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LEARNING OBJECTIVES:

Having worked through this chapter the student will be able to:

INTRODUCTION
• Explain the importance of Artificial Lift (AL) for world oil production.
• List the different types of AL.

SELECTION
• Select appropriate type AL based on ranking criteria.

ELECTRIC SUBMERSIBLE PUMP
• Identify the components of an Electric Submersible Pump.
• Describe the preferred applications and the mode of operation of the Electric Submersible Pump (ESP).
• Select well conditions suitable for ESP installation as preferred Artificial Lift option.
• Identify the application areas where an ESP is NOT suitable.
• Evaluate the advantages of an instrumented ESP completion.

BEAM PUMP
• Describe the concept and component parts of a Beam Pump.
• Select well conditions suitable for beam pump installation.
• Explain the beam pump design methodology
• State the background to the use of the Dynanometer card for troubleshooting.

FLUID DRIVEN HYDRAULIC PUMPS
• Describe the concept, implications for the well completion and advantages of using high pressure fluid as a power source.
• Explain the mode of operation of the:
  (i) Jet pump;
  (ii) Weir Multiphase pump;
  (iii) Hydraulic pump.
• Identify their advantages and disadvantages.

PROGRESSIVE CAVITY PUMP
• Describe the concept and area of application of the Progressive Cavity Pump (PCP).
• Compare rod and electric motor driven PCP’s.
• Discuss advantages of wireline retrievable PCESP.
ARTIFICIAL LIFT METHODS:

1. INTRODUCTION AND SELECTION CRITERIA

This module will introduce the topic of artificial lift - a production engineering topic of increasing importance in field development. The reasons leading to this increasing importance in the field development process will be reviewed. The main factors influencing the selection of the most important artificial lift techniques will be highlighted.

A brief description will then be given of all the common artificial lift techniques (rod pumps, electric submersible pumps, progressive cavity pumps and hydraulic pumps) apart from gas lift.

Hydrocarbons will normally flow to the surface under natural flow when the discovery well is completed in a virgin reservoir. The fluid production resulting from reservoir development will normally lead to a reduction in the reservoir pressure, increase in the fraction of water being produced together with a corresponding decrease in the produced gas fraction. All these factors reduce, or may even stop, the flow of fluids from the well. The remedy is to include within the well completion some form of artificial lift. Artificial lift adds energy to the well fluid which, when added to the available energy provided “for free” by the reservoir itself, allows the well to flow at a (hopefully economic) production rate. It has been estimated that in 1994 there was a world inventory of more than 900,000 producing wells. Only 7% of these flowed naturally while the remaining 93% required some form of artificial lift. The average production per well was less than 70 bpd.

2. THE NEED FOR ARTIFICIAL LIFT

Artificial lift is required when a well will no longer flow or when the production rate is too low to be economic. Figure 1(a) illustrates such a situation - the reservoir pressure is so low that the static fluid level is below the wellhead. Question: Is it possible for this well to flow naturally under and conditions.

Figure 1
Artificial lift fundamentals

Figure 1a
The well is unable to initiate natural flow.
Answer: Yes: If the well productivity Index is sufficiently high and the produced fluid contains enough gas that the flowing fluid pressure gradient gives a positive wellhead pressure. But, the well has to be "kicked off" (started flowing) by swobbing or other techniques.

Figure 1(b) shows how installation of a pump a small distance below the static fluid level allows a limited drawdown ($\Delta p'$) to be created. The well now starts to flow at rate $q$. N.B. the static and flowing pressure gradients in figures 1(a) & 1(b) are similar since frictional pressure losses in the tubing are small at this low flow rate.

It can be readily seen that the same production rate will occur when the pump is relocated to the bottom of the tubing, provided the pressure drop across the pump, and hence the drawdown, remains the same. The advantage of placing the pump near the perforations is that the maximum potential production can now be achieved (figure 1(c)) by imposing a large drawdown ($\Delta P''$) on the formation and "pumping the well off" by producing the well at $q_2$ is slightly smaller than the AOF.

Figure 1b
Pump creates a small drawdown and flow rate
Artificial lift design requires that the pump to be installed is matched to the well inflow and outflow performance.

3. REVIEW OF ARTIFICIAL LIFT TECHNIQUES

The most popular forms of artificial lift are illustrated in figure 2. They are:

- Rod Pump
- Hydraulic Pump
- Submersible Electric Pump
- Gas lift
- Progressing Cavity Pump (May also be driven by electric submersible motor)
(i) **Rod Pumps** - A downhole plunger is moved up and down by a rod connected to an engine at the surface. The plunger movement displaces produced fluid into the tubing via a pump consisting of suitably arranged travelling and standing valves mounted in a pump barrel.

(ii) **Hydraulic Pumps** use a high pressure power fluid to:

(a) drive a downhole turbine pump or

(b) flow through a venturi or jet, creating a low pressure area which produces an increased drawdown and inflow from the reservoir.

(iii) **Electric Submersible Pump** (ESP) employs a downhole centrifugal pump driven by a three phase, electric motor supplied with electric power via a cable run from the surface on the outside of the tubing.

(iv) **Gas Lift** involves the supply of high pressure gas to the casing/tubing annulus and its injection into the tubing deep in the well. The increased gas content of the produced fluid reduces the average flowing density of the fluids in the tubing, hence increasing the formation drawdown and the well inflow rate.

(v) **Progressing Cavity Pump** (PCP) employs a helical, metal rotor rotating inside an elastomeric, double helical stator. The rotating action is supplied by downhole electric motor or by rotating rods.

In fact, nearly all the major classes of pumps are employed in the various forms of artificial lift (figure 3).

4. CURRENT STATUS OF THE ROLE OF ARTIFICIAL LIFT IN FIELD DEVELOPMENT

Figure 4 shows relative frequency of the different types of artificial lift installed in the USA in 1992. The predominance of rod pumps indicates the vast majority of wells are on land locations in mature fields with low well production.
Selection of Artificial Lift Types

Figure 5 is a corresponding breakdown for a major international oil company’s more than two and a half million barrels a day of gross fluid production (which yields more than one million barrels a day of oil) which is lifted by the various types of artificial lift. The larger contribution from Gas Lift and ESPs reflects the greater contribution of high rate and offshore wells compared to the figures for the USA.

Artificial lift is being more widely applied in field development than ever before due to:

(i) **Field development status** - oil producing provinces such as the North Sea have become mature with the consequent reductions in flowing bottom hole pressure (depletion) and increasing water cuts.

(ii) **Absence of Pressure maintenance.** The development plans for many of the early, giant North Sea fields employed early water injection to maintain the reservoir pressure above the hydrocarbon fluid’s bubble point, even after a significant fraction of the hydrocarbon reserves had been produced. This meant that the high water cut wells still continued to flow at high production rates. Many of the current crop of smaller fields currently being developed do not employ any form of pressure maintenance, resulting in a early need for artificial lift.

(iii) **Satellite or Subsea Wells.** These wells are often positioned a considerable distance from the host platform. The extra pressure drop caused by flow through these long, subsea pipelines needs to be overcome by some form of pressure boosting. This could either be an increased pressure boost from an ESP installed downhole or by a multiphase pump mounted on the sea bed.
(iv) **Business drivers.** Profitable field development requires that the average well production rate exceed a minimum value with higher values being more profitable. Well design can increase the well flow rate of return. Recent well design innovations include:

(a) *Advanced well design:* drilling of long (horizontal) exposures to the producing formation.

(b) *Large diameter tubing* to decrease the frictional pressure losses e.g. Norske Shell’s Draugan field achieved flow rates of over 76,000 bopd with a 9 in. production tubing.

(c) *Early installation of artificial lift* to increase the flow rate.

Marginal (possibly subsea) field development requires reservoir development plans with a minimum number of wells where there is little or no need for well intervention to repair or modify the downhole installation. High equipment reliability is thus a “must”. Developments in the application of downhole electronics and measurement sensors means that monitoring of the performance of the artificial lift equipment of the operating conditions results in improved performance. One operator found that implementation of a real time, Supervisory, Control and Data Analysis (SCADA) system in a large artificial lift project consisting of more than 500 rod pumped wells resulted in a:

(a) 6% production increase (lift conditions optimised and immediate alarm given when wells ceased producing).

(b) 50% reduction in well entries (earlier recognition of developing problems allowed preventive maintenance).

(c) 5% reduction in energy consumption (wasteful “over-lifting” operating conditions recognised immediately).

(v) **Integration of artificial lift software into field development** planning and operation. Design procedures for artificial lift techniques has undergone a tremendous development:

(a) 1975: nomograms, slide rules and early calculators allowed single well, “snap shot” optimisation for the current production conditions.

(b) 1985: early, software based, field wide surveillance systems became available.

(c) 1995: “Thinking in systems” became a reality. The first field/production system models became available. These contain (simple) versions of models describing the performance of the reservoir, well (including any installed form of artificial lift), manifolds, facilities and pipeline (Figure 6). This integrated system has the ability to:
• Calibrate (or automatically history match) the various model elements against actual measured data.

• Compare the measured field data with the production plan or forecast.

• Optimise (normally maximise) the production within any (permanent or temporary) constraints.

• Recognise discrepancies between forecast and actual production. The identified wells/production systems are thus listed for engineering investigation and possible remedial activities.

Building and operation of such a model requires input from geoscientists, production technologists, pipeline and process engineers as well as production operations staff.

The availability of such an integrated models allows the “total cost of ownership”, or “total lifetime cost” of a particular form of artificial lift, to be evaluated when selecting the preferred artificial lift technique for a particular field development. For example, two or more lift methods may be technically capable of producing a well at the designated production rate. It is relatively easy to obtain figures for the initial, capital costs of installation. However, the equally (or even more important) costs due to (un)reliability, energy consumption, maintenance, manpower etc. figures have to be obtained from field operational data.

(vi) Technical innovation has increased the scope of artificial lift. One example is the development of multiphase pumps which are now available for both subsea and downhole application. For example, the B area of Captain field in the North Sea contains a viscous (50-150 cp) crude oil bearing zone overlain by a gas cap. Production of these reserves was only possible due to development of a pump capable of operating with free gas fractions in excess of the 30% vol (the normal operating limit of a conventional ESP). Innovation has also resulted in:

(a) the development of hybrid technologies such as downhole separation and pressure boosting for oil production and water injection.

(b) a step change in artificial lift reliability (see Table 1) through:
• improved engineering design
• the ability to monitor downhole conditions from the surface.
• better materials selection and, most importantly,
• better training of wellsite personnel who install and operate the equipment.

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<td>Lift Type</td>
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<td>37</td>
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<td>Data Source</td>
<td>Amoco*</td>
<td>Thums*</td>
<td>California</td>
<td>North Sea†</td>
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* Private communication J. Lea, Amoco.
*T. Lutz, presented at Artificial Lift 1997, Dubai.
† Presented at 1997 SPE Artificial Lift Workshop.

### 5. SELECTION OF ARTIFICIAL LIFT CRITERIA

There are many factors that influence which is the preferred form of artificial lift. Some of the factors to be considered are:

#### 5.1. Well and Reservoir Characteristics

(i) Production casing size.

(ii) Maximum size of production tubing and required (gross) production rates.

(iii) Annular and tubing safety systems.

(iv) Producing formation depth and deviation (including doglegs, both planned and unplanned).

(v) Nature of the produced fluids (gas fraction and sand/wax/asphaltene production).

