressure required at tubing well head

   Reason: This additional pressure must be included in the total dynamic head calculations.

10. Data: Available voltage at the well location

    Reason: For sizing transformers and other electrical components.

11. Data: Any problems, such as sand, scale, corrosion, or paraffin

    Reason: This is very important data to know previous to running a unit so precautions or protection can be made before the installation to safeguard against early failures or other problems, in most cases, if this data is available.

For a high GOR application, it is very useful if PVT data, including formation volume factor (FVF) and bubble point pressure can be provided for the sizing operations.

Specific Gravity and Head

The head (PSI) developed by a centrifugal submergible pump depends upon the peripheral velocity of the impeller. The head developed by the pump is independent of the weight of the liquid pumped. The head developed converted to feet would be the same whether the pump was handling water with a specific gravity of 1.0, oil with a specific gravity of 0.80, or a brine of a specific gravity of 1.35, or any other fluids with various specific gravities.

The pressure reading on a pressure gauge would differ although the impeller diameter and speed would be identical in each case.

Fig. 2 illustrates the relationship of identical pumps handling liquids of these different specific gravities.

Before entering into the actual sizing of a submergible unit, it will be beneficial to become acquainted with the pump curves, graphs, and terms that are used in sizing units.

Fig. 3 is a standard performance curve for a submergible pump.

The standard performance curve for a submergible pump is plotted with head in feet per 100 stages, in most cases. Where applicable, 100 stages are used instead of 1 stage. The reason for this is that the design, tolerances, etc., on the smaller pancake type stages are very close to being the same, but there is a very good possibility of some variances between each stage; therefore, the stacking of 100 of these stages gives a more accurate curve.

On the large, high volume stages, it is more practical to use only 1 stage to build the curves as the horsepower of a large stack of high volume stages would be prohibitive. Also, constant dimensions on the large stages are easier to machine and maintain.

The head capacity curve is plotted with the head in feet and meters as ordinate (vertical) against capacity in barrels per day and M^3/day as abscissae (horizontal). Fresh water (specific gravity 1.0) is the fluid used in rating submergible pumps. The head for a proposed application can be figured in feet, and the desired head and capacity can be read directly from the water curves without correction as long as the viscosity of the liquid is close to that of water. Because the head in feet developed by a submergible centrifugal pump is independent of the specific gravity of the fluid being pumped,

the total stages required are found by the formula:

$$\text{Total Stages} = \frac{\text{Total Dynamic Head (Feet)}}{\text{Head (Feet)/One Stage}}$$

As an example and referring to Fig. 3 (Standard Performance Curve) if the total calculated head was 5000 ft and the volume required was 1300 B/D, the number of stages would be found by entering the pump curve at the 1300 B/D rate, move up vertically to the head capacity curve and read on left side the head per 100 stages as 2200, or for 1 stage, it would be 22 ft. Therefore, required stages would be:

$$\text{Total Stages} = \frac{5000\text{ ft}}{22\text{ ft/Stage}} = 227\text{ Stages}$$

The horsepower shown on the water curve will apply only to liquids with a specific gravity of 1.0. For other liquids, the water horsepower must be multiplied by the specific gravity of the liquid being pumped.

The required motor size is determined by multiplying the maximum horsepower per stage of the type pump selected by the number of stages by the specific gravity of the fluid, or:

$$\text{HP} = \text{HP/Stage} \times \text{Total Stages} \times \text{Specific Gravity}$$

Again, using the Standard Performance Curve and assuming a specific gravity (1.0) of fresh water, the HP requirement for the 227 calculated stages would be found by taking the horsepower per stage from the pump curve.

Note that the horsepower is given in horsepower per 100 stages. The horsepower per stage in this case is found by moving the decimal point 2 places to the left. The horsepower requirement would be .35 HP/Stage. The horsepower requirement would be:

$$HP = .35HP/Stage \times 227\ Stages \times 1.0 = 80$$

Total Dynamic Head

In the sizing of a submergible application, we must consider the total head (referred to as total dynamic head) required to cause the proper required flow in a system. The definition of the terms used can best be understood by referring to the drawing in Fig. 4.

Pump Sizing Procedure

In sizing a submergible pumping unit, it is recommended that the following procedure be followed in the sequence given:

1. Collect and analyze well, production, fluid, and electrical data.

2. Determine well's production capacity at selected pump setting depth or determine pump setting depth at desired production rate. This includes determining what pump intake pressure (PIP) will be for the design. Also includes determining total volume to be pumped to achieve required stock tank barrels.

