Electrical Submersible Pumps in Horizontal Wells

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Introduction:

The basic configuration of the Electrical Submersible Pump was conceived over fifty years ago. It was originally designed for the traditional vertical well. Development of steerable drilling tools and "measurement while drilling" techniques over the last two decades has allowed drilling wells that radically depart from tradition. To be able to derive the maximum benefit from these complex geometry wells it is necessary to understand some of the production problems and the limitations of the Electrical Submersible Pump.

The traditional well has been thought of as being straight and vertical, however the exact path of the bore hole has never been straight nor vertical for very far. Different physical properties of the rock and the angle at which the bit intersects the formation can cause the bit to skip or dig, producing an infinite variety of bore hole paths. The severity of the deviation from a straight hole is called "dogleg" and is expressed in degrees of deflection per 100 feet of measured hole (fig. 1). Modern drilling techniques allow the bore hole to be purposely deviated, or steered, in order to intersect the producing formation in particular location and manner. These complex geometry wells can be divided into two major categories, the directional wells and the horizontal wells.

Directional Wells:

The directional well is drilled vertically for a short distance, then "kicked off" and angle is built to achieve the desired run angle (fig. 2). The hole continues straight, at the established run angle, until it is close to the target zone. At this point the angle may be decreased and the hole allowed to drop through the target zone. The rate at which angle is built in these wells is seldom greater than 7 degrees per one hundred feet. Wells of this type are used in situations where they must be clustered in a small area, such as offshore, or in locations where it is not feasible to drill from directly above the target.

Horizontal Wells:

The category "Horizontal Well" includes a variety of well geometries which share one common characteristic, that is that they attempt put the bore hole through the formation parallel to the run of the formation (fig. 3). The ideal hole would start vertically and continue until it approached the formation. The bore hole would then turn and build angle until the hole intersects and runs more or less parallel through the formation. Horizontal wells are classified by the radius or dogleg angle that is used in intercepting the formation (1).

Short Radius,	30-45 ft,	126-191 deg/100 ft
Medium Radius,	300-500 ft,	18.8-11.5 deg/100 ft.
Long Radius,	1200-1500 ft,	4.8-3.8 deg/100 ft.

Just as the traditional well is not truly straight and vertical, the horizontal well is not truly straight or horizontal. The producing formation itself probably does not lay horizontal and the steering corrections that are made as the well is drilled cause the path of the bit to fluctuate within a tolerance span.

Production in Horizontal Wells:

Horizontal wells have the advantage of a vastly increased drain radius. They may therefore be able to produce significantly more fluid than a traditional well in the same formation. However, Horizontal wells can present some production problems that are generally not severe in vertical wells.

The phenomena of casing heading or slugging can be a problem in vertical wells when the bottom hole flowing pressure is below the bubble point and the superficial velocities of the liquid and gas are low (2). This slugging phenomena is typified by alternate production of liquid with small amounts of gas followed by production of gas with very little liquid.

In horizontal wells slugging can be initiated by unstable flow in the horizontal run. If the velocity of the liquid and gas is low, a slug flow regime will develop. In cases where the velocity would normally be too high for slug flow, the gas bubbles collect on the upper side of the casing. If the casing slopes downward in the direction of the flow, the buoyant force on the gas will tend to decrease its velocity, allowing it to collect in pockets. The pockets produce a localized blocking of the liquid flow and will eventually belch through when pressure behind them becomes great enough. This forces the production into slug flow.

Effects of Gas on the ESP:

Electrical Submersible Pumps developed their place in the market as an economical method for producing high flow rates with low bottom hole pressure. Because of this they are often selected as the method of lift for horizontal wells. If the ESP is to be installed in the vertical portion of the hole, it can be done so with standard equipment and procedures. The limitation of the ESP then becomes its ability to function with gas. In many cases gas slugs are large enough to overload the gas separator and "gas lock" the pump. The unit must then be shut down and restarted after the well has settled down.

In a vertical well gas problems can by minimized setting the unit immediately above the perforations. This gives the maximum pressure and minimum free gas at the pump intake for the production flow rate. In a horizontal well, lowering the pump usually means pushing it through the bend and into the horizontal section. An ESP can operate satisfactorily at almost angle, up to and including horizontal, as long as the unit itself is straight. If it is felt necessary to locate the ESP in the horizontal section, a main concern must be that the stresses developed when passing through the bend do not permanently deform the unit.

ESP Installation in Horizontal Wells:

The ESP, like the drill string, is a long slender piece of equipment and can be considered flexible in some situations. However ESP construction differs from the drill string in that the functional parts, motor, gas separator, pump, etc, are bolted together with flange joints. This is necessary for shipping and ease of field assembly. The flange joints are weaker in bending than the rest of the unit. Bending stress is concentrated at the weakest points (fig. 4), deflecting and sometimes permanently deforming the joint. If the joint is damaged, it will put extra side load on the adjacent shaft bearings within the unit and drastically reduce the life of the equipment.