(vi) Well inflow characteristics. A “straight line” inflow performance relationship associated with a dead oil is more favourable than the curved “Vogel” relationship found when well inflow takes place below the fluid’s bubble point. Figure 7 shows that reducing the flowing bottomhole pressure from 2500 to 500 psi increases the well production rate by 125% for the dead oil. This is more than double the 60% increase expected for the same reduction in bottom hole pressure if a “Vogel” type inflow relationship is followed with a well producing below the bubble point.
5.2. Field Location

(i) Offshore platform design dictates the maximum physical size and weight of artificial lift equipment that can be installed.

(ii) The on-shore environment can also strongly influence the artificial lift selection made. For example:

(a) an urban location requiring a maximum of visual and acoustic impact or

(b) a remote location with minimal availability of support infrastructure

can lead to different artificial lift types being selected for wells of similar design and producing characteristics.

(iii) Climatic extremes e.g. arctic operations will also limit the practical choices.

(iv) The distance from the wellhead to the processing facilities will determine the minimum wellhead flowing pressure (required for a given production rate). This may, for example, make the choice of an ESP more attractive than Gas Lift. This is because the extra pressure drop in the flowline, due to the injected gas, makes Gas Lift an unsuitable option for producing satellite hydrocarbon accumulations isolated from the main field.

(v) The power source (natural gas, mains electricity, diesel, etc) available for the prime mover will impact the detailed equipment design and may effect reliability e.g. the voltage spikes often associated with local electrical power generation have been frequently shown to reduce the lifetime of the electrical motors for ESP’s.

5.3. Operational Problems

(i) Some forms of artificial lift e.g. gas lift are intrinsically more tolerant to solids production (sand and/or formation fines) than other forms e.g. centrifugal pumps.
(ii) The formation of massive organic and inorganic deposits - paraffins, asphaltenes, inorganic scales and hydrates - are often preventable by treatment with suitable inhibitors. However, additional equipment and a more complicated downhole completion are required unless, for example, the inhibitor can be carried in the power fluid for a hydraulic pump or can be dispersed in the lift gas.

N.B. The physics and chemistry of these processes was discussed in Chapter 4 entitled “Formation Damage”.

(iii) The choice of materials used to manufacture the equipment installed within the well will depend on the:

(a) Bottom Hole Temperatures.

(b) Corrosive Conditions e.g. partial pressure of any hydrogen sulphide and carbon dioxide, composition of the formation water etc.

(c) Extent of Solids Production (erosion).

(d) Producing Velocities (erosion/corrosion).

5.4. Economics

(i) A lot of attention is often paid to the initial capital investment required to install artificial lift. However, the operating costs are normally much more important than the capital cost when a full life cycle economic analysis is carried out. This was illustrated by J Clegg et al (JPT, December 1993, p 1128). His data has been used to prepare Figure 8. It can be seen that, for this well, the capital cost represents a small proportion of the total project costs. Thus it is often viable to invest extra to ensure the best equipment is installed in the well if this will result in increased revenue (production) and/or reduced operating costs.

(ii) Good operating cost data for the different artificial lift methods in different locations is difficult to find. Reliability (discussed earlier) is one key issue while the second is energy efficiency (and hence energy costs). This latter is
Selection of Artificial Lift Types

more tractable since it can be calculated from first principles. There is a wide variation - see Figure 9. Only rod pumps, ESP’s and PCP’s show values >50% while gas lift, particularly of the intermittent variety, is inefficient in energy terms. Changing energy costs can alter the ranking order of the various artificial lift methods.

![Comparison of the energy efficiency of the major artificial-lift methods](image)

Figure 9
Comparison of the energy efficiency of the major artificial-lift methods adapted from J.Clegg et al (JPT, December 1993, p1128)

(iii) Maintenance costs will vary between operating locations depending on the state of the local, service company infrastructure. It can be costly in remote locations.

(iv) The number of wells in the field with that particular form of artificial lift (economy of scale) will influence the operating costs.

(v) Similarly, the desirability and/or need for automation (how many operators are to be employed) and the decision as to whether or not to install centralised facilities will also influence the operating costs.

(vi) The speed with which the “learning curve” is climbed for the more sophisticated forms of artificial lift will depend on the training provided and the skill base of the operations staff.

5.5. Implementation of Artificial lift Selection Techniques

As discussed the artificial lift design engineer is faced with matching facility constraints, artificial lift capabilities and the well productivity so that an efficient lift installation results. Frequently, the type of lift has already been determined and the engineer has the problem of applying that system to the particular well. A more fundamental question is how to determine the optimum type of artificial lift to apply in a given field.

There are certain environmental and geographical considerations that may be overriding. For example, sucker rod pumping is by far the most widely used artificial lift method in North America. However, sucker rod pumping may be eliminated as a suitable form
of artificial lift if production is required from the middle of a densely populated city or on an offshore platform with it’s limited deck area. There are also practical limitations - deep wells producing several thousands of barrels per day cannot be lifted by rod pumps. Thus, geographic and environmental considerations may make the decision. However, there are many considerations that need to be taken into account when such conditions are not controlling.

Some types of artificial lift are able to reduce the sand face producing pressure to a lower value than others. The characteristics of the reservoir fluids must also be considered. Wax & formation solids present greater difficulties to some forms of artificial lift than others. The producing gas-liquid ratio is key parameter to be considered by the artificial lift designer. Gas represents a significant problem to all of the pumping methods; while gas lift, on the other hand, utilizes the energy contained in the produced gas and supplements this with injected gas as a source of energy. The “Advantages and Disadvantages of the Major Artificial Lift Methods” are listed and compared in Tables 2 & 3.

<table>
<thead>
<tr>
<th>Rod Pumps</th>
<th>Electric Submersible Pump</th>
<th>Venturi Hydraulic Pump</th>
<th>Gas Lift</th>
<th>Progressing Cavity Pump</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple, basic design</td>
<td>Extemely high volume lift using up to 1,000 low motors</td>
<td>High volumes</td>
<td>Solids tolerant</td>
<td>Solids and viscous crude tolerant</td>
</tr>
<tr>
<td>Unit easily changed</td>
<td>Unobtrusive surface location</td>
<td>Can use water as power fluid</td>
<td>Large volumes in high PI wells</td>
<td>Energy efficient</td>
</tr>
<tr>
<td>Simple to operate</td>
<td>Downhole telemetry available</td>
<td>Remote power source</td>
<td>Simple maintenance</td>
<td>Unobtrusive surface location with downhole motor</td>
</tr>
<tr>
<td>Can achieve low BHFP</td>
<td>Tolerant high well deviation / doglegs</td>
<td>Solids tolerant</td>
<td>Unobtrusive surface location / remote power source</td>
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</tr>
<tr>
<td>Can lift high temperature, viscous oils</td>
<td>Corrosion / scale treatments possible</td>
<td>Remote power source</td>
<td>Tolerant high well deviation / doglegs</td>
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<td>Pump off control</td>
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<td>Tolerant high GOR reservoir fluids</td>
<td>Tolerant high GOR</td>
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<td>Witreline maintenance</td>
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**Table 2**
Advantages of major artificial lift methods

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<thead>
<tr>
<th>Rod Pumps</th>
<th>Electric Submersible Pump</th>
<th>Venturi Hydraulic Pump</th>
<th>Gas Lift</th>
<th>Progressing Cavity Pump</th>
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<tbody>
<tr>
<td>Friction in crooked / holes</td>
<td>Not suitable for shallow, low volume wells</td>
<td>High surface pressures</td>
<td>Lift gas may not be available</td>
<td>Elastanes swell in some crude oils</td>
</tr>
<tr>
<td>Pump wear with solids production (sand, wax etc.)</td>
<td>Full workover required to change pump</td>
<td>Sensitive to change in surface flowline pressure</td>
<td>Not suitable for viscous crude oil or emulsions</td>
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<tr>
<td>Free gas reduces pump efficiency</td>
<td>Cable susceptible to damage during installation with tubing</td>
<td>Free gas reduces pump efficiency</td>
<td>Susceptible to gas freezing / hydrates at low temperatures</td>
<td></td>
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<tr>
<td>Obtrusive in urban areas</td>
<td>Cable deteriorates at high temperatures</td>
<td>Power oil systems hazardous</td>
<td>High minimum FBHP</td>
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<tr>
<td>Downhole corrosion inhibition difficult</td>
<td>Gas and solids intolerant</td>
<td>High minimum FBHP</td>
<td>Abandonment pressure may not be reached</td>
<td></td>
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<tr>
<td>Heavy equipment for offshore use</td>
<td>Increased production casing size often required</td>
<td>Abandonment pressure may not be reached</td>
<td>Casing must withstand lift gas pressure</td>
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**Table 3**
Disadvantages of major artificial lift methods
5.6. Long Term Reservoir Performance and Facility Constraints
Another factor that needs to be considered is long term reservoir performance. Some years ago Neely indicated that two approaches, both of which have disadvantages, are frequently used to solve the problem of artificial lift selection and sizing.

(i) A prediction of long term reservoir performance is made and artificial lift equipment installed that can handle the well’s production and producing conditions over its entire life. This frequently leads to the installation of oversized equipment in the anticipation of ultimately producing large quantities of water. As a result, the equipment may have operated at poor efficiency due to under-loading over a significant portion of its total life.

(ii) The other extreme is to design for what the well is producing today and not worry about tomorrow. This can lead to many changes in the type of lift equipment installed during the well’s producing life. Low cost operations may result in the short term, but large sums of money will have to be spent later on to change the artificial lift equipment and/or the completion.

Likewise, in a new field development, the fluid handling requirement from some artificial lift types can significantly increase the size and cost of the facilities required. Only the produced fluid is handled through the facilities with rod pumps and ESPs. However, gas lift requires injection gas compression and distribution facilities and the additional, produced gas increases the size of the production facilities required. Similarly, the use of Hydraulic pumps can result in the additional power fluid volumes being many times that of the produced oil volume. This results in high fluid handling costs as well as difficulties in accounting for the oil produced (when oil is used as a power fluid).

The selection of the artificial lift for a particular well must meet the physical constraints of the well. Once a particular type of lift is selected for use, consideration should be given to the size of the well bore required to obtain the desired production rate. It can happen that the desired production can not be obtained because the casing programme was designed to minimize well cost, resulting in a size limitation on the artificial lift equipment that can be installed. Even if production rates can be achieved, smaller casing sizes can lead to higher, long term production costs due to well servicing problems, gas separation problems etc.

Figure 10 is offered as a screening selection tool in which areas where particular artificial lift methods have been frequently applied are compared as a function of depth and well rate. It must be realised that there are many proven applications where a particular form of artificial lift has been installed in a well at greater depths or produced at higher rates than is indicated in this figure.
6. ROD PUMPS

6.1. Introduction
(Sucker) rod or beam pump was the first type of artificial lift to be introduced to the oil field. It is also the most widely used in terms of the number of installations worldwide. In 1993, some 85% of the USA population of artificially lifted wells was produced by rod pumps and more than 70% of these produced less than 10 barrels of oil per day. The low cost, mechanical simplicity and the ease with which efficient operation can be achieved makes rod pumps suitable for such low volume operations.

Rod pumps can lift moderate volumes (1,000 bfpd) from shallow depths (7,000 ft) or small volumes (200 bfpd) from greater depths (14,000 ft). They are normally manufactured to standards set by the American Petroleum Institute (API). This means that, unlike other artificial lift methods, the equipment manufactured by the various supplies is fully interchangeable.