3. Calculate the total dynamic head (TDH) (Friction losses + system pressure + vertical lift).

4. For the calculated capacity and total head, select from the various pump curves the pump type which will have the highest efficiency for the application. The selected pump must also be of the proper O.D. that will fit inside the casing of the well.

5. Calculate from type pump selected the number of stages required to supply the total required head at the required volume.

6. Determine motor horsepower required. The highest specific gravity of the fluid that will be encountered should be used for this calculation. Procedures of operation are sometimes used where the specific gravity of the live well fluid is used to calculate horsepower and steps are taken to unload kill fluid under minimum overload conditions. The protector type is usually determined from the series motor selected.

7. Select most economical cable size and type for the application from available technical data sheets.

8. Determine voltage loss in cable and determine required surface voltage. The value of the required surface voltage will set the size of the switchboard.

9. Calculate KVA required to size transformers.

10. Select proper size downhole accessories, such as:

    A. Tubing head, size, and type

    B. Servicing equipment required for complete installation

    C. Optional equipment

11. Determine what other steps are required to ensure good operations such as:

    A. Coat equipment for corrosion protection and use corrosive preventing materials

    B. Use shroud, if required, etc.

    C. Abrasives--Rubber stage bearings

We now move into the actual sizing of a submergible pumping unit. The following example will be worked out step by step.

The following well data information has been supplied by a potential user of a submergible pump and a design request from the data provided.

General Data:

Given: (Company, Well Name, Number, Field and Location)

Well Data:

Casing--5 1/2 In. O.D., 17# to 6150 ft
Tubing--2 3/8 In. EUE 8rd
Perforations--5900 to 5970; 6000 to 6030

Production Data:

Static bottom-hole pressure--2000 PSI @5950 ft Datum
Flowing bottom-hole pressure--1500 PSI
Present producing volume--475 BFPD (400 BOPD)
GOR--350 cubic ft per barrel; Bottom-hole temperature--170°F.
Type reservoir--solution gas drive

Fluid Data:

A.P.I. gravity of oil--30°
Specific gravity of oil--0.876
Specific gravity of water--1.02
Specific gravity of gas--0.75
% of water cut

Power System:

Primary voltage--7200/12470

Other:
Corrosive

Customer Request:

Pump setting depth--5850 ft
Pump intake pressure--300 PSI

Referring to the procedures for sizing, step 1 is to analyze the data received to insure a properly sized unit. We start by checking well data, production data, fluid data, and power system. With the data provided, there will be no problems supplying a pump for the given information. The casing is large enough to accommodate conventional 400 series equipment and the customer has provided good production data.

Step 2 is due to the customer's request for a PIP of 300 PSI and a pump setting depth of 5850 ft (50 ft above the perforations). This is very reasonable as the 300 PSI pump intake pressure will probably be required due to the amount of gas to be handled. This is a practical design as, from experience with this type application, it has been found that approximately 300 PSI pump intake pressure is required for good pumping conditions. The 50 ft setting above the perforations is fine. Unit is set above fluid entry point and fluid will pass motor to carry away heat.

The static bottom-hole pressure was taken at 5950 ft. The pump will be set at 5850 ft or 100 ft above the datum point. This will reduce the available drawdown pressure slightly. By finding the average specific gravity of the fluid below the pump neglecting gas in the calculation, this small drawdown can be determined. In this case, the 100 ft would represent approximately 40 PSI. Therefore, the bottom-hole pressure at pump can be estimated at 2000 - 40 = 1960 PSI.

The production capacity can now be calculated. Since this is a solution gas drive reservoir, the general IPR curve should be used to check volume available for pumping. IPR calculations would show the total fluid available was approximately 1125 B/D at a 300 PSI operating PIP.

Note that the volume to size for is 1125 BFPD of stock tank barrels. The volume of reservoir barrels that must be pumped to provide these stock tank barrels must now be determined. Sufficient data is available to determine a reasonable formation volume factor using a formation volume chart.

Using a formation volume chart with the given data would show that a total of 1350 BFPD would be the pumping volume to size for to produce 1125 BFPD in stock tank barrels.

The vertical lift is determined by calculating where the operating fluid level will be with the 300 PSI pump intake pressure. The 300 PSI must be converted to feet and subtracted from the pump setting depth.

