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# *Implementation of Progressive Cavity Pump (PCP): Selection Techniques and Design in El-Shrara Oil Field.*

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بسم الله الرحمن الرحيم

اقْرَأْ بِاسْمِ رَبِّكَ الَّذِي خَلَقَ (1) خَلَقَ الإِنسَانَ مِنْ عَلَقٍ(2) اقْرَأْ وَرَبُّكَ الأَكْرَمُ (3) الَّذِي عَلَّمَ بِالْقَلَمِ(4)عَلَّمَ الإِنسَانَ مَا لَمْ يَعْلَمْ (5).

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# ABBREVIATIONS

| Symbol | Description |
|---|---|
| PCP | Progressing cavity pump |
| ESP | Electrical submersible pump |
| DST | Drill stem test |
| API | American petroleum institute |
| RPM | Revolutions per minute |
| ROR | Rate of return |
| BEP | Best efficient point |
| DHMs | Down hole mud motors |
| PD | Positive displacement |
| RPMs | Rotation pump shaft speed |
| gpm | Gallon per minutes |
| T | Torque in inch pounds |
| N | Pump speed RPM |
| e | Eccentricity (in) |
| Ps | Pitch of thread of the stator |
| V | Pump displacement bbls/day/ rpm |
| d | Minor rate diameter (in) |
| p | Stator pitch length (in) |
| Q | Flow rate bbls/day |
| n | Volumetric pump efficiency (%) |
| H | Vertical column height (ft) |
| $\rho$ | Fluid or gas density (Ib/cf) |
| STB | Stock tank barrels |
| PVT | Pressure, volume,temperature |
| OEDP | Open ended drill pipe |
| R/U | Rigging up |
| csg | Casing |
| tbg | tubing |
| FC | float collar |
| sx | sacks |
| PBTD | plug back total depth |
| CMT | cement |
| POH | Pull out of hole |
| RIH | Run in hole |
| SPF | Shot per feet |
| AFR | After flow rate |

| | |
|---|---|
| BOPD | Barrel oil per day |
| N/U | Nibble up |
| P/T | Pressure test |
| ST | Shut in |
| BU | Build up |
| TCP | Tubing convey perforation |
| GR | Gamma ray |
| GOSP | Gas oil separation plant |
| KB | Kelly bushing (ft) |
| DFL | Dynamic fluid level (ft) |
| whp | Well head pressure at surface (psi) |
| AL | Artificial left |
| PWF | Flowing bottom hole pressure (psi) |
| PDSC | Downstream surface chock pressure (psi) |
| Psep | Separator pressure (psi) |
| Bo | Oil volume formation factor (bbl/STB) |
| wc | Water cut (%) |
| WOC | Water oil contact (ft) |
| SW | Water saturation (%) |
| $\mu$ o | Viscosity (cp) |
| GOR | Gas oil ratio (scf/stb) |
| Pr | Reservoir pressure (psi) |
| K | Permeability (mD) |
| PI | Productivity index (blls/d/psi) |
| Pi | Initial reservoir pressure (psi) |
| Rs | Solution gas oil ratio (scf/bbl) |
| C | Compressibility (1/psi) |

# ABSTRACT

Progressive cavity pump (PCP) is not new technology for the oil industry, it was invented by Rene Moineau in 1932 and became widely used as surface pumps, and in 1979 the first PCP was installed in sand production heavy oil wells in Canada.

In particular the planning for this project to rerun PCP in EL-Shrara oil field in order to reduce the workover cost besides applying another artificial lift in the field even for the oil wells which have low flow rate.

In this project three oil wells were applied for the study, software was running to get the results and comparing the results with actual production at the current artificial lift (ESP).

Implementation of Progressive Cavity Pump (PCP) in El-Sharara oil field was numerically evaluated to define the selection criteria and techniques for the application of PCP systems in light crude oil production wells.

Because of rig less operations is a characteristic of workover jobs for PCP, the aim of this study is to investigate the possibility to provide an alternative pump type to the widely used ESP type which associated with high workover cost.

The unique actual application of PCP as an artificial lift tool is took place on Feb to July 1999 in a production well completed in Mamuniyat formation concession 115& 186 operated by Akakus Oil Operations. The declared reason was the limited production achieved by the PCP system installed and no other specific justifications and/or failure causes were identified.

The recorded production rates with PCP system in Well XX-16 were 211,571,610,370 and 208 bbl /day during March, April, May, June and July 1999 respectively. They show a decreasing trend with time while all the

operating parameters were kept constant. The fluid losses was increasing indicating rotor malfunction which is can only be attributed to elastomer softening caused by light fractions reactivity with elastomer.

Installation and rig costs of PCP versus ESP in well XX-16 have shown a considerable savings in favor of PCP system. The rig cost was amounted to 22% of the total cost which includes PCP price plus the rig cost. On the other hand, rig cost for ESP system was amounted to 55% of the total cost. Keeping in mind that this was the first PCP installation experience, hence, rig cost would be minimized further in the future.

Implementation of PCP systems, in El-Sharara oil field, can only be improved or become economically acceptable, if an accurate selection methodology is implemented. For example, if a proper elastomer material is selected based on an extensive laboratory studies which should take in consideration the fluid composition and operating temperatures then, elastomer softening would be eliminated and/or minimized.

Since this first PCP trail in 1999, advanced elastomers were developed with great chemical resistance and with a fair mechanical resistance which should be supported by comprehensive laboratory investigations prior to the PCP installation.

# Chapter 1

## Introduction & literature review

## 1-1 INTRODUCTION:

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. The hydrocarbon fluid flows from the reservoir into the well, up the tubing the horizontal line and into the oil storage tank during this process the fluids pressure is reduced from the reservoir pressure to atmosphere pressure in a series of pressure loss processes, across the reservoir, across the completion (perforation / gravel pack – etc.), across the tubing and any restrictions, across the sub surface safety valve, across the surface choke, across flow line.

- **Well Productivity**

An oil or gas reservoir contains highly compressible hydrocarbon fluids at an elevated pressure and temperature and as such, the fluid stores up within it self-considerable energy of compression. The efficient production of fluids from a reservoir requires the effective dissipation of this energy through the production system. Optimum utilization of this energy is an essential part of a successful completion design and ultimately of field development economics.

Where necessary and economic, this lift process can be supported by artificial lift using pumps or gas lift. The productivity of the system is dependent on the pressure loss which occurs in several areas of the flow system namely:-

The reservoir, the wellbore, the tubing string, the choke, the flow line, the separator, the pressure drop across the reservoir, the tubing and choke are rate dependent and these relationships therefore define the means by which we can optimize the production of the fluid from the reservoir. In some cases there will be significant limitations on the extent to which we optimize the dissipation of this energy. These are the following:-

- **Limited Reservoir Pressure**

in cases where the reservoir pressure is limited, it may not be feasible to achieve a significant and economic production rate from the well. In such cases it may be necessary to either assist in maintaining reservoir pressure or arrest the production decline by the use of gas or water injection for pressure maintenance or possibly system re-pressurization.

Alternatively, the use of some artificial lift technique to offset some of the

Vertical lift pressure requirements, allowing greater drawdown to be applied across the reservoir and thus increase the production capacity of the system, may be implemented.

- **Minimum Surface Pressure**

On arrival at the surface, the hydrocarbon fluids are fed down a pipe line through a choke and subsequently into a processing system whereby the fluids will be separated, treated and measured. To be able to allow the fluids to be driven through this separation process and infectto provide some of the energy required for the process itself, it will be necessary to have a minimum surface pressure which will be based upon the required operating pressure for the separator. The level of separator operating pressure will depend upon the physical difficulty in separating the phases. In many cases the mixture will be "flashed" through a series of sequential separators.

- **Well Completion**

Historically the major proportion of production technology activities has been concerned with the engineering and installation of the down hole completion equipment. The completion string is a critical component of the production system and to be effective it must be efficiently designed, installed and maintained. Increasingly, with moves to higher reservoir pressures and more hostile development areas, the actual capital costs of the completion string has become a significant proportion of the total well cost and thus worthy of greater technical consideration

and optimization. The completion process can be split into several key areas which require to be defined including:

1. The fluids which will be used to fill the wellbore during the completion process must be identified, and this requires that the function of the fluid and the required properties be specified.
2. The completion must consider and specify how the fluids will enter the wellbore from the formation i.e., whether infect the well will be open or whether a casing string will be run which will need to be subsequently perforated to allow a limited number of entry points for fluid to flow from the reservoir into the wellbore.
3. The design of the completion string itself must provide the required containment capability to allow fluids to flow safely to the surface with minimal loss in pressure. In addition however, it would be crucial that the string be able to perform several other functions which may be related to safety, control, monitoring, etc.

In many cases the completion must provide the capacity for reservoir management. The completion string must consider what contingencies are available in the event of changing fluid production characteristics and how minor servicing operations could be conducted for example, replacement of valves etc.

- **Well Stimulation**

The productivity of a well naturally arises from the compressed state of the fluids, their mobility and the flow properties of the rock, primarily in terms of permeability. In some cases reservoirs may contain substantial reserves of hydrocarbons but the degree of inter-connection of the pore space and the ease with which the fluids can flow through the rock, may be very poor. In such situations it may be beneficial to stimulate the production capacity of the well. Stimulation techniques are intended to:

1. Improve the degree of intern-connection between the pore space, particularly for low permeability or vugular rocks.
2. Remove or bypass impediments to flow, e.g. Damage.
3. Provide a large conductive hydraulic channel which will allow the wellbore to communicate with a larger area of the reservoir. In general, there are four principal techniques applied, namely:

i. **Propped Hydraulic Fracturing-** whereby fluids are injected at a high rate and at a pressure which exceeds the formation break down gradient of the formation. The rock will then fail mechanically producing a "crack". To prevent closure or healing of the fracture, it is propped open by a granular material. This technique increases the effective well bore radius of the well.

ii. **Matrix Oxidization-** this process is conducted at pressures below the formation break down gradient and requires the injection of acid into the reservoir to either dissolve the rock matrix and/or dissolve damage material contaminants which has invaded the rock pore space. The main objective of acidulation is to increase the conductivity of the rock.

iii. **Acid Fracturing-** whereby acid injected at a pressure above the formation breakdown gradient, creates a fracture. The acid then etches flow channels on the surface of the fracture which on closure will provide deep conductive flow channels.

iv. **Frac Packing-** which is a shallow penetrating hydraulic fracture propagated usually into a formation of moderate to high permeability, and is subsequently propped open prior to closure. The process is used to reduce the near wellbore flow induced stress, and in some cases can also limit/reduce sand productions number of other chemical treatments are available for specific situations. Associated Production Problems, the ongoing process of producing hydrocarbons from a well is a dynamic process and this is often evidenced in terms of changes in the rock or

fluid production characteristics. Problems are frequently encountered as results of:

- Physical-chemical changes of the produced fluids as they experience a temperature and pressure reduction as a result of flow through the reservoir and up the wellbore. This can result in a deposition of heavy hydrocarbon materials such as asphaltenes and waxes. Incompatibility between reservoir fluids and those introduced into the wellbore which may result in formation damage, e. g., scale deposits or emulsions.
- The mechanical collapse or breakdown of the formation may give rise to the production of individual grains or "clumps" of formation sand with the produced fluids.
- In formations containing siliceous or clay fines, these may be produced with the hydrocarbons creating plugging in the reservoir and wellbore.
- Corrosion due to the inherent corrosive nature of some of the components contained in the hydrocarbon system, for example, hydrogen supplied (H2S), carbon dioxide (CO2), etc. chloride ions in produced water and oxygen in injected water can also create corrosion.
- Processing problems can be encountered such as radioactive scales, foams, heavy metals deposits, etc. Remedial and Work over Techniques the production technologist is responsible for monitoring and ensuring the ongoing safe operation of the well. As such the responsibilities include:

The identification and resolution of problems that will occur with the production system. This area of work is critical to the ongoing viability of field developments and wells, and can be sub divided into a number of areas namely:

i. Identification of problems and their source - this is normally conducted on the basis of surface information which indicates changes in production characteristics such as rate and pressures. In addition down hole investigations using production logging techniques and transient pressure

surveys (flow tests) can also help to identify the location of problems and the reasons for the changes.

ii. Plan the required corrective action - this requires considerable attention to detail and will necessitate:

a. Identifying the equipment, manpower and other capabilities required.
b. Identification and assessment of the unknowns/uncertainties.
c. Identification and evaluation of the key safety points and mile stones.
d. The assessment of the probability of technical and economic success.
e. To identify the required resources, skills and their supervision.
f. The work over phase is the most dangerous in terms of well control and the Potential for damage on existing production wells. Attention to detail and Careful planning is essential.[i]

A pump or compressor is after used to aid evacuation of fluid (gas/water/oil) from the separator. The separator is operated under gas pressure control and liquid (oil and water) level control. Hence it normally acts as the end point of flowing system since a pump is necessary to aid evacuation of the liquids from the separator.

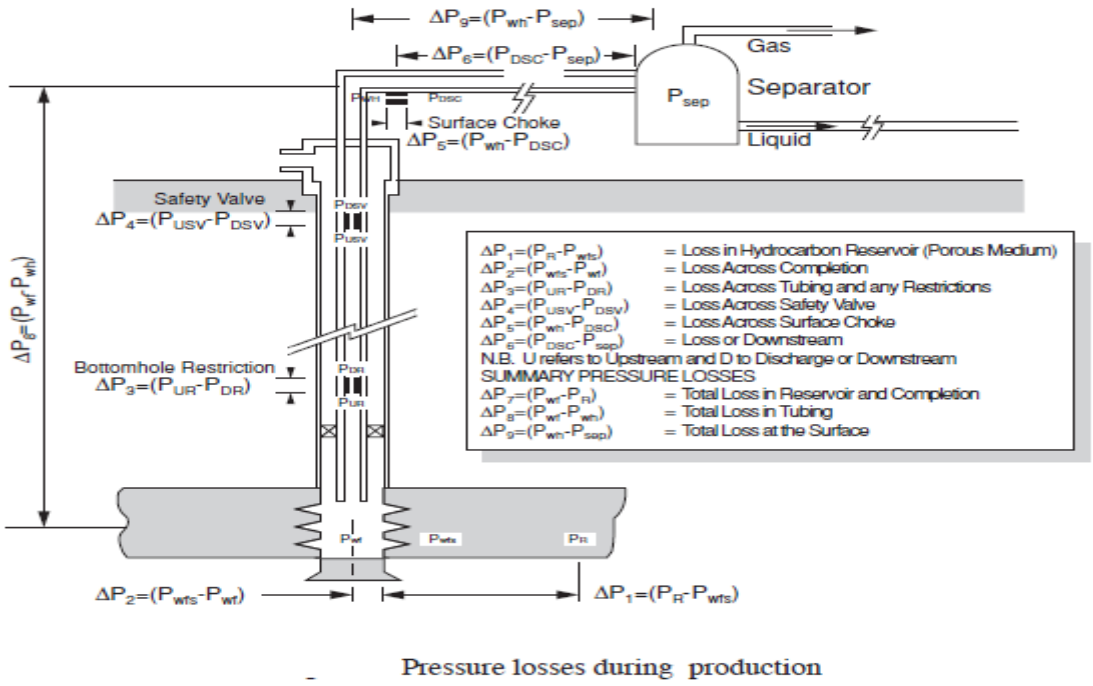



**Fig (1.1) shows possible pressure losses during production.**

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.

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.

## 1-2 Literature review:

The progressive cavity pump consists of a rotating cork-screw like sub-surface assembly which is driven by a surface mounted motor. Beam pump rods are used to connect the two. The flow rate achieved is mainly a function of the rotational speed of the subsurface assembly.

Progressive cavity pumps excel in low productivity shallow wells with viscous crude oils and can also handle significant quantities of produced solids.

The study will apply PC pump mechanism for several wells in El-Shrara oil field, and the possibility of being used in the future for both PCP & ESP, depended on reservoir condition by using Griffin Pumps software. In addition comparing the production results of PCP with the actual production results of ESP which is running at the moment.

However, PCP was running in Libya for more than one location in different company such as Akakus Oil Operations, Houroge Oil Operations and Waha Oil Company with failed to produce the decider production flow rate for all locations.

With years of study and experiments, a complete series of Progressive Cavity Pump (PCP) products has been developed.

Progressive cavity pumps (PCP) have been extensively used as artificial lift equipment in various oil field such as Canada oil fields as Melrose field, Wolf lake field, Elk polin west field, Furness jenner field, Cliffdale field, Milton field, Killarney field, Tangleflage field, viking-Kinsella field and chauvinas field, Albania oil fields as Patos-Marinz field, China oil fields as Daqing oil field, Russia fields and South America oil fields Colombia fields. These pumps have been under renewed attention from researchers and the pumping community in recent times. The first designs of these pumps were introduced by Dr. Rene Moineau in the early 1930s. Technical articles have been submitted mainly in dedicated symposiums. An

introduction is made to the advantages of PC pumps, their operating principles and their geometry with simplified formulae that show the working of a progressing cavity, and explain the progressing cavity which moves fluid from inlet to discharge. This discussion starts with single-lobe rotor geometry and gradually expands to multi-lobe units.

With more than 2000 PCP wells in Daqing Oilfield, the capital and operating costs have reduced dramatically. The PCP system, the most effective lifting method, has great potential for Daqing Oil field.

Daqing Oilfield lies in the center of Songliang basin in North east China. In the beginning stages, commingle water injection and separate zone water injection technologies were used which allowed the reservoir pressure to remain at a high level. Therefore, by natural power the oil field produced for nearly twenty years. To maintain the output, artificial lift technologies were used from 1980s. Beam pumping system was the most popular one. Up to the end of last century, the number of beam pumping systems in Daqing reached over 20,000 wells. There were also about 2,000 ESP wells in operation.[ii]

Till now, it was commonly admitted that 45°API was quite high for an elastomer PCP to run satisfactorily, however recently PCM hit a new challenging level with elastomer PCPs in Colombia where a customer carried out PCM PCPs in five wells producing oil at 47°API, not only the oil was severe to produce due to its very low density, but the wells featured also a high Gas-to-Oil ratio of 200 Scft/Sbbl with very high CO2 content (13%) that was an additional hurdle to overcome.

This extremely aggressive oil generates high elastomer swelling that was anticipated in the rotor / stator fit to avoid over torque and associated internal heat build-up damaging the pump.

This example illustrates that PCM elastomer PCPs - provided an accurate selection methodology has been implemented - can perform extraordinary well in light oil production.[iii]

## 1-2-1 Applications:

Early versions of progressing cavity pumping systems were used in Canadian heavy oil and bitumen applications in the early 1980's. By 1986, PC pumps had made their way into coal bed methane applications in the United States. Further improvements in the technology and manufacturing techniques allowed for expanded use in higher rate medium crude oil applications. In recent years, improvements in elastomers have allowed the use of PC pumps in light oil and elevated temperature applications.
Heavy oil and bitumen applications are commonly defined in the industry as those producing oil with an API gravity less than 20°. These conditions are common in Canada, Russia, Venezuela and China. Problems associated with heavy oil and bitumen are high viscosity, high flow losses, low to moderate flow rates, high sand cuts and rod string/tubing wear. Directional and horizontal wells are often used to ensure viable development of the reservoir. PC pumps are attractive in these conditions due to their ability to handle viscous, abrasive, multiphase fluids.
Medium crude oil applications are generally considered those that produce oil with an API between 18° and 30°. Medium crude oil has lower viscosity and tends to have higher gas to oil ratios when compared to heavy oil operations. Many operations produce a large amount of water (sometimes exceeding 95%) along with sand, $C0_2$ and $H_2S$. In medium crude applications, lower capital and operating costs are the primary advantages that PC pumping systems have over other artificial lift methods.
Light oil applications are generally considered those that produce oil with an API greater than 30°, Light oil has a lower viscosity and contains higher levels of aromatics and gas.

A large proportion of the production is water with minimal sand production. Sweet ($CO_2$) and sour ($H_2S$) gases as well as paraffin may also be present in significant quantities. In light oil applications, higher overall efficiency of PC pumping systems makes them an attractive alternative to beam pumps, electric submersible pumps and gas lift systems that have traditionally been used.

Elevated temperature applications are considered those in which the fluid level is greater than 50°C. This also includes hot fluid injection, mature steam floods and cyclic steam operations. For low temperature applications (<50°C), thermal expansion necessitates special equipment and pump sizing practices. For high temperature applications (>50°C), attention must be paid to the effect of temperature on the pump elastomer. Although the use of PC pumping systems in high temperatures is still limited, both manufacturers and operators continue to actively pursue developments to increase the temperature range of PC pumps.

## 1-2-2 New Developments:

- **Metal-to-Metal Pumps**

Metal stators were considered years ago, but only recently have newer manufacturing techniques and the application of metal-to-metal PCPs in thermal heavy oil and bitumen recovery applications, such as steam assisted gravity drainage (SAGD) and cyclic steam stimulation (CSS), brought this technology to the forefront. A metal stator does not have many of the shortcomings of elastomeric stators-specifically fluid interactions and temperature limitations. Metal stators may therefore be used in thermal applications (e.g. 160-350$^{o}$C), or applications with highly reactive fluids. Potential problems which are actively being resolved by metal-to-metal PCP vendors include vibration and salability with low viscosity fluids, the latter due to the fact that metal-to-metal PCPs have a gap between the rotor and stator and not an interference fit, as normally exists with an elastomeric stator.

- **High Temperature Elastomers**

One of the major limitations of elastomeric stators is the temperature. At high temperatures and over time, most elastomers, including the nitriles typically used in PCPs, become hard and brittle and may not form a seal with the rotor. In these conditions, pumps can fail very quickly. High temperatures can be caused by the external conditions in the well (from depth, or from thermal operations), or from internal friction between the rotor and stator in the absence of sufficient cooling. Fluorocarbon elastomers can operate at higher temperatures than nitriles, but at the cost of inferior mechanical properties. Research is ongoing into ways of improving elastomer formulations for PC pumps so that continued operation at higher temperatures is possible.

- **Fluidizing Sand**

PC pumps are capable of producing large quantities of sand, when the sand flows into the well on a continuous basis. Sand is known to enter the wellbore in slugs, however, and these slugs can overwhelm the pumps' capabilities of producing solids, particularly in applications where sand control is not employed (eg. in producing viscous heavy oil from unconsolidated sandstone reservoirs). Various methods of "fluidizing" sand to ensure that it can be produced through the pump have been used, and others are in development. Some methods are: the addition of a "paddle" rotor extending below the intake to continually agitate the fluid entering the pump; a hollow rotor feeding a small portion of produced fluid from the pump discharge to a jet located at the intake; and a fluidizer pump, where a large displacement-low pressure pump is installed below the main pump with holes in the tubing joint between the two so that an excess amount of fluid continually circulates in the annulus of the well and through the pump intake.

- **High Speed Pumps**

Currently most PCPs are run at speeds below 500 RPM - with viscous oils, the limit is normally even much lower. To produce larger volumes without exceeding these speed limits, higher displacement pumps are needed. Higher displacement pumps

are larger in diameter and/or length, have higher torque requirements, and normally result in increased axial load in the rod string. Being able to run smaller pumps at higher speeds (i.e. in excess of 500 RPM) reduces these loading effects, and also opens up "insertable" pumps (where the rotor and stator are run together on the rod string) to a larger range of applications.

# Chapter 2

## ARTIFICIAL LIFT

## 2-1 Introduction:

Artificial lift is required when a well will no longer flow or when the production rate, is too low to be economic. Fig (2.1) shows unable of the well to flow, the reservoir Pressure is so low that the static fluid level is below the wellhead.

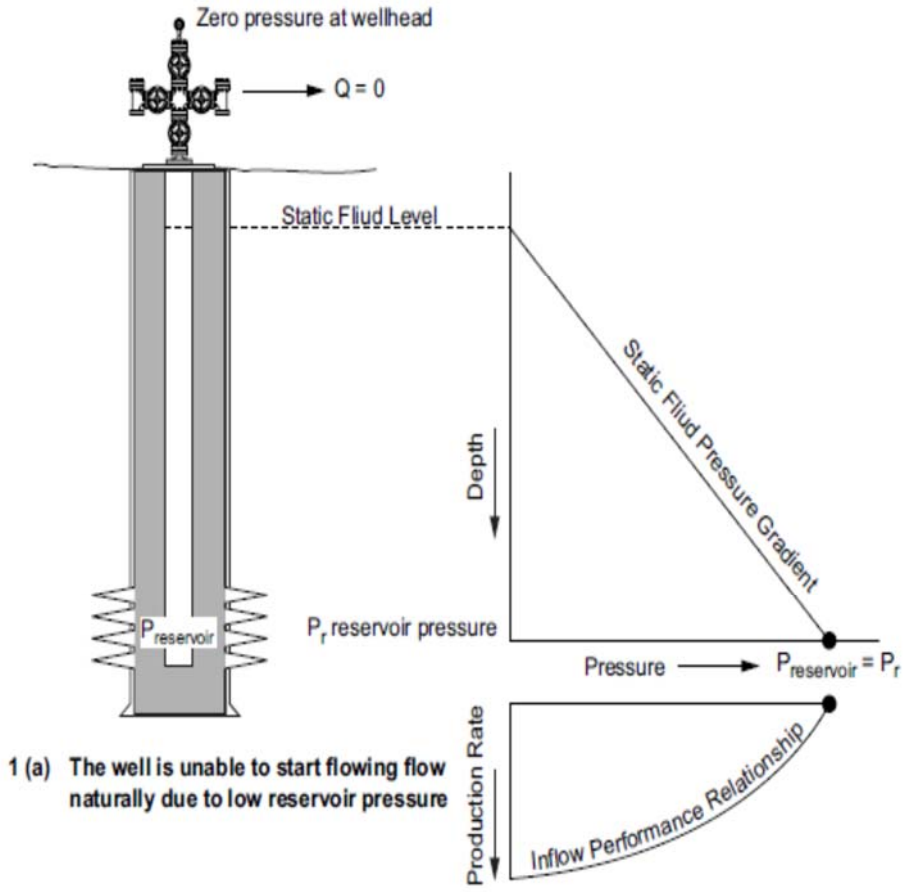



**Fig (2.1) shows oil wells unable to flow.**

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 swabbing or other techniques. Fig (2.2) Shows how installation of a pump a small distance below the static fluid level allows a limited drawdown (Δp') to be created.

The well now starts to flow at rate q. N.B. the static and flowing pressure gradients are similar since frictional pressure losses in the tubing are small at this low flow rate.

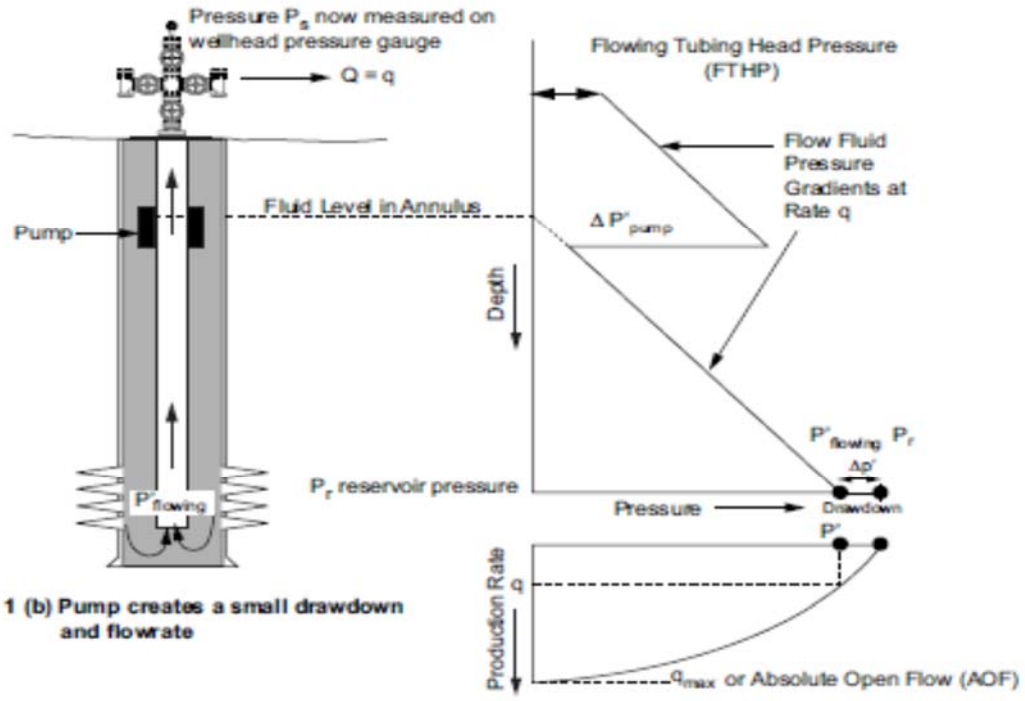



**Fig (2.2) pump creates a small drawdown.**

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 in fig (2.3) by imposing a large drawdown (ΔP") on the formation and "pumping the well-off" by producing the well at q2 is slightly smaller than the AOF.

Artificial lift design requires that the pump to be installed is matched to the well inflow and outflow performance.

*Installation of pump suction below the perforations maximises potential drawdown and production rates*

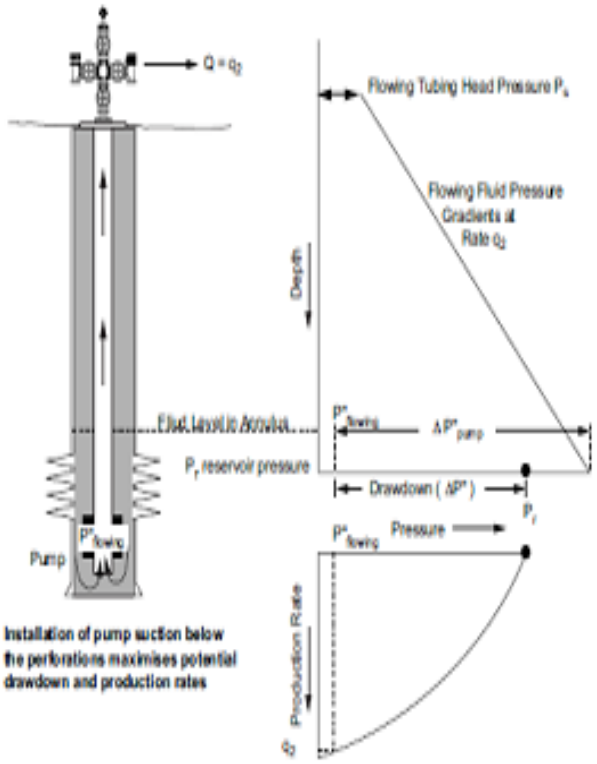



**Fig (2.3) Installation of pump suction below the perforation maximizes potential drawdown.**

## 2-2 Review of Artificial Lift Techniques:

The most popular forms of artificial lift are illustrated, in fig (2.4)

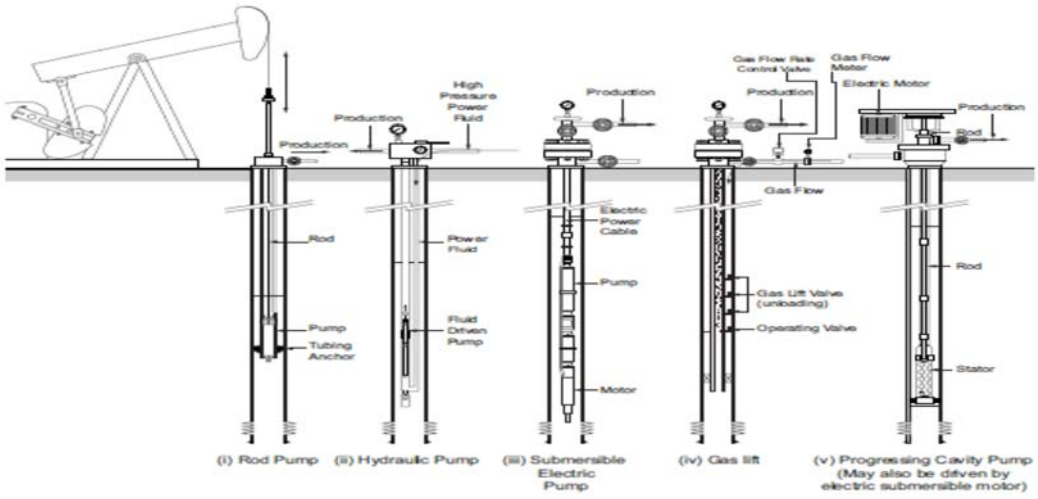



**Fig (2.4) most popular forms of artificial lift.**

### 2-2-1 Surface Processing:

In some cases surface processing falls within the domain of production technology but in other cases it is the responsibility of a separate production department. The objectives of surface processing are as follows:

1- To effectively separate oil, gas, water and remove other produced materials such as sand.

2- To monitor and adjust the chemical properties prior to separation/transport/reinjection for example:
Deaeration, Defoaming, Filtration, Scale Inhibition**.**

## 2-3 Type Of Artificial Left:

### 2-3-1 rod Pumps:

A sucker rod is the connecting link between the surface pumping unit and the subsurface pump, which is located at or near the bottom of the oil well. The vertical motion of the surface pumping unit is transferred to the subsurface pump by the sucker rods. Two types of sucker rods are in use today-steel rods and fiberglass-reinforced plastic sucker rods.

It is estimated that slightly less than 90 % of the rods sold in 1985 were steel rods, while slightly more than 10% were fiberglass rods. Steel rods are manufactured in lengths of 25 or 30 ft. Fiberglass rods are supplied in 37X- or 30-ft lengths. Both types of rods are connected by a 4-in.-long coupling.

The pin ends of the sucker rod are threaded into the internal threads of the coupling, as illustrated in Individual rods are connected to form rod strings that can vary in length from a few hundred feet for shallow wells to more than 10,000 ft. For deeper wells, Sucker rods were originally made from long wooden poles with steel ends bolted to the wooden rod. An improvement was to use steel instead of wood and to forge the upset end on the steel rod.

Forging the end generates a heat transfer zone by the upset, which is susceptible to corrosion attack. Full-length heat treating of the steel rod eliminated this problem. While the genera1 geometry of the steel rod has remained relatively

unchanged, improvements in surface finish, surface condition, end straightness, metallurgy, and quality control have been responsible for increased performance.[iv]

### 2-3-2 Hydraulic jet pumps:

Jet pumps are a type of down hole pump that can be used in hydraulic pumping systems instead of the reciprocating pumps previously discussed. They can be adapted to fit interchangeably into the BHA's designed for the stroking pumps. In addition, special BHA's have been designed for jet pumps to take advantage of their short length and their high-volume characteristics.

Because of their unique characteristics under different pumping conditions, jet pumps should be considered as an alternative to the conventional stroking pumps. Although technical references to jet pumps can be found as far back as 1852. " it was not until 1933" that a consistent mathematical representation was published, which included suggestions for pumping oil wells. Angier and Cracker I6 applied for a patent on an oil well jet pump in I864 that looked very much like those currently marketed.