6.2. The Pumping Unit
The surface equipment for a rod pump is illustrated in Figure 11. The prime mover, normally an electric motor or gas engine, drives a speed reducing set of gears so that its fast rotation, of say 600 revolutions per minute, is reduced to as low as 20 strokes...
per minute or less. The connection between the surface pumping unit and the
downhole pump is the polished rod and the sucker rods. The polished rod moves up
and down through a stuffing box mounted on top of the wellhead. This stuffing box
seals against the polished rod and prevents surface leaks of the liquids and gasses
being produced by the well.

![Pumping Unit Diagram](image1)

6.3. The Sucker Rods
The sucker rods, typically 25 ft long, are circular steel rods with diameters between
0.5 in and 1.125 in, in increments of 0.125 in. A threaded male connection or pin is
machined at each end of the rod. The two rods can be joined together by use of a double
box coupling (Figure 12). Square flats are machined near the pins and at the centre
of the coupling to provide a grip for a wrench to allow the rods and couplings to be
screwed together. The sucker rods are subjected to continuous fatigue when the pump
is in operation. The weight of the rod string is one component of this fatigue load -
it can be minimised by using a tapered sucker rod string. This involves installing
lighter, smaller diameter rods lower down in the well where the load they have to
support (weight of rods and fluid in the tubing string) is less than at the top of the well.

![Sucker Rods Coupling](image2)

6.4. The Pump
The pump is located near the perforations at the bottom of the string of sucker rods.
Figure 13 shows that it consists of a hollow plunger with circular sealing rings
mounted on the outside circumference moving inside a pump barrel which is either
inserted into the tubing or is part of the tubing itself. A standing valve is mounted at
the bottom of the pump barrel while the travelling valve is installed at the top of the plunger. The standing and travelling valves consist of a ball which seats (closes off) an opening.

![Diagram of rod pump operation](Figure 13)

The “UP” and “DOWN” movement of the pump barrel allows the fluid flow to open and shut these valves as shown in Figure 13. The left hand schematic shows the plunger status at the end of the “DOWN” stroke. The "Upward" rod movement reduces the pressure within the pump barrel and the upward flow of fluid from below the pump lifts the standing valve’s ball off its seat. The pressure due to the fluid column above the plunger keeps the travelling valve ball on its seat. The situation is reversed during the “DOWN” stroke - compression of fluid within the pump barrel forces it to flow through the hollow plunger and to lift the travelling valve off its seat; while ensuring that the standing valve remains closed.

6.5. Rod Pump Operation
This chapter describing of rod pump operation deals with some of their more important operational aspects.

6.5.1. Pump-Off Control
The well will produce the maximum gross volume of fluid when the drawdown is maximised i.e. the fluid level in the well is maintained at a limited distance above the pump. The pump capacity will often be greater than the well inflow capacity - the pump motor must be stopped at regular intervals when the fluid level is reduced to a specified, minimum safety level above the pump. This monitoring is often performed with an “Echometer”. Figure 13a. This tool is attached to the wellhead in a pressure tight housing. It consists of a firing mechanism, a microphone and an amplifier recorder. Typically, a gas actuated device generates an acoustic pulse at the wellhead.
This is reflected back by subsurface items such as tubing collars, but the main reflection is from the fluid level at the bottom of the casing. The depth of the fluid level can now be found by multiplying this time by half the velocity of sound in the casing/tubing annulus.

The pump can now be restarted once the casing fluid level has risen sufficiently due to inflow from the reservoir.

Once calibrated, the pump unit can be put on timer control, i.e. the “Echometer” need not be used continuously since well inflow performance normally shows a steady, predictable decline rate with time. Further, the performance of the pump itself can be checked by measuring the dynanometer card at regular intervals (see section 2.6.5.5 on Pump Diagnosis).

6.5.2. Gas Influx

(Free) gas sucked into the pump will reduce the pump efficiency due to its compressible nature. Placing the pump below the perforations maximises the use of the (limited) gas separation capacity of the casing. Minimising the volume between the travelling valve at the bottom and the downstroke and the standing valve helps ensure the gas is pushed out of the pump during each down stroke.

Placing the pump below the perforations is advantageous since it increases the maximum possible drawdown. This is not always possible in practice. Many types of “gas anchors” have been tried in order to overcome the resulting difficulties. They all aim to separate the “free” gas from the liquid prior to the liquid entering the pump. The gas flows into the tubing/casing annulus where it is vented or gathered at as low a pressure as possible (to allow a minimum bottom hole pressure to be reached). An example of an effective gas anchor is shown in Figure 14. Here a packer and crossover direct the multiphase flow above the pump, ensuring that only liquid is sucked into the pump barrel. (The extra packer also allows the tubing to be anchored - minimising the fatigue loads to which the rod string is exposed.)
6.5.3. Centralisers

The sucker rods may require centralisers or protectors in deviated wells to reduce wear on the tubing and rods (Figure 15). This requirement becomes more extreme in crooked or highly deviated wells, sometimes to the extent that rod pumps can not be used.
6.5.4. Solids
Rod pumps also have a very limited ability to lift sand due to the low fluid velocity in the production tubing plus wear on the pump valves, seats and plunger. The latter can be overcome by suitable pump design and choice of construction materials.

Wax and inorganic scale deposition also interfere with efficient rod pump operation. Continuous injection of an inhibitor below the pump to ensure protection of the complete downhole equipment is complicated unless there is a (normally unacceptable) complication of the completion design. Removal of wax by hot oil/solvent circulation or injection of a scale inhibitor into the formation are also possible (see Chapter 4). Further, recovery of the pump and rods using a well pulling hoist is often a relatively low cost, simple operation.

6.5.5. Pump Diagnosis
The condition of the pump can be evaluated by measuring the load at the top of the polished rod as a function of its position i.e. as it moves up and down during the stroke length. This is recorded in the form of a dynamometer card. Examples of theoretical dynamometer cards are shown in Figure 16.

Figure 16
(Theoretical) dynamometer cards for:
(a) inelastic rods
(b) elastic rods
(c) elastic rods with rod, fluid and surface pump unit
(i) Figure 16 (a) records the variation in load for inelastic rods. The load is either high or low depending on whether the polished rod is moving up or down.

(ii) Figure 16 (b) adds the elasticity of the rods - the full increase in load is no longer instantaneous when the polished rod starts moving in a particular direction.

(iii) Figure 16 (c) adds the further dimension of rod - fluid and surface pump unit dynamics. The times at which the various processes become controlling during the pump cycle are indicated.

These theoretical calculations have been made for a perfectly operating pump unit pumping liquid only. Practical problems such as:

(i) excessive rod or pump friction

(ii) restriction in the flow-path

(iii) vibrations

(iv) sticking plunger

(v) gas lock etc.

will all alter the shape of the dynamometer trace in a distinctive manner allowing the source of the problem to be diagnosed and then rectified.

6.6. Pump Design
API Recommended Practice 11L, published by the American Petroleum Institute, describes a field proven method for designing all elements of a Rod Pump. We will only discuss selected elements here.

6.6.1. Pump Rate
The pump rate (Q) is related to the volume displaced (V) by each pump stroke and the speed rate or number of strokes per minute (N). Thus:

\[ Q = K \times V \times N \times \phi = K \times A \times S \times N \times \phi \]

Where:

A is the area of the pump barrel
S is the length of the pump stroke
\( \phi \) is the efficiency factor
K is a constant to convert the above units to barrels per day

The maximum speed (N) of the pump unit is determined by the speed at which the sucker rods fall downward in the “DOWN” stroke. (Early pump rod failure occurs due to metal fatigue if they are placed under compression due to them being forced downwards by the pump unit exceeding this maximum speed.) As would be expected, this maximum speed decreases as the length of the pump stroke increases. Typical maximum values are quoted in Table 4.
Selection of Artificial Lift Types

Table 4
Maximum allowable pump speed

<table>
<thead>
<tr>
<th>Stroke Length (in.)</th>
<th>30</th>
<th>60</th>
<th>90</th>
<th>120</th>
<th>180</th>
<th>240</th>
<th>300</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Pump Speed (SPM*)</td>
<td>34</td>
<td>24</td>
<td>19</td>
<td>17</td>
<td>14.5</td>
<td>11.5</td>
<td>10.5</td>
</tr>
</tbody>
</table>

† For a Conventional Pump Unit
* Strokes Per Minute

N.B. Low pump speeds and large diameter plunges lead to the greatest energy efficiency, but also the largest equipment loads. It is common practice to put a few larger rods capable of carrying any compression loads due to buckling at the bottom of the rod string. Also, the addition of sinker bars will increase the rate of rod fall, but also increase the load on the rods.

Two factors which reduce the efficiency of the pump are gas influx (see section 2.6.5.2) and rod stretch.

6.6.2. Rod Stretch and Over Travel

During the “UP” stroke the rods support their own weight and that of the fluid in the tubing. Hooke’s law of elasticity dictates that the rods will increase in length in response to this load. This decreases the effective travel of the plunger downhole compared to the distance moved at the surface. For example, 0.875 in sucker rods driving a 2.25 in plunger pump set at 6,000 ft will show a stretch of 29 in when lifting fresh water.

The load imposed on the rods by the fluid is related to the area of the plunger times the hydrostatic head. Rod stretch thus increases when a larger diameter pump is selected. There is a similar effect of tubing stretch. This also reduces the effective stroke length, if the tubing is not anchored.

Plunger Overtravel”, by contrast, increases the effective stroke length. This effect is caused by elongation of the rods due to dynamic forces generated by the weight of the rods reversing direction during the pumping cycle. At this point, the weight of a 6,000 ft string of 0.875 in rods (weight 2.25 lb/ft or 13,500 lb total weight) will be brought to a halt and reverse direction over a time period of less than one second. The rod string velocity will be approximately 6 ft/second when the plunger nears the bottom of its stroke if the pump unit is operating with a 64 in stroke length at a pump speed of 15 strokes per minute. The resulting increase in length of the rods generated by halting and reversing this momentum is called “Plunger Overtravel” (approximately 14” according to Marsh and Coberly’s 1931 method for this example).

We can now estimate that:

\[
\text{Effective stroke length} = \text{surface stroke length} - \text{rod stretch} + \text{plunger overtravel} \\
= 64" - 29" + 14" = 49"
\]

6.6.3. Pumping Limit Load Calculations

API RP 11L can be used to calculate the maximum and minimum polished rod loads, the peak torque and the theoretical horsepower required once the pump speed, stroke length, plunger diameter and rod sizes have been chosen. Typically, a motor power of twice this theoretical value should be installed to allow for surface and downhole energy losses.
It was mentioned previously that the rod string was continuously subjected to fatigue. Goodman showed how the “Maximum Allowable Stress” on the sucker rods was a function of the grade of the sucker rods and the minimum polished rod load/cross sectional area of the top rod. This “Maximum Allowable Stress” has to be decreased by a service factor related to the operating conditions e.g. the presence of corrosive salt water or, more importantly, hydrogen sulphide. This explains why these aggressive fluids limit the application (either maximum depth of a pump installation or maximum fluid volume which can be lifted) of rod pumps unless more expensive, speciality grade sucker rods are used.

7. ELECTRIC SUBMERSIBLE PUMPS (ESPs)

7.1. Introduction
Electric Submersible Pumps (ESP’s) are a versatile form of artificial lift with pumps ranging from 150 to 60,000 bfpd in operation. A typical low pressure well that is being artificially lifted using an ESP system is illustrated in figure 17. The functions of the various components are summarised as follows:

Figure 17
A well completed with artificial lift using an electric submersible centrifugal pump
Frequency Drive (VFD). A VFD allows the speed of the electric motor to be altered e.g. starting the pump using the “nameplate” design frequency of 50Hz (Europe) or 60Hz (North America) results in high instantaneous electric motor currents since the power developed by the pump is proportional to the frequency. These can be reduced by supplying the electric power at lower frequencies. It also allows the pump flow rate to be adjusted to the well inflow conditions since flow rate is also proportional to frequency.