From basic petroleum engineering fundamentals, we can assume this 300 PSI will be an oil gradient. Gas and gas column will be neglected. Therefore, the 300 PSI represents:

$$\text{Head Feet} = \frac{300 \text{ PSI} \times 2.31 \text{ ft/PSI}}{0.876 \text{ Specific Gravity}} = 790 \text{ ft}$$

Vertical lift is equal to:

$$H_d = 5850 \text{ ft (PSD)} - 790 \text{ ft (FOP)} = 5060 \text{ ft}$$

Friction Loss Data is as follows:

Data: 5850 ft of 2 3/8 In.
1320 BFPD rate

Friction loss from friction loss chart for this volume is 2 3/8 in. tubing is 40 ft per 1000 ft.

$$F_t = 40 \text{ ft} \times 5.85 = 234$$

Use 250 ft for friction losses to include check and bleeder losses. Note that the friction loss through the check and bleeder can be considered; however, the losses are small compared to the total head and can be neglected.

System Pressure Data is as follows:

Data: 200 PSI system (tubing) pressure
0.890 average specific gravity

Calculation:

$$\text{Head feet} = \frac{200 \text{ PSI} \times 2.31 \text{ ft/PSI}}{0.89 \text{ Specific Gravity}} = 520 \text{ ft}$$

Total Dynamic Head calculation is as follows:

$$TDH = 5060 \text{ ft } (H_d) + 250 \text{ ft } (f_t) + 520 \text{ ft } (P_d) = 5830 \text{ ft}$$

Steps 4 and 5 of procedure are to select proper series pump for calculated capacity and determine number of stages required for application.

Since this unit is to be installed in 5 1/2 in. O.D. casing, a 400 series pump should be selected. At the 1350 BFPD volume, the D-40 is the most efficient of the 400 series pumps.

Note from Fig. 3 (Pump Curve), the stock tank barrels produced will be to left of capacity range. Actual design will be at peak efficiency.

At 1350 BPD, the head per stage on the D-40 pump is approximately 21.3 ft. Therefore, the required staging is:

$$\text{No. of Stages} = \frac{TDH}{\text{Ft/Stage}} = \frac{5830}{21.3} = 274$$

A D-40 pump with 275 stages is available in a 150 housing in a submergible pump catalog.

Step 6 is to determine motor horsepower requirement.

HP = No. of Stages x HP/Stage x Specific Gravity
HP = 275 Stages x .35HP/Stage x 0.890
HP = 86

Note that this horsepower requirement is for the well once kill fluid has been pumped out.

A 456 series motor must be utilized due to casing I.D. limitations. Checking the engineering tables in a pump catalog or referring to a service manual, it will be found that a 90 horsepower motor is available in the 456 series. This would be a good selection for this application.

Note that if well is killed with brine or heavier fluid, the 90 HP will be approximately 10% overloaded while the kill fluid is pumped out. This will have to be taken into account on the well's initial startup.

Referring to Step 7 (cable selection), the size cable and motor voltage and amperage for most economical operations can be determined. At this point, it must be an economical choice of what equipment is selected and still provide the customer with equipment that will do the job and not be a marginal design where the equipment is operating at its limit.

Data:

$170^{\circ}F$. Well Temperature

5950 ft of Cable Required (100 ft more than pump setting depth to be used for surface cable)

Referring to motor engineering tables, there are 4 90 HP motors of different voltages and amperage to choose from.

For this installation, the 1260 volt, 45 amp motor and No. 4 copper cable should be selected. The 45 amps fit the range of No. 4 cable's (largest size that can be used in 5 1/2 in. casing) current carrying capabilities. A 1500 volt switchboard can be utilized.

Step 8 is to determine cable voltage loss and required surface voltage. Size switchboard that will be used is evident.

Required Surface Voltage Data is as follows:

Data: 5950 ft of #4 Copper Cable
45 Amp 1260 Volt Motor

From voltage loss chart, it is found that the voltage loss for 45 amps with #4 cable at $170^{\circ}F$. is 24 volts per 1000 ft of cable. The required surface voltage is:

$$V_s = 24 \text{ volts} \times 5.95 + 1260 \times 102.5\% = 1438 \text{ volts}$$

Surface voltage of 1425 to 1450 volts will be proper voltage for the application.