Observation and experience have shown in the past that ESP's could take some bending without damage. The rule of thumb estimate stated that an assembled ESP could be deflected up to 3 degrees per one hundred feet without permanent damage (3). There is always some clearance between the diameter of the ESP and the inside diameter of the casing. This clearance permits the ESP to pass through bends more severe that maximum allowed for the unit itself. To find the bending that will occur in as ESP as it passes through a radius, it is necessary to calculate the deflection of the casing. This can be calculated using the following approximation:

$$d = 2.6 \times (L/100)^2 \times a \qquad (1)$$

Where:

d = deflection of center of arc (inches)
L = Length of section (feet)
a = Dogleg Angle (deg/100')

Example:

Assume that a ESP designed for 5 1/2 " casing, 60 feet long, is going to have to pass through an 8 deg/100' dogleg in 9.5/8"-36 Lb. casing (6.366' ID). From equation 1, the deflection of the casing at the center of the ESP would be:

Casing Deflection = 2.6(60/100)^2 x (8) = 7.488"

The deflection of the ESP in this section differs by the clearance between the ID of the casing and the OD of the ESP. The motor OD is approximately 4 1/2" and the pump diameter is 4". For simplicity assume that the ESP has a constant OD of 4.25".

Clearance = Casing ID - ESP OD = 8.921 - 4.25 = 4.671"

The deflection of the ESP is the difference between the deflection of the casing and the clearance between the casing and the ESP.

ESP Def. = Casing Def. - Clearance = 7.488 - 4.671 = 2.817"

Equation 1 is rearranged and solved backwards to find the bend that will occur in this ESP as it passes through the dogleg.

a = d/[2.6 x (L/100)^2] (2)

Actual ESP bending = 2.817/[2.6 x (60/100)^2] = 3.009 deg/100'

If an ESP can truly tolerate 3 Deg/100' bend, this unit should be able to pass through the dogleg without damage.

The method outlined suffers several drawbacks. The formula used (eq.1) starts to lose accuracy at doglegs greater than 20 degrees per one hundred feet. It also assumes that the motor and the pump are fairly close in diameter. More accurate methods of determining the bending limits of ESP's have been developed (4). The specific equipment manufacturer should be consulted about the equipment limitations before installed is attempted.

The example indicates that the standard ESP's should pass through a long radius well but would have trouble in the medium radius wells even with large casing. In the past this was the maximum safe limit on the ESP equipment. Recently specialized equipment has been developed that can tolerate bends in excess of 12 degrees per one hundred feet without damage. This development will allow ESP's to be landed in the horizontal section of many of the medium radius wells

ESP Operation in Horizontal Wells:

The ESP was designed to run vertically. The function of any feature that relies on the direction of gravity should be evaluated before attempting to operate in a horizontal position.

Motor:
The thrust bearing in the motor is designed to absorb the weight of the rotors. It presents no problem to run the motor horizontally, however the manufacturer should be consulted before running a motor on an upward incline. The motor uses the well fluid for its cooling. When a motor is set off vertical, so that it is against one side of the casing, it can not receive cooling on that side. This may present a problem in hot wells. Centralizers can be used to allow fluid to circulate on all sides of the motor, however the centralizers decrease the clearance between the ESP and the casing and can increases the stress when passing through a bend.

Seal Chamber:
The labyrinth and blocking fluid type seal chamber relies on the direction of gravity and will therefore not function correctly in a horizontal position. The bag type seal chambers usually have a labyrinth section as a backup. In a horizontal well, the bag type seal section will operate but has no backup in case of primary system failure.

Gas Separator:
Internally, the dynamic gas separator will function very much like it would in a vertical position. After the gas exits the separator, there is no buoyant force to transport the gas to the surface. The static gas separator relies on the buoyant force to separate the gas and will not function in a horizontal position.

Pump:
The thrust forces generated by the pump are a function of the direction that the fluid pumped and therefore present no problems when the direction of gravity is changed.

Recommendations:

In order to facilitate the use of ESP's in horizontal wells, the following practices are recommended:

Drill the well as large as economically possible. The clearance between the ESP and the casing reduces the magnitude of the bending that will be transferred to the ESP. It also provides room for cable protection devices.

Drill downhill if possible. It is desirable to have a path of escape for the gas. In uphill runs, the gas has no place to go and collects in the bottom of the hole.

A liner may be used to increase the superficial velocity in horizontal run of the hole to prevent slugging. If possible it should be set at least 100 feet beyond the end of the radius to allow a straight landing section for the ESP.

Labyrinth type seal chambers are non-functional in the horizontal position. Bag type seal chamber should be used. The number of seal chambers should be doubled if the bag type uses a labyrinth for its secondary sealing system.