Practical experience shows that a 60Hz motor can be operated between 35Hz and 80Hz. VFD installation increases the surface energy losses from some 3% to 5-15% of total power supplied.

(ii) The vent box separates the surface cable from the downhole cable. This ensures that any gas, which travels up the downhole cable, does not reach the electrical switchgear.

(iii) The downhole cable penetrates the wellhead. It is banded to the tubing at regular intervals. Additional protection is supplied by cable protectors which are installed at critical points to prevent damage while the completion is being run into the hole. A “flat pack” cable shape is employed across the larger diameter completion components to minimise total width. The cable enters the electric motor housing at the Pothead. It not only carries the electrical power supply for the motor (up to 750HP motors are being routinely installed), but also carries the measurement signal from the downhole sensor package installed underneath the motor.

(iv) The pump unit consists of a stacked series of rotating centrifugal impellers running on a central drive shaft inside a stack of stationary diffusers, i.e. it is essentially a series of small turbines. The pressure increase is proportional to the number of stages while the pump capacity (volume) increases as the diameter of the impeller increases. Rotation of the impeller accelerates the liquid to be pumped which is then discharged into the diffuser where this kinetic energy is transformed into potential energy i.e. a pressure increase. The impeller/diffuser pairs are arranged in series with the discharge of one unit being the suction of the next one. The number of pump stages (impeller/diffuser) pairs may range between 10 and more than 100, depending on the pressure increase required. Abrasion resistance to produced solids is very dependent on the detailed design and materials selection employed during pump design.

However, as discussed at the beginning of this chapter, ESP’s with their rapidly rotating internals are not really compatible with large quantities of produced sand even when hardened, wear resistant materials are used. The option of using other forms of artificial lift - gas lift and PCPs - should be considered.

Standard pump impellers are very sensitive to gas fractions greater than 20% vol in the produced fluid. Alternatively, changes in pump design such as altering the design of the impeller from pure radial flow to mixed (i.e. a combination of both radial and axial) flow can double the gas/fluid ratio to 40% vol.
A tapered pump design using mixed flow impellers in the lower pressure stages (with the higher gas volume fractions) and radial flow impellers in the upper stages can prove to be effective.

(v) The pump intake may include a rotary gas separator if gas fractions higher than 20%. This consists of a centrifugal device, which separates the lower density, gaseous phase from the denser liquid phase. The latter is concentrated at the centre of the device and enters the pump suction while the lighter, gas phase is directed towards the casing/tubing annulus where gas is vented/gathered at surface.

A reduction in casing/tubing annulus pressure increases the maximum achievable drawdown at the formation face. A single rotary gas separator can increase the ESP’s gas handling capabilities up to 80% vol. Two separators, arranged in tandem, are even more efficient, increasing the pumpable gas fraction to >90% vol. However, the addition of extra equipment always comes with the cost of greater operational problems e.g. produced formation solids can damage the rotary separator, scale formation can unbalance rapidly rotating equipment. Some operators will not use them due to these problems which have resulted in rotary separators having a poor reputation for reliability.
Alternative completion strategies where the pump is placed below the perforations or some forms of gas anchor (see also section 2.4) may be employed to limit the gas influx. Figure 18(a) illustrates the use of a shroud to make use of the casing’s ability to separate produced (free) gas from the liquid. Note that, if it is decided to mount the pump below the perforations (figure 18(b)), then a shroud is also required to initially direct the production flow below the electric motor where it provides the necessary cooling. The normal completion design of mounting the motor at the bottom of the ESP system, which is then placed above the perforation, provides this cooling automatically.

![Figure 18](image_url)

**Figure 18**

*Two ESP completion designs to aid gas separation in the casing*

It should be noted that:

(a) Liquid/gas separation in the casing will only work when the upward velocity of the gas bubbles is greater than downward fluid velocity, i.e. it will work better for lower rate wells with larger annular clearances and where the gas is produced as large bubbles e.g. from a separate zone or different perforations to those producing the liquid.

(b) The fitting of a shroud increases the maximum ESP diameter (requiring a large casing for installation of the same motor/pump combination or requires that a smaller diameter pump/motor be chosen. Practical experience has shown that, for a given power requirement, smaller diameter equipment is often less reliable. Further, high power equipment is not available in the smaller sizes.
(vi) The Protector or Seal unit connects the drive shaft of the electric motor to the pump or gas separator shaft. It also performs as:

(a) an isolation barrier between the clean motor oil and the well fluids;

(b) an expansion buffer for the motor oil when it reaches operating temperature;

(c) equalises internal motor pressure with the well annular pressure and

(d) absorbs any thrust generated by the pump.

(vii) The electric motor is powered by three phase alternating current supplied by the cable connected to the motor at the pothead. They are available in sizes between 15 and 900 HP in the manufacturer’s catalogue. Two or even three motors may be placed in series if high pump power requirements exist.

The motor is filled with oil which insulates the electrical winding. Ingress of reservoir fluids (water) is a common cause of motor failure. A second, less obvious cause of failure is power surges/voltage spikes/harmonics on the power supply. These are more prevalent when the power is generated locally rather than supplied by the (electrical) utility grid. The requirements for the use of a completion design which directs the fluid flow along the motor to provide sufficient cooling was discussed above in section (v) on pump intake design.

When the motor is switched off the head of fluid present in the tubing will reverse the flow direction through the pump as it flows back into the reservoir. This will cause the motor to spin backwards. Trying to restart the motor while it is rotating backwards will lead to the motor burning out very quickly. This can be avoided by

(a) installing a check valve in the tubing to prevent fluid backflow (however this results in a “wet string” when the tubing/ESP is recovered

(b) electronically preventing motor restart for a specified time after it has been shut down or

(c) using a sensor to detect backspin and preventing motor restart (see the next section on downhole sensors).

(viii) A downhole sensor package may be mounted underneath the motor. Measurements can include:

(a) Pump suction and discharge pressures and temperatures.

(b) Fluid intake temperature.
(c) Electric motor temperature.

(d) Vibration.

(e) Current leakage.

A downhole flow meter and/or phase cut can be added to the above and all the above data transmitted to surface via the power cable. The above can be combined with measurement of the power supply frequency and surface current/voltage as well as wellhead temperature, pressure and surface flow rate so as to be able to present a complete picture of well performance. The data can be:

(a) stored at the well site and downloaded to a (hand held) data log at regular intervals for later analysis

(b) used to trigger on-site alarms which shut the ESP unit down e.g. if the pump suction pressure falls below a preset value indicating that the fluid level in the well is reducing and the well is being “pumped off”

(c) transmitted continuously to the operations office where more sophisticated monitoring analysis can be carried out

(d) replace non-routine well surveillance operations e.g. the sensors may be sufficiently accurate to obviate the need for running memory gauges into the well when performing flowing bottom hole pressure surveys, build up tests or reservoir pressure monitoring.

Such sensor packages are now being applied to other forms of artificial lift e.g. directly to EPCPs (see Section 2.9.3) but also to PCP (Section 2.9) rod pumps (Section 2.6) and gas lift (Chapter 3), where similar measurements will enable corrective action to be taken to maximise the efficiency of the lift operation.

At the beginning of this section we stated that Figure 17 was for a low pressure well since a packer had not been installed in the well, i.e. the well will probably not flow without artificial lift. Inclusion of a packer in the completion design, as is often required by the regulatory authorities in live and many offshore wells, precludes venting the gas to the surface via the casing/tubing annulus unless a dual packer arrangement is employed with a safety valve installed on at least the main production tubing and (possibly) on the gas vent line as well. One example of a possible completion design is illustrated in Figure 19.
7.2. Well Completion Employing Electric Submersible Pumps (ESPs)

7.2.1. Typical ESP Applications
The ESP application illustrated in figure 17 is the standard application where it is used as to lift production from a single zone through a single tubing. Many other application configurations are possible. Examples are given in Figure 20:

(i) Figure 20 (a) shows aquifer water being lifted from supply zone and pumped directly to an injection well.

(ii) Figure 20 (b) illustrates a dump flood powered by an ESP where the water supply well and injection well are combined into one. Note that the ESP is inverted with the pump at the bottom. The ESP is being used here to replace the conventional surface mounted transfer pump. Measurement of the injection flow rate and pressure can be made by inclusion of a sensor package (not shown) in the well completion design.
(iii) Figure 20 (c) shows an ESP placed in a shallow well being used to boost pressure in a surface flow line (note the shroud installed to ensure adequate motor cooling).

Figure 20
ESP applications
(a) Direct water injection
(b) Powered dumpflood with ESP
(c) Pressure boosting surface pipelines with ESP
(d) Horizontally mounted ESP surface pump

The pump and motor may also be mounted at the surface - either horizontally (along the ground) or placed vertically (reduces required platform area for offshore application). In these cases a conventional, air cooled electric motor is used. Pressure increases of up to 3000 psi at 7000 bfpd flow rates have been achieved. Higher volume applications can be catered for by manifolding a series of pump units in parallel.

7.2.2. Horizontal Wells
The ability of ESP to pump large volumes of produced fluid coupled with the flexibility of pump design and operation makes them very suitable for the large volume production associated with horizontal wells. Experience has shown that the pump can be placed anywhere within the well at angles up to 80° providing the dogleg severity is not too great (<6°/100ft). Placing the pump near the bottom of the well not only maximises the potential drawdown which can be created at the formation while the (near) horizontal section will enhance the separation of the gas to the upper portion of the wellbore due to its lower density.
7.2.3. “Y" Tool

The “Y" tool is a device to allow wireline or coiled tubing access below the ESP. It is illustrated in Figure 21. The bypass tubing should be at least 2.375" OD (allowing 1.6875"/16" logging tools to pass), but 2.875" OD tubing is preferable since this allows the larger sizes of coiled tubing to pass. However, the larger diameter tubing does reduce the maximum diameter of ESP that can be installed. Larger diameter motors are more efficient, tend to have longer run lives and are shorter for a given power requirement.

Installation of “Y" tools allows all the normal wireline and coiled tubing conveyed operations to be carried out below the ESP. These include:

(i) cased hole logging

(ii) well stimulation

(iii) perforating

(iv) setting bridge plugs for water shut off

(v) installation and recovery of pressure memory gauges

(vi) running and retrieval of plugs

(vii) downhole sampling.

Omission of the “Y" tool from the downhole completion design implies that these operations are only possible when tubing and ESP are recovered to the surface.
7.3. Basic Pump Selection
The pressure increase that the pump is required to deliver, also called the “Total Dynamic Head (TDH)” or difference between the pump discharge and suction pressure, is the sum of three components. Figure 22 pictures the various components:

(i) The *hydrostatic head* from the ESP pump to the surface. This is equal to the (average) density of the produced fluid in the tubing ($\rho$) multiplied by the True Vertical Depth at which the ESP is installed ($h$) and the acceleration due to gravity ($g$).

(ii) Friction pressure loss in the tubing ($\Delta P_{\text{fric}}$)

(iii) The surface pressure ($P_{\text{surf}}$) required to overcome flowline back pressure and flow the produced fluid to the separator at the required production rate. This can have a high value if the completion is a satellite well situated some distance (up to 50 miles) from the host platform.