" Jacuzzi" received a patent in 1930 for jet pumps that were subsequently used in shallow water wells very successfully. McMahon's also received the first of six patents on oil well jet pumps in 1930. Apparently McMahon built and marketed pumps in California in the late 1930's. But they did not achieve widespread usage. Hardware improvements and the advent of computer models for correct application sizing in oil wells led to the successful marketing of jet pumps in 1970. Use of jet pumps has grown steadily since then.

More recent publications on hydraulic pumping that describe the use of jet pump in oil wells include those by Wilson. " (Bell and Spisak, - Christ and Zublin6 Nelson, I') Brown, O Clark," Bleakley. Much of the following discussion derives, example of the simplest down hole jet free-pump completion, the single-seal style, is shown in The most significant feature of this device is that it has no moving parts.

The pumping action is achieved through energy transfer between two moving streams of fluid. The high-pressure power fluid supplied from the surface passes through the nozzle where its potential energy (pressure) is converted to kinetic energy in the form of a very-high velocity Jet of fluid. Well fluids surround the power-fluid jet at the tip of the nozzle, which is spaced back from the entrance of the mixing tube.

The mixing tube. Usually called the throat, is a straight, cylindrical bore about seven diameters long with a smoothed radius at the entrance. The diameter of the throat is always larger than the dim ammeter of the nozzle exit, allowing the well fluids to flow around the power-fluid jet and be entrained by it into the throat. In the throat, the power fluid and produced fluid mix, and momentum is transferred from the power fluid to the produced fluid, causing an energy rise in it. By the end of the throat, the two fluids are intimately mixed, but they are still at a high velocity, and the mixture contains significant kinetic energy.

The mixed fluid enters an expanding area diffuser that converts the remaining kinetic energy to static pressure by slowing down the fluid velocity.

The pressure in the fluid is now sufficient to flow it to the surface from the down hole pump. With no moving parts, jet pumps are rugged and tolerant of corrosive and abrasive well fluids. The nozzle and throat are usually constructed of tungsten carbide or ceramic materials for long life. Jet pumps are compact and can even be adapted to TFL completions that require the pump to be circulated around a 5ft-radius loop in the power-fluid tubing at the wellhead. Successful jet-pump adaptations have also been made for sliding side doors in both the normal and reverse flow configurations. These are normally run in on wire line or as a fixed or conventional installation on continuous coiled tubing, and have been successful in offshore drillstock testing (DST) of heavy-crude reservoirs.

Other applications include the dewatering of gas wells.” With different sizes of nozzles and throats, jet pumps can produce wells at less than 50 B/D or up to rates

in excess of 10,000 B/D. As with all hydraulic pumping systems, a considerable range of production is possible from a particular down hole pump by controlling the power-fluid supply at the surface.

In a given size tubing, the maximum achievable rates are usually much higher than those possible with stroking pumps. Significant free-gas volumes can be handled without the problems of pounding or excessive wear associated with positive displacement pumps, or the inlet choking encountered in centrifugal pumps. The lack of vibration and the free pump feature make them ideal for use with pump down pressure recorders to monitor BHP's at different flow rates. Because they are high-velocity mixing devices, there is significant turbulence and friction within the pump, leading to lower horsepower efficiencies than can be achieved with positive-displacement pumps.

This often leads to higher surface horsepower requirements, although some gassy wells may actually require less power. Jet pumps are prone to capitation at the entrance of the throat at low pump intake pressures, and this must be considered in design calculations. Also, because of the nature of their performance curves, the calculations used for installation design are complex and iterative in nature and are best handled by programmable calculators or computers.

Despite these limitations, their reliability and volume capability make them attractive in many wells, and their use has become widespread since commercial introduction in the early 1970's.

- **Performance Characteristics**

Intuitively, larger-diameter nozzles and throats would seem to have higher flow capacities, and this is the case. The ratio of the nozzle area to the throat area is an important variable, however, because this determines the tradeoff between produced head and flow rate.

This leads to low production rates compared to the power-fluid rate, and because the energy of the nozzle is transferred to a small amount of production, high heads will develop.

Such a pump is suited for deep wells with high lifts. Substantial production rates can be achieved if the pump is physically large, but the production rate will always be less than the power-fluid rate. If a throat is selected such that the area of the nozzle is only 20% of the area of the throat, much more flow area around the jet is available for the production. However, because the nozzle energy is transferred to a large amount of production compared to the power-fluid rate, lower heads will be developed.

Shallow wells with low lifts are candidates for such a pump. Any number of such area combinations is possible to match different flow and lift requirements best. Attempting to produce small amounts of production compared to the power-fluid rate with a nozzle/throat-area ratio of 20% will be inefficient as a result of high turbulent mixing losses between the high-velocity jet and the slow-moving production. Conversely, attempting to produce high production rates compared to the power-fluid rate with a nozzle/throat-area ratio of 60% will be inefficient because of high friction losses as the produced fluid moves rapidly through the relatively small throat.

Optimal ratio selection involves a tradeoff between these mixing and friction losses. As a type of dynamic pump, jet pumps have characteristic performance curves similar to electric submersible pumps.

An example is shown in a family of performance curves is possible, depending on the nozzle pressure supplied to the pump from the surface. Different sizes of throats used in conjunction with a given nozzle give different performance curves.

If the nozzle and throat areas of the pumps represented in were doubled, the nozzle flow rates would double, and the production rates would double for each value of the pressure rise.

The maximum AI, at zero production rates would remain the same. The curves are generally fairly flat. Especially with the larger throats, which makes the jet pump sensitive to changes in intake or discharge pressure. Because variable fluid mixture densities, gas/liquid ratios, and viscosities affect the pressures encountered by the pump, the calculations to simulate performance are complex and iterative in nature, and lend themselves to a computer solution.[v]

**2-3-3 Electric Submersible Pump (ESP):**

Centrifugal pumps powered by down hole motors have been used for decades to lift fluids from oil wells. These pumps and their coupled motors are commonly referred to as "Electrical Submersible Pumps" or "ESPs".

In recent years, the meaning of the term "ESP" has become clouded with the application of down hole electric motors coupled to progressive cavity pumps. However, the industry still refers to the more conventional centrifugal pumping equipment using the term "ESP".

Some of the classical considerations for analyzing, designing, and monitoring of down hole centrifugal pumps.

The term "ESP" is always used as an abbreviation for "down hole centrifugal pump powered by a coupled electric motor". Experience has shown that proper design and application of ESP equipment rests on three pillars:

- Understanding the well's productivity.
- Understanding the fluid ratios and phase behavior of the fluids produced by the well.
- Careful analysis of activity in each stage of the actual installed pump.

Failure to accurately model the well's inflow performance behavior will inevitably result in over-sizing or under-sizing the pump. In the absence of a variable frequency drive for pump output, this can be disastrous.

An oversized pump will "pump the well-off". Typically, a "pump off" condition will trigger a "current under load" shutdown of the motor. The well will remain "down"

for a predetermined period of time and then start–up again. This behavior is commonly referred to as “cycling”.

Since startups create great strains on motors and pumps, cycling will often lead to premature equipment failure. Conversely, an undersized pump will fail to achieve optimum production. Once this is detected, the equipment may have to be replaced. Regardless of whether the equipment is replaced, an undersized pump will significantly reduce the well’s rate of return (ROR).

The types of fluids being pumped, and the response of those fluids to changes in temperature and pressure have a tremendous impact on pump performance. Proper design and monitoring requires an accurate description of the Pressure-Volume-Temperature, and phase behavior of produced fluids. Finally, the pump must be considered as a series of individual stages (or individual pumps).

In many cases, each pump stage compresses the produced fluids and passes a different volume (although same mass) of fluid to the next higher stage. These results in different head break horsepower, and efficiency ratings for each stage of the pump.

In addition, it is crucial to analyze pump performance based on a “known good” condition. Experience has shown that each serialized pump demonstrates unique performance data. Therefore, a factory pump test should be obtained before the pump is installed in a well. The data from this test can be used throughout the equipment life for accurate performance analysis.

This discussion is limited to conventional applications of centrifugal pumps – specifically excluding:

- Pumps installed below the producing formation.
- Down hole gas separation.
- Variable frequency drives considerations.

Focus is placed upon the pump itself. The down hole motor is discussed only in passing. Steady-state operation (no Pump cycling) is also assumed.

If the option of an ESP is to be considered for a particular well, the designer must compare the “well requirements” curve with the performance characteristics of different pumps. These performance characteristics are typically communicated in the form of “pump curves”, fig (2.5)

In Design, a single graph will contain curves for dynamic head, shaft horsepower requirements, and efficiency. The curves are typically based on fresh water and a fluid viscosity of 1 cp.

The horizontal axis represents actual rate through the pump. Head, brake horsepower, and efficiency are usually represented for more than one pump stage.

It is a good practice to operate the pump close to this high efficiency point (known as the Best Efficient Point or “BEP”). Therefore, one of the main pump selection criteria (along with physical size) is the pump’s advertised BEP.

Once a pump type has been selected.

The number of stages in the pump is calculated based on the pump’s “head” curve and pressure requirement derived from the “well requirements” curve

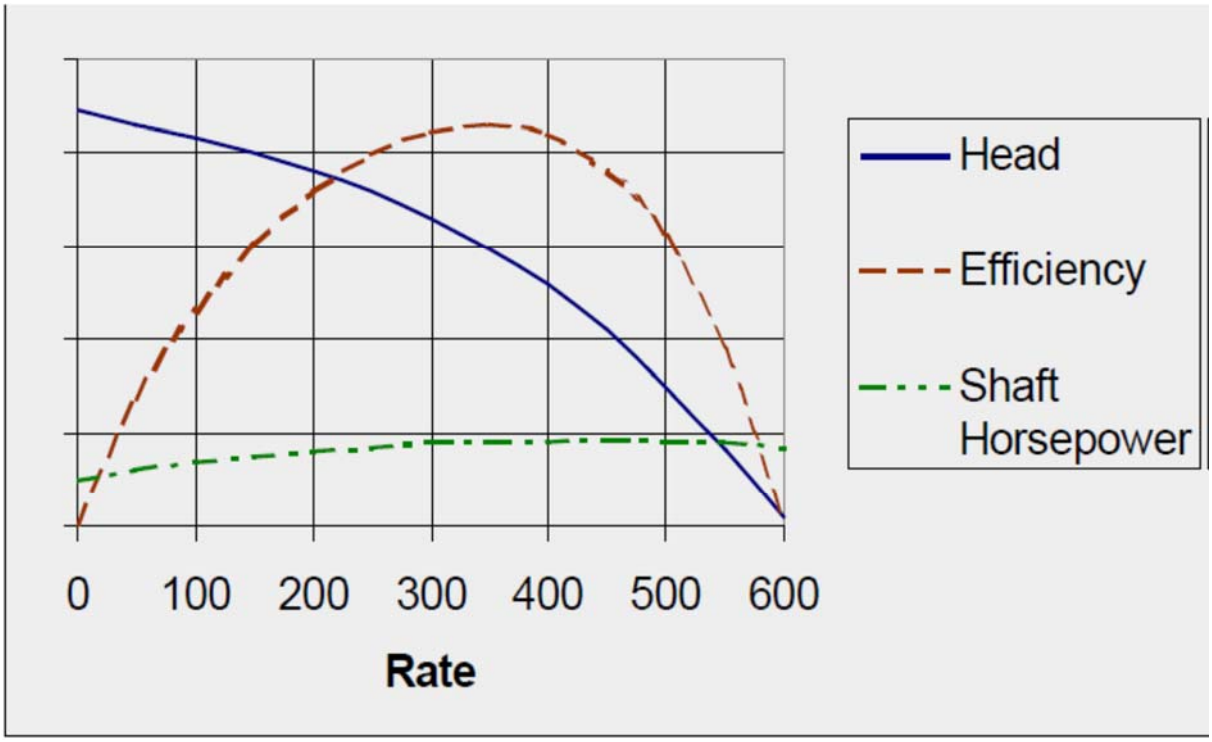



**Fig (2.5): ESP pump performance carve**

- **RPM "Rules"**

Another commonly overlooked feature of centrifugal pump design and analysis is true rotational speed of the pump.

Note that pump performance statistics are published at specific revolutions per minute (RPM) value. By American Petroleum Institute (API) standards, this value should be 3500 RPM. This is the "nominal" rotational speed of electrical submersible type motors under 60 Hz alternating current (AC) operations.

As the actual rotation of the centrifugal pump deviates from the published RPM basis, things begin to change rapidly.

Pump output volume is proportional to the ratio of the actual RPM to the published RPM basis. Head production; though, varies with the square (to the second power) of the RPM ratio.

Shaft horsepower requirements are proportional to the RPM ratio cubed (to the third power). Therefore, it is desirable to predict the pump rotational speed in order to gain an accurate understanding of the behavior of the pump system. The electrical motor used to drive the pump almost never operates at 3500 RPM. In fact, when the motor is significantly oversized, it may rotate 5 to 10% faster.

Under normal loading, however, the motor may only drive the pump to 3400 RPM or less. ESP manufacturers publish performance curves for motors as well as pumps. These performance specifications come in the form of "RPM as a function of percentage of nameplate horsepower loading".

Therefore, Subs Design calculates the shaft horsepower required to drive the pump under design conditions so the user can use the motor performance specifications to determine the operating RPM that should be expected when the pump is installed. However, as stated earlier, the pump shaft horsepower requirement is a function of – among other things – RPM. Therefore, an iterative process is required to accurately model the pump and motor as a coupled system.

First, pump shaft horsepower requirements are calculated based on 3500 RPM operation, then the motor's RPM is determined based upon that load. The new RPM value is then used to recalculate pump head, rate, and efficiency – as well as shaft horsepower requirements. Once again, the motor performance specifications are used to determine RPM.

The process is continued until the calculated RPM converges. Many would consider the process described above as "hair splitting". Based on manufacturers' published data, the maximum benefit that one could expect from this exercise is a 3% improvement in rate estimate, a 6% improvement in head estimate, and an 8.5% improvement in break horsepower estimate. However, small percentages in efficiency over the life of an ESP can result in significant savings in operating costs.[vi]

- **Pumping Equipment Efficiency**

One useful way to calculate efficiency in an electrical submersible centrifugal pump installation could be referred to as "pumping equipment efficiency". This efficiency reflects the ability of the power cable, motor, and pump to transform electrical energy at the surface into fluid energy at the pump discharge. The simplified equation for this efficiency is:

Pumping equipment efficiency = (⊗ Energy through the Pump)/ (Kilowatts of electricity in)

Where:

(⊗ Energy through the Pump) = Fluid energy at pump discharge – fluid energy at pump intake.

Given reasonable estimates of pump intake pressure, tubing discharge pressure, oil, water, and gas flow rates, and fluid PVT behavior, modeling tools can be used to derive the "⊗ energy" term in this equation. However, the calculations are quite rigorous and require computer software support.

The utility of this efficiency measurement is twofold. During the design phase, it can be used to compare the operating costs of various artificial lift alternatives for a given

well. The comparison could be between different ESP designs, or between an ESP design and other pumping method alternatives.

After the equipment has been installed, this efficiency calculation provides a useful tool for monitoring the artificial lift equipment.

The “pumping equipment efficiency” is fairly insensitive to conditions downstream of the well. The calculation also removes the influence of the well’s contribution to fluid flow. Therefore, this value is an excellent tool for surveillance of the cable, motor, and pump.

- **Well System Efficiency**

Once we fully understand the traditional equation for efficiency, we can use it in very practical ways. We define “well system efficiency” as:

Well system efficiency = (Hydraulic horsepower at tubing discharge)/ (Kilowatts of electricity in).

This efficiency measure is subject to all of the influences previously described. However, when it is used in conjunction with “pumping equipment efficiency”, it can reveal changes that occur in and around the well. For instance, a decline in “well system efficiency” that is not accompanied by a decline in “pumping equipment efficiency” may be an indication of reservoir depletion or damage. Large anomalies in both efficiency values may be an indication of a tubing leak.

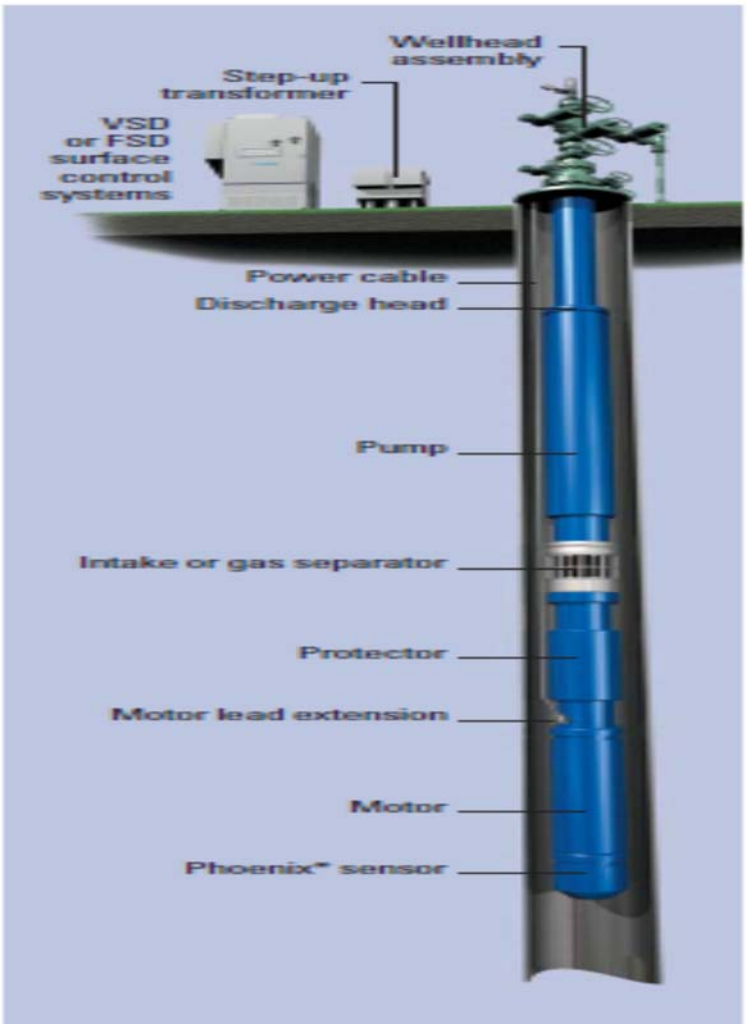



**Fig (2.6): ESP components**

- **Advantages of Electric Submersible pumps**

  1- Wide performance range and versatility.

  2- Most efficient and economical lift method on cost-per barrel basis.

- **Disadvantages of Electric Submersible pumps**

  1- Tubing must be pulled to change or repair.

  2- Depth and GOR restrict capacity and operation efficiency.

  3- Large volumes of gas can lock up the pump**.**

### 2-3-4 Gas Lift:

The only energy utilized in lifting liquids to the surface is that provided by the expansion of the compressed gas from the pressure in the production conduit at the point of injection to the pressure at the wellhead. The pressure drops taken (from the compressor to the wellhead, across the surface injection gas control device, through the injection conduit, across the gas lift valve into the production conduit, up the production conduit, and from the wellhead to the storage tank) are all energy losses. The intent of the gas lift installation design is to maximize the benefits from the lift energy used, i.e., to allow the compressed gas to be injected into the produced fluid as deep and at a pressure as close to compressor discharge pressure as possible or necessary. Such an approach normally maximizes production with a minimum of operating costs.

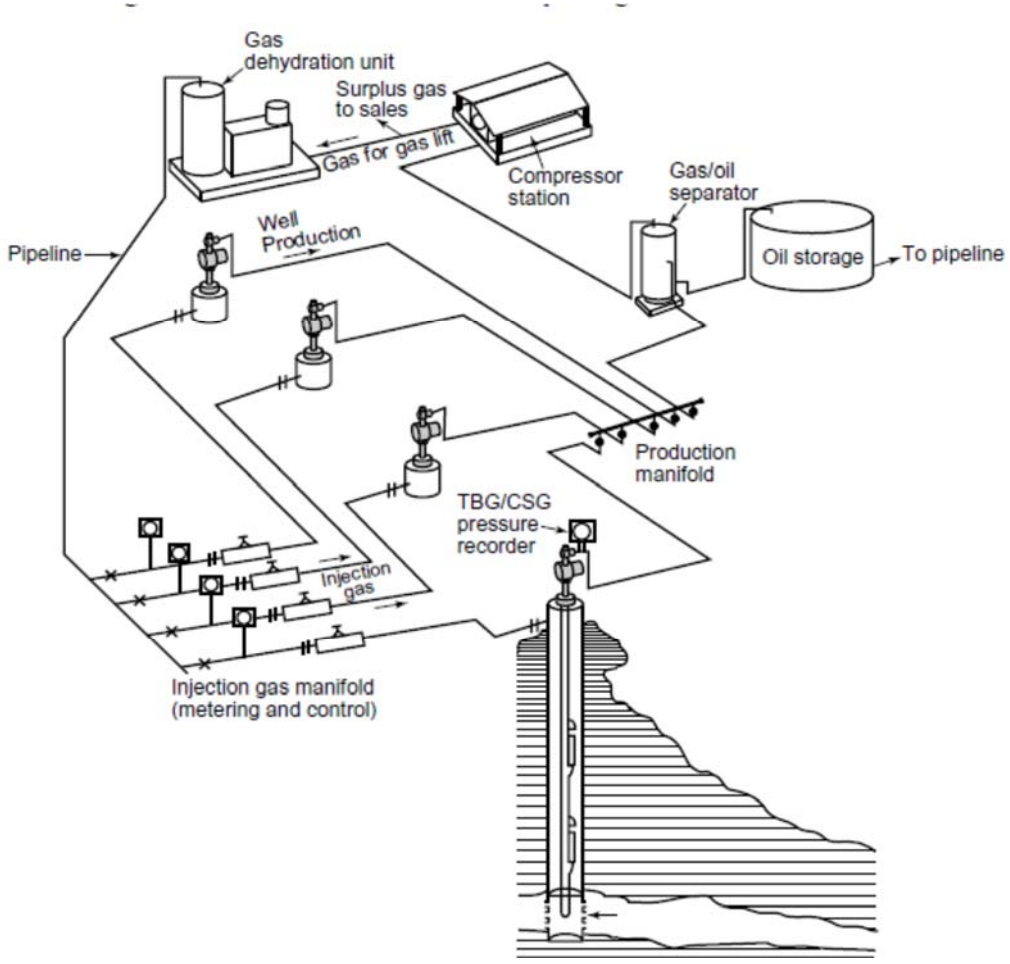



**Fig (2.7): gas left system.**

- **Tubing or annulus (production conduit) flow area/size**

The flow area is an important factor in gas lift design. A small conduit size increases the friction loss and may severely restrict rates. However, too large a conduit size may result in unstable flow (excessive gas slippage) and will cause the production to “head. Heading results in numerous producing problems.

In a typical design for flow up the tubing, the gas lift designer should always evaluate changing to different size tubing.

Select a conduit size that permits flow rates in the stable flow region without excessive friction losses. In general, tubing size should be selected by using a total systems analysis approach.

- **Facilities**

Gas handling facilities, gas compressors, meters, and pipelines are the highest equipment cost portion of the gas lift system. This equipment usually requires more operating and maintenance costs than any other part of the gas lift system. The design of such equipment is beyond the scope of this recommended practice. Hopefully, the surface facilities will provide an efficient, dependable, adequate volume and pressure supply of dry, noncorrosive, clean injection gas over the life of the project.

Also, back pressure exerted on the producing wells as a result of pressure losses in the surface production facilities should be relatively low and the system provided with good control and measurement equipment.

- **Gas Injection Pressure**

The operating injection gas pressure should be selected with care. Often the injection pressure used is based on the gas sales system discharge pressure rather than on the optimum gas lift performance. In general, gas lift systems are more efficient and cost effective if the gas injection point is near the producing formation. By deep injection, more production is normally achieved and/or less injection gas is required. Thus, when feasible, select an injection gas pressure that will permit gas injection just above the producing zone.

- **Kick-Off Injection Gas Pressure**

The injection system may permit using a higher than normal injection gas kick-off pressure for a short period of time. Some systems may have a higher pressure stage compressor or outside high pressure source that can be used for temporarily unloading or kicking off a well. Most systems have a range of normal operating pressure. Selecting a higher than normal pressure might restrict the unloading to specific time periods.

Use of a kick-off pressure in locating the depth of the first valve is a fairly common practice that is worthy of consideration, since it may allow deeper lift. Caution should be exercised in selecting this kick-off pressure since this elevated pressure will be required in future unloading cases.

- **Valves**

The heart of the gas lift system is the gas lift valve. In general, the designer should select a valve size, type, and design that will permit reliable, adequate single-point gas injection without frequent repairs. In most cases, simple, unbalanced, injection pressure-operated, nitrogen-charged bellows valves meet this requirement.

Valves can be classified as either injection pressure or production pressure (fluid) operated. Injection pressure operated valves are primarily controlled (opened) by the injection gas pressure; whereas, production pressure operated valves are primarily controlled by the flowing production pressure at valve depth.

Continuous flow gas lift valves normally have bellows. The most common type of valve has nitrogen charged bellows which makes the valve opening pressure subject to changes in temperature. Another common valve design uses a bellows that does not have a nitrogen closing force using a spring for the closing force. Temperature effects are negligible on such valves.

When using this type of valve in high pressure installations, it may be necessary to supplement the spring force with a dome charge because a spring alone may not develop adequate closing force. This practice does mean, however, that temperature

must be considered when calculating the valve test rack set pressure (for the portion of the opening force supplied by the dome charge).

Different sizes and types of valves have specific load rates, which mean that the stem will move off the seat an estimated distance for a specific opening pressure condition. Such conditions should be considered in selecting the valve for a given injection rate-especially in high rate wells that require high gas injection rates.

At high gas injection rates, some valves become restricted. Check with the manufacturer to see if a single valve will pass the required rate in such cases. Also as a general rule, select the smallest valve port size that will pass the required injection gas rate.

The large ported valves are more likely to inadvertently reopen and cause multi-point gas lift injection than are small ported valves, due to a higher production effect factor:

Gas lift valves typically are available in three sizes; 5/8-in., 1-in., and l1/2-in. The 5/8-in. valves are recommended only where clearance makes their use mandatory.

The most commonly used gas lift valve is the 1-in. These 1-in. valves are typically used in most low rate wells equipped with 23/8 in. tubing. They are used with both conventional and wire line retrievable mandrels. Some operators prefer the l-in. valve-especially for higher rate wells with larger tubing sizes. These larger valves have better flow characteristics than the smaller valves and have corresponding lower production pressure effect factors.

Thus, where port sizes larger than 1/4-in. are needed for gas passage, use of l1/2-in. valves are recommended.

- **Advantages and Limitations of Gas Lift**

1. Initial cost of down hole gas lift equipment is usually low.
2. Flexibility cannot be equaled by any other form of lift. Installations can be designed for lifting initially from near the surface and for lifting from near total depth at depletion. Gas lift installations can be designed to lift from one to many thousands of barrels per day.
3. The producing rate can be controlled at the surface.
4. Sand in the produced fluid does not affect gas lift equipment in most installations. Gas lift is not adversely affected by deviation of the wellbore.
5. The relatively few moving parts in a gas lift system give it a long service life when compared to other forms of artificial lift.
6. Operating costs are usually relatively low for gas lift systems.
7. Gas lift is ideally suited to supplement formation gas for the purpose for artificially lifting well, here moderate amounts of gas are presenting the produced fluid.
8. The major item of equipment (the gas compressor) in a gas lift system is installed on the surface where it can be easily inspected, repaired maintained. This equipment can be driven by either gas or electricity On the other hand, gas lift also has certain limitations which can be summarized as follows:

I. Gas must be available. In some instances air, exhaust gases, and nitrogen have been used but these are generally more expensive and more difficult work with than locally produced natural gas.

II. Wide well spacing may limit the use of a centrally located source of high pressure gas. This limitation has been circumvented on some wells through the use of gas-cap gas as a lifting source and the return of the gas to the cap through injection wells.

III. Corrosive gas lift gas can increase the cost of gas lift operations if it is necessary to treat or dry the gas before use. Installation of a gas lift system

including compressors usually requires a longer lead time and greater preparation than does single well pumping systems.

In addition, the initial surface installation for gas lift will sometimes be more expensive than equivalent pumping installations. However, the reduced operating cost of the gas lift system will usually far outweigh any additional cost of the initial installation. Also, if the associated gas will be gathered and compressed, as is usually the case, provisions for circulating some of the compressed gas for gas lift will not, in most cases, significantly increase the initial cost.

IV. In very low pressured reservoirs, continuous flow gas lift cannot achieve as great.

V. A pressure drawdown as can some pumping systems. However, hen low flowing Bottom hole pressure **is** desired, the use of intermittent lift and chamber lift forms of gas lift can usually achieve pressure draw down comparable to pumping systems.

VI. Conversion of old wells to gas lift can require a higher-level of casing integrity than would be required for pumping systems.[vii]

### 2-3-5 Progressing Cavity Pump (PCP):

Employs a helical, metal rotor rotating inside an elastomeric, double helical stator. The rotating action is supplied by down hole electric motor or by rotating rods in fact, nearly all the major classes of pumps are employed in the various forms of artificial lift In fact, nearly all the major classes of pumps are employed in the various forms of artificial lift.

## 2-4 All Methods at Glance:

| | Gas lift | SRP | ESP | Hydraulic piston pump | PCP |
|---|---|---|---|---|---|
| **Operation depth (TVD)(ft)** | 5000 - 15,000 | 100 - 16,000 | 1,000 - 15,000 | 7,500 - 17,000 | 2,000 – 6,500 |
| **Operation volume (BPD)** | 100 - 30,000 | 5 - 5,000 | 200 - 30,000 | 50 - 4,000 | 5 - 4,500 |
| **Operation tem (F)** | 100 - 400 | 100 - 550 | 100 - 400 | 100 - 500 | 75 –300 |
| **Corrosion handling** | Good to excellent | Good to excellent | good | excellent | fair |
| **Gas handling** | excellent | Fair to good | Poor to fair | good | good |
| **Sold handling** | good | Fair to good | Poor to fair | good | excellent |
| **Fluid gravity** | >15 | > 8 API | >10 API | > 8 API | <47 API |
| **surfacing** | Workover-wire line | Workover | Workover | Hydraulic/ wire line | Workover |
| **Prime mover** | Compressor(diesel/gas/electricity) | (diesel/gas/electricity) | Electric motor | (diesel/gas/electricity) | (diesel/gas/electricity) |
| **Off sure application** | excellent | limited | excellent | excellent | good |
| **Overall system efficiency** | 10 - 30%- | 45 - 60% | 35 - 60 % | 10 - 30 % | 40 - 85 % |

**Table (2-1) shows artificial lift methods in glance.**

# Chapter 3

## Progressing Cavity Pumps.

## PCP

## 3-1 INTRODUCTION:

The progressing cavity pump (PCP) is a type of positive displacement pump capable of moving nearly any fluid. Liquids of nearly any viscosity, liquid-gas mixtures, and even liquids with large solid particles in suspension can all be pumped equally well with a PCP [viii]

The Progressing Cavity (PC) Pump is a widely accepted means of artificial lift. High production, lift capacity, and system efficiency are benefits of PC pumping systems over other oil & water pumping systems. Their tolerance of sand and viscous fluids make PC pumps the best solution in heavy oil production. PC pumps tolerate high gas oil ratios and are very useful in pumping mixtures of sand, oil, gas and water. PC Pumps are comprised of only two parts - a helical shaped steel rotor and a stator. The rotor, which is the rotating internal component of the pump, is normally driven by a rod string. It is precision machined from high strength steel and coated with a wear resistance layer, such as chrome.

The stator is attached to the production tubing string and remains stationary during normal operation. It consists of a molded elastomer permanently bonded to the inside of a steel tube.

As a PC Pump operates, the cavities formed between the stator and rotor moves fluid upward, in a non-pulsating action, from the suction to the discharge of the pump. Pressure builds linearly from the inlet to the discharge of the pump providing the necessary lift to produce fluid to surface.

## 3-2 Progressing Cavity Pump History:

The Progressive Cavity Pump (PCP) was invented by René Moineau in 1932. PCP's became widely used as surface pumps, especially for the pumping of viscous mixtures. In 1979, the first PCP's were installed in the sand producing heavy oil wells of Canada.

The PCP is able to produce in highly viscous sand, making it the primary artificial lift system for conventional heavy oil production around the world.

PCP technology developed rapidly in Canada due to heavy oil accounting for a third of its conventional production. There are approximately 40,000 PCP's running worldwide, 80% of which are in Canada.

PCP's have reduced the lifting costs for heavy crude from approximately $8/bbl. to less than$3/bbl. It has made heavy oil production consistently profitable after many years of unsuccessful efforts with other technologies.

PCP manufactures has developed a high capacity head pumps as well as elastomers that are resistant to medium and light crudes. Compared to conventional artificial lift methods, PCP systems decrease capital and operating costs by 25% transport costs are also reduced due to the small footprint and easy installation procedures.

### 3-3 Typical progressing cavity pump:

PC pump basically consists of a hydraulic section (a rotor inside a stator) and a drive frame transmitting the shaft rotation to the hydraulic section by means of a connecting rod.

The connection is accomplished by various means: a pin joint, a universal joint (such as Cardan®), or a flexible joint arrangement.

A driver (motor, diesel, or other prime mover) is coupled to an input shaft, transmitting its energy into the mechanical energy of shaft rotation. The shaft is supported by bearings in the pump drive frame, and drive shaft rotation is translated into eccentric motion of a rotor in the hydraulic section.

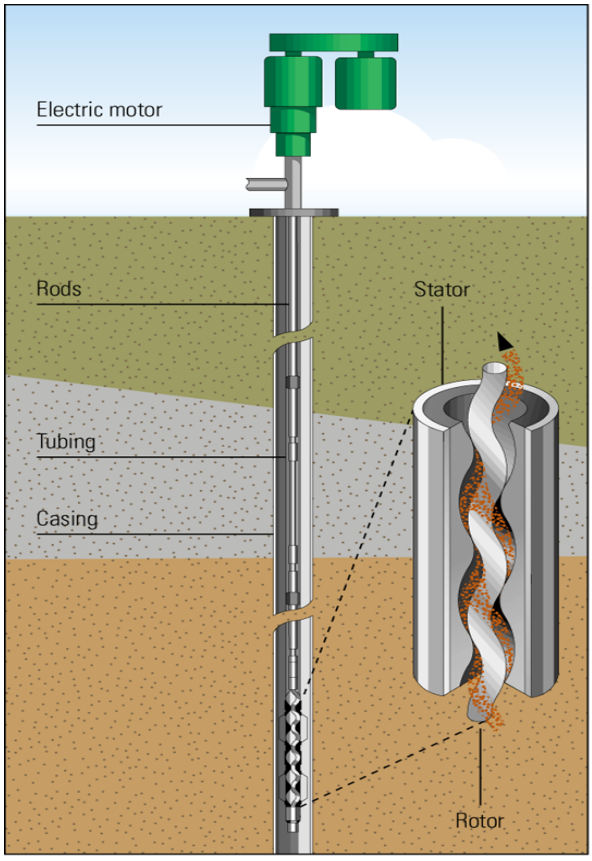



**Fig (3.1): Typical PCP pump.**

The rotor forms a cavity between itself and a stator, the eccentric motion of the rotor displaces the fluid the cavity, which "moves the term) along the axis from suction (inlet) to discharge (exit) (i.e., pumping the fluid against the discharge pressure).