Centralizers increase the bending when an ESP is passing through the radius and should be used only if necessary.

Consult manufacturer about equipment limitations and specialized equipment before installing in wells that will induce bends greater than 3 degrees per one hundred feet.

Conclusions:

To receive the maximum benefit from horizontal well technology the wells should be designed with the with the understanding that at some time in the future it may be necessary to produce the well with an ESP. Some specially constructed ESP units have been able to pass through a 12 degree per one hundred feet radius. Understanding the limitations of this method of lift is essential to obtaining good run life in horizontal wells.

References:

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3. ODI Training Manual, Oil Dynamics Inc., Tulsa, Ok, 1987

4. Wilson, B.L.:"Micro Computer Analysis of ESP Bending," SPE Microcomputer Applications in Artificial Lift Workshop, Long Beach Ca. Oct. 16-17, 1989

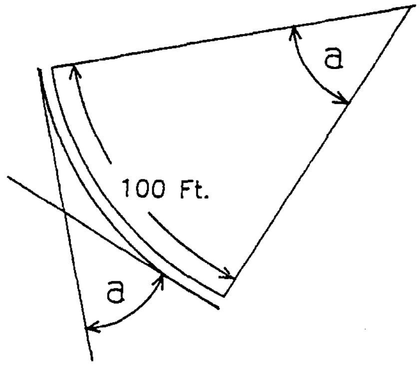

Figure 1 - Dogleg angle (a)

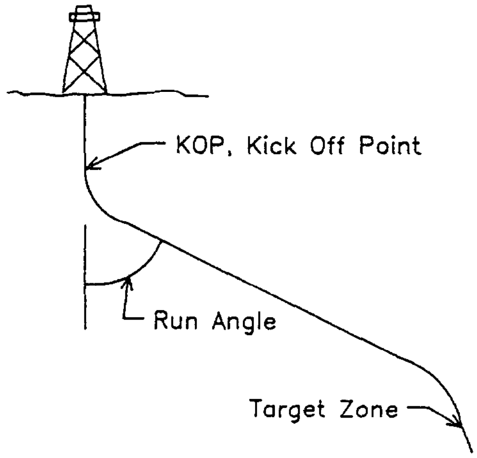

Figure 2 - Directional well

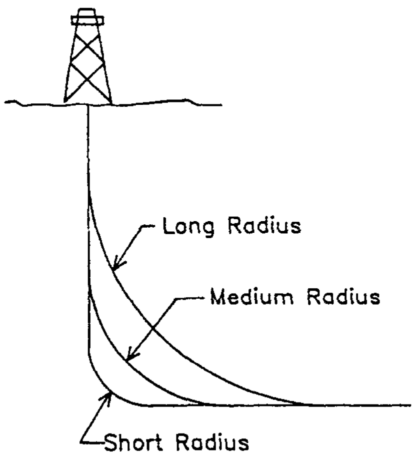

Figure 3 - Horizontal well

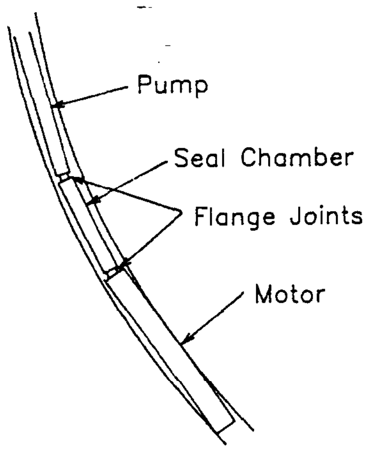

Figure 4 - ESP bending

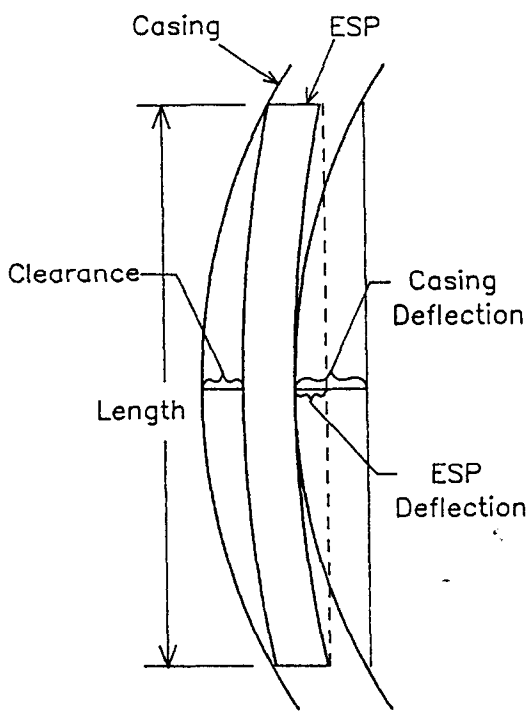

Figure 5 - ESP bending