Thus:

$$\text{TDH} = \rho g h + \Delta P_{\text{fric}} + P_{\text{surf}}$$

Assuming the flowing wellbore pressure at the pump inlet is essentially zero i.e. well is "pumped off" and is producing with a maximum drawdown.
The data describing the performance (see Section 2.7.A) of ESP’s provided by the manufacture is normally measured with water. They also supply a correction factor, based on the actual density and viscosity, when other fluids are being pumped. Further correction is required if significant volumes of free gas are being injected by the pump - not only will its volume decrease as the pressure increases, but it may also dissolve completely in the oil. One popular application area of ESP’s is the production of viscous crude oils at high water cuts. The design process can be simplified here since the density of the crude oil is similar to that of water, there is little gas and the produced fluid stream has an external water phase, i.e. the manufacturer’s performance curves based on pumping water can only be applied directly.

Once the pump has been chosen, optimum motor and seal section can be identified, along with the electric cable, variable speed drive, etc. It also needs to be checked that the chosen combination will operate efficiently for a variety of well conditions (higher/lower well PI, greater water cut, lower reservoir pressure etc).

The choice of correct ESP design, along with the actual, operational installation of ESP’s, is thus a complex task. This results in the average run lifetime, or “mean time before failure (MTBF)” often being very low initially when EPS’s are first introduced into a field/producing area (Especially when experienced staff are not available). The MTBF then increases as the “learning curve” is climbed. This is illustrated in Figure 23 prepared from data presented at IIR’s conference on Artificial Lift Equipment, Dubai, 1997, and IBC’s Artificial Lift Workshop, Aberdeen, 1997. This figure shows how the THUMS project at Long Beach, California, has been employing ESP’s since 1965 and how the average run lifetime gradually increased throughout the 16 year history. During this period, the numbers of operational ESP’s remained constant at about 600. ESP’s were only introduced into the North Sea in the late 1980’s. The initial run times were low compared to those achieved at THUMS, but a steep learning curve developed and by 1996 the average run lives had become similar.

![Figure 23](image)

*Figure 23
Average electric submersible pump lifetimes
It need to be mentioned here that average statistics need to be treated with caution - the actual run times will be very dependent on the aggressiveness of the producing conditions e.g. temperature, concentration of sand produced, corrosivity of the produced fluid (H₂S, CO₂, etc), skill of the rig crew, manufacturing quality control etc. This is illustrated by a more detailed study of the THUMS data:

(i) Oil is produced from three horizons where the average run lifetimes are 300, 700 and 800 days - indicating the importance of the role played by the actual producing conditions.

(ii) 10% of the ESP’s fail within 30 days and 32% within 180 days, confirming the potential for damage during installation and the need for the highest manufacturing quality control standards.

7.4. Advantages and Disadvantages of Electric Submersible Pumps
Tables 5 and 6 respectively (Advantages and Disadvantages of ESP’s) have been put together based on the discussion in Sections 2.7.1 and 2.7.2. The points discussed in these tables should be self-explanatory when read in conjunction with previous sections.

<table>
<thead>
<tr>
<th>Advantages of Electric Submersible Pumps</th>
</tr>
</thead>
<tbody>
<tr>
<td>Can be installed in deviated wells (&lt;80…)</td>
</tr>
<tr>
<td>High production rates</td>
</tr>
<tr>
<td>Suitable for high water cut wells</td>
</tr>
<tr>
<td>Controllable production rate</td>
</tr>
<tr>
<td>Efficient Energy usage (&gt;50% possible)</td>
</tr>
<tr>
<td>Access below ESP via “Y” tool</td>
</tr>
<tr>
<td>Comprehensive downhole measurements available</td>
</tr>
<tr>
<td>Can pump against high Flowing-Tubing Head Pressure</td>
</tr>
<tr>
<td>No extra flow lines required</td>
</tr>
<tr>
<td>Minimum surface footprint - 6ft well spacing</td>
</tr>
<tr>
<td>Low surface profile for Urban and offshore environments</td>
</tr>
<tr>
<td>Quick restart after shut down</td>
</tr>
<tr>
<td>Concurrent drilling and production safer compared to gas lift</td>
</tr>
<tr>
<td>(high pressure gas not present in annulus)</td>
</tr>
<tr>
<td>Long run pump life possible</td>
</tr>
</tbody>
</table>

Table 5
Advantages of electric submersible pumps

<table>
<thead>
<tr>
<th>Disadvantages of Electric Submersible Pumps</th>
</tr>
</thead>
<tbody>
<tr>
<td>Susceptible to damage during completion installation</td>
</tr>
<tr>
<td>Tubing has to be pulled to replace pump</td>
</tr>
<tr>
<td>Not suitable for low volume wells (&lt;150bpd)</td>
</tr>
<tr>
<td>Pump susceptible to damage by produced solids (sand / scale / asphaltene)</td>
</tr>
<tr>
<td>High GOR’s presents gas handling problems</td>
</tr>
<tr>
<td>Power cable requires penetration of well head and packer integrity</td>
</tr>
<tr>
<td>Viscous crude reduces pump efficiency</td>
</tr>
<tr>
<td>(Viscous) emulsions form over a range of water / oil ratios</td>
</tr>
<tr>
<td>High temperatures can degrade the electrical motors</td>
</tr>
</tbody>
</table>

Table 6
Disadvantages of electric submersible pumps
7.5. Monitoring the Performance of Electric Submersible Pumps
Prior to the implementation of automated SCADA (Supervisory Control and Data Acquisision) systems, the monitoring of ESP performance was limited to a surface measurement of the current supplied to the pump along with an infrequent (possibly monthly) well test. However, considerable information can be derived on well performance - Figure 24(a) is a schematic example of a 24 hour chart recording of electrical current consumed by an electric submersible pump during normal operation. The current taken is very constant.

By contrast, the current taken when the well is being pumped off shows a much more erratic behaviour (Figure 24b).

Figure 24(a)
Ammeter chart monitors electric submersible pump performance. Normal operation.
The chart was installed at 07.30 am and the pump started at 08.15 am - note the large, initial surge in current while the motor is getting “up to speed”. A steady current is then drawn for the next 3 hours - decreasing slightly as the fluid head above the pump decreases. At 11.10 the current begins to oscillate rapidly - the size of these oscillations increases until 1.15 pm when the pump was shut down. It was suspected that the problem was due to gas being formed when the flowing bottom hole pressure was reduced to below the bubble point, leading to gas locking and the pump ceasing to pump. This was confirmed by leaving the fluid level in the well to build up for 100 minutes and restarting the pump at 3.05 pm. The same cycle repeats itself, however this time the problems appear after some 2.5 hours steady production. The pump was shut down a second time at 6.15 pm. A third cycle was started at 8.20 pm after a second 100 minute shut in - current oscillation starting again after 2 hours production. The well was shut in just after midnight.

The basic problem is that the pump is pumping faster than fluid is flowing into the well. Continual stopping and restarting the ESP motor is not recommended due to excessive wear and tear followed by motor burnout. The options are to:

- Install a lower capacity (smaller) pump section.
- Operate the pump at a lower speed.
- Stimulate the well to improve the inflow.
Modern SCADA systems allow a much more complete picture to be built up. Installation of a downhole monitoring package (as shown in Figure 17) allow the motor/pump conditions to be monitored closely. Figure 25 is an example of a normal start up. It has been analysed as follows:

- Initially, prior to energising the pump, the pump intake and discharge pressures have the same value; as does the motor and pump intake pressures. The pump starts up at point A, as shown by:
  
  (i) the pump discharge pressure increasing,
  
  (ii) the motor temperature becoming warmer than the fluid entering the pump,
  
  (iii) a limited amount of vibration,

- There then follows a period of surface choke adjustment, as shown by fluctuations in the pump discharge pressure and increased vibration. However, after point B, steady operating conditions are achieved and a slow decline in pump suction and discharge pressure are observed as the well is pumped “off”.

Protection of the ESP can now be achieved by monitoring the pump’s condition and shutting it down when problems develop before physical damage to the pump results. Thus “pump off” control can be implemented by stopping the pump when the intake pressure drops below a preset value. The pump is then restarted once the well pressure builds up to a second, higher predetermined value. This type of monitoring is very diagnostic when problems develop, but can have much more “added value” when combined with surface flow measurements (gross flow rates and water cut). However, continually restarting pump motors reduces their operational life. Installing a correctly sized pump unit is the preferred solution.
7.6. New Technology

7.6.1. Coiled Tubing Deployed ESP's
The completion designs discussed so far within this section on ESP’s all employ the pump installed as part of a conventional completion string with the power cable attached to the outside of the tubing. Replacement of any part of the ESP following a failure requires a workover. The process of ESP installation and recovery can be speeded up and made more efficient by installing the ESP at the end of a coiled tubing (see Figure 26). The set up is “conventional” in the sense that the cable is mounted on the outside of the coiled tubing while the produced fluids flow to the surface via the inside of the coiled tubing. A dual packer arrangement is required with ESP arrangement shown. The produced fluid is pumped into the casing via the annulus, flows passed the seal and electric motor sections (cooling) and then back into the coiled tubing via a cross-over mounted below the upper packer.

Replacement of an ESP producing a shallow, depleted horizon in a land well requires a light workover hoist. A coiled tubing deployed ESP can speed up the process, but the advantages become much greater when access to the well site is limited e.g. when for an offshore well located in a small platform. The (limited) weight requirements of a coiled tubing package often allow its installation on the platform using the platform crane; while making a conventional (jackup) rig available is a much more time consuming, expensive operation.

An alternative, simpler arrangement is illustrated in figure 27 in which the ESP cable is installed within the coiled tubing and the production travels to surface via the annulus. This arrangement has the advantages that:
(i) Reduced frictional pressure losses lead to higher flow rate or reduced power requirements.

(ii) Faster running can be achieved with the cable inside the protected environment of the coiled tubing.

(iii) It opens up the possibility of installing the ESP in a live well (well killing is a major source of production loss due to formation impairment).

The disadvantage to the system is that the production takes place via the Production Casing/Coiled Tubing Annulus, which raises a number of safety issues concerning barrier policy and corrosion. Alternatively, a wider diameter well can be drilled and a (large diameter) production tubing installed.

7.6.2. Auto “Y” Tool
The advantage of installing a “Y” tool to allow access below the pump was described earlier. However, wireline/coiled tubing recovery and replacement of the plug in the bypass tube are required each time the conventional “Y” tool is used. The cost and risk associated with these two wireline operations can be avoided by use of the Auto “Y” tool developed by Phoenix Petroleum Services of Aberdeen. It’s operation is illustrated by figure 28:
Selection of Artificial Lift Types

(a) A spring holds the diverter plate across the pump leg when the ESP is switched off - full access is now provided to the bypass.

(b) Flow generated by the ESP starting up moves the diverter plate and opens the pump leg.

(c) The diverter plate is seated onto the bypass leg by the high pressure in the production tubing during normal ESP operation.

(d) The diverter plate can be held in the mid position if it is desired to operate the ESP during a logging run.

7.6.3. Dual Pump Installations

More than one Electric Submersible Pump can be installed for a number of reasons:

(i) greater power installed downhole than can be (economically) achieved with a single ESP. The ESPs are placed such that the discharge of the lower ESP forms the suction of the upper ESP.

(ii) Dual Zone Completion. Figure 29 shows a dual completion with each zone having its own ESP and production tubing. The production tubing for the upper zone is installed concentrically within that for the Lower Zone.
(iii) the completion could have been simplified by use of a single production tubing and allocating production between the Upper and Lower zones by installing downhole flow meters above the pumps (see figure 29).

