Designing and Applying The Oil Field Submersible Pump

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INTRODUCTION

In designing a submersible pump for an oil well application, the engineer can benefit greatly from the proper use of well data and conditions under which the pump will be operating. It would, of course, be easy to select a pump size if it were already established that the well could produce some given amount of fluid needed to make it a profitable operation. However, the submersible, like any other piece of equipment must be designed with a number of factors taken into account. Accurate well data and well-kept well production records can be of great value to the person designing a submersible installation.

A typical submersible installation is made up of three major down-hole components. In Fig. 1, the motor is on bottom. The seal section is attached to the motor, and above the seal is the pump itself. To lower the equipment into the well, the tubing is screwed into the pumphead. As the tubing is run into the hole, the three-conductor power cable is then banded to the tubing.

The motor, of course, is the driving force which turns the pump. It is the bottommost part of the unit so that well fluid moves by the motor housing and becomes the cooling medium. This is essential in the operation of the unit. The seal is a device designed to keep out all well fluids from the motor. The motor operates at zero pressure differential relative to the well annulus. The pump intake may be in the pump housing itself or through a high-capacity gas separator which is attached to the bottom of the pump. The pump can consist of any number of stages as required by the lift involved.

The essential basic requirements for designing a submersible are:

- (1) Casing diameter
  - (a) Tubing size
- (2) Volume desired
- (3) Well data
  - (a) Productivity index
    - 1. Static fluid level
    - 2. Producing fluid level
  - (b) Oil-water percentages
  - (c) Corrosive properties of fluids
  - (d) Ambient temperature
  - (e) Specific gravity
- (4) Required total head
  - (a) Lift
  - (b) Additional surface pressures and flow losses
- (5) Available voltages
  - (a) Transformers

Many times, accurate draw-down or PI data are not available for the well in question. Too often data from other wells in the same field or in a nearby area are used, assuming that wells from the same producing horizons will have similar characteristics. Unfortunately for the engineer designing the submersible, oil wells are much like people; that is, no two are quite alike. However, the engineer must make do with what he has. If accurate draw-down data is available, it can be used to good advantage in designing the down-hole submersible pump.

In the case of having PI and/or producing and static fluid levels at hand, a straight-line PI curve can be drawn. The extrapolated maximum fluid available from any given depth can then be shown. Pressure draw-downs can also be made if producing bottom-hole and static bottom-hole pressures are available. This information can many times be obtained by the operator with little time and effort. Tests can be made in the field and need not be elaborate. Often, this information can be obtained from well-kept records and files, though it is advisable to note

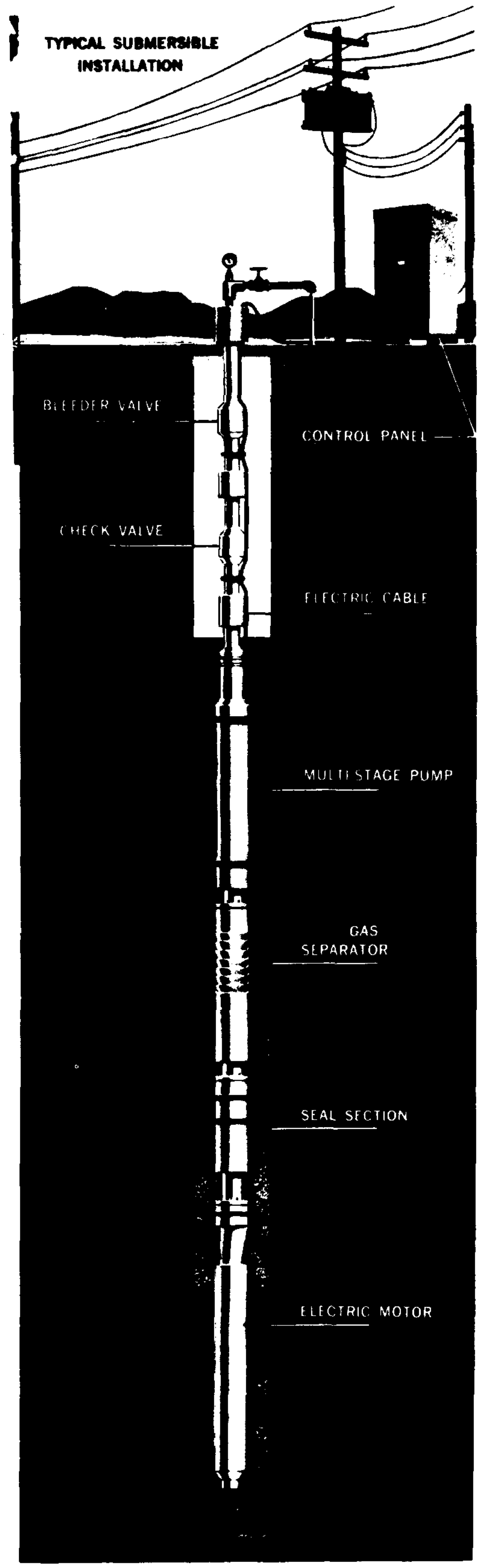

FIGURE 1
Typical Submersible Installation

the date of such tests and if the data may have changed since it was taken.