PC pumps have a low "lobe ratio" as 1:2 (a one-lobed rotor inside of a two lobed stator), although 2:3 lobe ratio designs have recently been introduced.[ix]

In this study a lobe ratio of 1:2 was selected.

At any cross-section the number of separate cavities is one more than number of lobes on rotor. Cavities equally out of phase

I.e. Exampled as shows in fig (3.2).

1:2 has two cavities 180 deg. out of phase.

2:3 has three cavities 120 deg. out of phase.

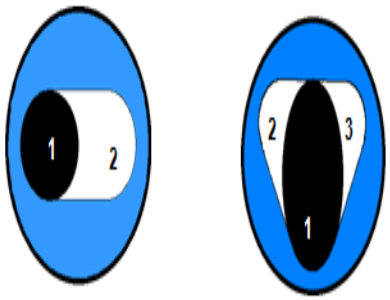



**Fig (3.2) cross section of separate cavities**

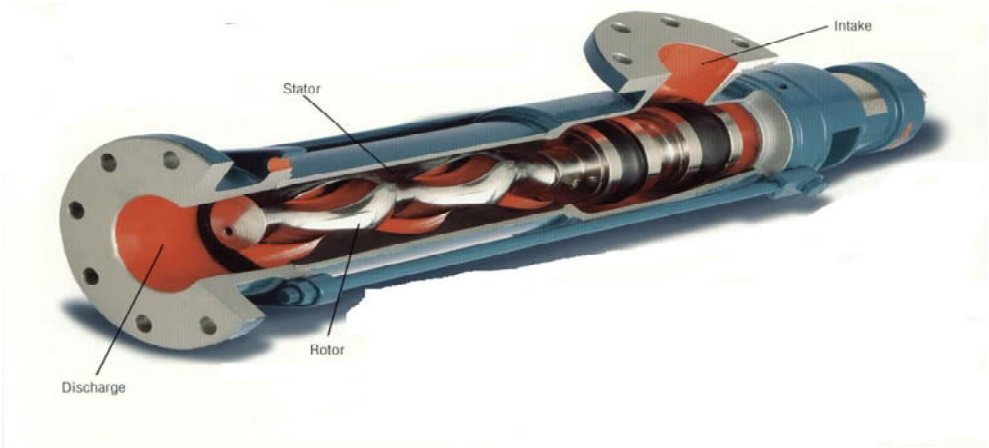



**Fig (3.3) fluid slippage for one stator pitch length.**

Progressing Cavity Pumps can be supplied in two different rotor geometries:

The more common Single Lobe, and the 2/3 Multi-Lobe arrangement.

Each design has its own characteristics and benefits depending on the application.

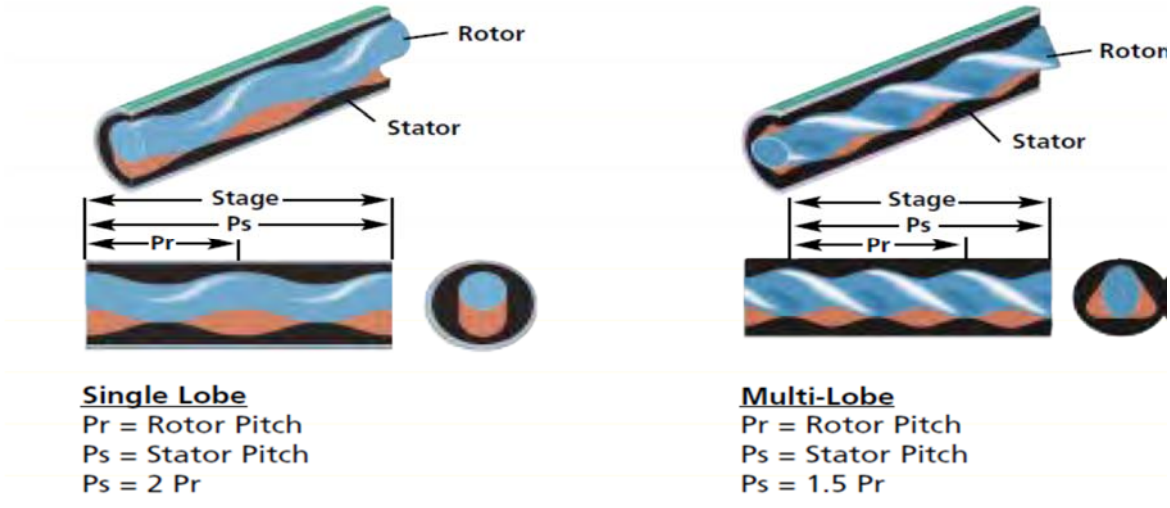



**Fig (3.4): shows number of PC pump stages.**

- Eccentricity is the difference between the rotor major and minor diameters.
- The geometry of the pump dictates the offset movement of the rotor about the stator center line.
- **Pump Displacement**

Displacement of any PC Pump is a function of the rotor diameter,
Eccentricity, and the pitch length.

- **Stage and Pressure Conventional Definition**

Pump Stage = 3 rotor pitches
= 1.5 stator pitches

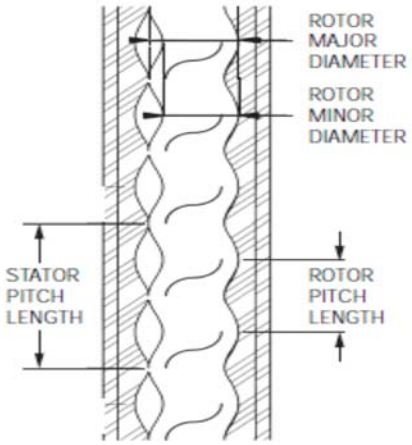



**Fig (3.5) showes the difference between stator & rotor pitch lenght**

## 3-4 Operating Principles of Hydraulic Sections:

- **Working Principle**

A PCP is made up of two parts:

### 3-4-1 Stator

The PC Pump stator consists of a steel tube, which encases an elastomer model designed to achieve a specific geometric configuration. The fabrication of the stator begins with machining a reusable metal core in the male configuration of the stator's double internal helix. The metal core is positioned in the center of the stator casing, which has been cleaned and coated internally with a metal bonding agent to the elastomer. In an application, the stator is attached to the end of the tubing

string and run into the well prior to the rotor or rods. An exception to this configuration is if an insurable PC Pump system is used.

The stator is often the weakest part of a pump. It is the part that usually gets worn out first, leading to a work over to replace it. Most of the innovation in the past has been focused on the stator elastomer material, attempting to make it stronger and adapting it to different types of well conditions (high gas/oil ration—GOR—wells, sandy wells, H2S, aromatics).

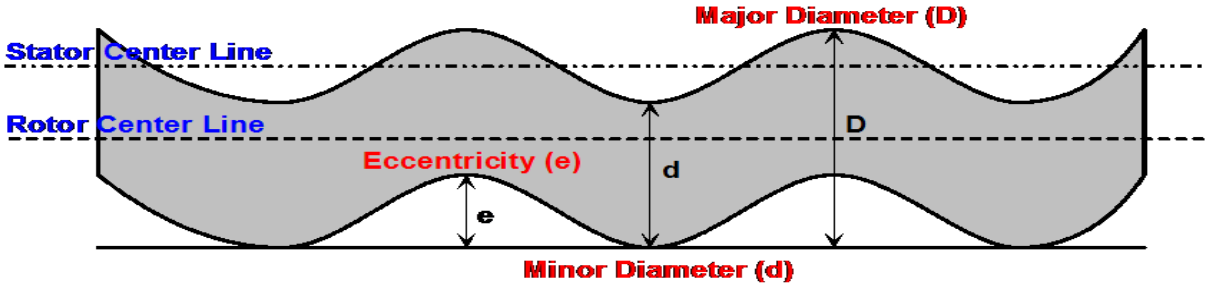



**Fig (3.6) shows the difference between the rotor major and minor diameters (e).**

### 3-4-2 Rotor

The rotor is the moving (rotating) component in a Progressing Cavity Pump. A rotor is machined from a cylindrical, high strength steel bar with a special lathe. After being machined, it is plated with a hard metal, such as chrome or a chrome alternative. This plating provides a protective coating to the rotor that minimizes abrasion, friction and corrosion damage. All rotors are made of a single, helical piece. One end of the helix is fitted with an API male thread for connection to the drive string.

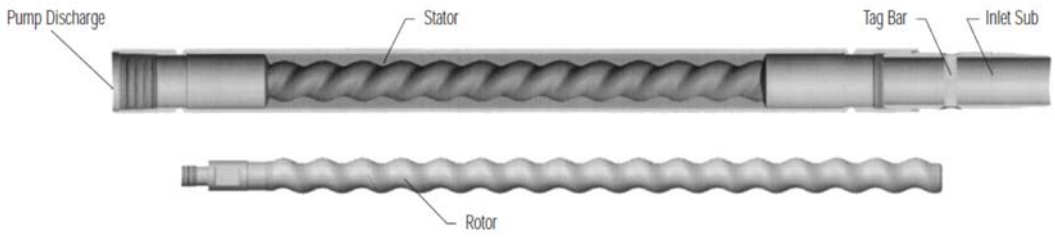



**Fig (3.7) shows stator and rotor shape.**

The rotor is supported from the surface by the drive string, which is typically a conventional or continuous sucker rod. The rotor fits secure inside the elastomer, as the rotor turns gaps or cavities are formed and fluid is driven to the surface within these cavities. With each rotation of the rotor, fluid will move one pitch length of the stator. A different type of rotor pitch determines the ideal usage for a particular application.

The amount or degree of interference fit is critical to the efficiency and life expectancy of the pump. For each pump model a range of rotors of slightly different diameters are machined. With the range of rotor lengths, diameters, and chrome thickness, there are numerous combinations available to create the optimal pump for each application.

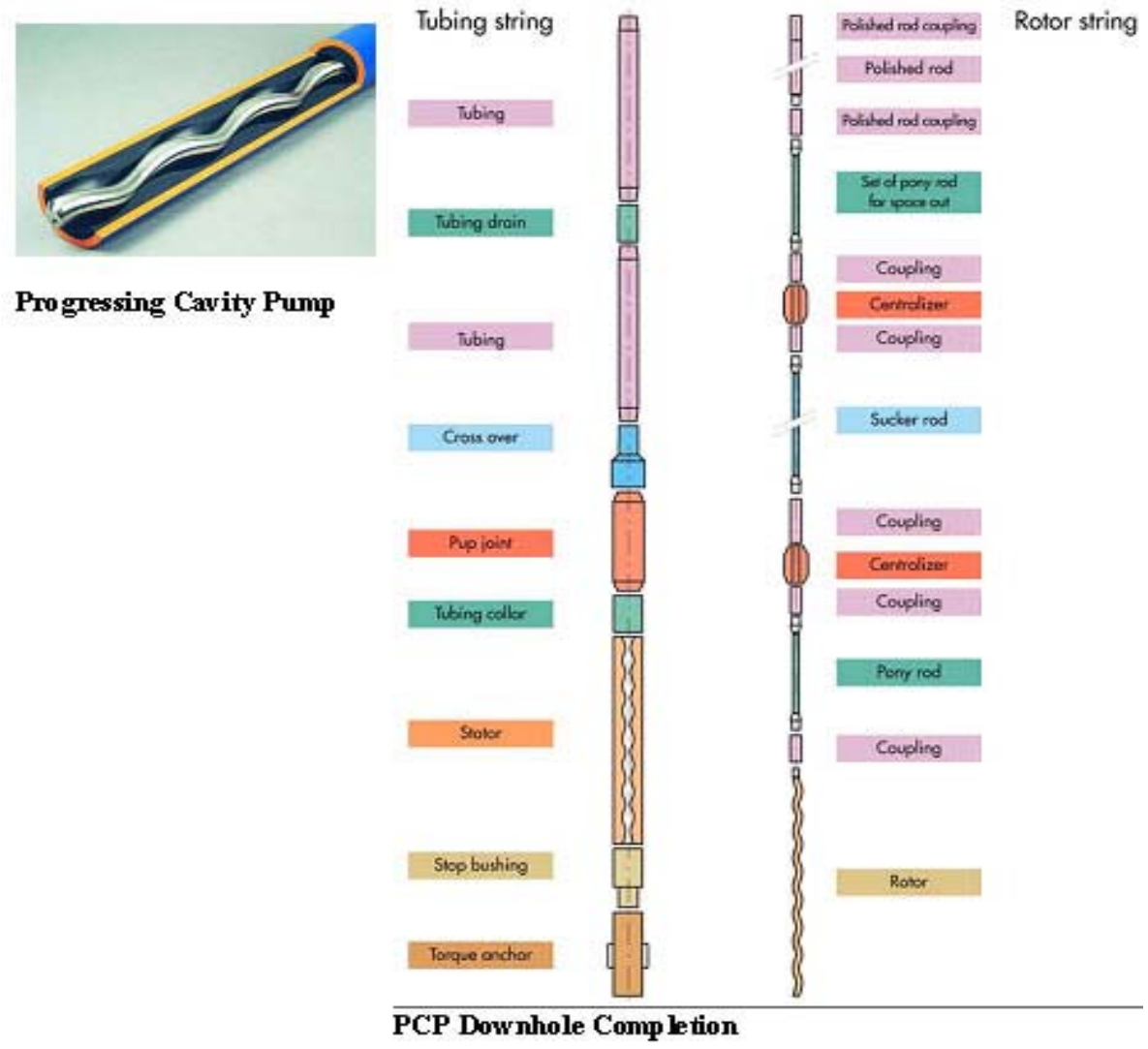



**Fig (3.8) shows PCP down hole completion**

## 3-5 Pumping System Schematic:

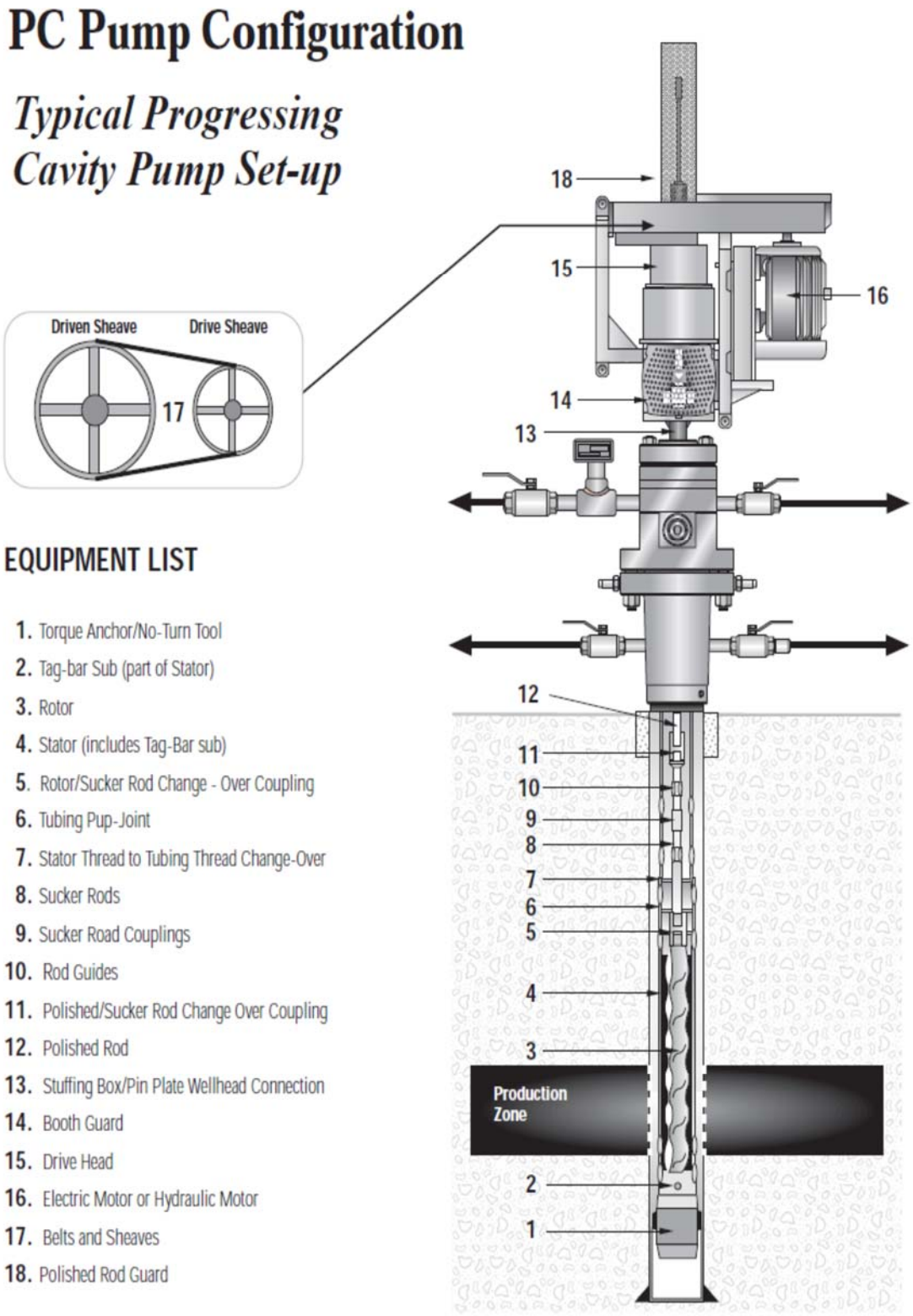



**Fig (3.9): PCP system schematic.**

### 3-6 Pump Components:

The two major components of the PC pump system are illustrated as follows,

1- Wellhead drive assembly.
2- Down hole pump (Rotor and Stator).

## 3-7 Selection Considerations:

PC Pump selection is dependent on the following conditions:

1- Production requirements.
2- Pump landed depth
3- Tubing and casing pressures
4- Fluid conditions
   - Density, viscosity, fluid level, sand and water content, aromatic content,
   - $CO_2$ & $H_2S$ presence, temperature, and gas oil ratio.
5- Tubing specifications
6- Casing specifications
7- Rod specifications
8- Drive capabilities
9- Well equipment configuration

An important factor to consider when selecting a PC Pump is the experience gained from other wells in the area. Weatherford personnel are available to assist with well design and pump selection using our wide network of experience or using a very powerful design program developed at C-FER. In order to complete a C-FER PC Pump run, the following input sheet must be filled out completely. This program can predict all elements of a Down hole Progressing Cavity Pumping System including:

- Pump speed
- Pump differential pressure
- Total input power required
- Polish rod drive torque

- Rod axial and sidewall loading
- Surface equipment loading
- Tubing life and location of high tubing wear

The program can then help determine the following:

1. Pump size (volume and lift)
2. Rod & tubing size
3. Drive system
4. Suggested rotor space out
5. Total system efficiency

## 3-8 Pump performance considerations:

There are 3 main factors that will determine the overall performance of a PC pump.

1. Well bore conditions.
2. Elastomer selection.
3. Rotor fit.

- **Well Bore Conditions**

Fluid properties, solids or abrasives concentration and gas properties all must be understood in order to properly apply a progressive cavity pump in any well.

Accurate well data is required to design a complete PC pump system that will provide satisfactory results.

Being a positive displacement pump, a certain volume of fluid is discharged with each revolution of the rotor. Unlike centrifugal pumps, the pump does not develop pressure or a head but will attempt to deliver the same volume of fluid regardless of the pressure (resistance) that must be overcome in the discharge line.

- **Elastomer Selection**

Elastomer selection for a particular application involves deciding on a particular formulation or type (i.e., medium or high NBR, HNBR, or FKM) and a specific stator supplier because the basic formulations differ between manufacturers. For the

most part, elastomer selection is based on the downhole conditions and required fluid resistance. Although mechanical properties are also important, sufficient detailed information is not routinely available from the PC pump manufacturers to make this a consideration in elastomer selection.

Most manufacturers publish guidelines for elastomer selection that are based on anticipated downhole conditions, including:

- Fluid type
- Gases
- Solids
- Operating temperature

Historically, API fluid gravity has been used as the primary measure of fluid aggressiveness in terms of elastomer swell and associated property deterioration. Although a strong trend does exist directionally, problems can arise when API gravity is used as the main selection criterion (i.e., especially at the higher end), given that fluids of the same gravity can have vastly different compositions of the aromatic components that cause swell. There are exceptions to this rule, such as the heavy oil fields in Venezuela, where the gravity is low but the quantity of aromatics is relatively high and can lead to problems with fluid swell. Although the exact value varies somewhat between manufacturers, the crossover point for medium to high NBR use is typically about 25°API. Most manufacturers do not recommend the use of a conventional NBR beyond 35 to 40°API. At the higher API gravities, the only options are FKM or perhaps HNBR formulations, although these elastomers are available only from certain manufacturers and their use is usually restricted to a narrow range of applications.

When a question exists as to the best elastomer to use, it is common practice to perform compatibility tests with the wellbore fluid and selected elastomer samples. These tests generally provide an effective means to rank the suitability of different

elastomers (i.e., especially of the same type from different manufacturers) and can be helpful in establishing appropriate rotor sizing. Results almost always consist of volume, mass, and hardness change and, in some cases, may include changes in mechanical properties. From previous testing experience and tracking of pump performance, most pump suppliers have established limits for the maximum volume and hardness change for which they recommend use of their products.

Although compatibility testing provides a more scientific way to select elastomers, it is not practical in many cases because it is difficult to get the well fluids, representative elastomer samples, and a laboratory that does the specialized testing all in the same location. Nevertheless, there are a number of techniques based solely on fluid analyses that may be used to assist in elastomer selection. Hydrocarbon analysis through chromatographic techniques has been the most widely used method, but for it to be helpful in assessing elastomer compatibility, the analysis must include detection of the hexanes plus. This results in a breakdown (mole, mass, and volume percent) by component up to C30+, so the test is often referred to by this name (i.e., C30+). Results are normally divided into paraffin, aromatic, and naphthene groups, with breakdowns of specific components within each group. The most useful information includes the total percent aromatics and levels of individual aromatic components. Most PC pump manufacturers are familiar with this testing method and have guidelines on the maximum percent aromatics recommended for each of their elastomers. A less expensive, more readily available method for fluid analysis is an aniline point test (ASTM D611). Aromatic hydrocarbons exhibit the lowest aniline point (e.g., 60°C [140°F] for diesel), whereas oils with low aromatics typically have values that are > 100°C [212°F]. This test has been used extensively to assess elastomer compatibility in the drilling industry, but its use for PC pumps is new, so relationships between aniline point and recommended elastomers are still being compiled.

The limitations to the elastomer selection "rules" associated with API gravity or hydrocarbon analysis are usually the result of temperature or H2S. Conventional NBR elastomers are normally not recommended for temperatures > 100°C [212°F] or with H2S concentrations > 2% because of the elastomer hardening that occurs over time, frequently leading to cracking and fatigue. In these cases, HNBR or FKM elastomers are more appropriate choices. However, caution must be exercised when these elastomers are considered because the fluid resistance of the HNBR elastomers varies significantly by manufacturer and mechanical loading considerations must be addressed with FKM elastomers.

Despite all these selection methods, it is important to point out that operators are typically faced with using a "trial-and-error" approach to determine optimal elastomer selection and pump sizing when applying PCP systems in new areas. [x]

Fluid properties and well bore temperature will determine the correct elastomer choice.

| Elastomer Name | Elastomer Type (ACN Level) | General Description & Application | Temp Limit | | Chemical Resistance | | | | Mechanical Properties | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | °F | °C | $H_2S$ | $CO_2$ | Aromatics | Water | Wear Resistance | Hardness (Shore A) |
| E1 | Medium Acrylonitrile | • Excellent Oil and abrasion resistance<br>• Superior mechanical and dynamic properties<br>• Good for up to 25° API Oil | 212 | 100 | Fair | Fair | Fair | Excellent | Good | 70-75 |
| E2 | High Acrylonitrile | • Excellent Oil resistance<br>• Superior mechanical and dynamic properties<br>• Good for up to 40° API Oil | 248 | 120 | Excellent | Excellent | Excellent | Good | Good | 70-75 |

[xi]

**Table (3.1) shows Elastomer Performance Guideline.**

## 3-9 PC Pump Elastomers:

An Elastomer is the rubber substance which makes up the internal portion of the stator and comes in contact with the rotor.

Most PC pump manufacturers have stator products available with several different elastomer types. Because the formulations of these elastomers are considered proprietary, there is no standard naming convention. Certain generic names are common to the different manufacturers, but elastomer properties may vary significantly.

Although there is a wide range of different elastomer types, almost all PC pumps use some variation of a synthetic nitrile elastomer. Within the class of nitrile elastomers, there is a virtually unlimited number of different formulations possible with an associated wide range of mechanical and chemical properties. A discussion of the more common types of elastomers used in PC pumps follows.

- **Nitrile (NBR)**

Most elastomers in PC pumps can be classified as conventional nitrile (NBR). The base polymers for these elastomers are manufactured by emulsion copolymerization of butadiene with acrylonitrile (ACN). ACN contents in nitrile elastomers typically vary from 30 to 50%, with the cost of the elastomer increasing marginally with increasing ACN level. Most manufacturers distinguish between a medium nitrile (sometimes called Buna, which typically has an ACN content < 40%) and a high nitrile (> 40% ACN). Increasing ACN levels produce increasing polarity, which improves the elastomer's resistance to nonpolar oils and solvents. However, higher ACN levels result in increased swell in the presence of such polar media as esters, ketones, or other polar solvents and leads to a decline in certain mechanical properties. It is important to note that aromatics such as benzene, toluene, and xylene swell NBR elastomers considerably, regardless of ACN level.

NBR elastomers are normally sulfur cured, and the combination of sulfur with the natural unsaturation of the elastomer can result in additional cross-linking and associated hardening in the presence of heat. As a result, NBR elastomers are not recommended for continuous use at temperatures that exceed 100°C (212°F). For a similar reason, NBR elastomers also are not recommended for applications that contain high levels of H2S because the sour gas contributes additional sulfur, which leads to post-vulcanization and surface hardening. These changes result in a loss of resilience and elasticity, typically causing premature stator failure.

Historically, the hardness of NBR elastomers has been between 65 and 75 Shore A. More recently, manufacturers have introduced soft medium NBRs (55 to 60 Shore A) for abrasive, heavy oil applications. The rationale was that they would be more forgiving to the gravel and iron pyrite solids that are produced occasionally and have a tendency to tear the stator material. The soft elastomer requires the use of a higher degree of rotor/stator interference fit, which has the advantage of maintaining some sealing even after extensive wear of the rotor or stator.

- **Hydrogenated NBR (HNBR)**

Conventional NBR elastomers, especially when sulfur cured, often contain a large degree of unsaturation in the form of double and triple carbon-carbon bonds in the base polymer. Relative to a more stable single bond, these unsaturated hydrocarbon groups are susceptible to chemical attack or additional cross-linking. This is the primary reason why NBRs experience problems upon exposure to high temperatures, H2S, and aggressive chemicals.

Through a hydrogenation process, it is possible to increase the saturation (i.e., decrease the number of double and triple carbon-carbon bonds) of the NBR polymer, thus stabilizing the associated elastomer. The degree of saturation can vary, but typically it is > 90% and can be as high as 99.9%. If the saturation is very high, then a sulfur cure system is no longer effective, and a peroxide cure must be used. These

compounds are typically referred to as highly saturated nitriles (HSN) or hydrogenated nitriles (HNBR). For an equivalent volume, the cost of an HNBR elastomer is typically four times that of a conventional NBR, making the stators made from such elastomers considerably more expensive.

The primary advantage of an HNBR is increased heat resistance. Sulfur-cured HNBRs can ideally be used up to 125°C [257°F], whereas higher-saturation peroxide-cured compounds can potentially be used in applications with temperatures up to 150°C [300°F]. Other advantages, especially if the elastomer is peroxide cured, include improved chemical resistance and H2S tolerance. The mechanical properties of HNBR elastomers usually are similar to those of NBR elastomers.

Most PC pump manufacturers offer HNBR stators, but the limited number of applications that warrant the higher cost have kept their use to relatively low levels. Historically, the HNBR polymers have been highly viscous and difficult to inject into stators, increasing manufacturing costs substantially. However, within the last few years, the polymer manufacturers have introduced lower-viscosity, high-ACN HNBR elastomers. As a result, pump manufacturers have taken a renewed interest in these elastomers, which may lead to more use of HNBR compounds in stator products in the future.

- **Fluoro elastomers (FKMs)**

FKMs have been expanding in availability and use over the last decade. Although a number of different varieties of FKMs are available, common to all is the presence of high levels of fluorine that saturate the carbon chain. The carbon-fluorine bonds in FKMs are extremely strong, giving this formulation heat and chemical resistance superior to that of most other elastomers.

FKMs are, to a large extent, made up of the fluoro-polymer and thus contain a low level of fillers and additives. As a result, the mechanical properties of FKMs tend to be inferior to those of NBR and HNBR elastomers. In terms of chemical stability,

they have excellent resistance to heat, although their mechanical properties tend to deteriorate further at high temperatures from already relatively low initial levels. A variety of cure systems are used for FKM elastomers, including peroxide, but they require an extended post-curing session to optimize their properties, adding considerably to manufacturing process costs. As a result, the cost for an equivalent volume of FKM elastomer may range from 20 to several hundred times that of a conventional NBR. This makes all but the lower-cost grades of FKMs uneconomical for PC pump stators, and even those that are viable carry a high cost premium.

The primary advantage of an FKM elastomer is the increased heat and chemical resistance. FKM elastomers have the potential to be used up to 200°C [400°F] as long as they are not subject to excessive mechanical loading (proper sizing of PC pumps is critical). In terms of fluid resistance, they have minimal swell with most oilfield fluids, including aromatics.

General use of FKM elastomers in PC pump applications is relatively recent, with several PC pump manufacturers now offering these products. Some success has notably been encountered in lighter-oil applications in which NBR stators swell, necessitating multiple rotor changes. Despite being expensive, FKM stator products appear to be viable in certain applications, especially if the pumps are sized properly and extended run times are achieved.

### 3-9-1 Fluid Viscosity:

The dynamic viscosity (μ) of a fluid is the property of a fluid that resists flow; it is the ratio of the shearing stress to the rate of shear. For fluids other than oil, the most common unit of measure for absolute (dynamic) viscosity is centipoise (cp). Sometimes the fluid viscosity is expressed in centistokes, which is the kinematic viscosity or the absolute viscosity divided by the specific gravity. When a fluid's viscosity is constant as the rate of shear is increased, it is said to be a Newtonian fluid.

Most fluids that are handled by the progressing cavity pump do not obey this law and are said to be non-Newtonian.

## 3-10 Inlet Conditions:

The key to obtaining good performance from a progressing cavity pump, as with all other positive displacement pumps, lies in a complete understanding and control of inlet conditions and the closely related parameters of speed and viscosity.

To ensure quiet and efficient operation, it is necessary to completely fill the cavities with fluid as they open to the inlet. This becomes more difficult as viscosity, speed, or suction lift increases. Essentially, it can be said that if the fluid can be properly introduced into the pumping elements, the pump will perform satisfactorily.

However, the problem lies in getting the fluid in. A pump does not pull or lift liquid into itself. Some external force must be present to initially push the fluid into the pumping elements.

Normally, atmospheric pressure is the only force present, although there are some applications where a positive inlet pressure is available.

Low viscosity fluids will flow quite rapidly and will quickly fill the cavities. It is obvious that if the cavities are moving too fast, the filling will be incomplete and a reduction in output will result.

The rate of fluid flow into the cavities should always be greater than the rate of cavity travel, in order to obtain complete filling. Most progressing cavity pump manufacturers provide recommended maximum speeds for their pumps when handling viscous fluids that minimize the effects of incomplete filling. The net positive suction head (NPSH) calculations are routinely used in centrifugal or high velocity pump applications. In many positive displacement pump applications where the pump velocities are usually low, the calculation of NPSH has little significance.

## 3-11 Guidance for Proper Selection and Installation:

There are some considerations in pump size that need to be made in order to achieve maximum performance. It is necessary to minimize the slip and internal velocities to achieve good results.

### 3-11-1 Temperature Effects and Limits:

The fluid temperature will affect the pump performance in two different ways. First, since the stator is an elastomeric material, the thermal expansion is roughly ten times greater than that of the metal rotor which is usually steel or stainless steel. This will cause a tighter fit for the elements, and higher starting and running torques. When the temperature reaches a certain limit it is then advisable to use an undersized rotor which compensates for the difference in size. Second, the life of the elastomer is greatly affected by heat Limits from one manufacturer for elastomers which are being worked such as in a stator, and will differ from other published information on elastomers used in a static state such as O-rings and gaskets.

Therefore, when a stator is being applied at less than its maximum pressure rating, the operating limit can be exceeded slightly but cannot exceed the static ratings shown in table (3-2).

### 3-11-2 Stator temperature rating:

**Temperature Rating (F)**

| Material | stator Rating | Maximum (Static) Rating |
|---|---|---|
| Nitrile | 180 | 250 |
| Natural rubber | 185 | 225 |
| EPDM | 300 | 350 |
| Fluor elastomer | 300 | 400 |

**Table (3.2) stator temperature rating.**

### 3-11-3 Mounting and Vibration:

The progressing cavity pump is inherently an unbalanced machine due to the eccentric rotation of the rotor. The vibration which occurs is dependent on the size of the element, the offset, and the speed of rotation. For this reason, the speed of the pump is limited with typical limiting speeds reaching 1200 RPM for small pumps (.02 gal/rev/and lower), decreasing to limits of 300 RPM for large pumps (3 gal/rev and larger).[xii]

## 3-12 Tag Bar Considerations & Selections:

The tag bar is simply a bar or rod that is welded in high strength mechanical tubing that is screwed into the pump intake. The tag bar has 2 primary purposes:

1- Used as a reference point for landing the rotor.
2- Used as a safety stop to prevent the loss of the rotor and rods in the event of a failure to the drive string. It is not designed to support the rod string during continuous operation.[xiii]



**Fig (3.10) show tag bar**

## 3-13 Power Requirements:

The power requirements for progressing cavity pumps are expressed differently by various manufacturers. Some manufacturers express the power requirements simply as horsepower required at a certain speed, and others express them as torque. Since the progressing cavity pump is considered a constant torque device when operating at a given differential pressure, using torque to determine power requirements is a simplified and accurate method of determining the power requirements and will

allow better selection of drive components, especially hydraulic and electrical variable speed type drives.

The stator is usually made from an elastomeric material, although designs with a merallic (or rigid) stator for specialized are knwn. This elastomeric stator allows the pump elents to have a compression fit and also offers a good abrasion resistant surface for handing particles in suspension. Thiscompression fit. however, does cause a resistance to turning (torqe) which is dependent on the element geometry and is shown on the performance curve as the initial torque required at 0 psi. there is also a starting tourqe which must be overcome. As a rule of thumb, this value is roughly four times the initail torque. Horspower can be derived from the torque value by the formula

$$Hp = \frac{TN}{63025},$$

Where:

T is torque in inch pounds, and N is pump speed RPM.