(iv) remote, offshore locations have very high cost associated with the frequent replacement of ESPs if the run lives are short e.g. due to excessive sand production. The concentration of sand in the produced fluid is often particularly high after a workover. Completion designs have been developed with a “sacrificial” lower ESP - see figure 30. The operational concept is as follows:
The lower ESP is started and the well produced until the sand production decreases to an acceptable level. The upper ESP may now be started to further increase the well production. The upper ESP can be operated independently of the lower ESP in the case that the lower unit fails due to erosion by produced sand or other reasons.

The auto “Y” tool allows production to be switched between the two ESPs without wireline or coiled tubing intervention. However, it must be checked that fluid is not being circulated around the pump, since this will lead to rapid pump failure (motor burnout due to overheating).

7.6.4. Reducing Water Production
The level of water production is an ever increasing problem as reservoirs mature.
Hydrocyclones (see section 9.25) have become the preferred technique to separate the produced oil and water. Their dimensions and lack of moving parts make them highly suitable for installing downhole (see also chapter 10). Figure 31 illustrates one equipment design. This shows a single electric motor powering an upper and lower pump unit. The equipment is installed below the producing zone. The lower pump unit supplies sufficient power to operate the hydrocyclone and to inject the underflow (water containing approximately 100ppm oil) into the water injection zone. The hydrocyclone overflow (typically 50% oil) is transferred via a bypass tube to the upper pump which pumps it to surface. The maximum production rate depends on the casing size and the number of hydrocyclones installed in parallel (maximum capacity of a hydrocyclone is 2,500 bfpd). Rates up to 20,000 bfd for a 9.675 in. casing are feasible.

This technology has been extended to meet the challenges of:

(i) **Installing two separators in series.** This 2 stage separation allows downhole water separation to be started at the lower water cut from the production zone of 65%. A minimum produced water cut of 80% is required to achieve efficient operation (acceptably low oil concentration in the rejected water stream) with a single hydrocyclone stage.

(ii) **Produced Sand.** Any sand particles produced will be separated with the water flow to be injected due to its greater density. Blockage of the injection zone will occur rapidly if significant volumes of sand are being produced. This can be avoided by treating the injection water stream with a hydrocyclone designed to concentrate the produced sand particles in the underflow (see figure 32). This (small) underflow stream is added to the oil concentrate and produced to surface while the bulk of the water stream is injected as normal.
(iii) **Coning Suppression.** This concept is illustrated in figure 33. Production from the oil zone perforations results in a water cone being formed once the critical oil production rate has been exceeded. This critical rate can be increased by producing water from below the oil/water contact via “coning suppression perforations” and injecting the water into an injection zone using an inverted ESP.

This concept has been shown to work - but alternative technologies such as horizontal production wells will often be more attractive economically.

(iv) **Managed Water Injection.** The water injection zones illustrated above were simple perforated completions. Advanced well concepts in which the water is injected into a long (near) horizontal lateral split into a number of zones, where the volume of injected water will be regulated by an electrically adjustable choke, will become feasible in the next few years.
7.7. Electric Submersible Pump Performance

The centrifugal pump unit employed in ESP’s is a dynamic-displacement pump in which the pump rate depends in the pressure head generated - the pump rate is low when the pressure head is high and vice versa. This is different from the positive displacement pumps discussed earlier in which the pump rate and discharge pressure are independent of one another.

The relationship between pump rate and pressure generated for dynamic displacement pumps is called the pump characteristic (see Figure 34). It is measured by the pump manufacturer in laboratory tests using a standard fluid (water) with the pump running at 3500 rpm (60 Hz electrical supply) or 2915 rpm (50 Hz supply).

![Figure 34](image)

A typical pump characteristic curve for a centrifugal pump

The “pump head”, or increase in pressure per stage ($\Delta P$), is expressed in terms of the pressure generated by an equivalent column of water ($H_{water}$). It decreases as the pump rate increases:

$$\Delta P = \rho * g * h = 0.433*\gamma * H_{water}$$

The discharge pressure is proportional to the specific gravity ($\gamma$) for other liquids with the same viscosity, i.e. the pump head - pump rate relationship can be used for all liquids, but only requiring correction for changes on viscosity.

Pump power is the work done per unit time which equals the pump rate multiplied by the pump head ($q*\Delta P$).

Power is normally expressed in terms of Kilowatt (KW) or Horse Power (HP); where 1 HP = 0.746 KW. The pump or hydraulic power is the (useful) work done by the pump.
while the mechanical power is the work done by the electrical motor which is required to drive the pump. The pump efficiency (E) is thus:

\[ E = \frac{\text{hydraulic power}}{\text{mechanical power}} \]

Pump Efficiency is also recorded in the pump characteristic curve and a recommended pump operating range indicated based on ±10% of the maximum efficiency point.

### 7.7.1. Simplified Electric Submersible Pump Design

ESP design is available as an option in many of the commercially available well performance programs, e.g. WellFlo™. The simplified, manual procedure outlined below to evaluate the installation of an ESP into the vertical well Edinburgh-1 follows the same basic steps as the more complex, computerised, design procedures.

Table 7 summarises the Edinburgh-1 well conditions.

<table>
<thead>
<tr>
<th>Well Edinburgh 1</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (h)</td>
<td>7000ft</td>
</tr>
<tr>
<td>Reservoir pressure (Pr)</td>
<td>1700psi</td>
</tr>
<tr>
<td>Well productivity index (Pi)</td>
<td>2 STB / day / psi</td>
</tr>
<tr>
<td>Tubing Internal Diameter (d)</td>
<td>2.26 in or 0.188 ft</td>
</tr>
<tr>
<td>Surface manifold pressure (Pm)</td>
<td>50 psi</td>
</tr>
<tr>
<td>Design Well Production (Q)</td>
<td>1400 STB / day</td>
</tr>
<tr>
<td>Produced Fluid properties</td>
<td>Water</td>
</tr>
<tr>
<td>Fluid Density</td>
<td>0.433 psi / ft</td>
</tr>
<tr>
<td>Viscosity</td>
<td>1 cp</td>
</tr>
<tr>
<td>Pump set at same depth as perforations</td>
<td></td>
</tr>
</tbody>
</table>

Table 7
Data for Well Edinburgh 1

(i) The pipe friction loss (\( \Delta P_f \)) at the desired well production is given by:

\[ \Delta P_f = (f_m) \left( \frac{L}{d} \right) \left( \frac{v^2}{2g} \right) \]

where \( f_m \) is the moody friction factor, \( v \) is the fluid velocity and \( g \) the acceleration due to gravity (32.173 (ft/s²) (lbm / lbf)). Now:

\[ v = \frac{Q \text{(STB / day)}}{86,400 \text{(s / day)} \cdot \pi d^2 / 4} \]

\[ = \frac{1400 \cdot 5.615 \cdot 4}{86,400 \cdot 3.14 \cdot 0.188^2} = 3.28 \text{ ft / s} \]

As discussed previously, the value of \( f_m \), a function of Reynolds Number, pipe roughness and the fluids’ properties, can be found from a Moody Diagram. It has a value of 0.03 for this calculation.
\[ \Delta P_f = (0.03) \times (0.433) \times \left( \frac{7000}{0.188} \right) \times \left( \frac{3.28^2}{2 \times 32.2} \right) = 81 \text{psi} \]

(ii) \[ P_d = P_s + \Delta P_f + \Delta P_{HH} \]

where \( P_d \) is the required pump discharge pressure and \( \Delta P_{HH} \) is the hydrostatic head due to the 7000 ft column of fluid. \( P_s \) is the wellhead pressure required to transfer the fluid to the surface facilities (50 psi).

\[ P_d = 50 + 81 + (0.433 \text{ psi/ft}) \times (7000 \text{ ft}) = 3162 \text{ psi} \]

(iii) The Flowing Bottom Hole Pressure and the pump intake pressure (\( P_{in} \)) are the same and can be calculated from:

\[ P_{in} = P_r - \frac{Q}{P} = 1700 - 1400/2 = 1000 \text{ psi} \]

N.B. It is essential that \( \{ P - P_{in} \} > 50 \text{ psi} \) to ensure select there is a minimum height of fluid above the pump section so that it doesn't "run dry".

(iv) Using the pump performance chart shown in Figure 34, the head per stage (H) at 1400 b/d is 58 ft and the hydraulic horsepower per stage (HHP) is 0.52.

The number of pump stages (N) and the minimum electric motor power (HHP) required can now be calculated for a pump running at 2915 rpm.

\[ N = \frac{(P_d - P_{in}) \text{ (psi)}}{H(\text{ft}) \times \gamma \times 0.433 \text{ (psi/ft)}} = \frac{(3162 - 1000)}{58 \times 0.52 \times 0.433} = 86 \text{ stages} \]

and \( \text{HHP} = 86 \text{ (stages)} \times 0.52 \text{ (HHP/stage)} \times (\gamma_f) = 45 \text{ HP} \)

where \( \gamma_f \) is the specific gravity of the fluid (unity in our case)

(v) An electric motor to power the pump may now be chosen (minimum 205 HP and 50Hz).

N.B. Choosing a pump speed other than 2915 rpm introduces extra complications since the pump rate of an ESP is proportional to the speed

i.e. \[ \frac{\text{pump rate}_2}{\text{pump rate}_1} = \frac{\text{pump speed}_2}{\text{pump speed}_1} \]

where \( (1) \) denotes the initial rate (2915 rpm) and \( (2) \) refers to the new speed of the motor (and pump, since ESP’s do not have a gearbox). Further, the motor speed also controls the hydrostatic head produced.

\[ \frac{\text{hydrostatic head}_2}{\text{hydrostatic head}_1} = \left( \frac{\text{pump speed}_2}{\text{pump speed}_1} \right)^2 \]
The power required may now be calculated

\[
\frac{\text{motor power}_2}{\text{motor power}_1} = \left(\frac{\text{pump speed}_2}{\text{pump speed}_1}\right)^3
\]

Variable Frequency Drive (VFD) provides the ability to change the pump and electric motor speed by altering the frequency of the electricity supply. The pump characteristic performance curves are also measured by the manufacturer for a range of conditions and are reported in their data books - Figure 35 shows the format of a typical example (not the same one as discussed above).

\[\text{Figure 35}
\]
Typical changes in pump / motor characteristic performance as a function of electric supply frequency

(vi) The final stage in this simplified design procedure is to evaluate the robustness of the design for a series of well inflow conditions i.e. changes in well productivity index or reservoir pressure. These are performed by carrying out a nodal analysis on the ESP pump. Figure 36 is a typical example of such an analysis (also not the same one as discussed above).
This figure shows that:

(a) The well fluid level above the pump (1000 psi or 2310 ft TVD) is high if the well’s PI was 2 STB/d/psi and 1400 STB/day were being produced i.e. the well is not being “pumped off” and a larger pump could have been installed. The production rises to 1540 STB/d (and the fluid level to 1315 psi or 3035 ft TVD) if the well productivity index increased to 4 STB/d/psi.

(b) The well production reduced to 1190 STB/d for the lower well productivity index of 1 STB/day. The lowest well PI plotted (0.5 STB/d/psi) results in a negative well inflow pressure. The well has now been “pumped off” - an unacceptable situation which would be corrected by restricting the tubing outflow with a choke. The minimum well inflow pressure will be dictated by the minimum pump charging pressure required (depends on pump design), gas interference e.g. bubble point etc.

(vii) Cable selection - which depends on pump power, voltage selected and downhole temperature, may now be made.