EQUIPMENT DESIGN AND SELECTION

To better illustrate the ideas just presented, consider a submersible pump design situation. Assume the volume capability as dictated by the well data to be 1500 BPD. First, establish the casing size. Figure 2 shows the G-48 pump curve; this is a one-stage curve giving the head, efficiency and horsepower requirements for one stage only. The G-48 is of such diameter as to fit in 5-1/2-in. casing with a maximum weight of 23 lb/ft. The diameter of this particular pump housing is 4.00 in. With 6-5/8-in. O. D. or larger casing, the I-42 model pump, as shown on the one-stage curve, could be used. This pump stage is of a larger diameter.

Assume that the well under consideration is cased with 5-1/2-in. and it is desired to lift 1500 BPD from 2000 ft.

The one-stage G-48 curve shows a head figure of 22-1/2 ft per stage at 1500 BPD. Dividing this into the 3000 ft of lift gives a requirement of 133 stages. The number of stages times the horsepower per stage, 0.40, gives a horsepower requirement of 50 Hp.

If the fluid were fresh water with specific gravity of 1.0, this would be sufficient horsepower to do the job. If it is not fresh water, it is important to note the specific gravity involved to avoid overloading the motor. Assume that the well is 90 per cent salt water of specific gravity of 1.1. Multiply 53 Hp times 1.1 which gives a total horsepower requirement of 59 Hp. If the specific gravity of the fluid is not known or is not allowed for, failure to use a large enough motor size can many times result in overloading of the motor. This, of course, will result in a shorter run life of the equipment due to excessive heating.

At this point, it is necessary to discuss pump efficiency. It is known from the G-48 curve that at 1500 BPD this pump design approaches absolute peak efficiency. The most desirable point at which to operate with a submersible is at peak efficiency, which in this case is 64 per cent. Submersibles have a certain amount of flexibility with regard to the operating point, but outside the optimum range, loss of efficiency can add to the cost of operation.

Assume now that instead of being 90 per cent salt water, the well is producing 90 per cent oil. Oil specific gravity being less than 1.0 will tend to lighten the motor load. Unless it is known that throughout the life of the well the fluid will always be oil with a specific gravity of less than 1.0, it is not wise to cut back in motor size. Among water-drive and water-flood reservoirs, there is always a chance of water influx and water breakthrough which will change the overall specific gravity of the fluid being lifted.

DESIGN FROM USE OF PRESENT PUMPING CONDITIONS

As was earlier stated, we can get an idea of the well's capability from its present pumping and draw-down characteristics. Consider this example:

Assume the well is currently pumping 600 bbl and the producing fluid level is determined to be 1200 ft from the surface. After the well fills up and stabilizes, a static fluid level is taken and found to be 400 ft from the surface. In other words, to pump 600 bbl the well fluid level is lowered from 400 ft to 1200 ft, a distance of 800 ft. This gives a figure of .75 bbl/ft of draw-down.

It is determined that the pump will be set at 2400 ft. Pumping from that point then, .75 bbl/ft times 1200 ft additional draw-down gives 900 BPD. Added to the 600 bbl obtained from the first 800 ft draw-down, the total fluid available to lift is 1500 BPD.

Figure 2 shows that the I-42 pump can be used in 7-in. casing. This pump is designed for a peak efficiency of 64 per cent at 1500 BPD. The head per stage from the curve is slightly over 40 ft. At this point, consider the additional head needed to overcome friction flow loss in the tubing and surface pressure. From a curve showing flow loss due to friction in API pipe, the loss is 19 ft per thousand feet at a flow rate of 1500 BPD in 2-7/8 in. tubing. At this point it is necessary to add approximately 30 ft to the total head requirement. This will then move the required volume of fluid to the surface.

To put the 1500 BPD into the tanks, it is necessary to overcome discharge pressure. Assume a separator and tank pressure of 50 lb with an overall fluid gravity of 1.1 allowing for salt water in the well; this gives an additional equivalent of 105 ft of head. The total head requirement is then 2535 ft.

From the curve, at 1500 BPD, with a head of 40 ft per stage, it is found that 64 stages are required of the I-42 model to put 1500 BPD from 2400 ft into the stock tanks.