Progressing cavity pumps are rarely applied on fluids with a viscosity of 1 cp, and there is an added torque which is depended on the viscosity of the fluid and the geometry of the elements. On slurries, the added torque required is dependent upon the particle size and concentration for viscosity and slurries with their standard technical literature. Typical power adder charts are reproduced below. These charts will of course vary with individual pump size and model.

## 3-14 PC pump system application considerations:

| Parameters | Typical | Maximum |
|---|---|---|
| Operating Depth | 2,000'- 4,500' TVD | 6,500' TVD |
| Operating volume | 5 - 2,200 BPD | Over 4,500 BPD |
| Operating Temp | 75 – 250 F | 300 F |
| System efficiency | 60% - 80% | 85% |
| Solids handling | Excellent | |
| Gas handling | Good | |
| Fluid gravity | Below 47 API | |
| Wellbore deviation | N/A | Build angle ( 15/100') |
| Offshore | Good footprint, surface hand handling | |
| Service & repair | Required Workover or pulling rig. | |

[xiv]

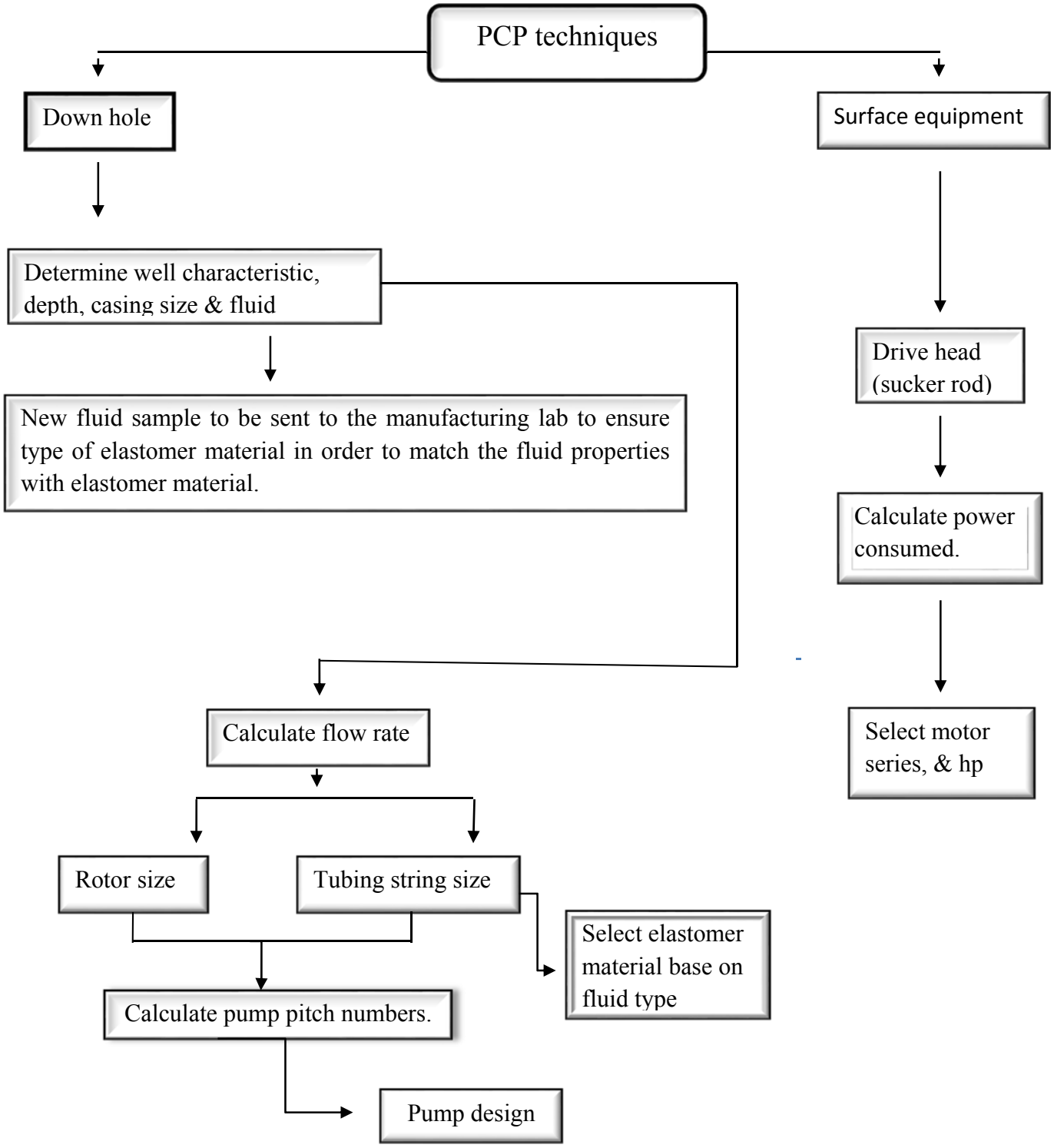
**Table (3.3) PC pump system application considerations**

## 3-15 Advantages and disadvantage of PCP:

- **PC pump Advantages**
  - High system efficiency (to 85% w/o &gas).
  - Tolerant of solids (50% sand slugs).
  - Multiphase pumping: oil, water, solids, gas.
  - Low power consumption.
  - Low capital cost.
  - Low maintenance costs.
  - Low surface profile for visual and height sensitivity areas.
  - Simple installation.
  - Portable surface equipment.
  - Horizontal / directional wells.

- **PC pump system limitations**
  - Depths to 6,500 feet.
  - Volume to 4,500 BPD.
  - Temperatures.
    - To 300 F (150 C) in oil.
    - To 185 F (85 C) in water.
  - Aromatics & some produced.
  - Low volumetric efficiencies in high- gas environments.
  - Potential tubing and rod coupling wear in deviated wells.
  - Requires constant fluid level above pump.[xv]

## 3-16 Progressive cavity pump (PCP) technique considerations:



### 3-17 Progressing cavity pump design:

Cavity area

= d*4E*P……..…… (1)

Pump displacement

V=Cedp ……...… (2)

Where:

V=pump displacement (bbl/day/rpm)

d= Minor rotor diameter (in) e= Pump Eccentricity (in)

p= Stator pitch length (in) C= Constant (SI: 5.94E-1)

Flow rate

Q=VN……..……. (3)

N=rpm ……..…… (4)

System design:

- In selecting a pump the two most critical requirement are:
    1. The pump has sufficient displacement capacity.
    2. The pump has sufficient pressure capability to overcome the net lift required for the application.

### 3-17-1 System Design Volume:

The designed flied rate is the maximum rate at which the pump must operate:

$Q_{design} = 100*Q_{act}/n$ ……..... (5)

$Q_{design}$ = Design pumping rate (bbl/day).

$Q_{act}$ = required fluid rate (bbl/day)

n = Volumetric pump efficiency.

The designed fluid rate is higher than the actual fluid rate due to pumping inefficiencies.

$V_{min} = Q_{design} / N$……...…… (6)

$V_{min}$ = Minimum required pump displacement (bbl/day)

N = pump rotational speed (rpm).

### 3-17-2 System Design Pressure:

The minimum required pressure capability is determined by the net lift requirements of the pump and is the difference between discharge and intake pressures.

$P_{lift} = P_{discharge} - P_{intake}$……..….. (7)

$P_{lift}$ = net lift required (psi).

$P_{discharge}$ = Pump discharge pressure (psi).

$P_{intake}$ = pump intake pressure (psi).

Pump intake pressure is a function of the casing head pressure plus pressure due to the gas and liquid Colum above the pump intake in the casing/ tubing annulus.

$P_{intake} = P_{chp} + P_{gas} + P_{liquid}$ ……..…... (8)

$P_{chp}$ = casing head pressure (psi) $P_{gas}$ = gas column pressure (psi).

$P_{liquid}$ = liquid column pressure (psi).

The pump discharge pressure is the sum of tubing head pressure, flow losses and hydrostatic pressure due to the liquid column tubing:

$P_{discharge} = P_{tbg} + P_{liquid} + P_{losses}$ …….……..... (9)

$P_{tbg}$ = tubing head pressure (psi)

$P_{losses}$ = tubing flow losses (psi).

Pressure exerted by a gas or liquid column can be calculated by:

$P_{column} = H \rho C$ ……... (10)

$P_{column}$ = gas or liquid column pressure (psi)

H = vertical column height (ft) $\rho$ = fluid or gas density (Ibs/cf)

C = Constant (SI: 9.81E-3 Imperial: 6.94E-3).

## 3-18 Recommended pump speed range vs. viscosity:

| Viscosity (cp) | Optimum speed (rpm) | Maximum speed (rpm) |
|---|---|---|
| <500 | 200 | 500+ |
| 500-5000 | 150 | 400 |
| > 5000 | 100 | 250 |

**Table (3.4) recommended PCP speed range vs. viscosity**

## 3-19 Drive head Design Considerations:

When purchasing PC pumping unit, the design consideration play an important role in the safe operations of the unit. The application designer must establish the maximum surface loading and ensure the equipment being purchased will operate within its maximum limit. The loading or work done by a PC pumping system is primarily determined by the following:

- Pump intake pressure.
- Pump discharge pressure.
- Rod string/ tubing friction.
- Internal pump friction.

Several other factors influence these parameters and they usually change throughout the life of an oil well, other factors may include:

- Fluid contaminants.
- Pressure, volume, temperature properties of the production medium, reservoir characteristics, tubing roughness.
- Side wall stress as a result of tubing/rod contact.
- Tubing and casing pressure fluctuation.
- Interference pump fit between rotor/stator.

Computer aided software tools are available to help determine these factors. Calculations must be made before purchasing a unit. When predicting load limits, a safety factor of at least 10 percent should be considered to account for error

associated with the reliability of assumptions or the accuracy of mathematical correlations. [xvi]

**3-20 Torque and power requirement**:

- Torque can be defined as the energy required to turn and move the fluid against a pressure. Pump torque is comprised of a hydraulic and friction component.
- Friction torque is the energy required to overcome the interference fit between the rotor and stator. Fraction torque is dependent on interference fit, type of rotor coating, stator elastomer, lubricating properties of the fluid and pump length
- Hydraulic torque is directly proportional to differential pressure and pump displacement.

  **$T_{hydraulic} = CVP_{lift}$**

  - $T_{hydraulic}$ = Hydraulic pump Torqe (ft.Ibs).
  - V= pump displacement (bbl/day/rpm)
  - $P_{lift}$ = differential pump displacement (psi)
  - C = Constant (SI; 0.111 Imperial: 8.97E-2)
  - **$T_{total} = T_{hydraulic} + T_{friction}$**
  - $T_{total}$ = Total pump Torque (ft.Ibs)
  - $T_{friction}$ = Pump friction Torque (ft.Ibs)

**3-21 Torque and Power Imperial:**

- Hydraulic Torque is the torque required to move the fluid.
- $Torque_{Hyd.}$(ft-lbs) = $\frac{0.03878 \text{ x(bbl/day) x (feet of lift)}}{\text{Rpm}}$
- Hydraulic H.P. is the horsepower to move the fluid.
- $H.P_{Hyd.}$ = 1.7E-5 x (bbl/day) x (psi)
- Horsepower Torque Relationship.
- H.P = Torque x Rpm /5252

### 3-22 Power:

The power required to drive the pump is a function of total pump torque.

- $P_{pump} = C\ T_{total}\ N$
- $T_{total}$ = Total pump Torque (ft.Ibs)
- N= pump Rotational Speed (rpm)
- C= Constant ( SI: 1.05 E-4  Imperial : 1.9 E-4)

### 3-23 Installation and start up procedure of a PCP:

### General considerations

The pump shall be installed below the dynamic level, because the pump required a positive inlet pressure to operate efficiently. Moreover permanent lubrication of the stator is necessary to avoid any elastomer failure. It is thus recommended to record the annular level.

### Pre-operation checks

Before starting the installation, it must be sure that all the elements required are available at the location.

### 3-23-1 Element of the production string:

- Torque anchor.
- Cross over to connect torque anchor to stop bushing.
- Stop bushing.
- Stator.
- Cross over to connect stator to pup joint.
- Tubing.

### 3-23-2 Element of the rod string:

- Rotor.
- Coupling to connect rotor to pony rod.
- Sucker rods.
- Sucker rod centralizer.
- Set of pony rods for rotor spacing out.

### 3-23-3 Element of surface facility:

- Drive unit.
- Polished rod.
- Coupling to connect polished rod to sucker rod.
- Flow (T).
- Hammer union.

### 3-23-4 Installation of the production string:

1. If torque anchor is being used, the manometer must be calibrated to make up all element of the production string with the maximum API torque. If a torque anchor is being used, the manometer must be calibrated to give the optimal API torque.
2. If the stator is made of two or three elements, no attempt should be made to apply torque between those elements.
3. Once the production has been run in the flow (T) is installed and then fitted with the male half of the hammer union used to connect the drive head to the wellhead, the top of the flow. Is reference point for the spacing out of the rotor.
4. The number of suck rods required to land the rotor in the stop bushing is calculated from the production string tally, measured from stop bushing to the top of the flow (T).

### 3-23-5 Installation of the Rod String:

Rotor Spacing Out:

1. Grease the rotor before running it in, this will make it easier to insert it in the stator and eliminate possible space out error due to the rotor hanging up in the stator.
2. Run the rotor and drive string in the hole carefully.
3. When the rotor enters the stator, the string rotates to the right tag this level.
4. Pick up as slow as possible and note the readings of both weight indicator and venire.
5. lower slowly until the rotor lands on the stop bushing and slack off the string weight drops and the venire reads
6. Pick up very slow. When both weight indicator and venire are back on their previous reading, stop and mark the rod as surface: the rotor is then just off the stop bushing.
7. Pull drive string up and remove upper extra rod.
8. Measure the distance between the mark and the lower part of the sucker rod that has been just removed.

It is very important that the pulling unit be in good condition and including the following:

- Weight indicator assures the accurate spacing out of the rotor.
- Manometer assure that the torque applied by the hydraulic tong to the tubing and to the rods is correct.

### 3-23-6 START UP OF PCP:

- **Pre-start check**

1. Carefully connect the power supply leads, assuming that the direction of rotation of the drive system has been checked.
2. Check the lubrication and the sealing of the bearing and stuffing box.
3. Open the flow line valve at the well head.
4. The PCP is ready to operate.

- **Starting procedure**

1. Switch on the motor. If the motor is provided with a variable speed drive, start at low speed, and increase speed progressively until the determined speed is reached. A time lapse corresponding to the filling of the tubing is required before the well fluid reaches the surface.
2. The rotating speed of the pump should be adjusted to the well productivity. Consequently, the dynamic or submergence level will be controlled frequently at the beginning of the operation.
3. Once the optimum speed is established, it will be maintained continuously and frequent ON/OFF operations should be avoided.

## 3-24 Progressing cavity pump failure:

### 3-24-1 Failure Analysis:

Failure analysis is often defined as the process of collecting and analyzing data to determine the cause of a failure and how to prevent it from recurring.

For PCP systems, failure analysis is the process of identifying the root cause of a PCP system failure and using the results to identify strategies to increase the PCP system run-life. A PCP system has failed if any of its components are no longer able to perform the required function. The failure cause is defined as the circumstances during design, manufacturing or use which led to a failure.

Failure analysis is among the most important means of improving the performance of a PCP system. People often say that they do not have time to perform failure analysis.

### 3-24-2 Failure Description and Identification:

It is important that failures are described and classified in a consistent manner so that similar failures can be properly grouped and analyzed.

- Stator Failures (Fatigue, Wear, Fluid Incompatibility, ...)
- Rotor Failures (Wear, Heat Cracking, Fatigue ...)
- Rod String Failure Mechanisms (Fatigue, Excessive Torque...)
- Tubing String Failures (Wear, Corrosion...)

### 3-24-3 Failure Symptoms, Root Causes and Remedial Actions:

The main process of a failure analysis is to identify symptoms of a failure (no fluid flow, high torque) that could indicate a system failure. Once a system failure has been identified, it is important to understand what caused the failure. By asking the question 'why' multiple times, the root cause of the failure can be identified. Only by understanding the root cause can successful remedial actions be taken to prevent a similar system failure from recurring.

### 3-24-4 Failure Tracking and Benchmarking:

The goal of benchmarking is to improve system performance and to reduce costs. Benchmarking is a continuous process of measuring and evaluating progress over time to ensure decisions are made based on facts rather than opinion. Failure tracking is used to compile and store data upon which benchmarking can be performed. Failure tracking ensures the collection of quality data that reflects the system as a whole.

### 3-25 Pump failure analyses:

When a PC pump is pulled during a workover, it should be sent to a pump shop for a thorough examination and pump test. Usually, the pump components are first cleaned and visually inspected. Inspection of the rotor involves examining the condition of the threads and pin, assessing the amount and location of any wear, and identifying the presence of any heat checking. Although equipment is available to perform a full examination of the internals of a stator (e.g., bore-scope camera), not all vendors have these systems, and stator inspections are often limited to the visual checking of the long stator cavity for signs of damage or deterioration from the two ends. The elastomer surface typically is examined as carefully as possible to locate any areas of worn, hardened, cracked, torn, swollen, or missing rubber. If the rotor and stator components show no evidence of failure, the pump will subsequently be bench tested. If the test results show that the pump is within the accepted performance guidelines for the particular application, it will usually be sent back to the field for redeployment. Pumps that are tested but do not meet the guidelines may be retested with a new rotor if the stator appears to be in good condition. The stator will be scrapped if further testing provides evidence that it has sustained permanent damage (e.g., severe wear or loss of rubber).

Observations made during failed-pump inspections typically provide information that is crucial to the accurate determination of the root cause of failures. This knowledge is usually essential for establishing appropriate remedial actions to achieve improved pump run lives. The failure attributes provide clear indications of the physical mechanisms that resulted in damage to either the rotor or stator. The following sections provide descriptions of the unique damage characteristics associated with different types of pump failure mechanisms.

### 3-25-1 Stator fatigue failure:

Fatigue failures are characterized by missing rubber primarily along the rotor/stator seal lines. The regions of torn or missing rubber are typically shiny and irregular (Fig 3.10) Fatigue failures can be attributed to excessive cyclic deformation of the elastomer. As the material properties degrade, shear stresses can more readily generate cracks in the elastomer that subsequently propagate and eventually cause pieces of the rubber to separate from the pump. Excessive hysteretic heat buildup can accelerate material damage and associated crack growth. The loss of material along the rotor/stator seal lines leads to increased slip and a rapid decline in pump performance. Stators that have missing rubber as a result of fatigue damage are not suitable for reuse and must be scrapped.



**Fig. (3.11)-Example of fatigue failure.**

### 3-25-2 Stator wear:

Stator wear usually can be attributed to the forced movement of abrasive solids along the stator cavities, although some wear can also occur because of the normal interaction of the rotor and stator during pump operation. Worn stators are characterized by the presence of roughened worn surfaces, usually along the minor diameter. The rate of abrasive wear is related most strongly to the quantity and abrasiveness (i.e., size, shape, and hardness) of the solid particles contained in the produced fluid. Wear rates are also influenced by elastomer type. Soft stator materials are more likely to deform instead of tearing as solids pass through the pump. Stator wear is also proportional, but not necessarily linear, to the amount of interaction that occurs between the rotor and stator; consequently, stators tend to

wear out more quickly at higher rotational speeds. Stator wear produces a gradual decline with time in volumetric efficiency and fluid rate. This effect is most pronounced when producing low-viscosity (< 100 cp [100 mPa•s]) fluids. Stators damaged by significant wear cannot be repaired and should be scrapped.

### 3-25-3 Rotor wear:

Rotor wear results from normal pumping action. Depending on the downhole conditions and exposure time, the severity of the wear rates can vary dramatically. Normal abrasive wear can be identified by the presence of erosion marks in the chrome plating along the major diameter of the rotor. Extreme abrasive wear is characterized by material loss through the surface coating and into the underlying base metal of the rotor. Examples of coating wear and severe base metal wear are shown in (Fig 3.11) Worn rotors can be rechromed and reused as long as the wear has not progressed through the chrome surface. Rotors that have sustained base-metal wear usually must be scrapped.

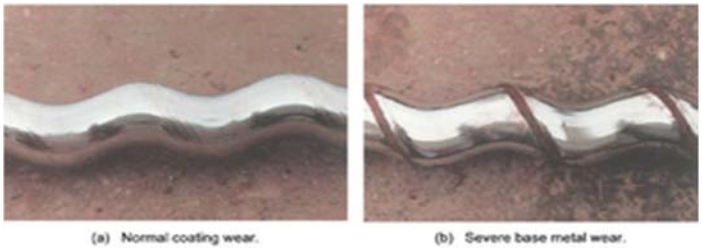



**Fig. (3.12) Abrasive rotor wear.**

In some cases, base-metal wear is observed only on the top section of a rotor. This usually indicates contact between the upper portion of the rotor and the production tubing and can be attributed to the rotor being landed too high above the tag bar.

### 3-25-4 Stator fluid incompatibility:

Fluid incompatibility and gas permeation can pose serious problems for stator elastomers. Signs of damage caused by fluid incompatibility include swelling,

softening, or surface blistering of the stator elastomer. Visible swelling is the most common, occurring to some extent in many different applications. The compatibility between the elastomer and produced fluid determines the degree of swelling and the rate of any subsequent deterioration in mechanical properties. Badly swollen stators will often fail pump tests as a result of excessive torque or poor performance and must be scrapped. Stators that are only slightly swollen may be paired with a smaller-diameter rotor and reused.

- **Gas permeation and rapid decompression**

In gassy wells, stators are prone to severe damage under rapid decompression conditions (e.g., shutdown events) that facilitate the expansion of any gas that has diffused into the elastomer. The damage is caused when the force exerted by the pressurized gas trapped within the elastomer exceeds the tear strength, which leads to subsurface tearing of the material. These failures are characterized by a number of very soft, typically raised bubble areas or blisters on the stator cavity surface.

- **Rotor fluid incompatibility**

Fluid incompatibility also occurs with rotors, but to a much lesser extent than with stators. Incompatibility can be identified by discoloration of the rotor and, in some cases, pitting of the base metal. It usually results from corrosive or acidic fluids attacking the chrome coating. Removing the outer chrome coating makes the rotor more susceptible to abrasive wear and may produce a noticeable increase in friction torque because of the loss of the smooth surface finish. Unless the rotor has extensive pitting, it usually can be rechromed and reused.

- **High temperature stator damage**

Stators that have failed because of exposure to high temperatures typically exhibit elastomer surfaces that are hard, brittle, and extensively cracked. (Fig 3.12) shows

an example of a stator damaged by high-temperature operation. Causes of excessive heat include:

- Running the pump dry
- High produced-fluid temperatures
- Heat generation within the pump



**Fig. (3.13)—High-temperature stator damage.**

Heat damage usually produces a rapid decline in the pump's volumetric efficiency. Stators that have failed because of high-temperature damage cannot be repaired and must be scrapped.

- **Rotor heat-cracking damage**

Heat cracking can be identified by fine cracks in the chrome plating of the rotor, primarily along the major diameter, although cracking may extend over the entire surface. Heat cracking is the result of differential expansion of the chrome and base metal in response to temperature changes. These cracks are considered normal, and minor heat cracking does not appear to affect PC pump performance negatively, although the slightly roughened surface may affect pump life. Most operators reuse rotors that have sustained minor heat cracking.

- **Stator debris damage**

Occasionally, stators will exhibit damage in the form of large gouges or tears in the elastomer. This type of damage can be attributed to large foreign particles, such as pebbles, perforation plugs, or metallic debris, passing through the pump. In many cases, debris damage may go undetected unless an internal camera is used or caliper

inspection is performed. Depending on the degree of damage, the pump may or may not be suitable for reuse.

- **Stator high-pressure wash**

High-pressure wash or channeling is a common stator damage mechanism characterized by worm-like holes or groves cut in the elastomer (Fig 3.13). These channels develop during production when a large sand particle or other debris becomes embedded in the elastomer material, creating a small orifice across the rotor/stator seal through which fluid passes at high velocity, eroding and cutting away the stator rubber. Because the channeling damages the pressure integrity of the pump, stators with extensive pressure-wash damage are not recommended for reuse.

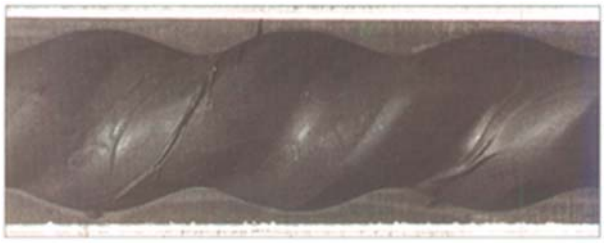


**Fig. (3.14) Stator damage caused by pressure wash.**

- **System failure analysis**

A thorough analysis should be conducted after each downhole equipment failure incident to identify the circumstances during design, manufacturing, installation, and operation that likely resulted in the failure. Over time, this will lead to a valuable database of information that can be used to optimize PCP system design and operation for a particular well or field.[xvii]

## 3-26 Comparison between PC pump & ESP:

| PCP | ESP |
|---|---|
| Low capital cost. | High capital cost (mainly power cable). |
| Multiphase pump. | Multiphase pump with low GOR. |
| Portable surface equipment. | Pump and motor running inside the well. |
| Low maintenance cost. | Tubing must be pulled to change or repair pump (Workover rig needed). |
| No power cable problems (cable less). | Cable susceptible to damage during running operations. |
| Capable of pumping viscous crude oil. | Viscous fluid reduces pump efficiency. |
| suitable for shallow & low volume wells | Not suitable for shallow & low volume wells ( ＜ 150 bpd) |
| Full bore pump intake. | Scale causes plug round intake pump Corrosion / scale treatment possible. |

**Table (3.5) shows comparison between PCP and ESP**

# Chapter 4

# Case study

## 4-1 Introduction for El-Shrara Oil field:

El-Sharara oil field is located in Murzuq basin, in the south west part of Libya near the city of Ubari, in national Concession 115 & 186.

The field was discovered in October 1984 by well XX-01. This well found of Mamuniyat sand, with excellent reservoir properties and the production started in 1996 and the water injection stared up in 1999.

At July 2010, the cumulative oil production was 425519425 BO, and the cumulative water production to 21986787 STB. The cumulative of water injected was 275736337 MM STB. The water cut was approximately 14.30 %

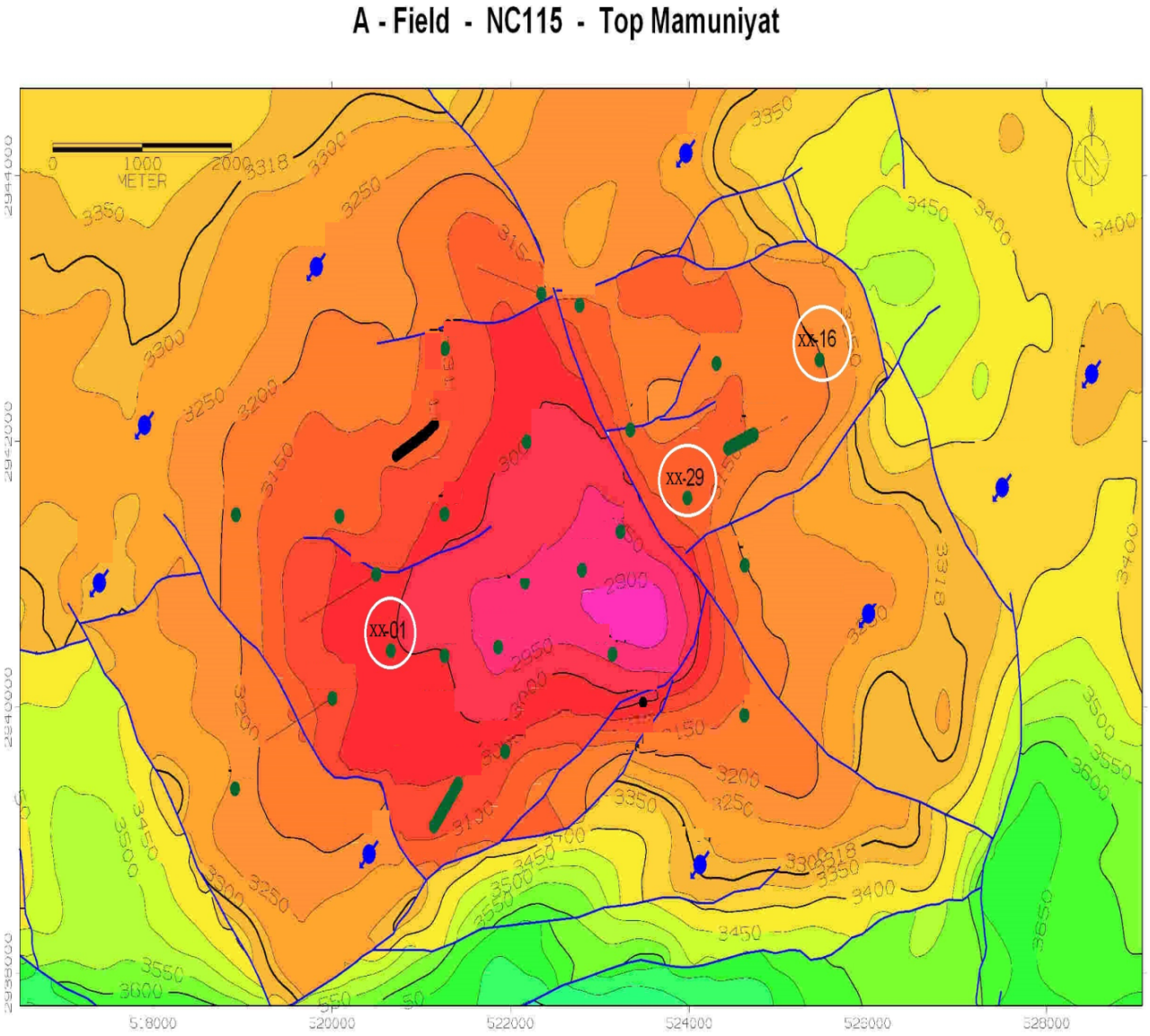



**Fig (4.1) field structure map**

## 4-2 Reservoir Characterization:

PVT reports had conducted by Libyan Petroleum Research Center Lab, Four bottom hole samples were collected from wells XX field from Mamuniyat formation. The Samples from field A NC-1115 have been received for four wells as representative's wells. In the pre-production phase (before 1996) sample were taken from the well XX-06 in A-field.

In 1997 samples were taken from well XX-01 in A-Field three bottom hole samples taken from Mamuniyat Sands By using PVT model of Eclipse software the equation of state ‘’EOS’’ has been used by the service company to tuned EOS parameters, and match the experimental data for the mentioned wells.

From wells XX-01, used for fluid characterization, Corresponding laboratory reports of the samples mentioned are available. The PVT data on a Bottom hole sample taken from XX-06 well (Libyan Petroleum Research Center Lab PVT Laboratory were used as the input data for the calculation.

## 4-3 Selected Oil Production Wells for the Study:

Three oil production wells have been selected to run a model of PC pump as fallowing:

### 4-3-1 Well XX-01:

- **WELL HISTORY**

The well was drilled in on June 7th, 1984. Drilled 17 ½’’ hole T/989`.Ran 32 jts, 13 3/8`` csg and cemented. Then w/12 1/4`` bit drilled cement and csg shoe continued drilling 12 ¼’’ hole T/4734`. R/U and ran 128jts, 9 5/8`` csg. And cemented. After W/8 ½`` bits. drilled cement, csg shoe and continued to 7806` then the bit pulled and Run w/5`` O.E.D.P to 5584` mix and pump 80 sx. Later on Ran 7`` csg, and set csg shoe @ 5246ft and F.C @ 5102`and cemented, and run w/taper mill bit on 3 ½`` tbg to tag 5102 (PBTD).

**On June**, 1985 the well was perforated intreval #1 ( 4999` to 4976`) and tested. Perforated interval #2 ( 4871` to 4756`)and tested. CMT plug was set at 4557`.

**On Sep**,1993 drill out CMT plug, the interval ( 4745` to 4922`) was perforated then the well was completed w/3 ½ `` tbg.

**On May**,1999 the well was Re- perforated interval (4745` to 47810`) and ESP installed on 3 ½'' tubing. Prod. Start in December 13th , 1997.

Cumulative oil produced from this well until February 5th 2003 = 3,695, 618 bbls.

- **Completion and Work over History**

**First WO**: To complete the well as a producer in Mamuniyat formation.

Spud in on Aug/05/1993, RIH w/6'' bit, tag CMT @ 14 ft, drilled out T/50 ft, and continued RIH to plug no. 2, tagged @ 4570' hole cleaned, test casing up to 1000 psi, ok, drilled out CMT from 4575 ft to 4577. POH.

The well was perforated in seven runs using wire line guns F/4922 ft T/4745 ft (157 ft, 4 SPF), RIH production string with 7'' production packer, the side back was tested w/500 psi, ok, R/U swab equipment, swab the well, well flows to separator after recovering 33.5 bbls, A.F.R. 5600 bbls/day w/64/64'' choke, then the well choked to 32/64'', A.F.R. 2260 BOPD, then the well SI for BU. WHP=345 psig, casing pressure=0 psi, POH w/Amerada stop each 500 ft. RIH w/Amerada, open well through 32/64'' for draw down test. POH w/Amerada, stop every 500 ft, R/D wire line unit, unset the packer, kill the well, POH, RIH w/ open end 3 ½'' tubing T/4680 ft, N/U X-mass tree.

**Second WO**: To Re-test the well to investigate production capacity and skin damage.

It was rig less operation, connect surface lines to test separator, P/T to 1000 psi, ok, RIH w/gauges, gauges were set @ 4622ft, open well to flow through test separator, the well SI for BU, then the well flowed using 32/64'' choke, followed by 12 hours.

**Third WO**: To Re-perforate and run ESP.

Reverse out and kill the well with 200 bbls filtered water, POH production string, BPTD @ 4962 ft, Re-perforate the well F/4745 T/4810 ft, pump down tubing, fluid

level was at 1800 ft, unset the packer, reverse out 60 bbls, POH TCP string, ran 2GN4000 pump (66+32), intake @ 3196 ft (the pump installation date 23/May/99).

**Fourth WO**: To Upgrade ESP.

Rig was moved on March/03, well was killed using dead oil, 40 bbls was pumped down annulus, and 10 bbls down tubing, POH w/GN4000 pump, ran 7'' scrapper, 2GN4000 (86+86) were run, intake @ 4515 ft.