(viii) Further details can be found in API RP 1154 - “Recommended Practice for Sizing and Selection of Electric Submersible Pump Installations”.

The ESP manufacturers can supply software to carry out a more sophisticated design analysis than that described here. Further, many of the well design of nodal analysis packages included data from the pump manufacturers so that the well analysis and selection process can be automated.
8. HYDRAULIC PUMPS

Hydraulic pumps use a high pressure power fluid pumped from the surface (Figure 37) which:

(i) drives a downhole, positive displacement pump. Figure 38 shown how the flow of power fluid through the upper engine unit is translated into a flow of high pressure produced fluid during both the “UP” and “DOWN” strokes.
(ii) powers a centrifugal or turbine pump (see Section 2.8.3).

(iii) creates a reduced pressure by passage through a venturi or nozzle (Figure 39) where pressure energy is converted into velocity. This high velocity/low pressure flow of the power fluid commingles with the production flow in the throat of the pump. A diffuser then reduces the velocity, increasing the fluid pressure and allowing the combined fluids to flow to surface.
The power fluid consists of oil or production water (the large oil inventory in the surface power fluid system makes oil accounting difficult once high water cuts are being produced). The power fluid is supplied to the downhole equipment via a separate injection tubing. The majority of installations commingle the exhaust fluid with the production fluid (an “open system” Figure 40(a)). If difficulties or high costs are encountered in preparing power fluid of the required quality from the production fluid, then a “closed system” may be installed in which the power fluid returns to the surface via a (third) separate tubing (Figure 40(b)). This option is not available with a venturi pump. The completion design may also allow gas to be vented to surface via the casing/tubing annulus.
A typical power fluid supply pressure of between 1,500 and 4,000 psi. is provided by a pressurising pump (Figure 37). This may be a reciprocating plunger (triplex) pump or a multi-stage, centrifugal pump. This pressure determines the pressure increase achievable by the downhole (positive displacement or centrifugal) pump. The pump rate (and the rate at which power fluid has to be supplied) is determined by the diameter and speed of the downhole pump.

“Clean” power fluid is required to avoid erosion of the downhole pump components. The power fluid is often drawn from a settling tank where the larger solids are removed. It is then pumped via a desanding hydrocyclone and a guard filter before having its pressure raised to the operating pressure by the charge pump. The power fluid from the pressurising pump may supply one or more wells (Figure 37).

8.1. Advantages of Hydraulic Pumps
Hydraulic pumps have the following advantages:

(i) Suitable for crooked and deviated wells.

(ii) Reciprocating and turbine pumps can work at great depths (up to 17,000 ft), while jet pumps are restricted to about half that value.
(iii) Very flexible speed control by the (surface) supply of power fluid. Turndown to <20% of design maximum speed can be achieved.

(iv) Jet pumps, with no moving parts can handle solids. Weir pumps are claimed to be manufactured from erosion resistant materials which aim to give a 5 year lifetime with “reasonable” solids production associated with a prepacked screen completion for installation in a soft formation.

(v) The power source is remote from the wellhead giving a low wellhead profile, attractive for offshore and urban locations.

(vi) The power fluid can carry corrosion or other inhibitors downhole, providing continuous inhibition when the well is producing.

(vii) The pump unit can be designed as a “free” pump; the pump unit having the capability of being pumped through the power fluid tubing from the surface to its downhole location (figure 41). It can then be recovered by reversing the flow direction. The ability to recover the pump without the need to move a rig/workover hoist to the wells is attractive for offshore platforms as well as remote and urban locations.

![Figure 41](image_url)

*Figure 41*

*Installation and recovery of a "free" hydraulic pump*
8.2. Disadvantages of Hydraulic Pumps
(i) Pumps with moving parts have a short run life when supplied with poor quality (solids containing) power fluid. Jet pumps can have a long run life under similar conditions.

(ii) Positive displacement and centrifugal pumps can achieve very low flowing bottom hole pressures in the absence of a gas effect. The lowest pressure achievable by jet pumps are much higher, being comparable to gas lift.

8.3. New Technology (Weir Pumps)
A recent innovation that has been field tested over the last few years is the Weir Pump - a hydraulically driven engine coupled to a turbine pump with improved gas handling abilities. It uses an open power fluid circuit - the power fluid is returned to the surface commingled with the production. Its performance characteristics are very similar to that of an ESP - but it also has the ability to achieve stable operation over a wide range of flow rates with gas fractions of at least 80%. In addition, large gas slugs associated with surging flow can be handled without mechanical damage to the pump or its motor.

Hydraulic (and Weir) pumps have several intrinsic advantages over ESP’s:

(i) The continuous supply of cool power fluid increases the maximum allowable bottom hole formation temperature at which the pump can be installed.

(ii) Solids free power fluid lubricates the pump bearings, enhancing their produced solids handling capabilities (typical power fluid specifications are 100 ppm solids with a maximum diameter of 0.1 mm). The need (and cost) of continual cleaning of the power fluid in a (multi-well) subsea development could be minimised by use of a “closed” power loop.

(iii) There is no requirement for a mechanical seal to be installed between the motor and the pump, as is the case for an ESP.

(iv) Variation in the power fluid flow rate provides pump speed control as well as a “soft start” capability.

(v) The pump set operates at high speeds. This results in a short (3-4 m) pump unit since:

\[ \text{Number of pump stages required} \propto \left\{ \frac{1}{(\text{pump speed})^2} \right\} \]

This short length (and weights typically less than 500 kg) allow wireline retrieval of the pump unit in wells at deviation angles of up to 55°. Coiled tubing installation is required for higher deviation angles (up to 80°).

Figure 42 illustrates the completion design used in the Texaco field trial in their North Sea “Captain” field. This included:
(i) Installation of an upper and lower “Y” tool connected by a 2.375” by-pass tubing. This tubing allows access (e.g. for production logging purposes) to the producing interval without having to recover the pump. A Surface Controlled, Sub Surface Safety Valve has been installed below the lower Y tool. Also, a “Fluid Loss Control” valve is installed at the bottom of the tubing to prevent injection of workover fluid into the completion during pump recovery or other operations being carried out above the packer.

(ii) Comprehensive flow rate, temperature and pressure measurement as well as pump performance monitoring, such as pump speed and vibration measurements, has also be installed.

(iii) As discussed previously, the development of the viscous oil rim in Texaco’s “Captain” field depended on developing a reliable artificial lift system having a combination of effective gas handling and viscous fluid pumping capabilities. It was concluded after a one year’s field trial that:

(a) The viscous crude oil, and any resulting high viscosity emulsions, was pumped at flow rates ranging from 20% - 120% of design with water cuts varying from 0 - 100%.

(b) Fluid gas fractions of 30% to 75% at the pump suction were routinely pumped while exceptional, slug flow conditions of greater than 90% gas volume fraction, were managed by the fluid driven turbine pump.

(c) The pump and turbine design was robust. It withstood the imposed loads and was resistant to the typical solids production encountered in completions requiring sand control.
9. Progressing Cavity PUMPS

Progressing Cavity (or Moyno) Pumps are becoming increasingly popular for the production of viscous crude oils. Figure 10 summarises the application area (well rates & depths) where Progressing Cavity Pumps (PCP) are typically employed. A typical completion is illustrated in Figure 43 where a prime mover (in this case an electric motor) is shown rotating a sucker rod string and driving the PCP. This section will describe the principle on which the pump operates, the resulting advantages and disadvantages and, finally, takes a look at new technology.

Figure 43
A well completed with artificial lift using a progressing cavity pump
9.1. Progressing Cavity (or Moyno) Pump Principle

Figure 44 illustrates the main components of a PCP. A steel shaft rotor of diameter \( d \) has been formed into a helix \{Figure 44(a)\}. The rotor is rotated inside an elastomeric pump body or stator, which has been molded in the form of a double helix with a pitch of the same diameter and exactly twice the length of the pitch given to the rotor \{Figure 44(b)\}. Figure 44(c) shows that, when assembled, the centre line of the rotor and the stator are slightly offset, creating a series of fluid filled cavities along the length of the pump. Figure 45 is a perspective view of Figure 44(c), which helps explain how the interference fit between the rotor and stator creates two chains of spiral (fluid filled) cavities.

\[ d \] is minor diameter of rotor and stator, \( \text{ecc} \) is rotor eccentricity

**Figure 44**

Cross section progressing cavity pump and its components.
The rotor within the stator operates as a pump. This causes the fluid, trapped in the sealed cavities, to progress along the length of the pump from the suction to the pump discharge. These cavities change neither size nor shape during this progression. Figure 46 (a-e) shows how, as one cavity diminishes, the next one increases at exactly the same rate; giving a constant, non-pulsating flow. It acts as a positive displacement pump. The pressure increase that can be achieved by the pump depends on the number of “seal-lines” formed along the pump body by the rotor and stator. Typically, this is found to be 300-200 kPa pressure increase per stage. It is found that fluid will “slip” backwards if a greater pressure increase is demanded from the pump. This can be avoided by increasing the number of pump stages. Wear of either the stator or rotor will decrease this value since the the maximum pressure increase depends on this interference fit. However, the construction of the stator body from an elastomer makes this pump design relatively tolerant to produced solids - particularly since they are often used to pump viscous oils which provides a lubrication film to protect the rotor and stator from wear.
The flow rate achieved by a liquid filled (no gas) PCP pump is directly proportional to the speed of rotation of the rotor (N):

$$\text{Flow rate} = k \times \text{Pitch of Stator} \times 4 \times \text{eccentricity} \times \text{Stator minor diameter} \times N$$

Where $k$ is a constant.

The presence of gas reduces the efficiency and a gas anchor is frequently included in PCP completions (see also Section 2.6.5.2 for discussion of gas anchors). Figure 14 illustrates one of the many available forms of gas anchors that can be used.

The advantages and disadvantages of a PCP are summarised in Tables 8 and 9. It can be seen that the pump’s characteristics make it very suitable for artificial lifting wells producing medium to high viscosity crude oil reserves. These crude oils often have a tendency to form highly viscous emulsions when mixed under high shear with the produced water (as occurs in a centrifugal pump). They are often found in (relatively) shallow, young (geologically speaking), soft formations where the inclusion of sand control in the completion design is a necessity. Finally, elastomer selection problems are minimised because these crude oils tend to have a low GOR as well as a low aromatic content and their shallow location results in a cool Bottom Hole Temperature.
<table>
<thead>
<tr>
<th>Advantages of PCP</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>Simple design</td>
<td>Quick pump unit repaired by replacing rotor and stator as a complete unit</td>
</tr>
<tr>
<td>High volumetric efficiency</td>
<td>In the absence of gas</td>
</tr>
<tr>
<td>Efficient design for gas anchors available</td>
<td>Tolerant of produced solids at reasonable levels</td>
</tr>
<tr>
<td>High energy efficiency</td>
<td>PCP is a Positive Displacement Pump</td>
</tr>
<tr>
<td>Emulsions not formed due to low shear pumping action</td>
<td>ESPs and Weir pumps promote emulsion formation due to high pump speeds</td>
</tr>
</tbody>
</table>
| Capable of pumping viscous crude oils | (1) Diluent mixed as required with crude oil if extreme viscosities to be pumped  
                                      | (2) "Water-like" behaviour observed at high water cuts when oil becomes the internal phase |

<table>
<thead>
<tr>
<th>Disadvantages of PCP</th>
<th>Comment</th>
</tr>
</thead>
<tbody>
<tr>
<td>High Starting Torque</td>
<td></td>
</tr>
<tr>
<td>Fluid compatibility problems with elastomers in direct contact with aromatic crude oils</td>
<td>Carry out tests prior to producing a new crude oil</td>
</tr>
<tr>
<td>Gas dissolves in the elastomers, at high bottom hole pressure</td>
<td>Avoid rapid depressurisation of the pump destructive bubbles formed when pressure is lowered rapidly</td>
</tr>
</tbody>
</table>

Table 8
Advantages of a PCP

Table 9
Disadvantages of a PCP

9.2. Progressing Cavity Pump Power Supply
Traditionally, PCP’s have been powered by an electric motor and gearbox mounted above the wellhead and turning a string of sucker rods connected to the PCP pump; i.e. the rods are rotated rather than reciprocated (Figure 43). As discussed in section 2.6 on Rod Pumps, this string of sucker rods is susceptible to failure - especially in crooked or deviated wells or when formation sand is being produced. There is a similar tendency to a higher frequency of tubing failures, since the rods are rotating inside the tubing. Installation of centralisers on the sucker rod string can mitigate this problem (Figure 15). This rod/tubing frictional contact, even when reduced by centralising the sucker rod string, leads to a large loss of starting torque as well as wastage of power when the pump is operating.