The horsepower requirement for the 64-stage pump is taken from the horsepower curve (Fig. 2) which shows that 0.71 Hp per stage is required, giving a total requirement of 45.5 Hp. Note once again that this would be the true

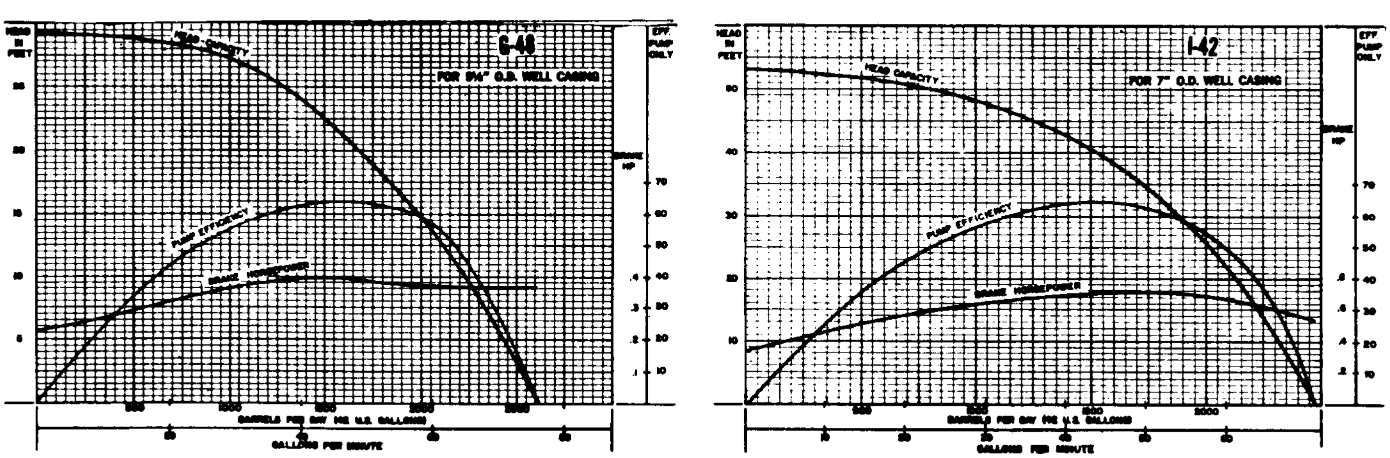

FIGURE 2

Pump Performance Curves of Similar Volume for 5½" O.D. and 7" O.D. Casing motor load if dealing with fresh water of specific gravity of 1.0, which is not the case. Multiplying the 45.5 by 1.1, the actual motor loading is 50 Hp.

A pump has now been selected with the correct number of stages and the proper size motor.

Look at another example illustrating the submersible pump design, this time with surface facilities and their capabilities in mind. Assume that a well is currently pumping 600 BFPD, salt water and oil. Of this total fluid, 5 per cent is oil. Further assume that the salt water disposal system to which this well is connected has a total capacity of 2000 BPD. Equipment must be designed to obtain maximum fluid, but not to the point where the disposal system is overloaded. Assume, for this illustration, that no other wells are hooked into the system.

At 5 per cent oil, a total of 2100 BFPD can be pumped. This means, using the 5 per cent figure, that 1955 bbl salt water will be put into the disposal lines.

Looking at the pump curves, and assuming the well casing is 5-1/2 in., it is seen that the Z-69 model is the best one for this volume. The exact peak efficiency falls between 2100 and 2200 BPD. At 2100 BPD, the head per stage is 19-1/2 ft.

Using the PI figure from the previous illustration, 0.75 bbl/ft, divide this into the 2100-bbl design volume getting a required lift of 2800 ft. Here again, things such as friction flow loss and surface pressure must be considered. From a friction flow loss curve, it is found that at 2100 BPD in 2-7/8 in. tubing, the loss is about 35 ft per thousand feet. Since the fluid will be lifted from 2800 ft, this is 2.8 times the 35 ft, which gives a friction flow loss of 97-1/2 ft (or approximately 100 ft). Again assuming a surface pressure of 50 lb, another 105 ft of head must be overcome with the 1.1 specific gravity fluid, giving 3005 ft of total head. From a curve, then, at 2100 BPD, we have 19-1/2 ft of head per stage and the requirement is for 154 stages of the Z-69 pump. To find the horsepower, simply multiply the number of stages times the horsepower per stage taken from the curve at 2100 bbl, which is 0.44 Hp, giving a requirement of 68 Hp. Correcting for a specific gravity of 1.1 gives a 75 Hp requirement. A 75 Hp nameplate-rated motor can be used with this pump.