- **Well schematic for well XX-01**

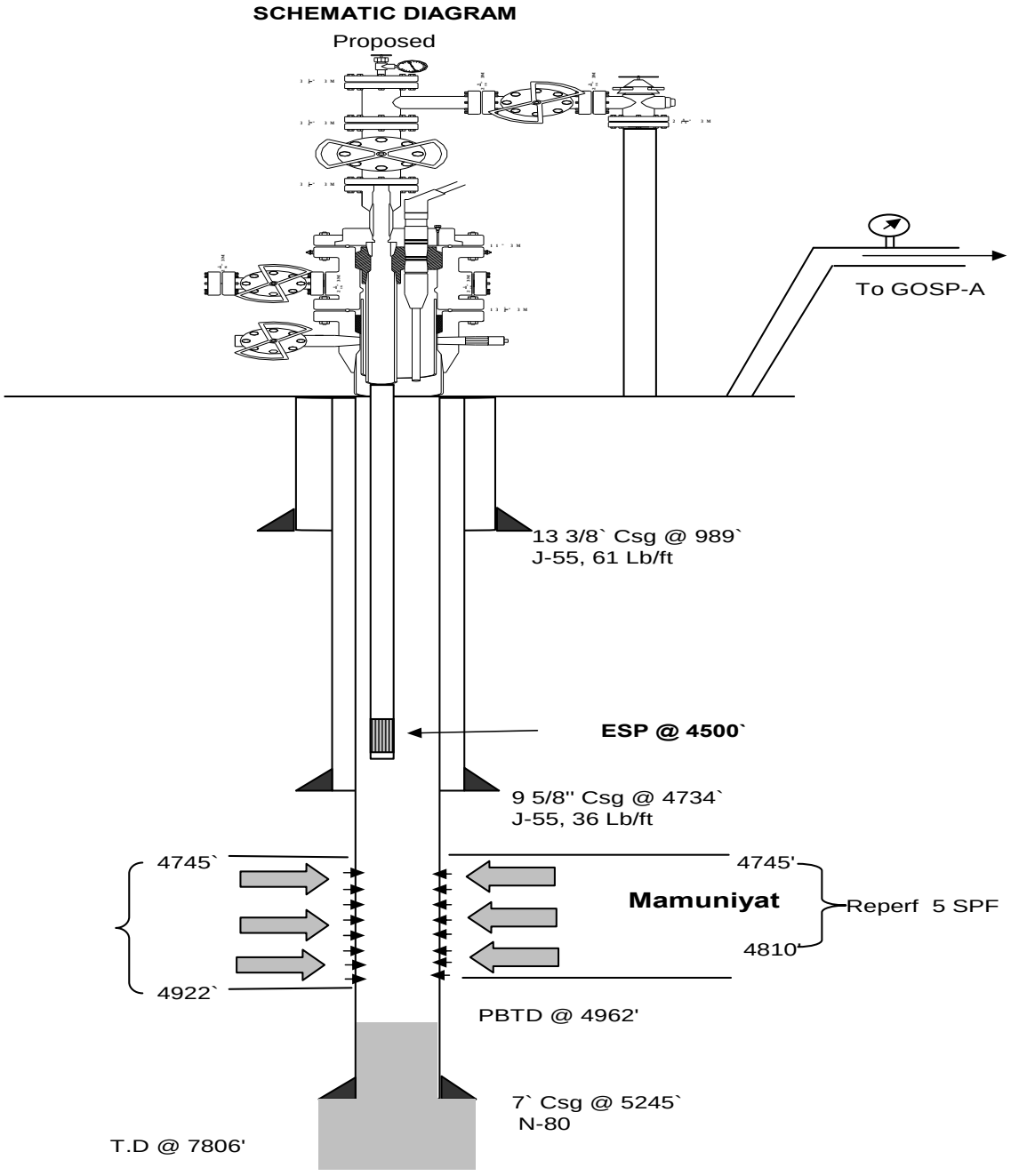



**Fig (4.2) well XX-01 schematic diagram.**

- **Well XX-01- production history:**

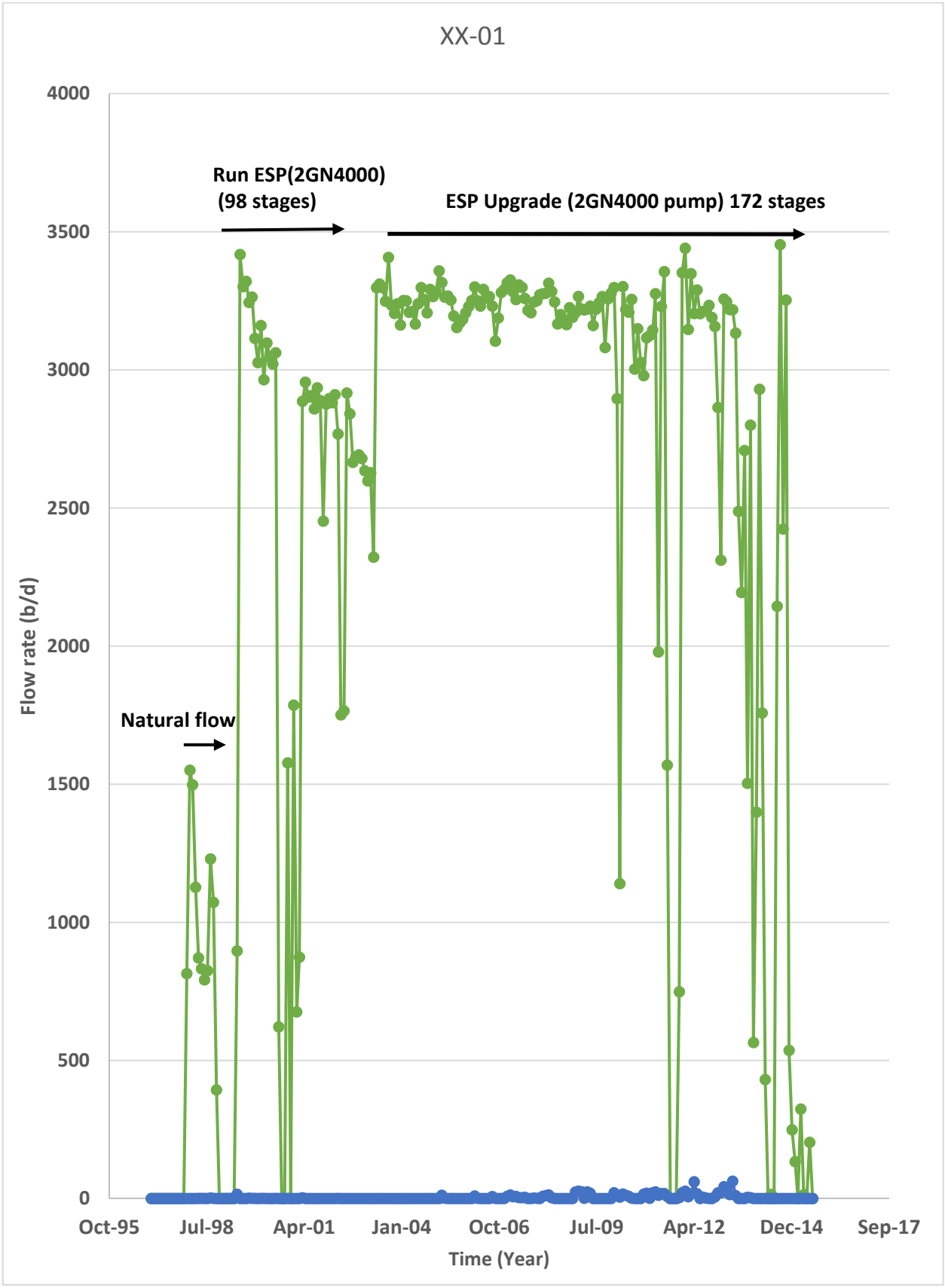



**Fig (4.3) well XX-01 production history.**

## IPR curve for well XX-01

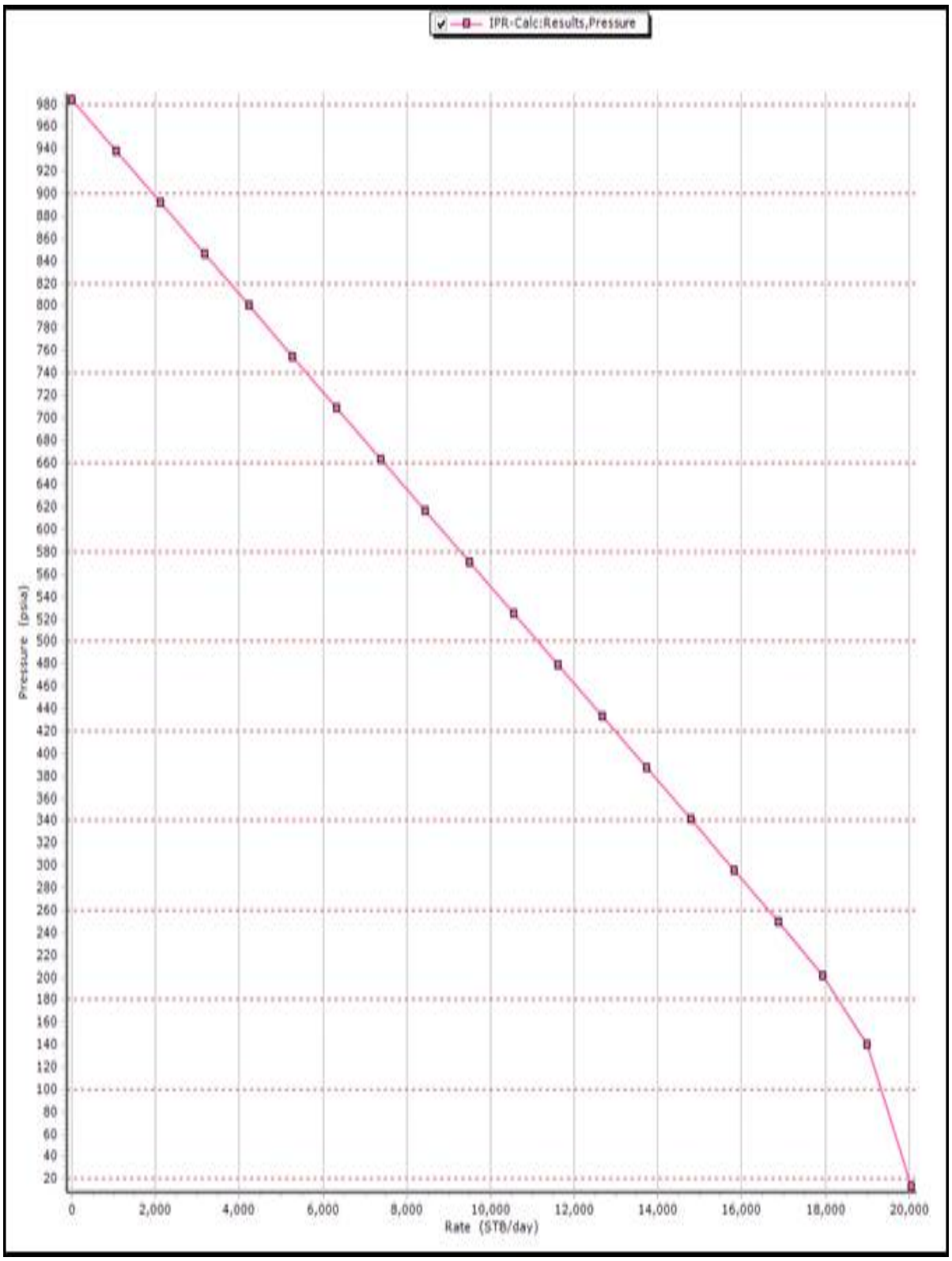



**Fig (4.4) well XX-01 IPR curve.**

## AOF: 20052.6 (STB/D)

### 4-3-2 Well XX-16:

- **Well History**

XX-16 was spudded in on Aug, 13th /1993. A 30'' hole was drilled T/30', 20'' conductor pipe was ran, set @ 30' and cemented to surface. Drilled out cement and continued drilling 17 ½'' hole T/3914', logs were ran -GR, Caliper 13 3/8'' casing, was ran and set @ 3913', and cemented to surface. Drilled out cement and continued drilling 12 ¼'' hole T/5180' (TD). Logs were ran LL3-GR, IEL-GR, BHC-GR, FDC-GR, CNL-GR, CBL.

9 5/8'' casing, was run, set @ 5,179' (float shoe depth), D.V @ 4,004', and cemented in two stages to surface. Drilled out D.V tool with 8 ½'' hole, then bit and scraper was run, PBTD tagged, well secured with X-mas tree, and rig released.

The well was perforated from 5,005-4968 ft, 4,950-4,908 ft and completed with 3 1/2'' tbg. PLT tools lost during PLT job on July 97, and then retrieved on Apr, 98.

Workover rig was moved and commenced operation on Feb/99, set BP @ 4965 with cement on it Re-perforation well 4950 – 4908', PCP installed again with no success.

ADWOC15 was moved on Aug/99 and ran new PCP, then retrieved on July/01 to run 3 ½'' completion string, set @ 4876'

The well was producing naturally from December 1996 to June 1997. A PCP pump was installed then in March 1999 cumulating around 60 Mstb of oil from March to July 1999.A failure occurred, new PCP pump was running, but without success.

- **Completion and Work over History**

March 1994-Initial Completion& First Test: completion with 3 1/2" tubing and perforation of interval 4913'-5005' ft KB; production test.

**First WO**: To complete the well as a producer in Mamuniyat formation

On Feb/1994 rig was moved to location, bit & scraper were run up to 5094 ft, then CBL was run to evaluate the cement job, the intervals F/4749 T/4050 shows good to fair CMT, while the intervals F/4050 T/290 shows very poor cement, the well was

perforated F/5005 T/4913 ft, 3 ½'' tubing was run with 9 5/8'' packer T/4870 ft, packer was set, after swabbing the well, the well flows AFR=2415 BOPD and 16-18% emulsion, unset the packer, well was killed, POH and set the packer again at 4959 ft, after swabbing the well, the well flow with AFR of 1900 BOPD plus 27% of emulsion, unset the packer, reverse out, and POH to surface, L/D same. Re-run CBL-GR, shows band cement F/5008 ft to bottom, possible communication with lower intervals. Packer was run again with ball plug on bottom, one perforated joint above the packer to test the upper interval, packer was set at 4959 ft, reverse out w/300 bbls of oil, R/U swab equipment, well flows AFR=1717 BOPD (upper interval) and 18% Bs&w. well was killed in reverse, packer was pulled out of hole, rerun one perforated joint and 9 5/8'' packer T/4870 ft, after swabbing the well, well flows AFR=3770 BOPD, Bs&w=60%, continued flowing with 32/64'' choke, AFR=2400 BOPD, Bs&w=16%, then well SI for BU. Then gauges were retrieved, well was killed and the testing string was retrieved, also the final production string was run T/4870 ft, well displaced with dead oil, rig released.

**Second WO**: To Re-test the well to investigate production capacity and skin damage.

On 01/July/1996 rig less operation was commenced on well XX-16 to investigate production capacity and skin damage, well flows AFR=2989 BOPD.

**Third WO**: To Retrieve the PLT tools

PLT was performed on March/1998, PLT tools were lost in the hole, rig was moved to location on April/1998 to retrieve the fish.

**Fourth WO**:PCP initial installation, plug back and re-perforate.

Rig was moved to location on Feb/1999, well was killed using 340 bbls, of filtered water, ran bit & scraper T/5090 ft, re-perforate F/4908 ft T/4950 ft, TCP string pulled out of hole, found bottom 20 ft not fired, BP was ran and set at 4965 ft to isolate the

bottom perforations, PCP pump was installed, with no flow to surface, pump was pulled out of hole, ran another TCP string (40 ft), run PCP again, the pump flows with AFR of 588 BOPD.

**Fifth WO**: Check PCP failure:

Rig was moved to location on Aug/1999, PCP pulled out of hole, pump replaced, then flow divert to GOSP, rig released on Aug/06/1999

**Sixth WO**: Run PCP no. 3:

Rig was moved to location on Oct/2000, to pull the existing pump and to run another one, PCP was retrieved; a new PCP was run, well flows to GOSP and rig released on Sep/06/2000.

**Seventh WO**: Retrieve PCP:

Rig was moved to location on July/2001 to retrieve the PCP pump and to run 3 ½'' tubing as a kill string with F-Nipple @ 4876 ft.

**Eighth WO**: Run ESP:

Workover rig was moved to location on July/2003, kill string pulled out of hole, ran 3GN2100 pumps (35+35+61) (installation data was 23/July/2003), pump started, flow diverted to GOSP, and rig released.

- **PCP history during run life in well XX-16**

The PCP pump was installed several times between 1999 to 2001 with few months of run life of each of them, 1999 was Back on line for production roughly 211 BOPD with zero water cut the production reached the pick at 571 BOPD on April 1999, in Jun 1999 the well was workover the pump did not last for long with production 10 BOPD with zero water cut, the PCP pump was recovered on July 2001 and, finally the decision was taken to run a new ESP pump.

- **Well schematic for well XX-16**

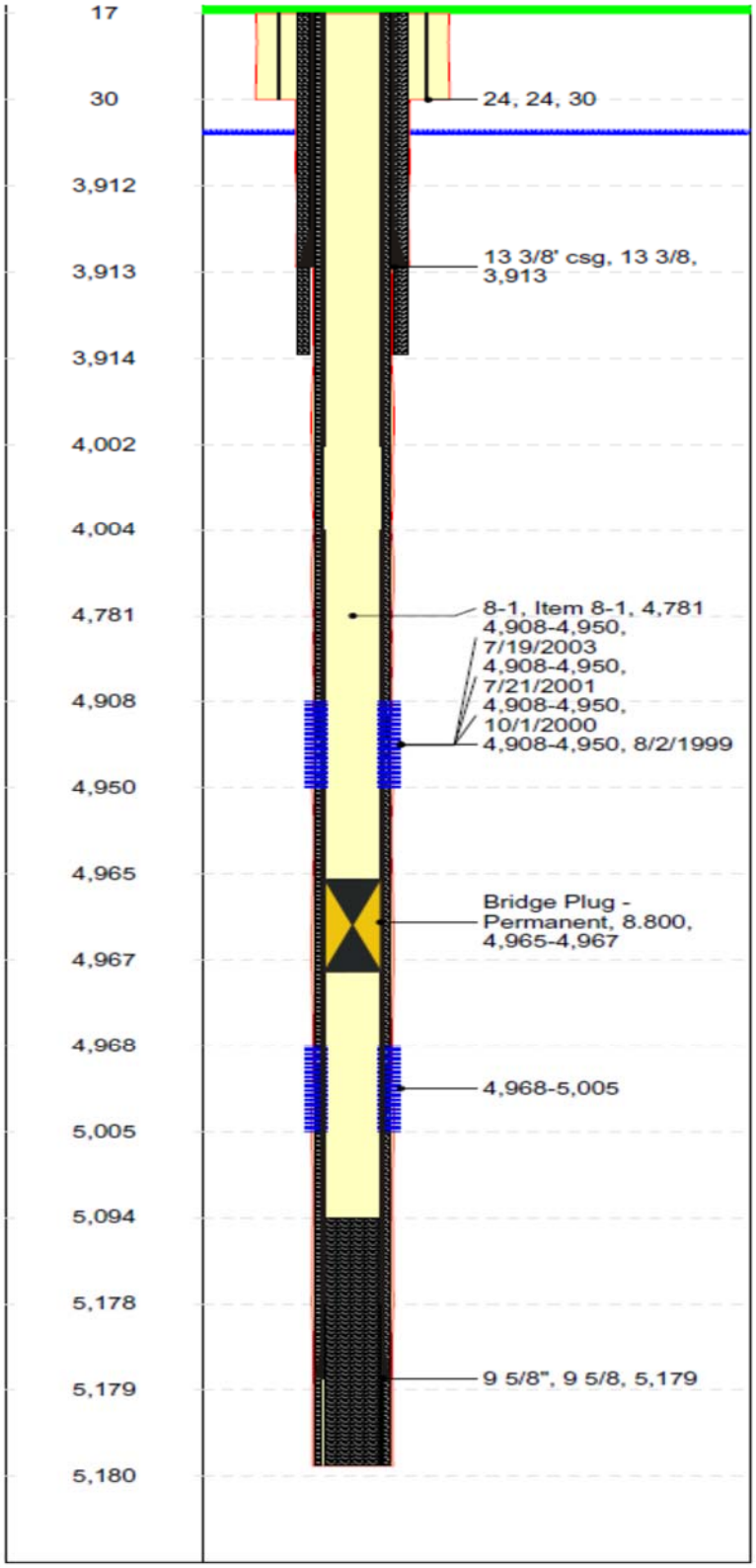



**Fig (4.5) well XX-16 schematic diagram.**

- **Well XX-16 production history**

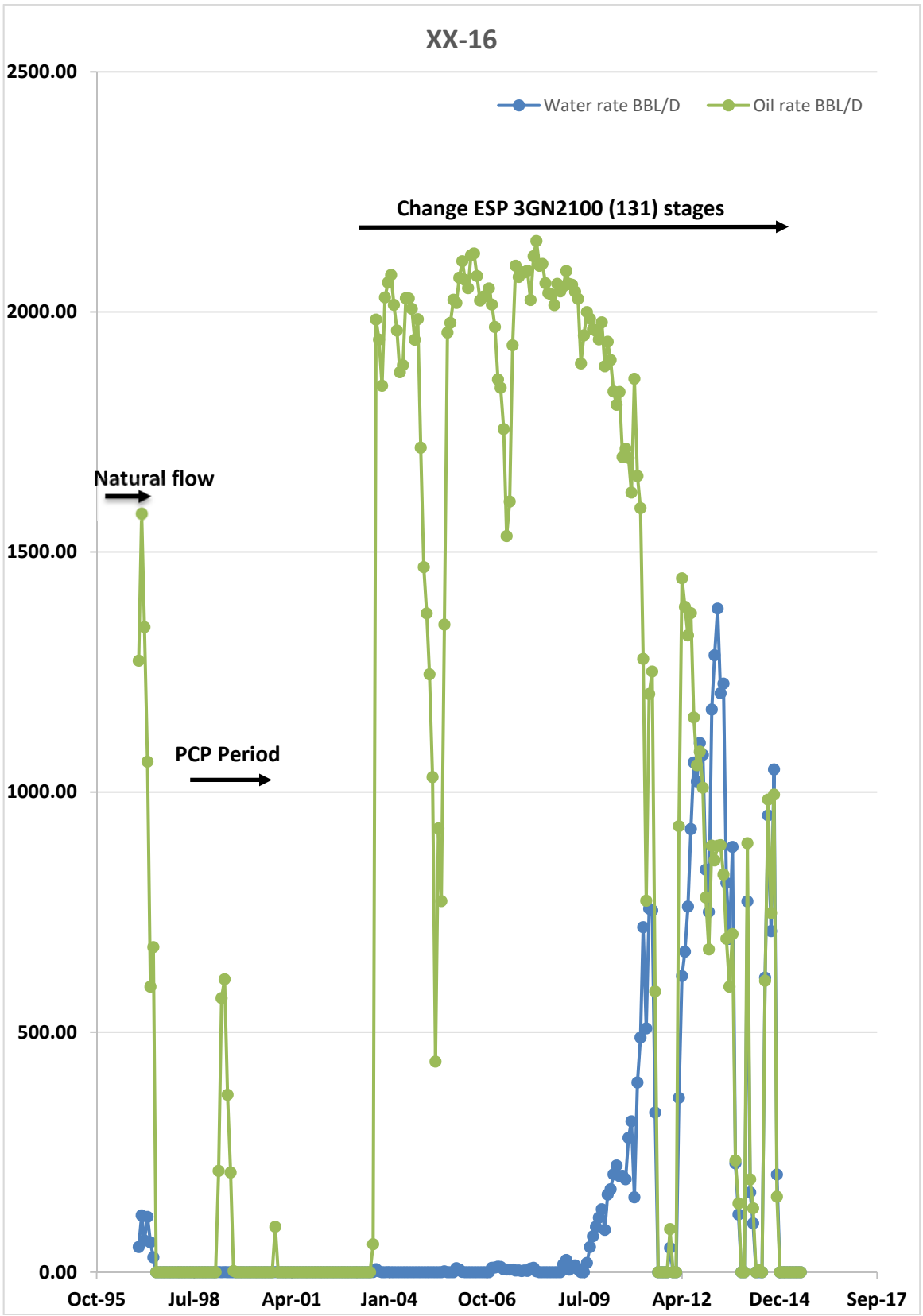



**Fig (4.6) well XX-16 production history.**

## IPR curve for well XX-16

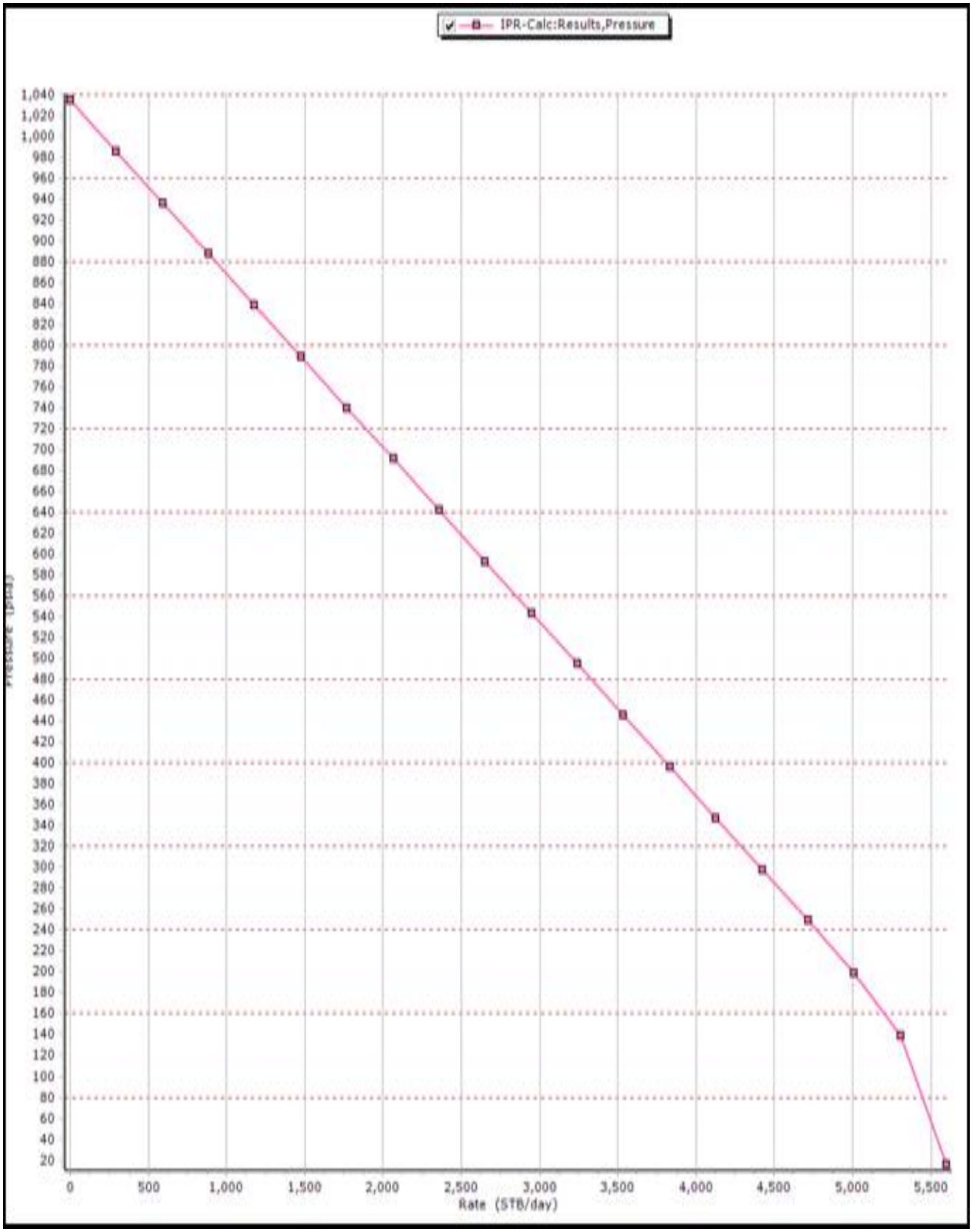



**Fig (4.7) well XX-16 IPR curve.**

## AOF: 5597 (STB/D)

### 4-3-3 Well XX-29:

Well is situated at the East of A field the well was completed in December 1995. The well was initially completed in February 1996 as an open-hole oil producer. The open-hole interval was 4,792-4,956 ft KB. In April 1999 a 3 ½" tubing was run. A cement retainer was set in the open-hole section at 4,920 ft KB and cemented with a stinger.

- **Completion and Work over History**

**First WO**: To complete the well as a producer in Mamuniyat formation.

**Second WO**: To RIH ESP

On Apr/27/1999, the well was completed as (open hole well). POH completion string from 4760 ft. One run of scraper to 4782. RIH wire line retainer. Set retainer @ 4920 ft. RIH 3 ½ tbg and cement retainer.

Top of cement 4913 ft. RIH ESP (GN5600 pumps seri 540 77 stages, HL protector and 83 HP motor 954 V, 55 A).

**Third WO**: To upgrade ESP and Y-tool.

On Jan/12/2003, POH W/ ESP to the surface , L/D ESP. Equipment check ok. RIH 8 1/2" bit & 9 5/8" scraper on 3 1/2" tbg from 130' to 4750'. POH 8 1/2" bit &scraper from 4750' to surface, L/D extra joints & L/D 8 1/2"bit with scraper. RIH W/ESP&Y-tool from surface to 3244',Band cable every 10' and check conductivity. ESP-BHA (2-PK-UT motor100HP,55A+BPBSL-HL protector + stander Intake + 4 pumps GN5600 FL-CT ) W/Y-tool .As per program. Startup ESP pump, check rotation Ok, pressure build up, well flowing to flare pit.

**Fourth WO**: To upgrade ESP and Y-tool

On Oct/06/2004, pump was replacement and RIH with intake depth @ 4527.35 ft.