Further, the tubing has to be pulled and then rerun when the pump unit requires repair. This can normally be done by a light workover hoist, since the wells are not normally capable of natural flow.
9.3. New Technology
The resulting high torque and friction losses, as well as the tubing and rod failure discussed above, can be reduced by placing the motor downhole - this is known as a Progressing Cavity Electric Submersible Pump. Secondly, low cost replacement of the PCP unit can be achieved by making it wireline retrievable. These new developments will be discussed in the following two sections.

9.3.1. The Progressing Cavity Electric Submersible Pump (PCESP)
The PCESP share the same electric motor, seal, cable and control technology as the conventional Electric Submersible Pumps (ESP) discussed in Section 2.7. The major difference is that a gearbox is required to reduce the speed of rotation since the centrifugal pump employed with a conventional ESP is a high-speed device; while a PCP is a low speed device. The layout of the two pump types is compared in Figure 47. Some typical dimensions have been included to illustrate the length of the complete PCESP unit. In the example shown, which can be run inside a 7” casing, it ranges from 34 ft for a low power unit to 81 ft for a medium power device.

Figure 47
Comparison between layout of an ESP and a PCESP

*Depends on power required
Practical experience has shown that the expected gains in reduced pump power requirements and tubing failures are achieved on changing from a rod driven PCP to a PCESP. Electric submersible motors have become very reliable - providing proper design and operational procedures are in place. The most frequently replaced item in many PCESP projects is the PCP unit itself. These costs could be reduced by redesigning the wellhead, completion and the PCP unit so that it becomes retrievable by wireline. This is discussed in the next section.

9.3.2. Wireline Retrievable PCESP

The wellhead and the tubing are enlarged so that they are both large enough to pass the PCP motor and stator unit, which is modified as follows (Figure 48):

(i) A (re)latchable drive shaft connection is made at the bottom of the unit so that it can be connected and disconnected to the motor unit and gearbox.

(ii) The PCP Unit is seated on a nipple placed on top of the seal unit.

(iii) The PCP unit body is sealed against a pump pack-off element.

(iv) A fishing neck is provided for wireline recovery.

Figure 48
Modification of a PCESP to allow wireline retrieval
The motor, gearbox and seal unit are all installed as per the conventional PCESP design at the bottom of the production tubing.

Extensive testing of this concept at the Thums field, Long Beach, California, provided the operational data summarised in Table 10. This shows that, despite the considerable increase in capital cost, the much reduced pump charge out costs resulted in a very significant saving in production lifting costs. (This cost saving is very dependent on the MTBF or “Mean Time Before Failure” of the pump and other downhole components). This is a good example of the concept discussed earlier (Section 2.5.4) when extra up-front capital expenditure can result in reduced “Total cost of ownership” through more efficient operations. Also, that these decisions can only be made when a comprehensive cost database is available.

<table>
<thead>
<tr>
<th>Economics of wire line retrievable PCESP*</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial Installation Cost</td>
</tr>
<tr>
<td>180% of ESP</td>
</tr>
<tr>
<td>125% of ESPCP</td>
</tr>
</tbody>
</table>

*Data provided by Thomas Lutz to the conference on Artificial Lift Equipment '97, Dubai, December 1997

10. HYBRID SYSTEMS

The combination of two forms of artificial lift has been used in a few cases. Most hybrid systems combine gas lift with one of the other types of artificial lift. For example it has been shown that injection of gas above an ESP or PCP can reduce the hydrostatic head against which the positive displacement pump (e.g. ESP, PCP etc.) is pumping against by upto 40%. This can lead to a significant increase in pump performance. It may also allow the well to continue to produce even when the pump is experiencing mechanical problems e.g. ESPs are susceptible to high levels of sand production and may show frequent failure. Gas lift is tolerant of sand production and will often be capable of drawing the well down sufficiently that production continues, although at a lower rate compared to when the pump is operational.

Table 11
Benefits of combining gas lift with a positive displacement artificial lift method e.g. ESP, PCP sucker rod etc.

• Increased volumetric efficiency - higher liquid volumes.
• Decreased injection gas requirements compared to gas lift alone.
• Increased reservoir drawdown and production.
• Increase pump installation depth - allows greater reservoir drawdown.
• Reduction in pump and motor power requirements.
• Lower electrical energy consumption compared to pump alone.
• Reduces electrical conduit requirements.
• Gas lift provides backup in case of pump failure.
11. ARTIFICIAL LIFT METHODS TUTORIAL

Question 1.

Hardly any artificial lift equipment was installed during the first 10 years of Oil Production in the North Sea. Suggest four factors that could explain this.

Answer 1.

Artificial lift was not required due to properties of developments typical in that period:

- Light oil being produced from high permeability reservoirs i.e. (relatively low drawdowns),
- Reasonable high GOR aided natural flow,
- Water Injection supported reservoir pressure above the bubble point pressure at near hydrostatic or greater pressures, allows the production wells to continue to flow under natural flow
- Large reservoirs and distant well spacing delayed water breakthrough
- High water cut wells were shut-in. Other, lower watercut wells produced in preference to watered out wells since production was facility or pipeline constrained.

Question 2.

Two types of artificial lift were installed once it became apparent that production pressure boosting would be required. Which types were these and what were the reasons that they were chosen?

Answer 2.

The two artificial lift types were:

Gas Lift
- High GOR water drive reservoirs
- High reservoirs permeabilities
- No need for very low FBHPs (Water Injection, drawdown was relatively low).
- High Pressure gas availability, often surplus to power or export requirements
- (reasonably) deviated holes
- Wireline equipment maintenance - no extra demand placed on drilling rig which could continue drilling development wells.
- Tolerate some sand production as was experienced in completions without sand control
- No extra space required at production wellhead
- Full-access to oil producing formation

ESP
- High production rates even at high water cuts
- Suitable for highly deviated wells
- Logging / coiled tubing access to formation via Y tool
- Flexible - flow rate controllable over a wide range
  - downhole flow measurement and pump condition monitoring available
Selection of Artificial Lift Types

- Efficient use of Energy
- Can pump against high wellhead pressures e.g. for satellite wells
- No extra space required at production wellhead

Question 3.

New completion technology has contributed to reduction of the Operating costs of Artificial Lift Equipment. Name two significant developments.

Answer 3.

Examples of new technology:
- Coiled tubing for:
  - Insert strings
  - Conveyed pumps
- Wireline maintainable pumps.
- Variable speed drives for ESPs
- Downhole measurement & control for ESPs

Question 4.

Which IPR Curve (AL1 or AL2) is more beneficial for Artificial Lift?

![Inflow Performance Relationship (AL1)](image1)

![Inflow Performance Relationship (AL2)](image2)
Answer 4.

A “straight line” inflow performance relationship associated with a dead oil is more favourable than the curved “Vogel” relationship found when well inflow takes place below the fluid’s bubble point. This is because for a “straight line” inflow performance relationship the % Increase in production is directly related to the % increase in drawdown achieved by the introduction of the form of artificial lift. The increase in production is considerably less for a curved “Vogel” relationship.

Question 5.

i) Why are these curves different?
ii) What impact might this have on the selection of the Artificial Lift type?

Answer 5.

i) A straight-line IPR assumes that oil is undersaturated, that is, only slightly compressible. This condition does not apply to gases or saturated oil wells, both of which are highly compressible. The effect of compressible gas and two-phase flow on IPR results in “larger-than-linear” pressure drops being required to increase the production rate i.e. a curved IPR is observed in this case. The rate - pressure relation tends to show a more pronounced curvature at higher production rates.

ii) By applying the same drawdown, i.e. producing under similar flowing bottomhole pressures, wells with the “Straight line” IPR (dead or undersaturated oils) would yield higher production rate than wells with the curved “Vogel” IPR. The increasing production of associated gas due to producing below the bubble point pressure in the latter case would tend to favour the installation of Gas lift while, for example, Rod Pumps can be applied to the dead oil or undersaturated oil wells.

Question 6.

List up to 6 key features for both Rod Pumps and Gas Lift that form the basis of the following statement:

“Worldwide, 85% of Artificial Lift equipment installed is rod pumps. This is mainly in low production rate wells while gas lift is the most popular artificial lift technique for medium rate wells”.

Answer 6.

Rod Pump - Main features
• The vast majority of wells produce at low rates (generally less than 100 bpd) and moderate depths
• Relatively cheap, so their use can be justified on such low rate wells
• Rod pumps are mechanically simple to operate and easy to repair/maintain/replace.
  Can be operated by inexperienced personnel
Selection of Artificial Lift Types

- Sensitive to gas and solids (wax/scale/sand) - Solids can cause wear as well as damage moving parts which then need to be replaced
- Not suitable for (highly) deviated wells (most land wells are near vertical)
- Obtrusive in urban locations. Equipment too heavy for offshore use
- Pump can be easily changed and performance monitored using relatively simple and inexpensive techniques
- Viscous oil can be pumped

**Gas Lift - Main features**
- Suitable for medium to high rates
- Suitable for water drive reservoirs with a high bottomhole pressure
- High well PIs and high permeabilities mean FBHP can be excessively high, limiting production
- High GOR => advantage rather than a drawback
- Gas has to be available
- Wireline serviceable at deviation up to 65°. Coiled tubing can service more highly deviated / horizontal wells
- Limited surface requirements once gas available
  - can be used off-shore or in urban locations
- Fully open tubing giving access for production logging
- Subsurface tubing, and annular, safety valve
- Flexible - gas lift string design can be adjusted as well conditions change
- Forgiving of poor design & operation, but difficult to run efficiently
- Can handle (tolerate) produced solids

**Question 7.**

What considerations are important when choosing an Artificial Lift Method for subsea wells for a satellite development at a distance 30 Km from a host platform?

**Answer 7.**

ESP’s are normally the preferred Artificial lift method for the following reasons:
- Can generate high pump pressures to overcome extra friction from 30 km pipeline
- Does NOT use power fluid (gas for gas lift, liquid for hydraulic pumps) which would lead to extra friction in pipeline.
  - Hence electricity probably preferred source of power
  - Remote control capability at long distances
- Advantageous to place pump so as to minimise length of flowline with multi phase flow
- System design (artificial lift type/tubing/flowline/reception facilities) should be suitable for complete life of oil field.
- Long pump lifetime (reliability to complement lifetime design)

Multiphase pumping means Subsea pressure boosting can also be considered as an option as well as ESPs
FURTHER READING

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