Notice that in these two illustrations, the motor sizes come out very conveniently to a round number, that is 50 Hp and 75 Hp. This is very handy, though it will not always occur in actual application. If, for instance the horsepower requirements were 56 or 84 Hp, there would be reason to pause in the design of the previous applications to consider what could be done to avoid overloading of the equipment. Incidentally, overloading of equipment is one of the most common causes of short runs and frequent failures. This can be avoided through careful design. In the case of the horsepower requirement of 56 Hp, it would be better in most cases to go to a 60 Hp motor, the next larger size. In the case of the 84 Hp requirement, one should disregard the 75 Hp nameplate motor and go to the next larger size.

The design of the submersible motor is done in such a way as to allow for peaks and valleys in loading and conditions. That is, the staring requirements are always greater than the stable running requirements of the unit. With the submersible pump, it is not unusual to have starting loads of four to five times the nameplate amperage. In other words, a 745-volt, 42-amp motor will have a starting load of from 170 to 210 amps. This is an instantaneous condition and ceases in 10-20 milliseconds after the starting button is pushed.

In the stable running condition, if the motor is seriously overloaded, fluctuations in power, changes in fluid level, changes in the gravity of the fluid due to the influx of solids into the wellbore or a decrease in the oil and an increase in salt water of gravity over 1.0 can add to the loading. A pump initially put in a predominantly all-oil well with a specific gravity of 0.88 may tend to go to water some months or years later, pumping 90 per cent salt water of 1.1 and only 10 per cent of the lighter gravity oil. This then drastically changes the loading factor on the original motor.

ELECTRICAL EQUIPMENT

Other necessary items to be considered are cable, switchboard and transformers as required. Regarding the cable, it is necessary that the proper size conductor is selected for the electrical requirements of the motor.

A good rule of thumb to remember in conductor sizes is that No. 6 copper has a maximum capacity of 55 amps. In most cases one would go to the next larger conductor size for a motor with an amperage rating higher than 55. No. 4 is rated at a maximum of 70 amps. The No. 2 conductor is good up to 90 amps and the largest conductor normally used with submersibles is the No. 1 and has a maximum rating of 110 amps. The selection of the proper size conductor with ample current-carrying capacities is very important as overloaded cable will have a shorter life and create maintenance problems.

Figure 3 shows the maximum length cable recommended with various combinations of motor voltages and amperages. In the case of the 50 Hp motor, a 745-volt, 42-amp winding or a 420-volt, 72-amp winding is used. In the first case, 42 amps are well within the carrying capacity for a No. 6 conductor. On the graph at 745 volts, it is found that plenty of leeway is available at a setting depth of 2400 ft.

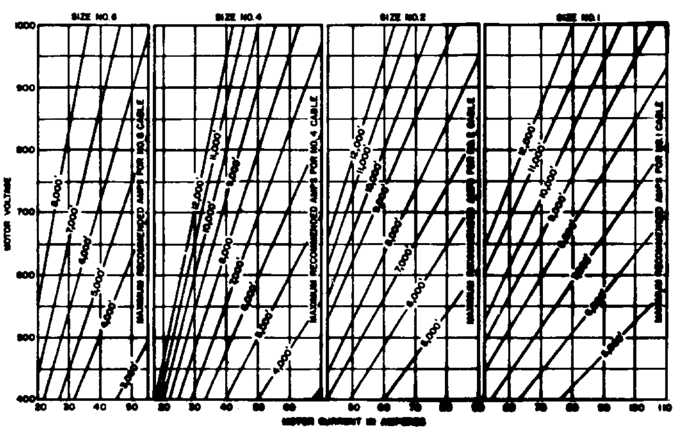

FIGURE 3

Maximum Recommended Cable Lengths for Motor Volt/Amp Rating

As shown from the chart the above "rule of thumb" is not to be taken as hard and fast rule. Even though the No. 6 conductor can carry 55 amps, a length of cable excessively long for the corresponding voltage rating of the motor would force this conductor to carry more current than is practical and hence, it would overheat, giving a shorter life span in the installation.

In the design example, even though the 50 Hp, 42-amp motor is well within the range of the No. 6 conductor, it is seen that the maximum recommended length of cable is 6000 ft when used at the 745-volt lever. Attempting to run this size motor with a string of cable longer than 6000 ft will overheat the conductor itself.

The round cable is normally available in two types of armor. The armor consists of an interlocking metal either of galvanized steel or Monel. The armor serves as physical protection to the rubber jacket and has no sealing properties. For most normal wells where there is either non-corrosive or mildly corrosive fluids present, the galvanized armor is used. For severe corrosion, Monel is preferred. For water wells or high water-cut producing wells where ambient temperature is below 140° F, a polyethylene unarmored conductor is often used. This is a hard plastic-type jacket which ordinarily comes without any armor. Because of its inability to resist heat, polyethylene is not recommended in wells of temperatures higher than the 130-140° F range.