- **Well schematic for well XX-29**

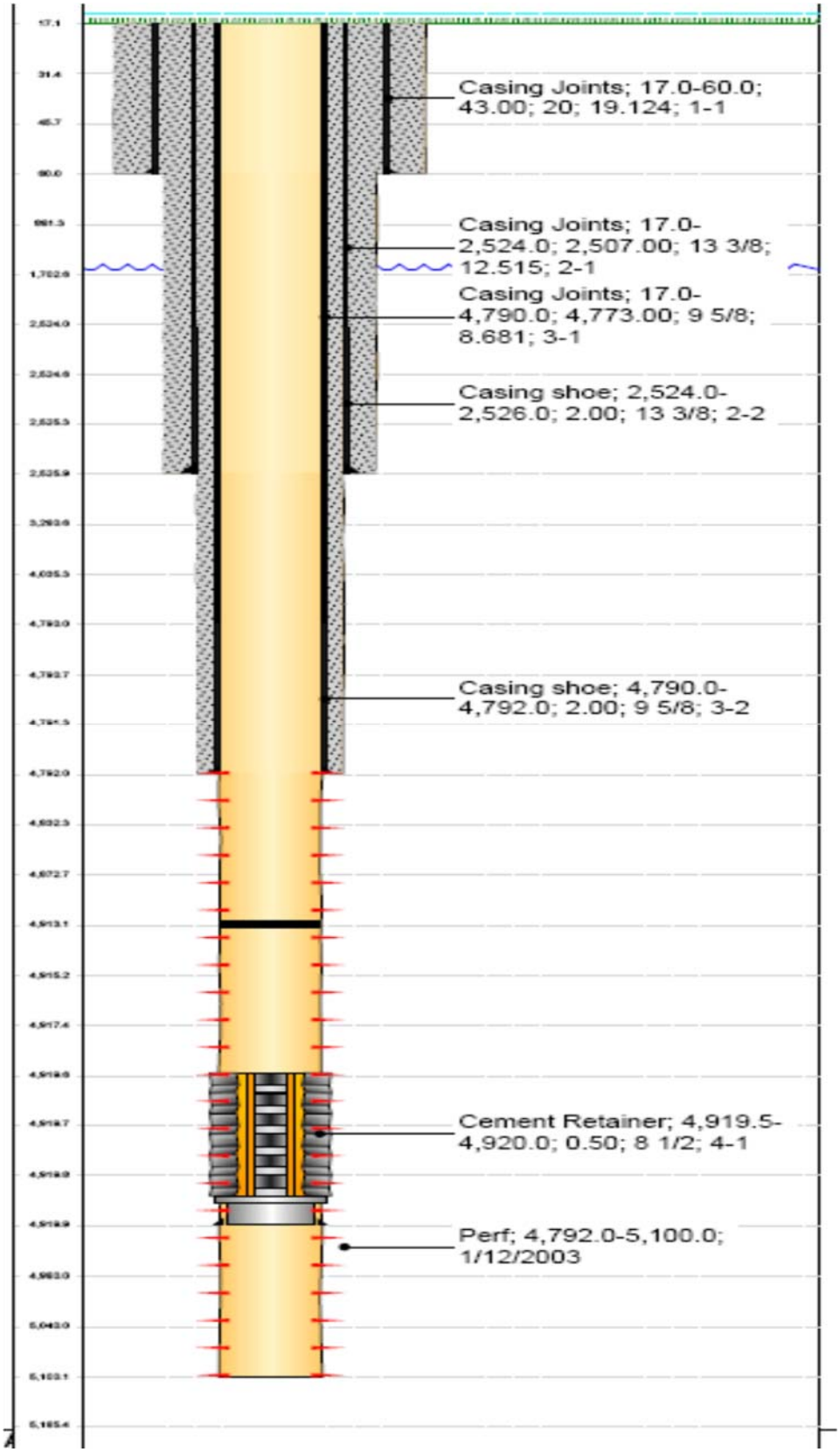



**Fig (4.8) well XX-29 schematic diagram.**

- **Well XX-29 production history**

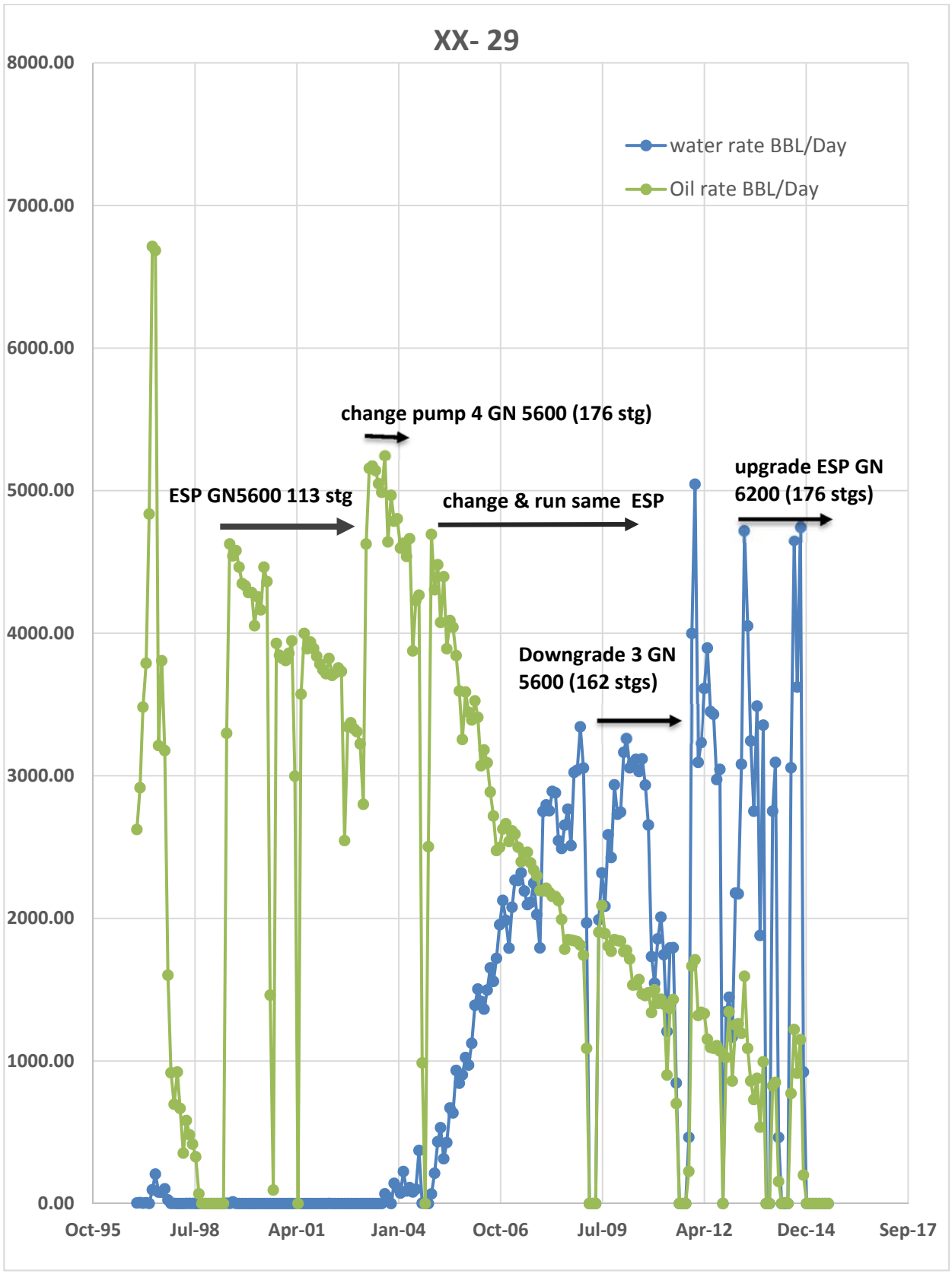



**Fig (4.9) well XX-29 production history.**

## IPR curve for well XX-29

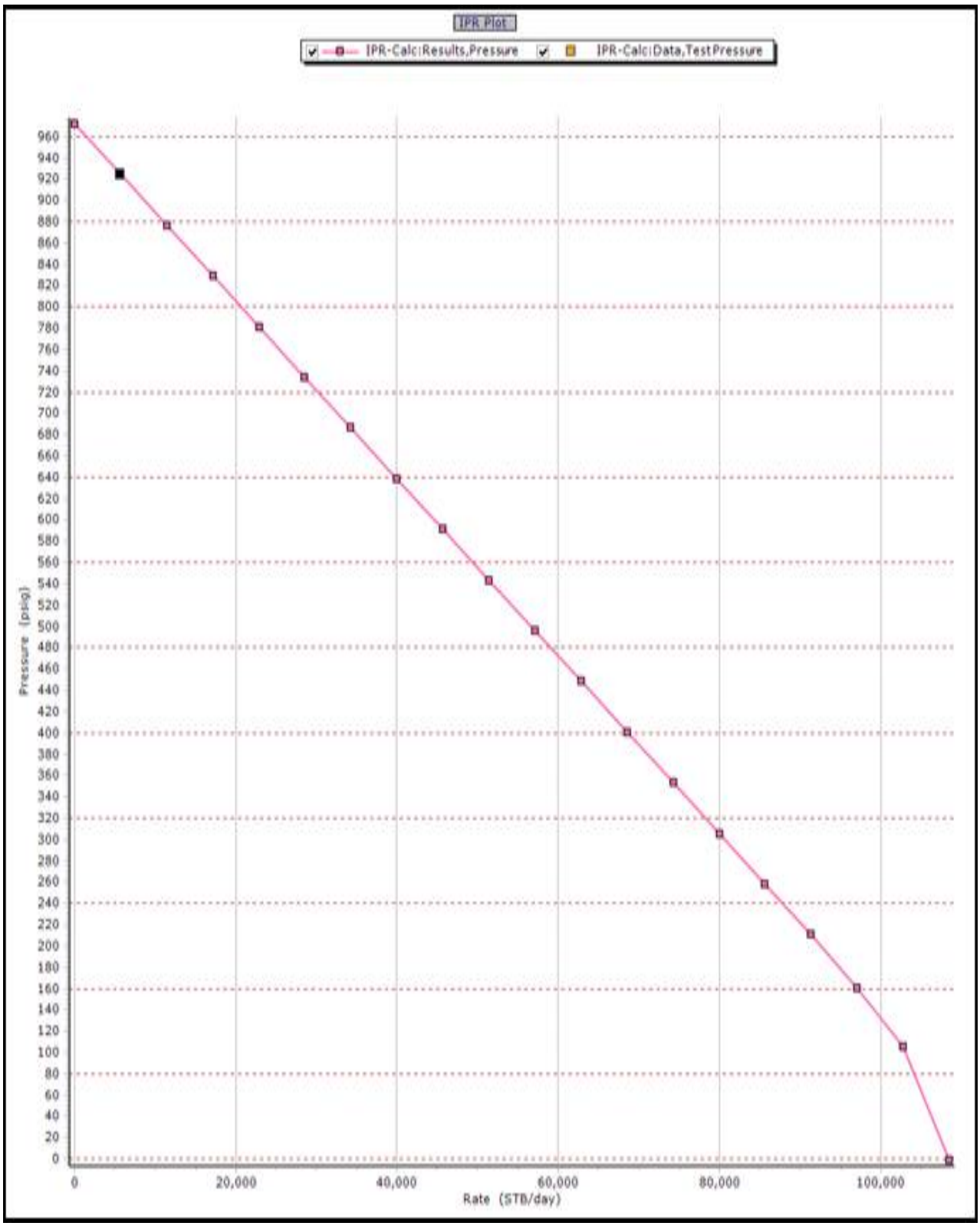



**Fig (4.10) well XX-29 IPR curve.**

**AOF: 108500 (STB/D).**

# Chapter 5
## Results &discussions

## 5-1 Griffin Pump Software results for well XX01:

## Normal PC pump capacity 6.85 bbl/d/rpm.

| PC pump | | ESP |
|---|---|---|
| RPM | Q bbl/d at 3 1/2" Tbg | Q bbl/d at 3 1/2" Tbg |
| 1 | 6.85 | 3436 |
| 100 | 685 | |
| 200 | 1370 | |
| 300 | 2055 | |
| 400 | 2740 | |
| 500 | 3425 | |

**Table (5.1) shows ESP rate vs PCP rate at different rpm for well XX-01**

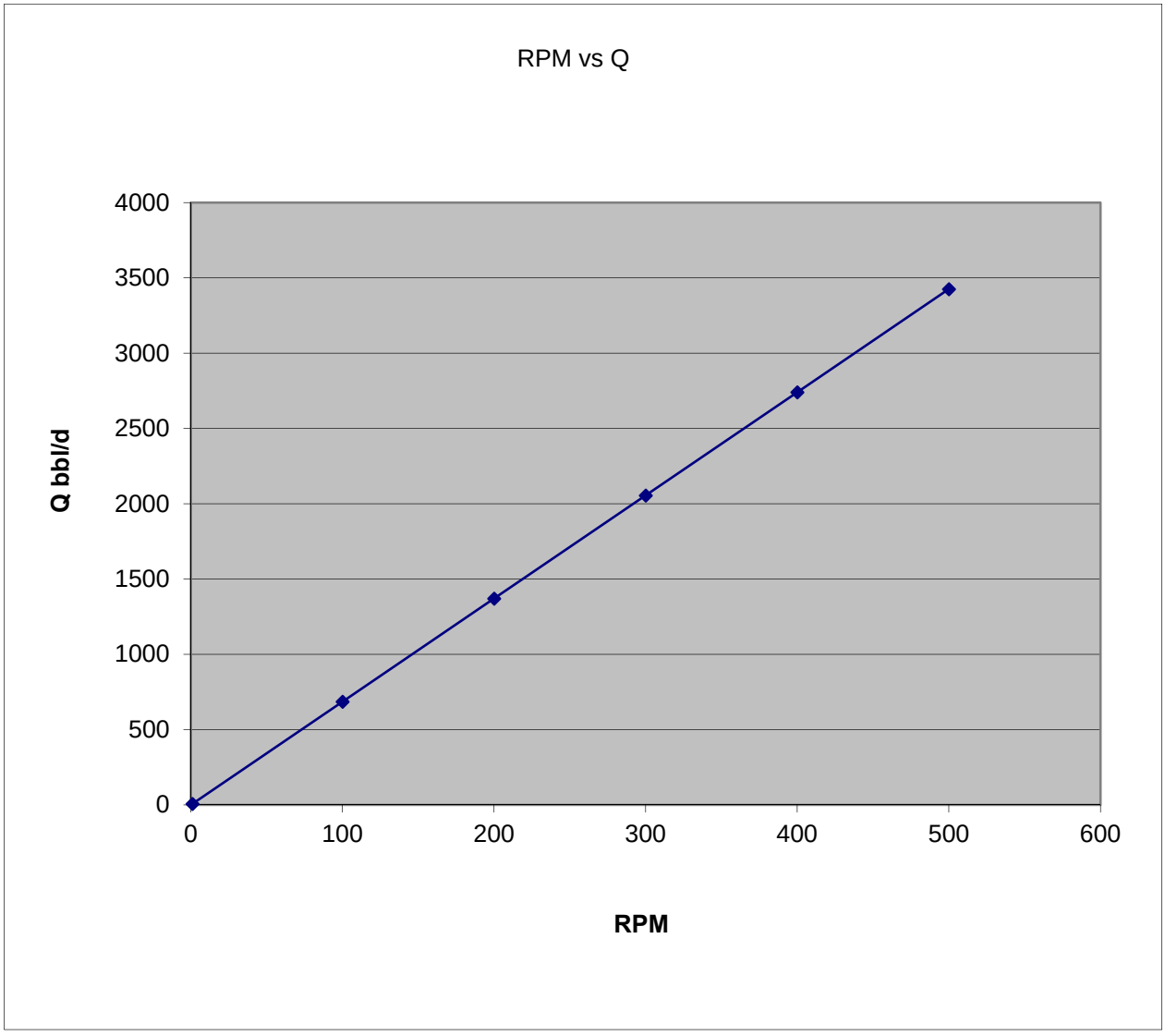



**Figure (5.1) shows PCP rate at different rpm for well XX-01**

## 5-2 Software outcome for well XX-01:

Sun Jan 24 2016 **ScrewPUMP 2.00 Summary Report** 06:50:22
grrl, , Serial # 099

1. **Well Description** **Case 1**

| | |
|---|---|
| Company Name: | AOO |
| Location: | |
| Field Name: | EL-Shrara Oil field. |
| Reservoir Name: | Momenyat. |
| Engineer: | Hatem |
| Comment: | XX-01 |
| Case Date: | 01/24/16 |

2. **Wellbore**

| | |
|---|---|
| Plug Back Depth MD/TVD, ft: | 4962 / 4962 |
| Pump Depth MD/TVD, ft: | 4515 / 4515 |
| Mid-Point of Perfs MD/TVD, ft: | 4777 / 4777 |
| Downhole Temp, °F: | 204 |

3. **Fluid Properties and Rates**

| | |
|---|---|
| Oil Rate, Bbl/d: | 3436 |
| Oil Gravity, °API: | 41.0 (1.3 cP) |
| Water Rate, Bbl/d: | 0 |
| Water Sp Grav, (fw = 1.0): | 1.006 |
| Gas Rate, Mcf/d: | 474.168 |
| Gas Sp Grav, (air = 1.0): | 0.650 |
| Oil & Water Rate, Bbl/d: | 3436 |
| Total Fluid @ Flowtee, Bbl/d: | 87889 |
| @ Pump Suction, Bbl/d: | 3823 (0.8 cP) |

4. **Equipment Selected**

| | |
|---|---|
| Casing/Liner OD, in: | 9.625 (4962 ft) |
| Tubing OD, in: | 3.500 (4515 ft) |
| Separation: | Natural Separation |
| Suckerrods OD, in: | 1.250 (4515 ft) Grade D |
| ScrewPump: | 20--685 |
| Drivehead Model: | B-DTX Direct |
| Drivehead Sheave: | 4B250 |
| Prime Mover Power, HP: | Electric Motor, 40.0 |
| Prime Mover Speed, rpm: | 1800 |
| Prime Mover Sheave: | 4TB80 |
| Prime Mover Mount: | Swing Frame, BX99 |

5. **Operation and Performance**

| | |
|---|---|
| Polishrod Speed, rpm: | 576 |
| Polishrod Torque, ft-lb: | 336.5 |
| Polishrod Power, HP: | 36.9 |
| Fluid Level TVD, ft: | 2130 |
| Flowtee Pressure, psi: | 172 |
| Casing Pressure, psi: | 40 |
| Viscous Drag, psi: | 0 |
| DriveHead Bearing Life, yrs: | 1.3 |
| Suckerrod Oper Stress, psi: | 19249 |
| Pump Differential Press, psi: | 79 (9 /stg) |
| Pump Volumetric Eff, %: | 90 |

Griffin Pumps, Inc.; (403) 279-4985

## Fluid Data - Case 1

| | | |
|---|---|---|
| Standard Temperature, | °F: | 60.00 |
| Standard Pressure, | psi: | 14.70 |
| Oil Gravity, | °API: | 41.00 |
| Specific Gravity of Gas, | (air = 1.0): | 0.650 |
| Specific Gravity of Water, | (wtr = 1.0): | 1.006 |
| Salinity, | ppm: | 9500 |
| Water Cut, | %: | 0.0 |
| Prod Gas-Oil Ratio, | scf/STB: | 138.0 |
| Prod Gas-Liquid Ratio, | scf/STB: | 138.0 |

IPR Calculation Method: Vogel corrected for water cut

| | | |
|---|---|---|
| Total Test Rate, | Bbl/d: | 3434.00 |
| Productivity Index, | bfpd/psi: | 26.3608 |
| Bubble Point Rate, | Bbl/d: | 19406.92 |
| Max Oil Flow Rate, | Bbl/d: | 23675.84 |
| Max Total Flow Rate, | Bbl/d: | 23680.05 |

| | | Static | Test |
|---|---|---|---|
| Casing Pressure, | psi: | 0.00 | 0.00 |
| Fluid Level, | ft: | 0.00 | 0.00 |
| Bottom Hole Pressure, | psi: | 1013.00 | 882.73 |

## Theoretical Pump Performance - Case 1

| | | Intake | Discharge | Surface |
|---|---|---|---|---|
| Oil Rate, | Bbl/d: | 3613.8 | 3558.9 | 3399.7 |
| Gas Rate through Pump, | Bbl/d: | 0.0 | 0.0 | N/A |
| Gas Rate from Casing, | Bbl/d: | 0.0 | 0.0 | N/A |
| Total Gas Rate, | Mcf/d: | N/A | N/A | 219.8 |
| Free Gas Percent, | %: | 0.0 | 0.0 | N/A |
| Water Rate, | Bbl/d: | 35.6 | 35.5 | 34.3 |
| Total Rate, | Bbl/d: | 3649.4 | 3594.4 | 3434.0 |
| Pumping Pressure, | psi: | 794.6 | 1742.1 | 165.0 |
| Specific Gravity Liquid, | wtr=1: | 0.78 | 0.99 | N/A |
| Specific Gravity Mixture, | wtr=1: | 0.78 | 0.99 | N/A |
| Liquid Density, | lb/cf: | 48.5 | 62.0 | N/A |
| Mixture Density, | lb/cf: | 48.5 | 62.0 | N/A |

## Correlation Data - Case 1

| Description | | Method |
|---|---|---|
| Gas Viscosity | : | Lee |
| Oil Viscosity, (Dead ) | : | Glaso |
| Oil Viscosity, (Saturated) | : | Beggs & Robinson |
| Oil Viscosity, (UnSaturated) | : | Vasquez & Beggs |
| Water Viscosity | : | Brill & Beggs |
| Oil Formation Volume Factor | : | Glaso |
| Water Formation Volume Factor | : | HP41C |
| Oil Surface Tension | : | Baker+Swerdloff |
| Water Surface Tension | : | Hough |
| Gas Density | : | Beggs |
| Oil Density | : | Standing |
| Water Density | : | Beggs |
| Z-Factor | : | Hall & Yarborough |
| Oil Isothermal Compressibility | : | Vasquez & Beggs |
| Water Isothermal Compressibility | : | Meehan |
| Solution Gas-Oil Ratio | : | Glaso |
| Bubble Point Pressure | : | Glaso |

## Design Criteria Data - Case 1

| | | |
|---|---|---|
| Total Fluid Rate, | Bbl/d: | 3436.00 |
| Pump Depth, | ft: | 4515.00 |
| Fluid Over Pump, | ft: | 2385.00 |
| Fluid Level, | ft: | 2130.00 |
| Pump Intake Pressure, | psi: | 883.76 |
| Flowline Pressure, | psi: | 172.00 |
| Casing Pressure, | psi: | 40.00 |
| Bottom Hole Pressure, | psi: | 977.54 |

## Pump Data - Case 1

| | | | |
|---|---|---|---|
| Selected Pump | : | 20--685 | |
| Rotor Fit | : | Standard | (Default) |
| BHT @ Pump, | °F: | 197 | |
| Maximum Net Lift, | ft: | 2000 | |
| Net Lift Required, | ft: | 172 | (@ 0.341psi/ft) |
| Net Lift Required, | ft: | 135 | (@ 0.433psi/ft) |
| Nominal Pump Capacity, | Bbl/d/RPM: | 6.850 | |
| Friction Torque, | ft-lb: | 180.0 | |
| Pump Stages | : | 9 | |
| Diff Pressure per Stage, | psi/stg: | 8.7 | |
| Target Liquid Rate @ Pump, | Bbl/d: | 3587.5 | |
| Free Gas in Pump, | Bbl/d: | 235.2 | |
| Target Fluid Rate in Pump, | Bbl/d: | 3822.7 | |
| Polish Rod Speed, | RPM: | 558.1 | |
| Volumetric Efficiency, | %: | 89.9 | |
| Polish Rod Torque, | ft-lb: | 333.4 | |
| Polish Rod Horsepower, | HP: | 35.4 | |

## Rod String - Case 1

| | | | |
|---|---|---|---|
| Rod Size, | in: | 1.250 | |
| Rod Grade | : | D | |
| Rod Weight, | lb/ft: | 4.53 | |
| Maximum Allowable Stress, | psi: | 65714.0 | |
| Total Fluid Weight, | lb: | -1876.9 | |
| Total Rod Weight, | lb: | 18561.4 | |
| Bearing Load, | lb: | 16684.5 | |
| Axial Stress, | psi: | 13595.7 | |
| Shear Stress, | psi: | 10431.6 | |
| Max Combined Stress, | psi: | 19249.0 | |
| Max Shear Stress, | psi: | 12451.1 | |
| Von Mises Stress, | psi: | 22612.0 | |

## Wellhead Drive - Case 1

| | | | |
|---|---|---|---|
| Selected Wellhead Drive | : | B-DTX | (Direct Drive) |
| Speed Reduction Ratio | : | 1:1 | |
| Polish Rod Speed, | RPM: | 200-1200 | |
| Gear Torque Rating, | ft-lb: | rod limit | |
| Thrust Bearing Rating, | lb: | 25900 | |
| Wellhead Drive Shaft Size, | in: | 2.187 | |
| Wellhead Drive Output Speed, | RPM: | 558.1 | |
| Wellhead Drive Output Torque, | ft-lb: | 333.4 | |
| L10 Wellhead Drive Life, | years: | 1.3 | |
| Thrust Bearing Load, | lb: | 16684.5 | |

## Electric Motor - Case 1

| | | Equipment Rating | Design Conditions |
|---|---|---|---|
| Manufacturer | : | TEFC | |
| Model | : | 324T | |
| Motor Horsepower, | HP: | 40 | 0.0 |
| Motor Speed, | RPM: | 1800 | |
| Motor Shaft Size, | in: | 2.125 | |
| Motor Sheave Size, | in: | 7.8 | |

## Electric Motor Sheave - Case 1

| | | Electric Motor Sheave | Wellhead Drive Sheave |
|---|---|---|---|
| Sheave Manufacturer | : | Browning | Browning |
| Sheave Model | : | 4TB80 | 4B250 |
| Sheave Size, | in: | 8.0 | 25.0 |
| Bushing Type | : | Q1 | R1 |
| Bushing Size, | in: | 2.125 | 2.187 |
| Center Length (between Shafts), | in: | 22.0 | |

## Electric Motor Belt - Case 1

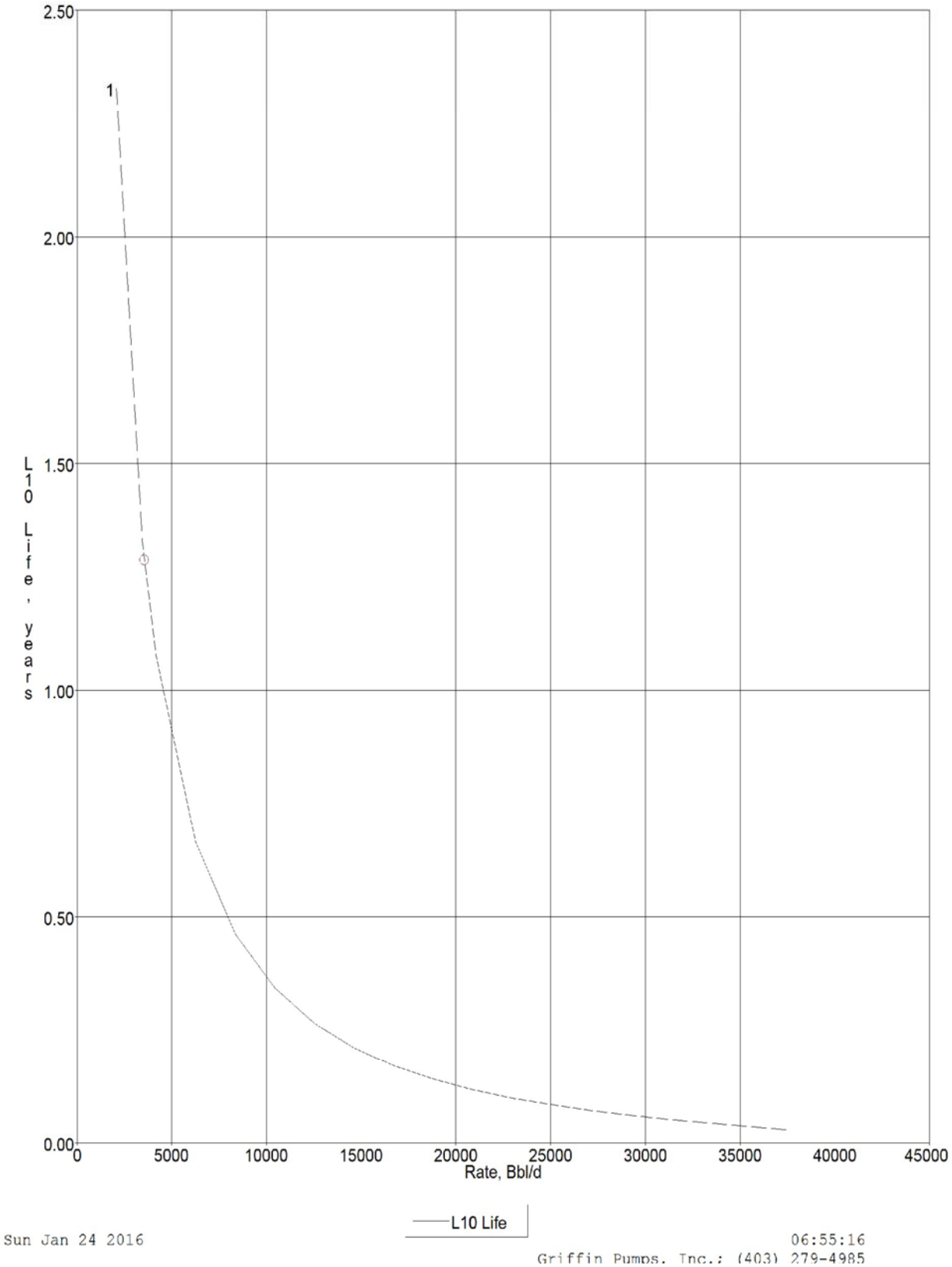
| | | |
|---|---|---|
| Belt Number | : | BX99 |
| Belt Pitch Length, | in: | 100.8 |
| Maximum Horsepower per Belt, | HP: | 11.3 |
| Required Number of Belts | : | 3 |

## Final Solution Analysis - Case 1

| | | Initial Design | Final Solution |
|---|---|---|---|
| Wellhead Drive Shaft Speed, | RPM: | 558.1 | 576.0 |
| Polish Rod Speed, | RPM: | 558.1 | 576.0 |
| Polish Rod Horsepower, | HP: | 35.4 | 36.9 |
| L10 Wellhead Drive Life, | years: | 1.3 | 1.3 |
| Fluid Rate into Pump, | Bbl/d: | 3822.7 | 3945.6 |
| Liquid Rate @ Pump, | Bbl/d: | 3587.5 | 3710.4 |
| Design Rate, | Bbl/d: | 3436.0 | 3553.7 |
| Volumetric Efficiency, | %: | 89.9 | 90.1 |
| Producing BHP @ Perfs, | psi: | 1815.3 | 1810.2 |

**Full Wellhead Drive L10 Life**

B-DTX Direct Drive



## 5-3 Griffin Pump Software results for well XX16:

## Normal PC pump capacity 4.00 bbl/d/rpm.

| PC pump | | ESP |
|---|---|---|
| RPM | Q bbl/d at 3 1/2" Tbg | Q bbl/d at 3 1/2" Tbg |
| **1** | **4.00** | 2014 |
| 100 | 400 | |
| 200 | 800 | |
| 300 | 1200 | |
| 400 | 1600 | |
| 500 | 2000 | |

**Table (5.2) shows ESP rate vs PCP rate at different rpm for well XX-16**

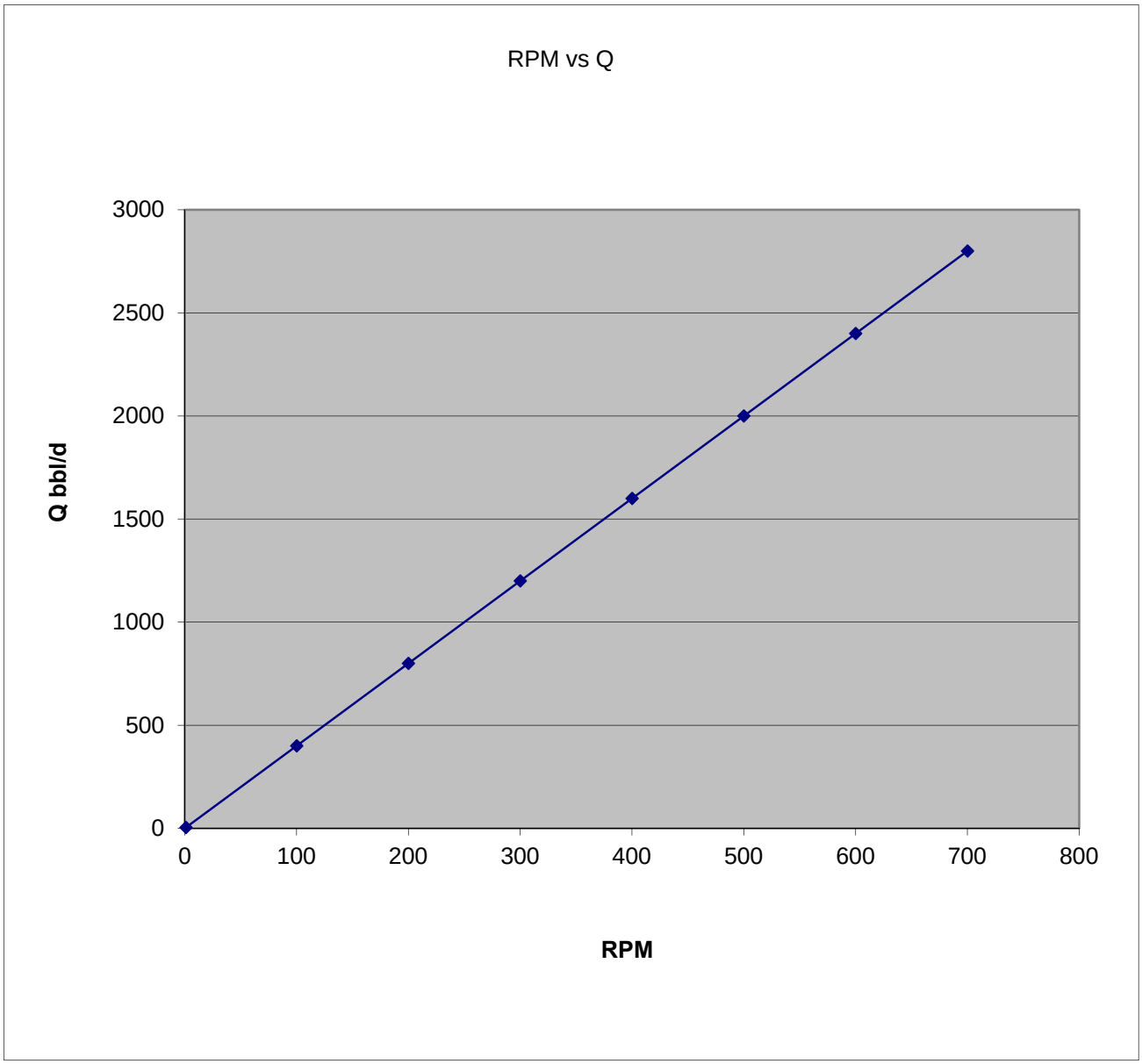



**Figure (5.2) shows PCP rate at different rpm for well XX-16**

## 5-4 Software outcome for well XX-16:

Mon Nov 02 2015 **ScrewPUMP 2.00 Summary Report** 19:15:19
grrl, , Serial # 099

1. **Well Description** **Case 1**

| | |
|---|---|
| Company Name: | AKAKUS OIL OPERATIONS. |
| Location: | |
| Field Name: | EL_Shrara Oil Field. |
| Reservoir Name: | Momenyat |
| Engineer: | Hatem |
| Comment: | Well XX-16 tbg 3.5'' |
| Case Date: | 11/02/15 |

2. **Wellbore**

| | |
|---|---|
| Plug Back Depth MD/TVD, ft: | 4965 / 4965 |
| Pump Depth MD/TVD, ft: | 4745 / 4745 |
| Mid-Point of Perfs MD/TVD, ft: | 4929 / 4929 |
| Downhole Temp, °F: | 190 |

3. **Fluid Properties and Rates**

| | |
|---|---|
| Oil Rate, Bbl/d: | 967 |
| Oil Gravity, °API: | 41.0 (1.4 cP) |
| Water Rate, Bbl/d: | 1047 |
| Water Sp Grav, (fw = 1.0): | 1.000 |
| Gas Rate, Mcf/d: | 128.896 |
| Gas Sp Grav, (air = 1.0): | 0.650 |
| Oil & Water Rate, Bbl/d: | 2014 |
| Total Fluid @ Flowtee, Bbl/d: | 24971 |
| @ Pump Suction, Bbl/d: | 2156 (0.8 cP) |

4. **Equipment Selected**

| | |
|---|---|
| Casing/Liner OD, in: | 9.625 (4965 ft) |
| Tubing OD, in: | 3.500 (4745 ft) |
| Separation: | Natural Separation |
| Suckerrods OD, in: | 1.250 (4745 ft) Grade D |
| ScrewPump: | 60--400 |
| Drivehead Model: | B-DTX Direct |
| Drivehead Sheave: | 10B250 |
| Prime Mover Power, HP: | Electric Motor, 100.0 |
| Prime Mover Speed, rpm: | 1800 |
| Prime Mover Sheave: | 10B74 |
| Prime Mover Mount: | Swing Frame, BX97 |

5. **Operation and Performance**

| | |
|---|---|
| Polishrod Speed, rpm: | 533 |
| Polishrod Torque, ft-lb: | 904.1 |
| Polishrod Power, HP: | 91.7 |
| Fluid Level TVD, ft: | 3240 |
| Flowtee Pressure, psi: | 120 |
| Casing Pressure, psi: | 20 |
| Viscous Drag, psi: | 0 |
| DriveHead Bearing Life, yrs: | 0.5 |
| Suckerrod Oper Stress, psi: | 39024 |
| Pump Differential Press, psi: | 1435 (51 /stg) |
| Pump Volumetric Eff, %: | 93 |

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## Fluid Data - Case 1

| | | |
|---|---|---|
| Standard Temperature, | °F: | 60.00 |
| Standard Pressure, | psi: | 14.70 |
| Oil Gravity, | °API: | 41.00 |
| Specific Gravity of Gas, | (air = 1.0): | 0.650 |
| Specific Gravity of Water, | (wtr = 1.0): | 1.000 |
| Salinity, | ppm: | 0 |
| Water Cut, | %: | 52.0 |
| Prod Gas-Oil Ratio, | scf/STB: | 133.3 |
| Prod Gas-Liquid Ratio, | scf/STB: | 64.0 |
| Bubble Point Pressure, | psi: | 658.04 |
| Solution Gas-Oil Ratio, | scf/STB: | 133.36 |
| Fluid Viscosity, | cP: | 0.788 |
| Total Fluid Gradient, | psi/ft: | 0.369 |

## Inflow Data - Case 1

IPR Calculation Method: Vogel corrected for water cut

| | | |
|---|---|---|
| Total Test Rate, | Bbl/d: | 2014.00 |
| Productivity Index, | bfpd/psi: | 4.8372 |
| Bubble Point Rate, | Bbl/d: | 1788.11 |
| Max Oil Flow Rate, | Bbl/d: | 3556.47 |
| Max Total Flow Rate, | Bbl/d: | 3713.69 |

| | | Static | Test |
|---|---|---|---|
| Casing Pressure, | psi: | 0.00 | 0.00 |
| Fluid Level, | ft: | 0.00 | 0.00 |
| Bottom Hole Pressure, | psi: | 1013.00 | 595.02 |

## Pump Data - Case 1

| | | | |
|---|---|---|---|
| Selected Pump | : | 60--400 | |
| Rotor Fit | : | Standard | (Default) |
| BHT @ Pump, | °F: | 185 | |
| Maximum Net Lift, | ft: | 6000 | |
| Net Lift Required, | ft: | 3729 | (@ 0.369psi/ft) |
| Net Lift Required, | ft: | 3176 | (@ 0.433psi/ft) |
| Nominal Pump Capacity, | Bbl/d/RPM: | 4.000 | |
| Friction Torque, | ft-lb: | 350.0 | |
| Pump Stages | : | 28 | |
| Diff Pressure per Stage, | psi/stg: | 51.2 | |
| Target Liquid Rate @ Pump, | Bbl/d: | 2121.3 | |
| Free Gas in Pump, | Bbl/d: | 34.7 | |
| Target Fluid Rate in Pump, | Bbl/d: | 2156.0 | |
| Polish Rod Speed, | RPM: | 539.0 | |
| Volumetric Efficiency, | %: | 93.4 | |
| Polish Rod Torque, | ft-lb: | 905.9 | |
| Polish Rod Horsepower, | HP: | 93.0 | |