Step 9 is to calculate required KVA for transformer sizing.

Transformer Data is as follows:

Data: 1450 Volt Surface Voltage
45 Amps (Normal Operation)

Therefore:

$$KVA = \frac{1450 \text{ Volts} \times 45 \text{ Amps} \times 1.73}{1000} = 113$$

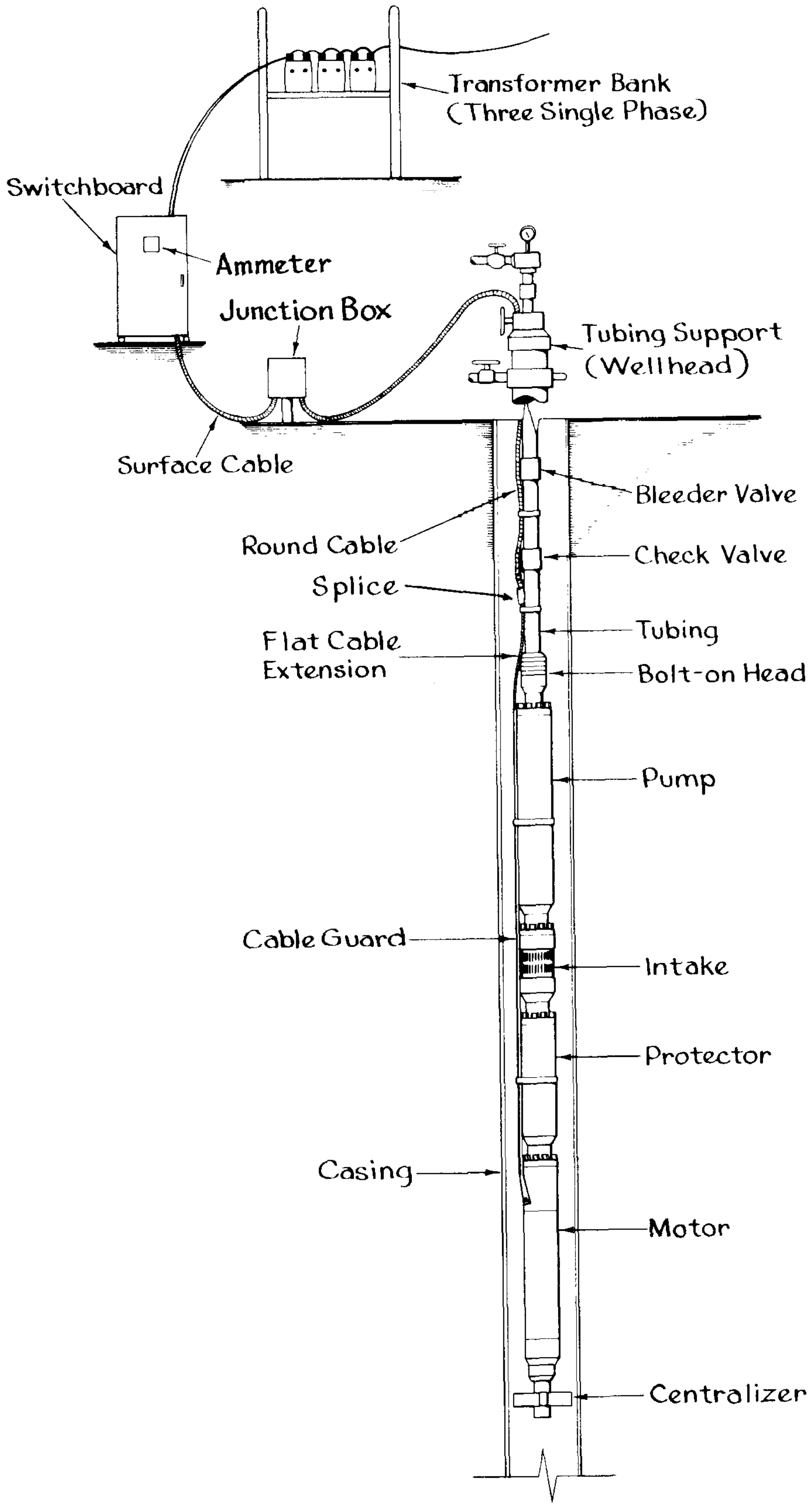
Three single phase transformers will be used (standard domestic operations). The value required per single transformer is:

$$\frac{\text{113 Required KVA}}{\text{3 Single Phase Transformers}} = \text{37.67 each}$$

Note that 37.5 KVA transformers could be used because the amperage, once the kill fluid has been unloaded, will be less than motor nameplate amps (45), since the calculated horsepower requirement for the installation is 86 HP and the initial horsepower requirement did not include gas in the specific gravity of the fluid. However, due to the slight difference in cost between 37.5 KVA and 50 KVA transformers and the future flexibility with the 50 KVA transformers, recommendations would be to use 50 KVA.