In calculating the voltage requirement at the surface, it must be known how much voltage will be lost through the cable in transmitting the power to the motor. Figure 4 is a voltage loss curve showing voltage drop per one thousand feet of cable for conductor sizes 1 through 10. In calculating the voltage lost, the motor amperage is found at the bottom of the graph and then moving upwards to the band representing the size conductor being used. For a 42 amp motor and No. 6 conductor, note that

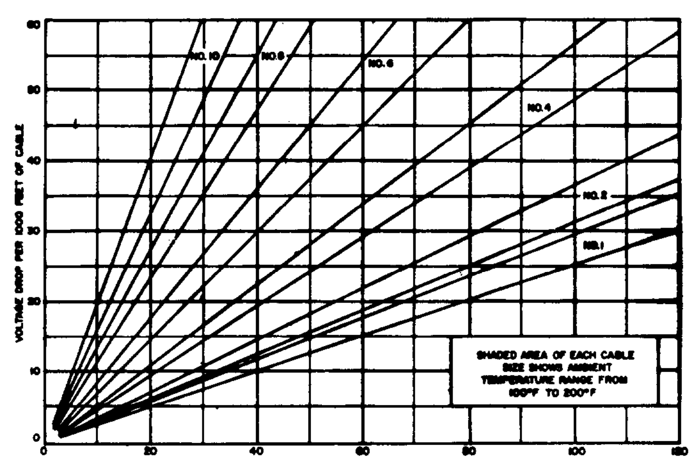

FIGURE 4

Cable Voltage Loss-Per 1,000 Ft. Sizes 1-10 the bottom of the band shows 31-1/2 volts drop per thousand feet of cable. If the temperature of the fluid in which the cable would be installed were 200° F, we must move up to the top of the band, which would show that approximately 38 volts per thousand feet of cable would be lost in transmitting power to the motor downhole.

If the 50 Hp motor were to be set at 2400 ft with a normal temperature of 110°F, there would be a voltage drop of approximately 32 volts per thousand feet of cable. For 2500 ft of cable, this would represent a loss of 80 volts. This 80 volts must then be added to the motor nameplate voltage of 745, which gives a required surface voltage of 825.

When the surface voltage requirements have been calculated, a switchboard size may be selected. A 440-volt panel can be hooked to a 440-volt system; if a 762-880-volt power system were available, an 880-volt panel could be used. Transformers can be used to step up or step down any voltages as required though care must be taken not to overload a switchboard designed for a given voltage.

In the case of the higher voltages, larger capacity switchboards with ratings of 1500 and even 2300 volts are made available. These are ordinarily to be used when stepping down from primary voltages such as 12,470, 13,200 or 24,000 volts.

In each switchboard, certain safety devices and/or automatic controls are available if desired. It is generally a good idea to have protective devices in the panel; these can include such things as an undercurrent shut-down, which will automatically cut power to the unit downhole in the event of gas or air lock or a closed pump discharge. Other optional items include a recording ammeter and an automatic restart device which will let the unit come on after a pre-set down period. Most switchboards come in weatherproof panels and are specially designed for use with a submersible unit. They will also include as standard equipment a 110-volt control circuit, a magnetic-type overcurrent relay, a fused disconnect switch, lightning arrester and a hand-off-automatic selector switch and start push-button. Though some of these items are considered unnecessary in some applications, it is considered advisable to have the undercurrent relay. If the operator is interested in monitoring the motor amperage, a recording ammeter is indispensable in this respect. This will give a continuous running-amperage chart on either a 24-hour or 7-day basis.

Other accessory equipment can include a liquid level relay for an externally-placed liquid level controller, such as in a tank. Also for controlling tank levels, a pressure shut-down relay can be used to prevent the equipment from overfilling the tanks.

If the required surface voltage and the available voltage which can be used safely with the switchboard are not in accordance with the switchboard capacity, transformers must be used. For use from a 440/480-volt system, an auto transformer can be used to step up to a secondary tap range of 750 to 1050 volts. This transformer comes in a single-unit design and is specifically used with 440-volt systems.

When dealing with primary voltages, ranging anywhere from 2400 to 24,000, an outdoor-type power transformer is advisable. These come in various sizes normally ranging from 15 to 100 KVA. The secondary voltages, that is the output voltages to be connected down-hole, come in a wide variety of ranges depending on the size and primary winding of the power transformer. Since the submersible motor is a three-phase design, three power transformers are required for each installation. These are installed at the well as a bank and interconnected through their terminals.