## Rod String - Case 1

| | | | |
|---|---|---|---|
| Rod Size, | in: | 1.250 | |
| Rod Grade | : | D | |
| Rod Weight, | lb/ft: | 4.53 | |
| Maximum Allowable Stress, | psi: | 65714.0 | |
| Total Fluid Weight, | lb: | 3272.2 | |
| Total Rod Weight, | lb: | 19347.8 | |
| Bearing Load, | lb: | 22620.0 | |
| Axial Stress, | psi: | 18432.4 | |
| Shear Stress, | psi: | 28346.7 | |
| Max Combined Stress, | psi: | 39023.5 | |
| Max Shear Stress, | psi: | 29807.3 | |
| Von Mises Stress, | psi: | 52443.9 | |

## Wellhead Drive - Case 1

| | | | |
|---|---|---|---|
| Selected Wellhead Drive | : | B-DTX | (Direct Drive) |
| Speed Reduction Ratio | : | 1:1 | |
| Polish Rod Speed, | RPM: | 200-1200 | |
| Gear Torque Rating, | ft-lb: | rod limit | |
| Thrust Bearing Rating, | lb: | 25900 | |
| Wellhead Drive Shaft Size, | in: | 2.187 | |
| Wellhead Drive Output Speed, | RPM: | 539.0 | |
| Wellhead Drive Output Torque, | ft-lb: | 905.9 | |
| L10 Wellhead Drive Life, | years: | 0.5 | |
| Thrust Bearing Load, | lb: | 22620.0 | |

## Electric Motor - Case 1

| | | Equipment Rating | Design Conditions |
|---|---|---|---|
| Manufacturer | : | TEFC | |
| Model | : | 2x326T | |
| Motor Horsepower, | HP: | 100 | 0.0 |
| Motor Speed, | RPM: | 1800 | |
| Motor Shaft Size, | in: | 2.125 | |
| Motor Sheave Size, | in: | 7.5 | |

## Electric Motor Sheave - Case 1

| | | Electric Motor Sheave | Wellhead Drive Sheave |
|---|---|---|---|
| Sheave Manufacturer | : | Browning | Browning |
| Sheave Model | : | 10B74 | 10B250 |
| Sheave Size, | in: | 7.4 | 25.0 |
| Bushing Type | : | R2 | R2 |
| Bushing Size, | in: | 2.125 | 2.187 |
| Center Length (between Shafts), | in: | 22.0 | |

## Electric Motor Belt - Case 1

| | | |
|---|---|---|
| Belt Number | : | BX97 |
| Belt Pitch Length, | in: | 98.8 |
| Maximum Horsepower per Belt, | HP: | 10.1 |
| Required Number of Belts | : | 9 |

## Final Solution Analysis - Case 1

| | | Initial Design | Final Solution |
|---|---|---|---|
| Wellhead Drive Shaft Speed, | RPM: | 539.0 | 532.8 |
| Polish Rod Speed, | RPM: | 539.0 | 532.8 |
| Polish Rod Horsepower, | HP: | 93.0 | 91.7 |
| L10 Wellhead Drive Life, | years: | 0.5 | 0.5 |
| Fluid Rate into Pump, | Bbl/d: | 2156.0 | 2131.2 |
| Liquid Rate @ Pump, | Bbl/d: | 2121.3 | 2096.5 |
| Design Rate, | Bbl/d: | 2014.0 | 1990.4 |
| Volumetric Efficiency, | %: | 93.4 | 93.4 |
| Producing BHP @ Perfs, | psi: | 610.6 | 615.6 |
| Pump Intake Pressure, | psi: | 527.1 | 546.8 |
| Producing Fluid Level, | ft: | 3237.4 | 3182.0 |

## 5-5 Cost review for well XX-16:

| Date | Pump state | ESP Equipment prise ($) | PCP equipment prise ($) | Rig operation cost ($) | Total cost ($) |
|---|---|---|---|---|---|
| 4-Mar-99 | New | | 95,000 | 26,425 | 121,425 |
| 4-Oct-00 | New | | 111,365 | 31,370 | 142,735 |
| 25-Jul-03 | Repired | 51,883 | | 64,260 | 116,143 |
| 7-Jul-05 | Repired | 98,059 | | 53,900 | 151,959 |

**Table (5.3) shows cost review for PCP and comparing it with ESP cost**

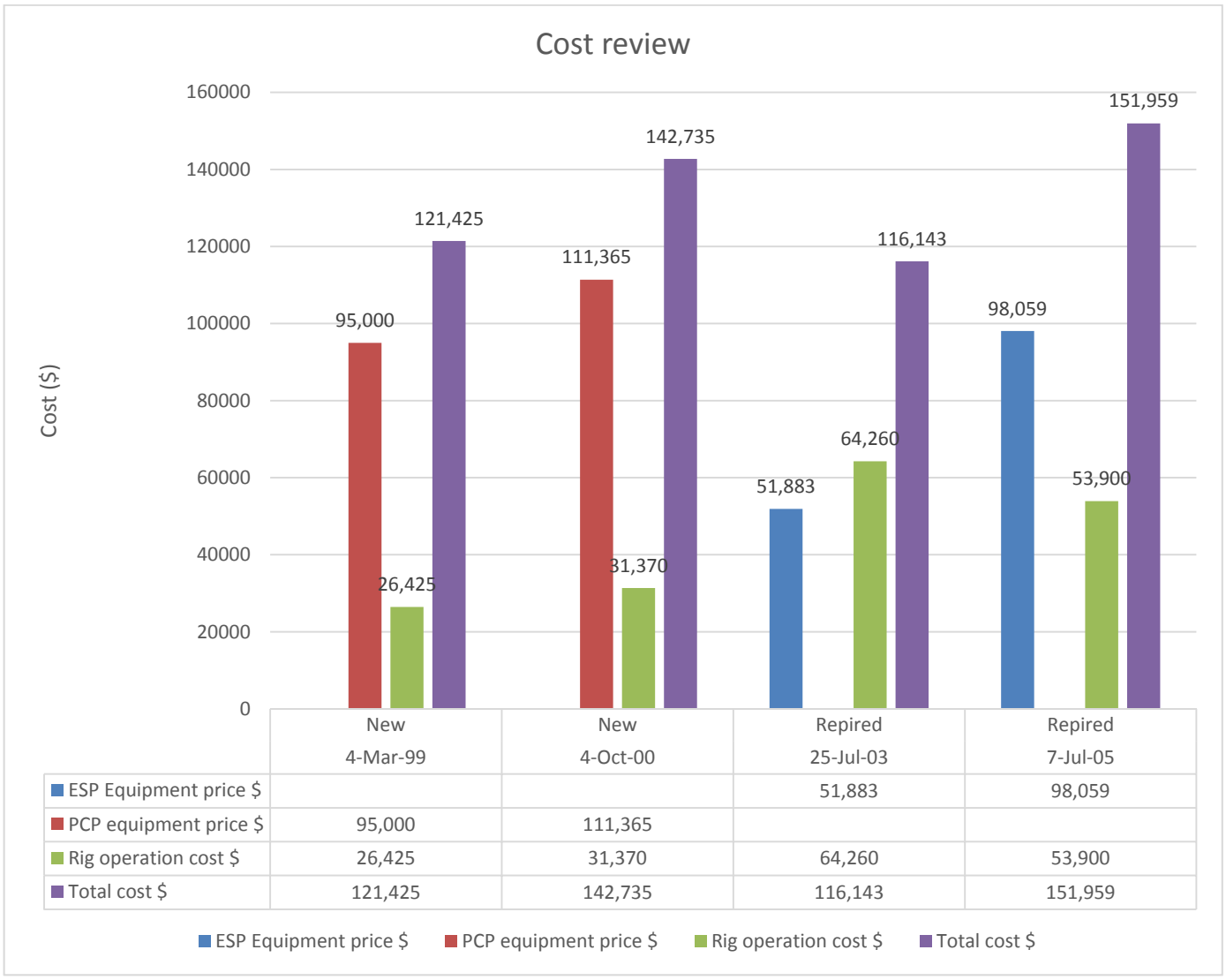



**Fig (5.3) describe cost review for well XX-16 during operation life.**

## 5-6 Griffin Pump Software results for well XX29:

Normal pump capacity 6.85 bbl/d/rpm

| PC pump | | ESP |
|---|---|---|
| RPM | Q bbl/d at 3 1/2" Tbg | Q bbl/d at 3 1/2" Tbg |
| **1** | **6.85** | |
| 100 | **685** | |
| 200 | 1370 | |
| 300 | 2055 | 4121 |
| 400 | 2740 | |
| 500 | 3425 | |
| 600 | 4110 | |

**Table (5.4) shows ESP rate vs PCP rate at different rpm for well XX-29**

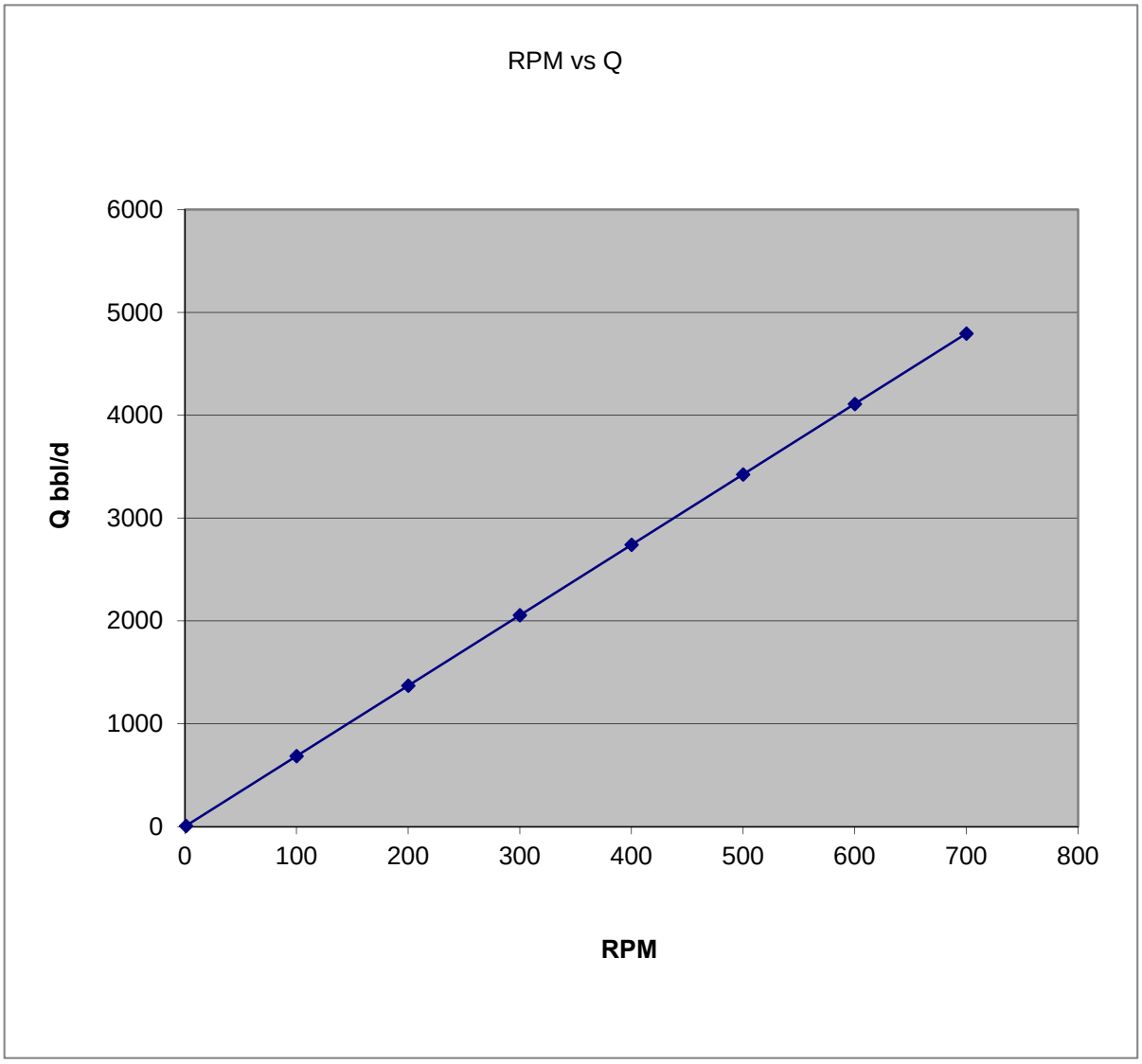



**Figure (5.4) shows PCP rate at different rpm for well XX-29**

## 5-7 Software outcome for well XX-29:

Sun Jan 24 2016 **ScrewPUMP 2.00 Summary Report** 05:40:19
grrl, , Serial # 099

1. **Well Description** **Case 1**

| | |
|---|---|
| Company Name: | AAO |
| Location: | |
| Field Name: | EL-shrara Oil Field. |
| Reservoir Name: | Momenyat |
| Engineer: | Hatem |
| Comment: | XX-29 |
| Case Date: | 01/24/16 |

2. **Wellbore**

| | |
|---|---|
| Plug Back Depth MD/TVD, ft: | 4920 / 4920 |
| Pump Depth MD/TVD, ft: | 3506 / 3506 |
| Mid-Point of Perfs MD/TVD, ft: | 4855 / 4855 |
| Downhole Temp, °F: | 199 |

3. **Fluid Properties and Rates**

| | |
|---|---|
| Oil Rate, Bbl/d: | 907 |
| Oil Gravity, °API: | 39.0 (1.6 cP) |
| Water Rate, Bbl/d: | 3214 |
| Water Sp Grav, (fw = 1.0): | 1.000 |
| Gas Rate, Mcf/d: | 125.114 |
| Gas Sp Grav, (air = 1.0): | 0.650 |
| Oil & Water Rate, Bbl/d: | 4121 |
| Total Fluid @ Flowtee, Bbl/d: | 26405 |
| @ Pump Suction, Bbl/d: | 4308 (0.8 cP) |

4. **Equipment Selected**

| | |
|---|---|
| Casing/Liner OD, in: | 9.625 (4920 ft) |
| Tubing OD, in: | 3.500 (3506 ft) |
| Separation: | Natural Separation |
| Suckerrods OD, in: | 1.250 (3506 ft) Grade D |
| ScrewPump: | 15--685 |
| Drivehead Model: | G-600 Direct |
| Drivehead Sheave: | 4TB154, Torque Indicator |
| Prime Mover Power, HP: | Electric Motor, 100.0 |
| Prime Mover Speed, rpm: | 1800 |
| Prime Mover Sheave: | 4TB110 |
| Prime Mover Mount: | Swing Frame, BX85 |

5. **Operation and Performance**

| | |
|---|---|
| Polishrod Speed, rpm: | 643 |
| Polishrod Torque, ft-lb: | 457.8 |
| Polishrod Power, HP: | 56.0 |
| Fluid Level TVD, ft: | 2190 |
| Flowtee Pressure, psi: | 200 |
| Casing Pressure, psi: | 20 |
| Viscous Drag, psi: | 0 |
| DriveHead Bearing Life, yrs: | 2.5 |
| Suckerrod Oper Stress, psi: | 20723 |
| Pump Differential Press, psi: | 302 (50 /stg) |
| Pump Volumetric Eff, %: | 96 |

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## Fluid Data - Case 1

| | | |
|---|---|---|
| Standard Temperature, | °F: | 60.00 |
| Standard Pressure, | psi: | 14.70 |
| Oil Gravity, | °API: | 39.00 |
| Specific Gravity of Gas, | (air = 1.0): | 0.650 |
| Specific Gravity of Water, | (wtr = 1.0): | 1.000 |
| Salinity, | ppm: | 0 |
| Water Cut, | %: | 53.0 |
| Prod Gas-Oil Ratio, | scf/STB: | 137.0 |
| Prod Gas-Liquid Ratio, | scf/STB: | 64.4 |
| Bubble Point Pressure, | psi: | 731.09 |
| Solution Gas-Oil Ratio, | scf/STB: | 137.05 |
| Fluid Viscosity, | cP: | 1.160 |
| Total Fluid Gradient, | psi/ft: | 0.372 |

## Inflow Data - Case 1

IPR Calculation Method: Vogel corrected for water cut

| | | |
|---|---|---|
| Total Test Rate, | Bbl/d: | 2882.00 |
| Productivity Index, | bfpd/psi: | 118.5672 |
| Bubble Point Rate, | Bbl/d: | 35167.81 |
| Max Oil Flow Rate, | Bbl/d: | 83325.43 |
| Max Total Flow Rate, | Bbl/d: | 87742.27 |

| | | Static | Test |
|---|---|---|---|
| Casing Pressure, | psi: | 0.00 | 0.00 |
| Fluid Level, | ft: | 0.00 | 0.00 |
| Bottom Hole Pressure, | psi: | 1013.00 | 988.69 |

## Design Criteria Data - Case 1

| | | |
|---|---|---|
| Total Fluid Rate, | Bbl/d: | 4121.00 |
| Pump Depth, | ft: | 3506.00 |
| Fluid Over Pump, | ft: | 1316.00 |
| Fluid Level, | ft: | 2190.00 |
| Pump Intake Pressure, | psi: | 487.85 |
| Flowline Pressure, | psi: | 200.00 |
| Casing Pressure, | psi: | 20.00 |

## Pump Data - Case 1

| | | | |
|---|---|---|---|
| Selected Pump | : | 20--685 | |
| Rotor Fit | : | Standard | (Default) |
| BHT @ Pump, | °F: | 166 | |
| Maximum Net Lift, | ft: | 2000 | |
| Net Lift Required, | ft: | 714 | (@ 0.407psi/ft) |
| Net Lift Required, | ft: | 670 | (@ 0.433psi/ft) |
| Nominal Pump Capacity, | Bbl/d/RPM: | 6.850 | |
| Friction Torque, | ft-lb: | 180.0 | |
| Pump Stages | : | 9 | |
| Diff Pressure per Stage, | psi/stg: | 34.7 | |
| Target Liquid Rate @ Pump, | Bbl/d: | 4235.5 | |
| Free Gas in Pump, | Bbl/d: | 73.6 | |
| Target Fluid Rate in Pump, | Bbl/d: | 4309.2 | |
| Polish Rod Speed, | RPM: | 629.1 | |
| Volumetric Efficiency, | %: | 95.6 | |
| Polish Rod Torque, | ft-lb: | 493.6 | |
| Polish Rod Horsepower, | HP: | 59.1 | |

## Rod String - Case 1

| | | |
|---|---|---|
| Rod Size, | in: | 1.250 |
| Rod Grade | : | D |
| Rod Weight, | lb/ft: | 4.53 |
| Maximum Allowable Stress, | psi: | 65714.0 |
| Total Fluid Weight, | lb: | -807.9 |
| Total Rod Weight, | lb: | 14133.0 |
| Bearing Load, | lb: | 13325.0 |
| Axial Stress, | psi: | 10858.2 |
| Shear Stress, | psi: | 15446.2 |
| Max Combined Stress, | psi: | 21801.7 |
| Max Shear Stress, | psi: | 16372.6 |
| Von Mises Stress, | psi: | 28873.2 |

## Wellhead Drive - Case 1

| | | | |
|---|---|---|---|
| Selected Wellhead Drive | : | G-600 | (Direct Drive) |
| Speed Reduction Ratio | : | 2:1 | |
| Polish Rod Speed, | RPM: | 60-800 | |
| Gear Torque Rating, | ft-lb: | 600 | |
| Thrust Bearing Rating, | lb: | 25900 | |
| Wellhead Drive Shaft Size, | in: | 1.437 | |
| Wellhead Drive Output Speed, | RPM: | 629.1 | |
| Wellhead Drive Output Torque, | ft-lb: | 493.6 | |
| L10 Wellhead Drive Life, | years: | 2.5 | |
| Thrust Bearing Load, | lb: | 13325.0 | |

## Electric Motor - Case 1

| | | Equipment Rating | Design Conditions |
|---|---|---|---|
| Manufacturer | : | TEFC | |
| Model | : | 2x326T | |
| Motor Horsepower, | HP: | 100 | 0.0 |
| Motor Speed, | RPM: | 1800 | |
| Motor Shaft Size, | in: | 2.125 | |
| Motor Sheave Size, | in: | 10.8 | |

## Electric Motor Sheave - Case 1

| | | Electric Motor Sheave | Wellhead Drive Sheave |
|---|---|---|---|
| Sheave Manufacturer | : | Browning | Browning |
| Sheave Model | : | 4TB110 | 4TB154 |
| Sheave Size, | in: | 11.0 | 15.4 |
| Bushing Type | : | Q1 | Q1 |
| Bushing Size, | in: | 2.125 | 1.437 |
| Center Length (between Shafts), | in: | 22.0 | |

## Electric Motor Belt - Case 1

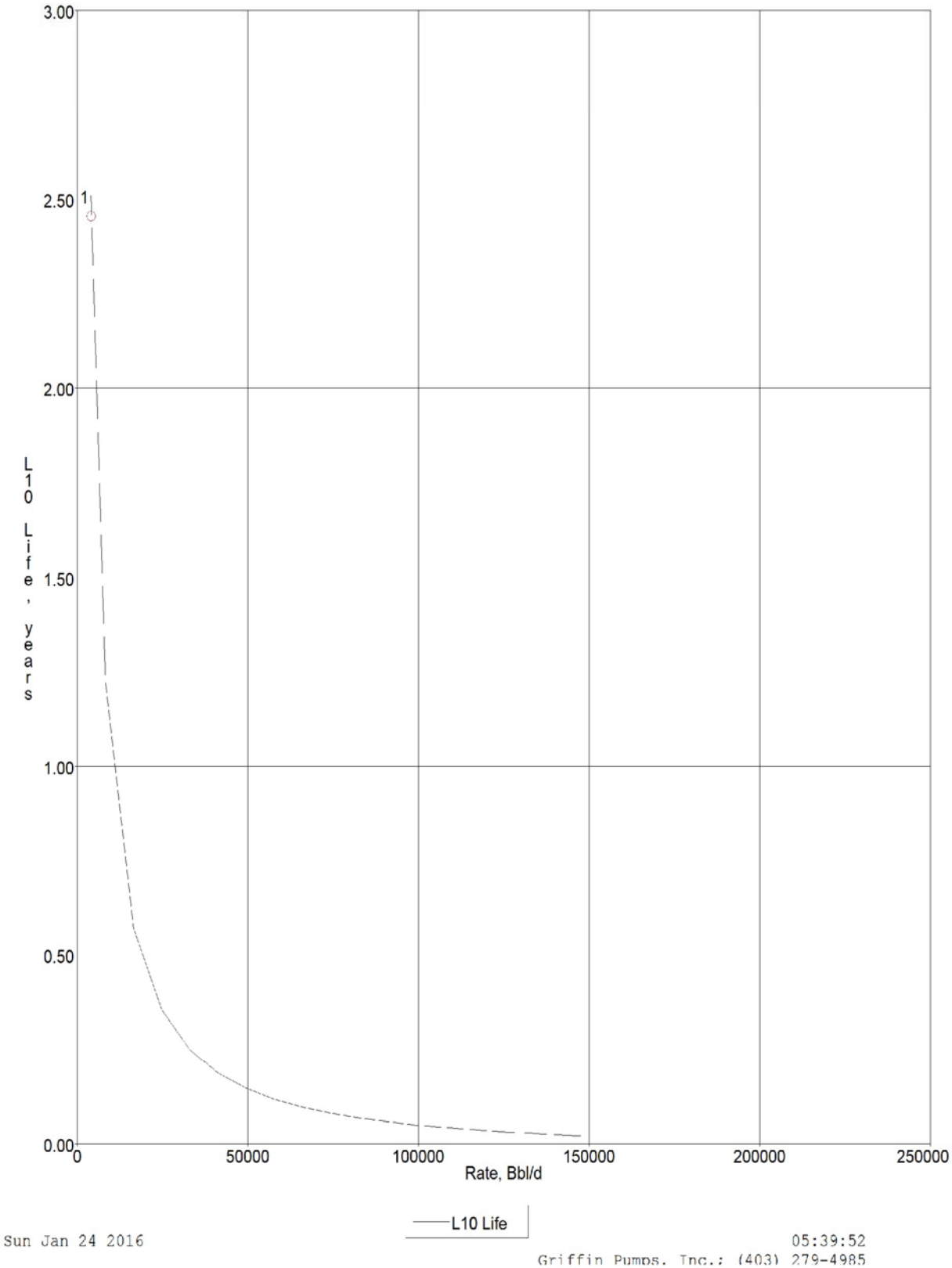
| | | |
|---|---|---|
| Belt Number | : | BX85 |
| Belt Pitch Length, | in: | 86.8 |
| Maximum Horsepower per Belt, | HP: | 17.0 |
| Required Number of Belts | : | 4 |

## Final Solution Analysis - Case 1

| | | Initial Design | Final Solution |
|---|---|---|---|
| Wellhead Drive Shaft Speed, | RPM: | 1258.2 | 1285.7 |
| Polish Rod Speed, | RPM: | 629.1 | 642.9 |
| Polish Rod Horsepower, | HP: | 59.1 | 60.5 |
| L10 Wellhead Drive Life, | years: | 2.5 | 2.4 |
| Fluid Rate into Pump, | Bbl/d: | 4309.2 | 4403.6 |
| Liquid Rate @ Pump, | Bbl/d: | 4235.5 | 4329.9 |
| Design Rate, | Bbl/d: | 4121.0 | 4212.8 |
| Volumetric Efficiency, | %: | 95.6 | 95.7 |
| Producing BHP @ Perfs, | psi: | 1930.4 | 1929.6 |
| Pump Intake Pressure, | psi: | 1359.6 | 1373.6 |

**Full Wellhead Drive L10 Life**

G-600 Direct Drive



# CONCLUTIONS

1- PCP system has installed in well xx16 in 1999 and failed to produce the desired production rate.
2- The production rate could not be sustained at constant rate during five months of operation.
3- System hardware such as electric motor and drive head were not damaged during the operation period.
4- The main cause for the system failure for first installation was due to improper elastomer material of the stator and for second installation was reported as rotor broken (mechanical failure).

1. Rig operation cost for PCP system is 40% lower than the rig cost for ESP system.
2. Elastomer selection and rotor sizing is a key determiner in pump performance and life but is usually done primarily based on experience.

# RECOMMENDATIONS

1- Elastomer selection should be based on experimental studies rather than acceptance of the commercially available elastomers offered by the manufacturers.
2- Accelerated ageing experiments should be conducted to ensure long time stability of the elastomers material in light crude oil environments.
3- Closed monitoring for any new artificial lift system such as, daily production tests, fluid level and well head pressure should be included in the operations policy to track system performance & have better evaluation results.
4- Selecting the appropriate elastomers, understanding and adjusting for its interaction with the fluid downhole is essential to maximizing the performance longevity of a PCP system.
5- PCP should trial for more wells in different areas in order to verify the ability of the success or failure for this system.
6- Due to PCP applications, PCP is more suitable to run in oil wells with low flow rates in El-Shrara field.
7- Mechanical problems can be avoided by experienced team with high skills for PCP installation, especially in the case of first run.
8- Once PCP system is applying in a new area, it is important to point out that operators are typically faced with using a (trial-and-error) approach to determine optimal elastomer selection and pump size.

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# Appendixes

# APPENDIX (A)

- **Progressing cavity pump selection**

Length of stator, rotator, lift capacities and Selected PC pump series based on the calculation and software results as flowing:

Table (3-5) shows PCP pump specification.

| *Pump* | | | | | | *Stator* | | | *Rotor* | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| PC Pump series | | Style | Displacement | lift capacities | | Top connection (in) | Length | Max O.D | length | Max O.D | weight |
| Metric | Imperical | | bbl/day/100 rpm | psi | ft | EUE box | (in) | (in) | (in) | (in) | (IB) |
| 28-600 SH | 175-2100 SH | 1:2 | 175 | 900 | 2100 | 4"*2 7/8" EUE box | 156 | 3.8 | 100 | 2.27 | 74 |
| 28-900 SH | 175-3100 SH | | | 1350 | 3100 | | 202 | | 146 | | 103 |
| 28-1200 SH | 175-4100 SH | | | 1800 | 4100 | | 240 | | 187 | | 125 |
| 28-1200 SH XL | 175-4100 SH XL | | | 1800 | 4100 | | 240 | | 190 | | 129 |
| 28-1600 SH | 175-5200 SH | | | 2250 | 5200 | | 294 | | 238 | | 155 |
| 28-1600 SH XL | 175-5200 SH XL | | | 2250 | 5200 | | 294 | | 246 | | 157 |
| 28-1800 SH | 175-6000 SH | | | 2600 | 6000 | | 312 | | 256 | | 161 |
| 28-1800 SH XL | 175-6000 SH XL | | | 2600 | 6000 | | 312 | | 264 | | 166 |
| 42-900 SH | 265-3100 SH | 1:2 | 265 | 1350 | 3100 | 4"*3 1/2" EUE box | 231 | 4.18 | 186 | 2.36 | 111 |
| 42-1400 SH XL | 265-4600 SH XL | | | 2000 | 4600 | | 304 | | 258 | | 156 |
| 42-1600 SH XL | 265-5200 SH XL | | | 2250 | 5200 | | 338 | | 288 | | 181 |
| 42-1800 SH XL | 265-6000 SH XL | | | 2600 | 6000 | | 327 | | 320 | | 202 |
| 56-500 SH | 350-2500 SH | 1:2 | 350 | 700 | 1600 | 4"*2 7/8" EUE box | 210 | 3.8 | 156 | 2.27 | 93 |
| 56-800 SH | 350-3200 SH | | | 1100 | 2500 | | 287 | | 233 | | 139 |
| 56-1000 SH | 350-4100 SH | | | 1400 | 3200 | | 335 | | 279 | | 172 |
| 56-1200 SH | 350-5100 SH | | | 1800 | 4100 | | 407 | | 351 | | 215 |
| 56-1500 SH | 350-6000 SH | | | 2200 | 5100 | | 490 | | 436 | | 260 |
| 56-1800 SH S | 350-1600 SH S | | | 2600 | 6000 | | 631 | | 512 | | 300 |
| 64-600 SH | 400-2100 SH | 1:2 | 400 | 900 | 2100 | 4"*2 7/8" EUE box | 304 | 3.8 | 248 | 2.235 | 151 |
| 64-900 SH | 400-3100 SH | | | 1350 | 3100 | | 412.5 | | 357 | | 217 |
| 64-1200 SH | 400-4100 SH | | | 1800 | 4100 | | 510 | | 456 | | 275 |
| 64-1500 SH S | 400-5100 SH S | | | 2200 | 5100 | | 611 | | 608 | | 350 |
| 83-400 SH | 520-1400 SH | 1:2 | 520 | 600 | 1400 | 4"*2 7/8" EUE box | 240 | 3.8 | 186 | 2.27 | 119 |
| 83-600 SH | 520-2100 SH | | | 900 | 2100 | | 312 | | 256 | | 164 |
| 83-800 SH | 520-3100 SH | | | 1200 | 3100 | | 408 | | 352 | | 231 |
| 83-1050 SH | 520-3500 SH | | | 1500 | 3500 | | 480 | | 424 | | 277 |
| 83-1600 SH | 520-4100 SH | | | 1800 | 4100 | | 576 | | 522 | | 334 |
| 83-1200 SH | 520-5200 SH S | | | 2250 | 5200 | | 690 | | 707 | | 440 |
| 120-300 SH | 750-1100 SH | 1:2 | 750 | 450 | 1100 | 4"*2 7/8" EUE box | 256 | 3.8 | 200 | 2.185 | 119 |
| 120-475 SH | 750-1670 SH | | | 700 | 1670 | | 344 | | 288 | | 159 |
| 120-600 SH | 750-2100 SH | | | 900 | 2100 | | 464 | | 384 | | 212 |
| 120-775 SH | 750-2750 SH | | | 1100 | 2750 | | 528 | | 474 | | 278 |
| 120-900 SH | 750-3100 SH | | | 1350 | 3100 | | 708 | | 600 | | 349 |
| 120-1075 SH S | 750-3550 SH S | | | 1600 | 3550 | | 808 | | 672 | | 402 |

- **PVT data for studying oil wells selected**

| *Well name* | *XX-01* | *XX-16* | *XX-29* |
|---|---|---|---|
| WHP (psi) | 172 | 158 | 200 |
| PWF (psi) | 981 | 579 | 720 |
| PI (psi)) | 1950 | 1950 | 1950 |
| Static RP (psi) | 1013 | 1013 | 1013 |
| K (md) | 1400 | 1100 | 3022 |
| Bubble point | 219 | 219 | 219 |
| T (F) | 204 | 190 | 199 |
| GOR | 138 | 138 | 64.4 |
| μ o (cp) | 0.769 | 0.788 | 0.786 |
| Oil volume formation factor (βo) bbl/STB | 1.1272 | 1.1239 | 1.0893 |
| Density@Pi g/cc | 0.731 | 0.731 | 0.705 |
| Productivity index (PI) B/D/psi | 23 | 10 | 118 |
| API GRAVITY | 41 | 41 | 39 |
| Oil PRODUCTION b/d | 3436 | 967 | 1360 |
| Water production b/d | 0 | 1047 | 2761 |
| Water cut (%) | 0 | 48 | 78 |
| Intake depth (ft) | 4515 | 4745 | 3506 |
| Interval depth (ft) | 4745-4810 | 4908- 4950 | 4792-4919 |
| PBTD (ft) | 4962 | 4965 | 4920 |
| TD (ft) | 7806 | 5180 | 5100 |
| DFL (ft) | 2130 | 3000 | 2190 |
| Salinity(ppm) | 9500 | 9500 | 9500 |
| Tubing size (inch) | 3 1/2" | 3 1/2" | 3 1/2" |
| Casing size (OD) (inch) | 9 5/8" | 9 5/8" | 9 5/8" |
| Oil gradient | 0.31 | 0.32 | 0.32 |
| Water gradient | 0.425 | 0.42 | 0.42 |
| WOC (FT) | 4998 | 5042 | 4490 |
| SW (%) | 39.5 | 40.4 | 42.3 |
| Net oil pay (ft) | 300.1 | 236 | 224.9 |
| AOF (STB/D) | 20052.6 | 5597 | 108500 |
| Compressibility (1/psi) | 0.00000943 | 0.00000943 | 0.00000943 |