For all practical purposes, we now have the unit sized. Steps 10 and 11 are to select accessory equipment and to insure precautions are taken to ensure good operations.

Figure 1 Complete illustration of submergible installation



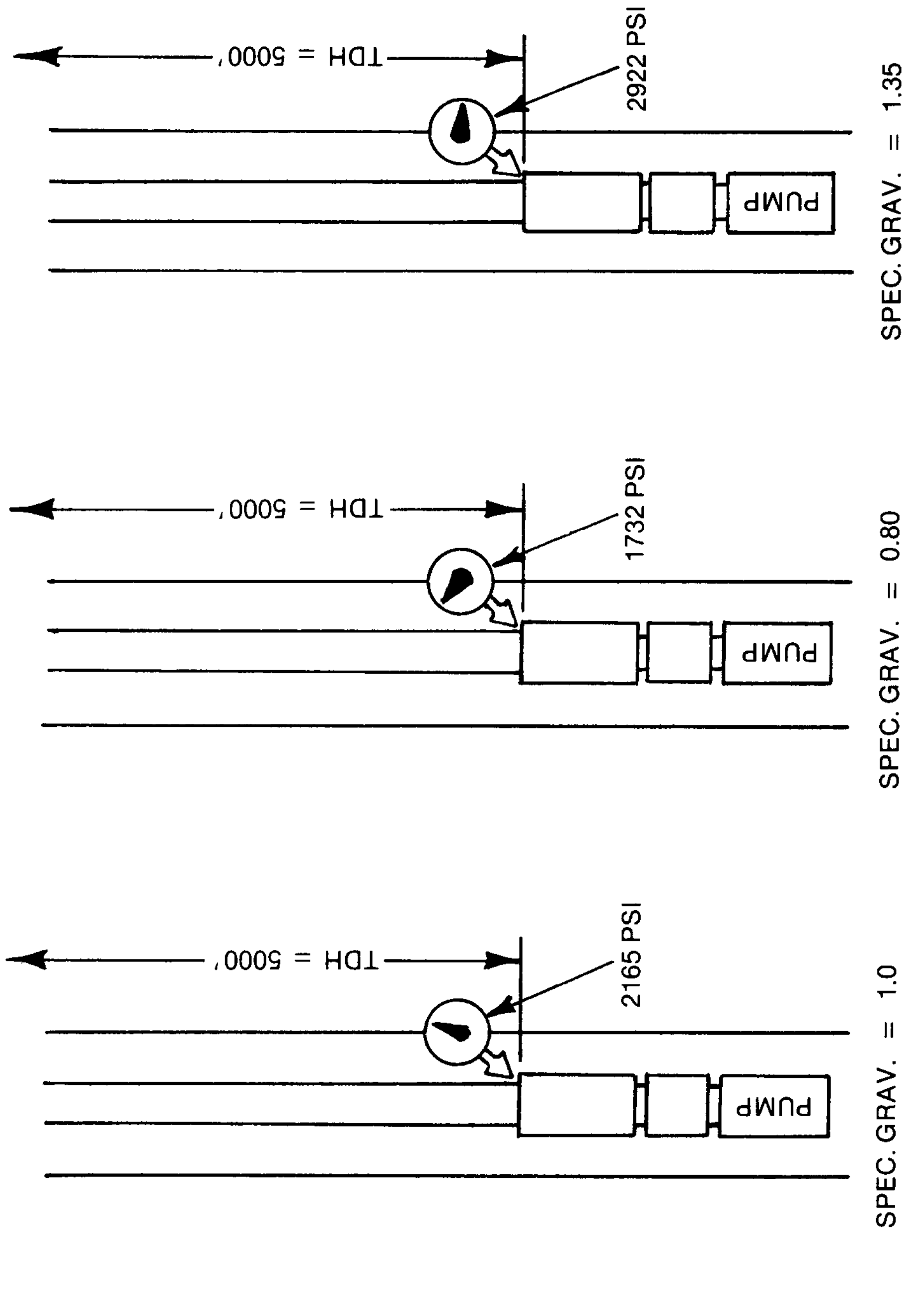

TDH = 5000'
2165 PSI
PUMP
SPEC. GRAV. = 1.0
TDH = 5000'
1732 PSI
PUMP
SPEC. GRAV. = 0.80
TDH = 5000'
2922 PSI
PUMP
SPEC. GRAV. = 1.35