In selecting the KVA size of the transformers to be used, it can be generally remembered that one horsepower equals one KVA. To more accurately determine a KVA load in the system, the required surface voltage times motor amperage times 1.73 will give the actual KVA loading factor. It is a good idea to check this against any initial selection to make sure that the transformers are not overloaded.

In the case of the 50 Hp motor, we have a required surface voltage of 825 volts and a motor amperage of 42 amps. Multiplying 825 x 42 x 1.73 we come up with a figure of 60 KVA. If working with a 440/480-volt power system, one could select a 60 KVA auto transformer which would have a secondary tap range of 750 to 1050 volts. If dealing with a primary voltage system of 13,200 volts, the secondary tap range would be 450 to 1310. In either case, the required surface voltage of 825 would then be readily available on the secondary tap side.

WELL FLUID CONDITIONS AND THEIR EFFECT ON EQUIPMENT

The effect of corrosion on cable armor was previously mentioned. Corrosion effects on the pump parts themselves should now be considered. Today, down-hole submersible pump impellers and diffusers are constructed of Ni-Resist which is a nickel steel alloy with higher than average resistance to corrosive fluids. The pump and motor shafts are normally made of K-Monel which not only has substantial corrosion resistance but is also a high-strength type of material. Naturally in the cases of very corrosive wells, these materials will have a shorter life than in a fresh water application. However, they are at the same time much more desirable in the oil well application than would be plain bronze or cast iron stages or a carbon steel shaft.

Many times in the oil well application, loose sand is encountered. The submersible pump when turning at approximately 3500 RPM's, can very quickly wear out internally if a steady amount of sand is pulled into it at this speed. The fluid velocities carrying sand particles in suspension will create a scouring effect depending on the coarseness and the amount of sand as well as the length of time it is taken in through the pump. To help eliminate some of the wear encountered under sand conditions, rubber bearing diffusers are used in the pump. These are fluted rubber bearing inserts which eliminate metal-to-metal contact between the hub of the diffusers and the shaft of the pump. The severe scoring or abrasive effect between the two metal surfaces is reduced by using the rubber bearing.

To protect the external housings of the motor, pump and seal sections, various types of plastic spray-on coatings are readily available and quite easy and inexpensive to apply. For severe corrosion, a Babbitt or hot metal spray is available and has been used with a wide degree of success for several years.

As previously mentioned, armored cable is available in either galvanized or Monel, the latter having the most resistance to severe corrosion. It should be emphasized at this point that a polyethylene cable, while not affected by corrosion at all, does have its temperature limitations. The upper limit of 140° F should be kept in mind at all times when selecting this cable for use with a submersible.

As was previously mentioned, heat is perhaps the biggest single enemy of an electric motor or a rubber-jacketed cable. Whereas over the years high temperature materials for submersible motor insulation and cable insulation have been developed, extreme ambient well temperatures should be taken into account when designing the equipment. This is not to say that high temperatures should eliminate the use of submersibles. They should instead be given close consideration in the design and selection of the equipment. As an example, if a submersible installation were to be considered in a well with ambient fluid temperatures of 240° F, this factor alone should not eliminate the use of the equipment. Motor-insulating materials are available which will withstand a heat rise of some 100° to 150° higher than was available several years ago. This factor alone has extended the use and application of submersible pumps. The amount of heat rise in a motor, if known, can solve the mystery of a short run or complete motor failure.

In many instances when it is known that consistently high temperatures in the well fluid will be encountered, a motor can be sized accordingly to help reduce heat rise internally. That is, going back to the previous 50 Hp combination, if the ambient temperatures of fluids surrounding this motor were to be 240° F, it would be highly advisable that the operator consider the economics of going to a pump which would have only a 40 Hp loading factor. That is, a pump with that number of stages which would load a 50 Hp motor to 40 Hp. This reduced load then on the 50 Hp would provide enough "cushion" in the higher temperature surroundings so as to reduce heat rise in the motor windings and insulation. This method can be used to extend the life of equipment in the higher than normal well temperatures.

When dealing with oil wells, there is always some gas to be encountered unless the fluid is considered "dead". Many times it cannot be known until the well is pumped at the higher rate with the submersible as to what the amount of gas encountered will be. Centrifugal gas separators are available with submersibles. It is always helpful to know beforehand what the gas-oil ratio or gas-fluid ratio of the well is. Each well and each field may vary one to the other as to the amount of GOR or GFR that can be effectively handled with a submersible pump with gas separator.

If the desired amount of fluid can be pumped and still not draw the fluid level down to the point where the gas breaks out of solution, no gas separator is necessary. Of course, the most desirable situation is one where gas is not allowed to break out until it is above the pump. If gas bubbles break out in the pump, this cuts volumetric efficiency of the pump and in extreme cases cavitation and pump wear can occur. This will result in loss of fluid and short equipment life if allowed to continue over a period of time.

WATER FLOODS AND THE SUBMERSIBLE

In areas where strong natural water-drive reservoirs abound, a submersible can often be used quite handily. In Oklahoma, Texas and New Mexico, there are, of course, the proration laws to contend with. As the wells are pumped over a period of years, the depletion rate gathers momentum until it is no longer practical to pump individual wells because of a high water cut. More and more operators have come to recognize that a high capacity submersible will economically prolong the life of the field when it is put under water flood. A greater amount of fluid can be lifted with the submersible as conventional beam pumps become more uneconomical.

In an actual case history of an Oklahoma water flood, Fig. 5 shows depletion of the field late in 1950 on an 80-acre lease. This information revealed by R. C. Earlougher and E. T. Guerrero on their presentation of "New Developments in Water Flooding" shows how excessive water production and problems created by water flooding can be overcome by the high capacity submersible pump application.[1] The peak production under a 5-spot injection pattern was obtained early in 1952. By the end of 1954 the economic life was indicated to be for the end of 1955. Late in 1954 a submersible was installed in one well increasing the fluid withdrawal rate from 700 to 900 BPD. Throughout 1955 and early 1956, other submersibles were installed to handle the increased fluid rate. By the use of the submersibles in producing wells, an additional 215,000 barrels of oil was recovered. The shaded part of the graph shows that the average operating cost for the submersibles was very similar to the cost of the last year of operation with conventional pumps.

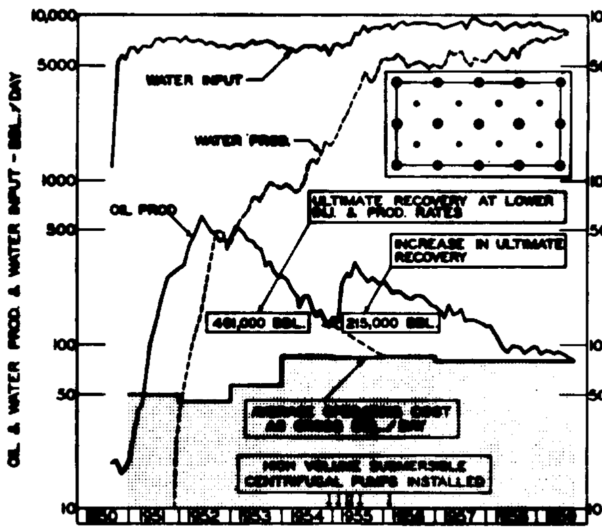

FIGURE 5

History of Oklahoma 80 Acre Lease Showing Effects of High Water Injection and Production Rates

Highly fractured reservoirs such as those found in the Rocky Mountains will give up the oil in the fracture system early in the productive life of the well.[2] These fractures then become filled with water from the aquifer and a high oil-water ratio results in the well bore. As a result, it has become common practice in this part of the country to pump high volumes from these highly active water drives. As it is very often impossible to shut off the water in these reservoirs without also shutting off oil production, the use of high volume pumps such as the submersibles has been widespread. Through this method, the flowing pressure in the fractures is then lowered so that oil trapped in the matrix system can migrate to the fracture system.

By the use of high volume submersibles, overall profits may be increased by a more rapid depletion of the reservoir providing the rate of production will not materially affect ultimate recovery. An operator faced with fluctuating market conditions, but not restricted by statutory proration, may find high volume pumping with a submersible to be the solution to his economic situation. This results when he will be able to produce more with a submersible when the markets are favorable.

VARIATIONS AND SPECIAL APPLICATIONS OF THE SUBMERSIBLE

Besides the normal installation procedure just described, there are variations which can be innovated with submersible equipment to accomplish something other than to lift a given amount of fluid from a given depth. Besides pumping up a string of tubing to the surface, the submersible can be modified with very little trouble to pump down. This then provides a combination water source and injection well. Such was the case in a West Texas application where it was desirable to avoid going into surface lines and other equipment needed for a water flood.[3] The water source zone was above the formation into which the water was to be injected. As seen from Fig. 6 water was taken from the source formation through a slotted tubing joint above the pump. The water travelled past a turbine flow meter which is placed in the tubing string to meter the water as it enters the inverted pump. The stages of the pump in this case were merely turned upside down and placed in the pump housing. In this way instead of pumping up the tubing string, the water was pumped down. This also necessitated reversing the rotation of the motor to counter-clockwise from clockwise.