FIG. 2

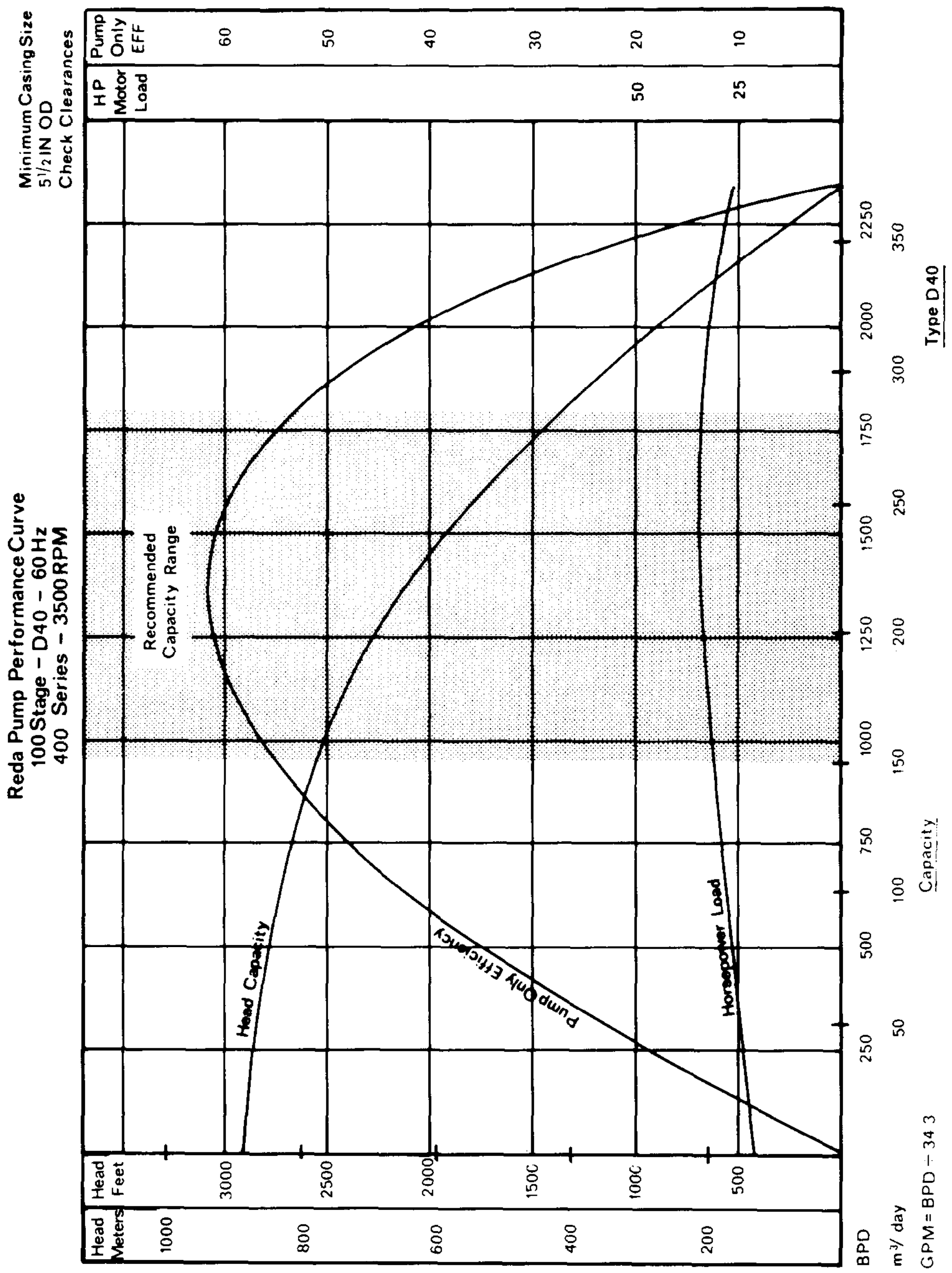
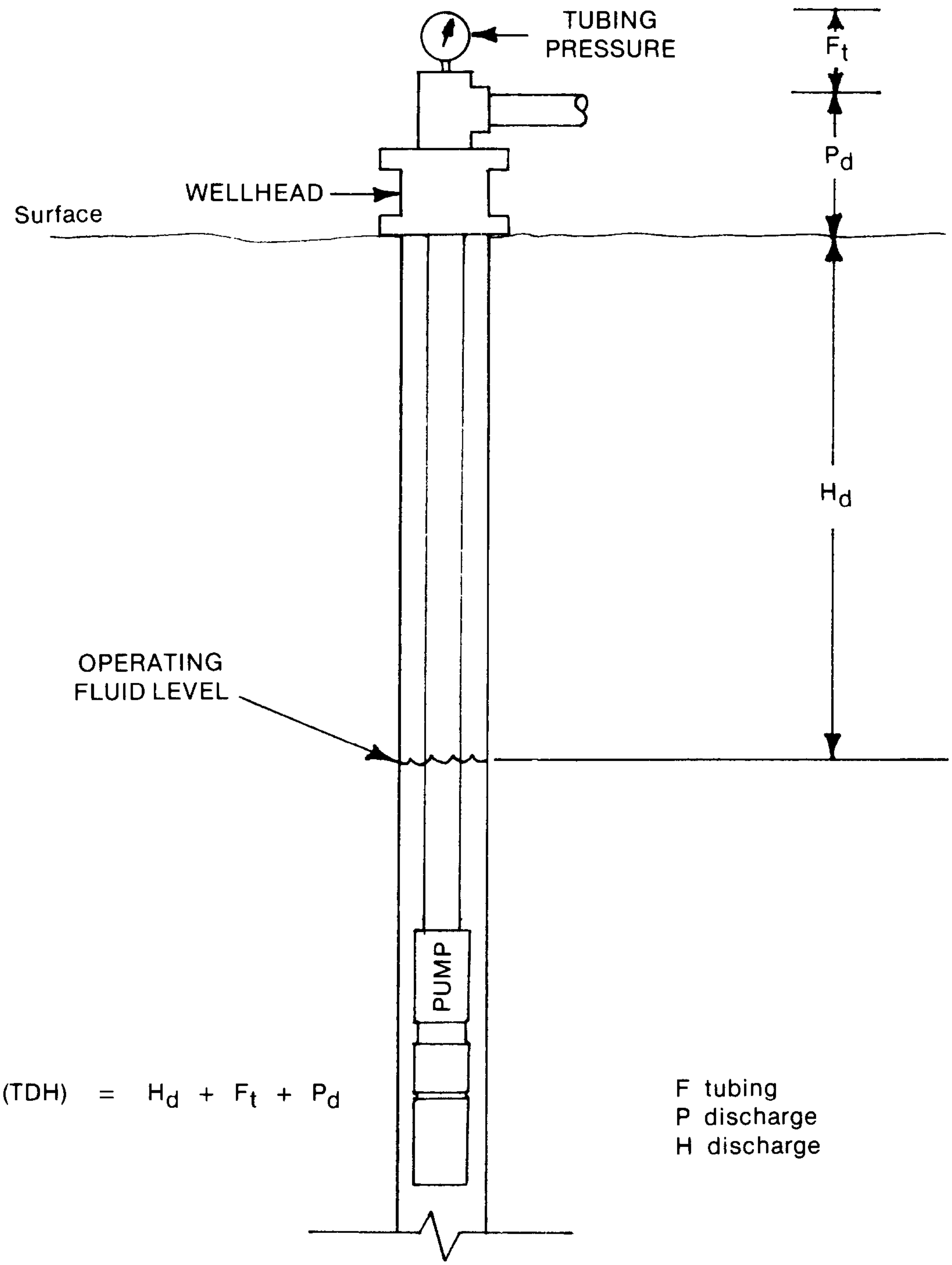


FIGURE 3 — Standard performance curve for a submergible pump



Total Dynamic Head (TDH) $= H_d + F_t + P_d$

F tubing
P discharge
H discharge

Where:

TDH = Total head required to be delivered by the pump when pumping desired capacity.

FIGURE 4