A tension-type packer was run on the tubing between the upper and lower zones and was placed about 30 feet above the pump. A perforated nipple was attached to the bottom of the pump and the water was forced out of the nipple which was set opposite the zone to be flooded. By this technique the operator was able to save a substantial amount of money by avoiding normal surface equipment.

Another variation of a submersible installation is shown in Fig. 6-A where an operator made

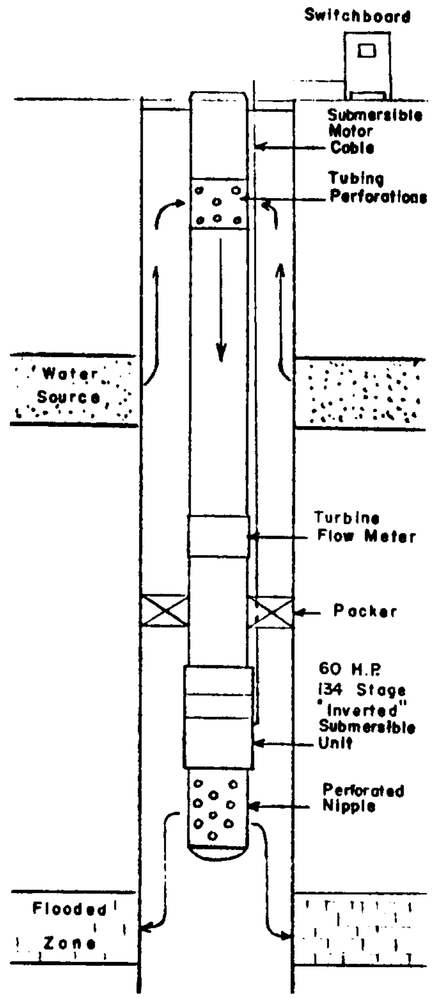

FIGURE 6

Inverted Pump Injecting Water From Upper Zone Into Lower Zone in West Texas Flood

use of two complete units. The lift and resulting horsepower requirements could have been performed by one large unit; however, the operator had on hand smaller equipment which, when combined in proper fashion, was able to do the job required. This eliminated the added expense of purchasing the new equipment. Fortunately in this case the operator had drilled a large enough hole to accept the large pipe required. The 13-3/8-in. casing was big enough to take the lower unit which consisted of a 200 Hp, 19-stage pump set at 2200 ft. This pump was run on 9-5/8-in. casing swaged down to fit the pump head. Inside of the 9-5/8-in. the upper unit consisted of a 225 Hp motor and a 22-stage pump was run on a string of 5-1/2-in. casing to a depth of 2125 ft. The lower unit then had a total head of 1140 ft and the upper unit a total head of 1320 ft. The combined head of the two units was equal to the required lift of the 400 GPM of water to the surface. This, of course, necessitated the use of two switchboards and two separate strings of cable. We have seen here that special use can be made of submersibles without greatly altering the basic construction and design.

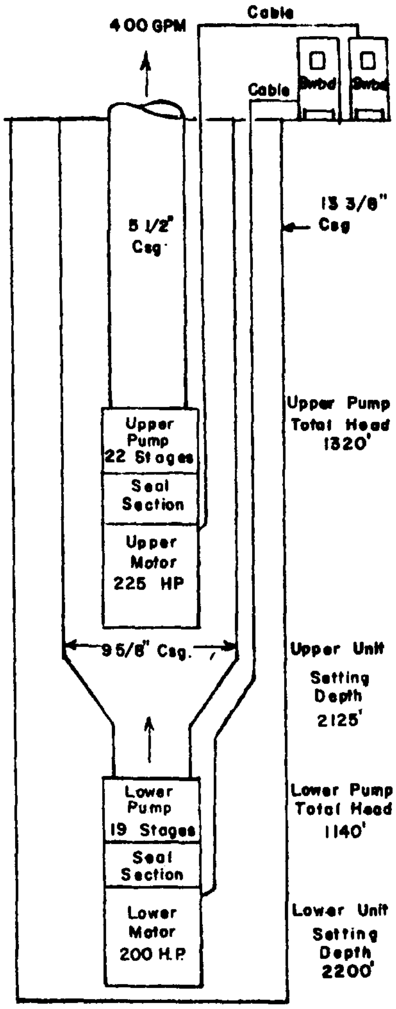

FIGURE 6-A

Combining Two Complete Submersible Units For High Volume and Lift Application

Particularly in the case of the strong water drive or high water-cut wells, a submersible can be used to great advantage in recovering oil which otherwise would not have been profitable to the operator.

Those engineers whose responsibility it is to obtain maximum profits from the reservoirs can well afford to study the submersible application and learn to use well and reservoir data adequately. Through the diligent use and application of this well data, greater profits can be realized.

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