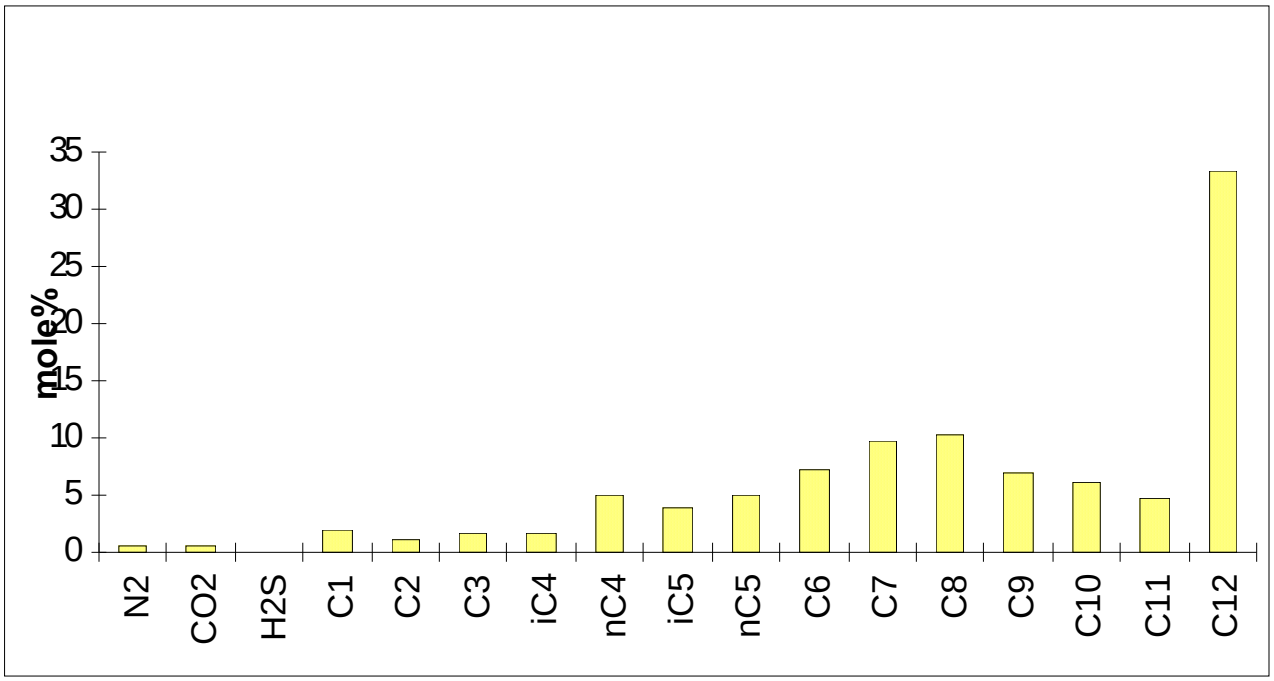
- **Compositional analysis from separation**

| Component | Liquid | Gas | Reservoir | Stock Tank | Stock Tank | 2nd stage | 2nd stage | 1st stage | 1st stage |
|---|---|---|---|---|---|---|---|---|---|
| | | | Fluid | Liquid | Gas | Liquid | Gas | Liquid | Gas |
| N2 | | 7.65 | 0.53 | 0 | 0 | 0 | 1.01 | 0.05 | 11.75 |
| CO2 | 0.01 | 8.58 | 0.61 | 0.01 | 3.17 | 0.03 | 6.05 | 0.3 | 9.39 |
| H2S | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| C1 | 0.04 | 29.15 | 2.06 | 0.01 | 6.33 | 0.05 | 13.03 | 0.64 | 38.06 |
| C2 | 0.11 | 13.96 | 1.08 | 0.07 | 7.81 | 0.12 | 14.59 | 0.78 | 12.29 |
| C3 | 0.93 | 13.13 | 1.78 | 0.36 | 15.38 | 0.46 | 17.96 | 1.25 | 9.25 |
| iC4 | 1.18 | 6.3 | 1.54 | 0.79 | 11 | 0.86 | 9.91 | 1.27 | 4.3 |
| iC5 | 3.96 | 4.04 | 3.96 | 3.43 | 12.1 | 3.49 | 6.58 | 3.63 | 2.94 |
| C6 | 7.79 | 1.14 | 7.33 | 8.51 | 4 | 8.48 | 2.02 | 8.19 | 0.87 |
| C7 | 10.54 | 0.33 | 9.83 | 12.08 | 1.05 | 12.01 | 1.26 | 11.52 | 0.19 |
| C8 | 11.04 | 0.05 | 10.27 | 10.63 | 0.28 | 10.56 | 0.97 | 10.12 | 0.02 |
| C9 | 7.34 | | 6.84 | 7.82 | | 7.77 | 0.45 | 7.44 | |
| C10 | 6.6 | | 6.13 | 5.89 | | 5.85 | 0.37 | 5.6 | |
| C11 | 5.02 | | 4.67 | 6.97 | | 6.92 | 0.26 | 6.62 | |
| C12 | 35.89 | | 33.39 | 35.79 | | 35.55 | 0.98 | 33.99 | |

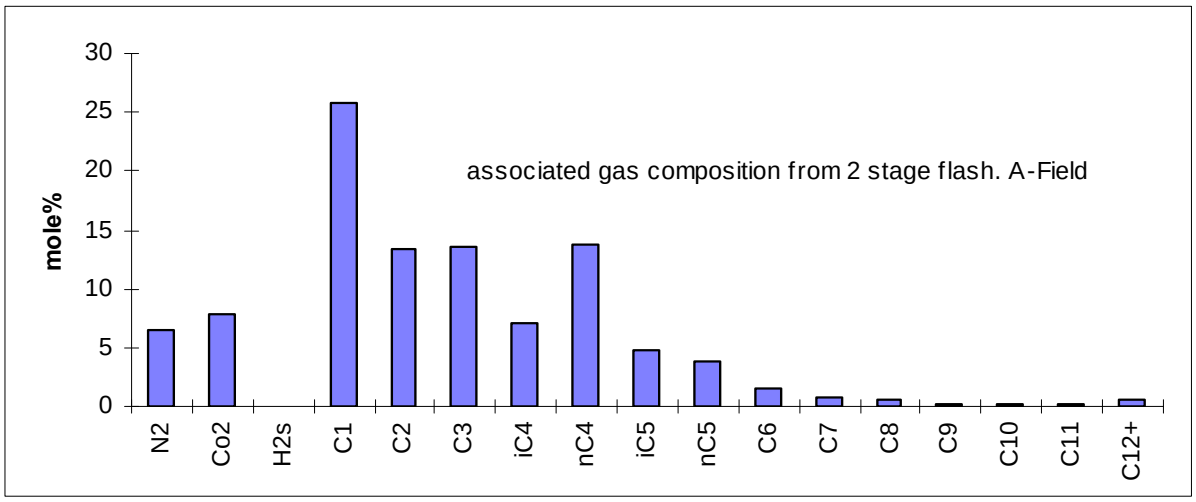
- **Comparison of Reservoir fluid compositions in Field- NC115**

| Composition | well name | |
|---|---|---|
| | XX-01 | XX-29 |
| N2 | 0.1 | 0.11 |
| CO2 | 0.18 | 0.14 |
| C1 | 0.22 | 0.18 |
| C2 | 0.22 | 0..20 |
| C3 | 0.53 | 0.72 |
| iC4 | 0.6 | 0.73 |
| nC4 | 1.92 | 2.05 |
| iC5 | 1.92 | 1.89 |
| nC5 | 2.44 | 2.03 |
| C6 | 4.23 | 4.44 |
| C7 | 6.1 | 6.69 |
| C8 | 7.24 | 8 |
| C9 | 5.4 | 6.25 |
| C10 | 5.44 | 6 |
| C11 | 4.52 | 5.04 |
| C12+ | 58.9* | 55.52 |

- **Reservoir fluid composition:**




- **Associated gas composition:**

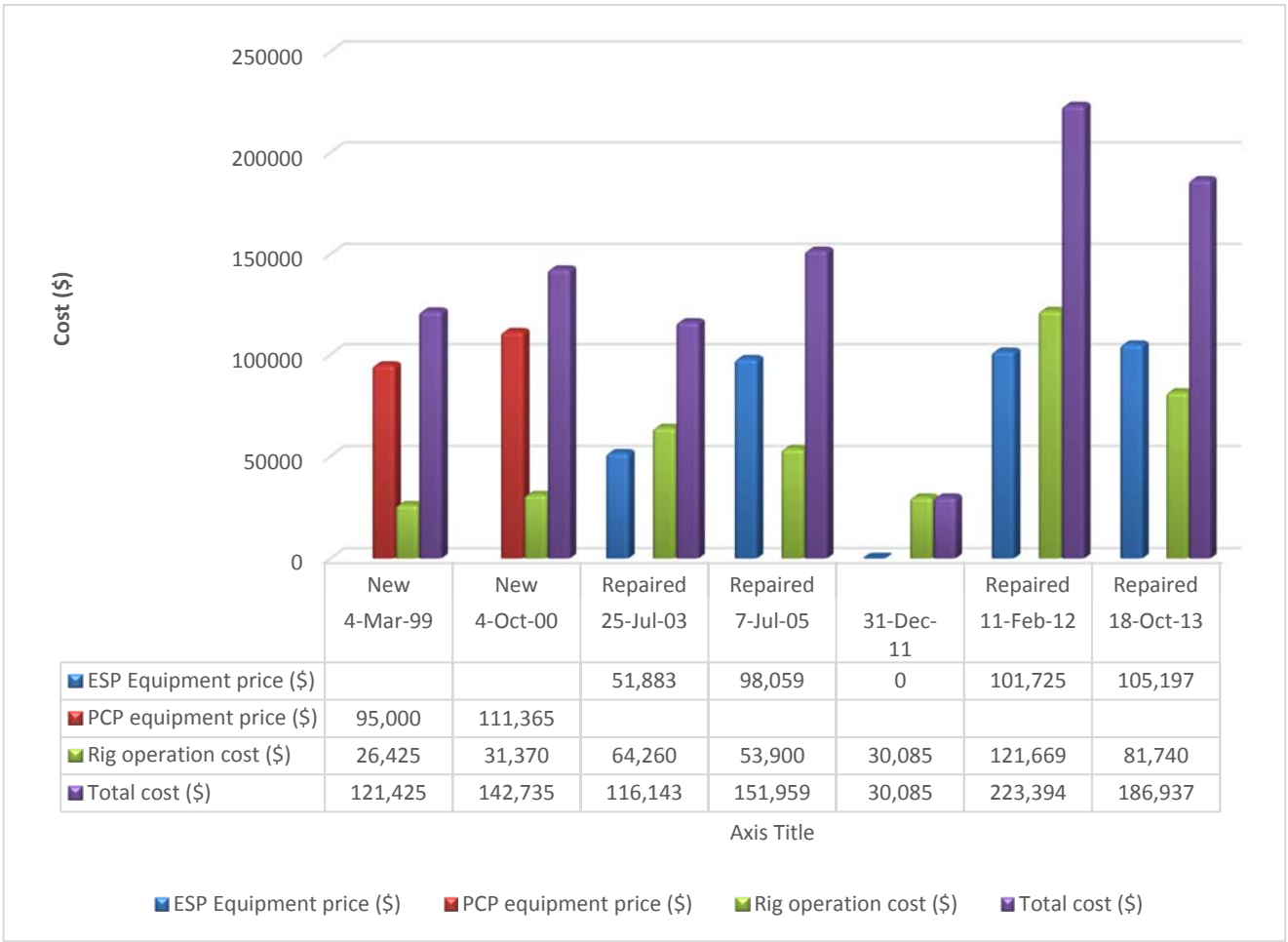


- **Associated gas composition for the field**

| Components | Mole fraction | Mole fraction |
|---|---|---|
| N2 | 1.01 | 6.47 |
| Co2 | 6.05 | 7.75 |
| H2s | 0 | 0 |
| C1 | 13.03 | 25.75 |
| C2 | 14.59 | 13.42 |
| C3 | 17.96 | 13.53 |
| iC4 | 9.91 | 7.057 |
| nC4 | 19.29 | 13.73 |
| ic5 | 6.58 | 4.73 |
| Nc5 | 5.27 | 3.90 |
| C6 | 2.02 | 1.43 |
| C7 | 1.26 | 0.72 |
| C8 | 0.97 | 0.47 |
| C9 | 0.47 | 0.23 |
| C10 | 0.37 | 0.18 |
| C11 | 0.26 | 0.13 |
| C12+ | 0.98 | 0.48 |
| Total | 100 | 100 |
| GOR | 29 | 59 |

- **Workover cost review during operation running life for well XX-16**

| Date | Pump state | ESP Equipment price ($) | PCP equipment price ($) | Rig operation cost ($) | Total cost ($) |
|---|---|---|---|---|---|
| 4-Mar-99 | New | | 95,000 | 26,425 | 121,425 |
| 4-Oct-00 | New | | 111,365 | 31,370 | 142,735 |
| 25-Jul-03 | Repaired | 51,883 | | 64,260 | 116,143 |
| 7-Jul-05 | Repaired | 98,059 | | 53,900 | 151,959 |
| 31-Dec-11 | | Splice lower pigtail | | 30,085 | 30,085 |
| 11-Feb-12 | Repaired | 101,725 | | 121,669 | 223,394 |
| 18-Oct-13 | Repaired | 105,197 | | 81,740 | 186,937 |



# APPENDIX (B)

- **Production history for well XX-01**

| Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) | Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) |
|---|---|---|---|---|---|
| 12/31/1996 | 0 | 0.00 | 8/31/2000 | 0 | 0.00 |
| 1/31/1997 | 0 | 0.00 | 9/30/2000 | 0 | 0.00 |
| 2/28/1997 | 0 | 0.00 | 10/31/2000 | 1577 | 0.32 |
| 3/31/1997 | 0 | 0.00 | 11/30/2000 | 0 | 0.00 |
| 4/30/1997 | 0 | 0.00 | 12/31/2000 | 1786 | 0.00 |
| 5/31/1997 | 0 | 0.00 | 1/31/2001 | 675 | 0.00 |
| 6/30/1997 | 0 | 0.00 | 2/28/2001 | 874 | 0.00 |
| 7/31/1997 | 0 | 0.00 | 4/30/2001 | 2955 | 0.00 |
| 8/31/1997 | 0 | 0.00 | 5/31/2001 | 2901 | 0.00 |
| 9/30/1997 | 0 | 0.00 | 8/31/2001 | 2935 | 0.00 |
| 10/31/1997 | 0 | 0.00 | 1/31/2002 | 2880 | 0.00 |
| 11/30/1997 | 0 | 0.00 | 2/28/2002 | 2910 | 0.00 |
| 12/31/1997 | 814 | 0.00 | 3/31/2002 | 2767 | 0.05 |
| 1/31/1998 | 1550 | 0.00 | 4/30/2002 | 1750 | 0.00 |
| 2/28/1998 | 1498 | 0.00 | 6/30/2002 | 2916 | 0.00 |
| 3/31/1998 | 1127 | 0.00 | 11/30/2002 | 2679 | 0.00 |
| 4/30/1998 | 871 | 0.16 | 12/31/2002 | 2634 | 0.00 |
| 5/31/1998 | 831 | 0.09 | 1/31/2003 | 2598 | 0.00 |
| 6/30/1998 | 791 | 0.05 | 2/28/2003 | 2627 | 0.00 |
| 7/31/1998 | 825 | 0.00 | 3/31/2003 | 2321 | 0.00 |
| 8/31/1998 | 1229 | 1.67 | 4/30/2003 | 3297 | 0.00 |
| 9/30/1998 | 1072 | 0.30 | 6/30/2003 | 3297 | 0.00 |
| 10/31/1998 | 393 | 0.00 | 7/31/2003 | 3248 | 0.00 |
| 11/30/1998 | 0 | 0.00 | 12/31/2003 | 3162 | 0.00 |
| 12/31/1998 | 0 | 0.00 | 1/31/2004 | 3250 | 0.00 |
| 1/31/1999 | 0 | 0.00 | 2/29/2004 | 3250 | 0.00 |
| 2/28/1999 | 0 | 0.00 | 11/30/2004 | 3265 | 0.00 |
| 3/31/1999 | 0 | 0.00 | 12/31/2004 | 3282 | 0.00 |
| 4/30/1999 | 0 | 0.00 | 1/31/2005 | 3358 | 0.00 |
| 5/31/1999 | 896 | 15.17 | 2/28/2005 | 3316 | 11.42 |
| 6/30/1999 | 3417 | 0.00 | 3/31/2005 | 3263 | 0.97 |
| 7/31/1999 | 3301 | 0.00 | 6/30/2005 | 3195 | 0.00 |
| 8/31/1999 | 3320 | 0.00 | 1/31/2005 | 3358 | 0.00 |
| 9/30/1999 | 3244 | 0.98 | 2/28/2005 | 3316 | 11.42 |
| 10/31/1999 | 3263 | 0.41 | 3/31/2005 | 3263 | 0.97 |
| 11/30/1999 | 3113 | 0.21 | 1/31/2005 | 3358 | 0.00 |
| 12/31/1999 | 3026 | 0.00 | 2/28/2005 | 3316 | 11.42 |
| 1/31/2000 | 3160 | 0.31 | 3/31/2005 | 3263 | 0.97 |
| 2/29/2000 | 2964 | 0.23 | 4/30/2005 | 3267 | 0.00 |
| 3/31/2000 | 3097 | 0.00 | 6/30/2005 | 3195 | 0.00 |
| 4/30/2000 | 3045 | 0.00 | 7/31/2005 | 3153 | 0.00 |
| 5/31/2000 | 3020 | 0.00 | 8/31/2005 | 3170 | 0.00 |
| 6/30/2000 | 3061 | 0.20 | 9/30/2005 | 3183 | 0.00 |
| 7/31/2000 | 621 | 0.00 | 10/31/2005 | 3206 | 0.00 |

| Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) | Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) |
|---|---|---|---|---|---|
| 12/31/2005 | 3250 | 0.00 | 1/31/2010 | 2895 | 12.41 |
| 1/31/2006 | 3300 | 8.88 | 2/28/2010 | 1139 | 4.85 |
| 2/28/2006 | 3249 | 0.71 | 3/31/2010 | 3301 | 16.09 |
| 3/31/2006 | 3230 | 0.00 | 4/30/2010 | 3218 | 11.32 |
| 4/30/2006 | 3291 | 0.00 | 5/31/2010 | 3208 | 7.46 |
| 5/31/2006 | 3259 | 0.00 | 6/30/2010 | 3255 | 1.20 |
| 6/30/2006 | 3265 | 0.00 | 7/31/2010 | 3002 | 0.00 |
| 7/31/2006 | 3230 | 6.93 | 9/30/2010 | 3026 | 0.00 |
| 8/31/2006 | 3104 | 0.24 | 10/31/2010 | 2978 | 15.41 |
| 9/30/2006 | 3187 | 0.00 | 11/30/2010 | 3115 | 19.18 |
| 11/30/2006 | 3290 | 0.00 | 1/31/2011 | 3143 | 20.97 |
| 12/31/2006 | 3315 | 7.80 | 2/28/2011 | 3276 | 23.91 |
| 1/31/2007 | 3325 | 12.40 | 3/31/2011 | 1978 | 11.45 |
| 2/28/2007 | 3283 | 6.48 | 4/30/2011 | 3229 | 17.92 |
| 3/31/2007 | 3254 | 7.29 | 5/31/2011 | 3355 | 17.84 |
| 4/30/2007 | 3307 | 3.11 | 6/30/2011 | 1569 | 7.87 |
| 5/31/2007 | 3298 | 2.78 | 7/31/2011 | 0 | 0.00 |
| 6/30/2007 | 3258 | 4.40 | 9/30/2011 | 0 | 0.00 |
| 7/31/2007 | 3215 | 0.00 | 10/31/2011 | 748 | 3.32 |
| 8/31/2007 | 3207 | 0.00 | 1/31/2012 | 3146 | 6.20 |
| 9/30/2007 | 3245 | 1.61 | 7/31/2012 | 3213 | 1.64 |
| 10/31/2007 | 3250 | 0.79 | 8/31/2012 | 3233 | 0.00 |
| 11/30/2007 | 3271 | 0.00 | 9/30/2012 | 3189 | 0.00 |
| 12/31/2007 | 3275 | 7.74 | 10/31/2012 | 3157 | 6.04 |
| 1/31/2008 | 3277 | 10.19 | 11/30/2012 | 2863 | 20.48 |
| 2/29/2008 | 3313 | 12.89 | 1/31/2013 | 3256 | 42.73 |
| 3/31/2008 | 3284 | 3.01 | 4/30/2013 | 3218 | 62.50 |
| 4/30/2008 | 3246 | 0.00 | 5/31/2013 | 3132 | 10.29 |
| 5/31/2008 | 3166 | 0.00 | 6/30/2013 | 2487 | 0.00 |
| 7/31/2008 | 3180 | 0.00 | 8/31/2013 | 2708 | 0.00 |
| 8/31/2008 | 3163 | 0.00 | 10/31/2013 | 2799 | 2.78 |
| 9/30/2008 | 3225 | 0.00 | 11/30/2013 | 564 | 0.00 |
| 10/31/2008 | 3190 | 0.00 | 12/31/2013 | 1398 | 0.00 |
| 11/30/2008 | 3206 | 23.35 | 5/31/2014 | 15 | 0.00 |
| 12/31/2008 | 3265 | 26.46 | 6/30/2014 | 0 | 0.00 |
| 1/31/2009 | 3219 | 24.24 | 7/31/2014 | 2144 | 0.00 |
| 2/28/2009 | 3217 | 0.88 | 8/31/2014 | 3453 | 0.00 |
| 3/31/2009 | 3220 | 23.92 | 10/31/2014 | 3252 | 0.00 |
| 4/30/2009 | 3230 | 19.10 | 11/30/2014 | 536 | 0.00 |
| 5/31/2009 | 3160 | 0.00 | 12/31/2014 | 248 | 0.00 |
| 6/30/2009 | 3220 | 0.00 | 1/31/2015 | 133 | 0.00 |
| 7/31/2009 | 3243 | 0.00 | 2/28/2015 | 0 | 0.00 |
| 8/31/2009 | 3265 | 0.00 | 3/31/2015 | 324 | 0.00 |
| 9/30/2009 | 3080 | 0.00 | 4/30/2015 | 14 | 0.00 |
| 10/31/2009 | 3257 | 0.00 | 5/31/2015 | 0 | 0.00 |
| 11/30/2009 | 3277 | 0.00 | 6/30/2015 | 203 | 0.00 |
| 12/31/2009 | 3298 | 20.55 | 7/31/2015 | 0 | 0.00 |

- **Production history for well XX-16**

| Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) | Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) |
|---|---|---|---|---|---|
| 12/31/1996 | 1274 | 52.35 | 3/31/2001 | 0 | 0.00 |
| 1/31/1997 | 1582 | 118.34 | 8/31/2001 | 0 | 0.00 |
| 2/28/1997 | 1343 | 66.14 | 9/30/2001 | 0 | 0.00 |
| 3/31/1997 | 1063 | 115.05 | 2/28/2002 | 0 | 0.00 |
| 4/30/1997 | 595 | 62.20 | 8/31/2002 | 0 | 0.00 |
| 5/31/1997 | 677 | 31.04 | 9/30/2002 | 0 | 0.00 |
| 6/30/1997 | 0 | 0.00 | 10/31/2002 | 0 | 0.00 |
| 7/31/1997 | 0 | 0.00 | 11/30/2002 | 0 | 0.00 |
| 8/31/1997 | 0 | 0.00 | 1/31/2003 | 0 | 0.00 |
| 9/30/1997 | 0 | 0.00 | 2/28/2003 | 0 | 0.00 |
| 10/31/1997 | 0 | 0.00 | 3/31/2003 | 0 | 0.00 |
| 11/30/1997 | 0 | 0.00 | 4/30/2003 | 0 | 0.00 |
| 12/31/1997 | 0 | 0.00 | 5/31/2003 | 0 | 0.00 |
| 1/31/1998 | 0 | 0.00 | 6/30/2003 | 0 | 0.00 |
| 2/28/1998 | 0 | 0.00 | 7/31/2003 | 58 | 0.29 |
| 3/31/1998 | 0 | 0.00 | 8/31/2003 | 1984 | 6.37 |
| 4/30/1998 | 0 | 0.00 | 9/30/2003 | 1942 | 1.76 |
| 5/31/1998 | 0 | 0.00 | 10/31/2003 | 1846 | 0.00 |
| 6/30/1998 | 0 | 0.00 | 11/30/2003 | 2030 | 0.00 |
| 12/31/1998 | 0 | 0.00 | 12/31/2003 | 2061 | 0.14 |
| 1/31/1999 | 0 | 0.00 | 1/31/2004 | 2077 | 0.00 |
| 2/28/1999 | 0 | 0.00 | 2/29/2004 | 2015 | 0.00 |
| 3/31/1999 | 211 | 0.11 | 3/31/2004 | 1961 | 0.00 |
| 4/30/1999 | 571 | 0.05 | 8/31/2004 | 2006 | 0.00 |
| 5/31/1999 | 610 | 0.08 | 9/30/2004 | 1942 | 0.00 |
| 6/30/1999 | 370 | 0.03 | 11/30/2004 | 1717 | 0.00 |
| 7/31/1999 | 208 | 0.05 | 12/31/2004 | 1468 | 0.00 |
| 8/31/1999 | 3 | 0.00 | 1/31/2005 | 1372 | 0.00 |
| 9/30/1999 | 0 | 0.00 | 2/28/2005 | 1245 | 0.00 |
| 10/31/1999 | 0 | 0.00 | 3/31/2005 | 1031 | 0.00 |
| 12/31/1999 | 0 | 0.00 | 4/30/2005 | 439 | 0.00 |
| 1/31/2000 | 0 | 0.00 | 5/31/2005 | 924 | 0.00 |
| 2/29/2000 | 0 | 0.00 | 6/30/2005 | 773 | 0.00 |
| 3/31/2000 | 0 | 0.00 | 7/31/2005 | 1349 | 1.89 |
| 4/30/2000 | 0 | 0.00 | 8/31/2005 | 1957 | 0.00 |
| 5/31/2000 | 0 | 0.00 | 9/30/2005 | 1977 | 0.00 |
| 6/30/2000 | 0 | 0.00 | 10/31/2005 | 2025 | 0.00 |
| 7/31/2000 | 0 | 0.00 | 11/30/2005 | 2019 | 8.49 |
| 8/31/2000 | 0 | 0.00 | 12/31/2005 | 2071 | 5.83 |
| 10/31/2000 | 95 | 0.28 | 1/31/2006 | 2105 | 0.41 |
| 11/30/2000 | 0 | 0.00 | 2/28/2006 | 2066 | 0.00 |
| 12/31/2000 | 0 | 0.00 | 3/31/2006 | 2049 | 0.00 |
| 1/31/2001 | 0 | 0.00 | 4/30/2006 | 2118 | 0.00 |
| 2/28/2001 | 0 | 0.00 | 5/31/2006 | 2122 | 0.00 |

| Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) | Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) |
|---|---|---|---|---|---|
| 6/30/2006 | 2075 | 0.00 | 1/31/2011 | 1591 | 488.57 |
| 7/31/2006 | 2023 | 0.00 | 2/28/2011 | 1277 | 718.45 |
| 9/30/2006 | 2033 | 0.00 | 3/31/2011 | 774 | 507.73 |
| 10/31/2006 | 2049 | 0.00 | 4/30/2011 | 1204 | 757.10 |
| 11/30/2006 | 2015 | 9.24 | 5/31/2011 | 1251 | 753.58 |
| 12/31/2006 | 1969 | 9.71 | 6/30/2011 | 585 | 332.52 |
| 1/31/2007 | 1859 | 11.61 | 7/31/2011 | 0 | 0.00 |
| 2/28/2007 | 1842 | 11.01 | 9/30/2011 | 0 | 0.00 |
| 3/31/2007 | 1756 | 6.13 | 1/31/2012 | 0 | 0.00 |
| 4/30/2007 | 1533 | 5.47 | 2/29/2012 | 929 | 363.04 |
| 5/31/2007 | 1605 | 5.55 | 3/31/2012 | 1445 | 616.83 |
| 6/30/2007 | 1930 | 5.53 | 4/30/2012 | 1386 | 667.42 |
| 7/31/2007 | 2096 | 3.36 | 5/31/2012 | 1326 | 761.40 |
| 8/31/2007 | 2073 | 3.58 | 6/30/2012 | 1372 | 922.83 |
| 9/30/2007 | 2082 | 2.25 | 7/31/2012 | 1155 | 1061.69 |
| 10/31/2007 | 2082 | 3.66 | 8/31/2012 | 1056 | 1022.20 |
| 11/30/2007 | 2086 | 2.54 | 9/30/2012 | 1084 | 1102.02 |
| 12/31/2007 | 2025 | 7.52 | 10/31/2012 | 1009 | 1077.50 |
| 1/31/2008 | 2116 | 9.11 | 11/30/2012 | 780 | 838.22 |
| 2/29/2008 | 2148 | 1.83 | 12/31/2012 | 672 | 750.42 |
| 3/31/2008 | 2096 | 0.00 | 1/31/2013 | 888 | 1171.71 |
| 4/30/2008 | 2100 | 0.00 | 2/28/2013 | 858 | 1284.79 |
| 5/31/2008 | 2060 | 0.00 | 5/31/2013 | 828 | 1225.77 |
| 9/30/2008 | 2058 | 0.00 | 6/30/2013 | 694 | 810.65 |
| 10/31/2008 | 2043 | 0.00 | 8/31/2013 | 704 | 885.56 |
| 11/30/2008 | 2053 | 16.32 | 9/30/2013 | 233 | 226.56 |
| 12/31/2008 | 2085 | 25.46 | 10/31/2013 | 143 | 120.20 |
| 1/31/2009 | 2058 | 5.28 | 11/30/2013 | 0 | 0.00 |
| 2/28/2009 | 2057 | 10.57 | 12/31/2013 | 0 | 0.00 |
| 3/31/2009 | 2042 | 14.31 | 1/31/2014 | 893 | 772.39 |
| 4/30/2009 | 2027 | 5.73 | 2/28/2014 | 193 | 166.11 |
| 5/31/2009 | 1893 | 0.00 | 3/31/2014 | 133 | 101.59 |
| 6/30/2009 | 1951 | 0.00 | 4/30/2014 | 0 | 0.00 |
| 7/31/2009 | 1999 | 19.28 | 5/31/2014 | 5 | 0.00 |
| 9/30/2009 | 1964 | 74.59 | 6/30/2014 | 0 | 0.00 |
| 10/31/2009 | 1960 | 94.44 | 7/31/2014 | 607 | 613.36 |
| 11/30/2009 | 1942 | 113.64 | 8/31/2014 | 984 | 951.26 |
| 12/31/2009 | 1978 | 131.15 | 9/30/2014 | 748 | 710.33 |
| 1/31/2010 | 1887 | 88.02 | 10/31/2014 | 995 | 1046.90 |
| 2/28/2010 | 1938 | 161.87 | 11/30/2014 | 157 | 203.42 |
| 3/31/2010 | 1900 | 172.69 | 12/31/2014 | 0 | 0.00 |
| 5/31/2010 | 1806 | 222.26 | 2/28/2015 | 0 | 0.00 |
| 7/31/2010 | 1698 | 200.70 | 3/31/2015 | 0 | 0.00 |
| 8/31/2010 | 1715 | 193.61 | 4/30/2015 | 0 | 0.00 |
| 9/30/2010 | 1696 | 279.98 | 5/31/2015 | 0 | 0.00 |
| 10/31/2010 | 1624 | 314.37 | 6/30/2015 | 0 | 0.00 |
| 11/30/2010 | 1861 | 156.02 | 7/31/2015 | 0 | 0.00 |

- **Production history for well XX-29**

| Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) | Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) |
|---|---|---|---|---|---|
| 12/31/1996 | 2623 | 4.26 | 5/31/2001 | 3572 | 0.00 |
| 1/31/1997 | 2916 | 6.25 | 6/30/2001 | 3998 | 0.00 |
| 2/28/1997 | 3482 | 2.49 | 10/31/2001 | 3839 | 0.00 |
| 3/31/1997 | 3790 | 5.72 | 11/30/2001 | 3783 | 0.00 |
| 4/30/1997 | 4836 | 1.01 | 12/31/2001 | 3743 | 0.00 |
| 5/31/1997 | 6712 | 96.63 | 1/31/2002 | 3715 | 0.00 |
| 6/30/1997 | 6684 | 206.51 | 2/28/2002 | 3823 | 0.70 |
| 7/31/1997 | 3211 | 79.99 | 3/31/2002 | 3704 | 0.12 |
| 8/31/1997 | 3808 | 78.88 | 4/30/2002 | 3722 | 0.00 |
| 9/30/1997 | 3177 | 102.79 | 9/30/2002 | 3372 | 0.00 |
| 10/31/1997 | 1602 | 25.48 | 12/31/2002 | 3224 | 0.00 |
| 11/30/1997 | 917 | 0.91 | 1/31/2003 | 2800 | 0.00 |
| 12/31/1997 | 696 | 0.60 | 2/28/2003 | 4626 | 0.00 |
| 1/31/1998 | 922 | 0.00 | 3/31/2003 | 5156 | 0.00 |
| 2/28/1998 | 667 | 0.00 | 4/30/2003 | 5173 | 0.00 |
| 3/31/1998 | 353 | 0.05 | 5/31/2003 | 5140 | 0.00 |
| 4/30/1998 | 582 | 0.84 | 6/30/2003 | 5048 | 0.00 |
| 5/31/1998 | 483 | 0.31 | 9/30/2003 | 4640 | 44.04 |
| 6/30/1998 | 417 | 0.18 | 10/31/2003 | 4967 | 0.00 |
| 7/31/1998 | 328 | 0.02 | 11/30/2003 | 4785 | 141.39 |
| 8/31/1998 | 68 | 0.13 | 12/31/2003 | 4802 | 110.59 |
| 9/30/1998 | 0 | 0.00 | 1/31/2004 | 4596 | 73.29 |
| 10/31/1998 | 0 | 0.00 | 2/29/2004 | 4631 | 224.79 |
| 3/31/1999 | 0 | 0.00 | 3/31/2004 | 4538 | 88.08 |
| 4/30/1999 | 0 | 0.00 | 4/30/2004 | 4663 | 111.61 |
| 5/31/1999 | 3298 | 2.10 | 5/31/2004 | 3875 | 80.97 |
| 6/30/1999 | 4625 | 0.94 | 6/30/2004 | 4229 | 100.70 |
| 7/31/1999 | 4542 | 11.73 | 7/31/2004 | 4267 | 372.26 |
| 9/30/1999 | 4463 | 0.00 | 8/31/2004 | 987 | 2.02 |
| 10/31/1999 | 4348 | 0.00 | 9/30/2004 | 0 | 0.00 |
| 11/30/1999 | 4333 | 0.00 | 10/31/2004 | 2503 | 0.00 |
| 12/31/1999 | 4285 | 0.00 | 11/30/2004 | 4693 | 67.12 |
| 1/31/2000 | 4286 | 0.00 | 12/31/2004 | 4304 | 212.57 |
| 6/30/2000 | 4363 | 0.00 | 1/31/2005 | 4480 | 433.30 |
| 7/31/2000 | 1461 | 0.00 | 2/28/2005 | 4076 | 531.73 |
| 8/31/2000 | 95 | 0.00 | 3/31/2005 | 4397 | 314.15 |
| 9/30/2000 | 3929 | 0.00 | 4/30/2005 | 3891 | 427.58 |
| 10/31/2000 | 3844 | 0.00 | 5/31/2005 | 4089 | 670.13 |
| 11/30/2000 | 3823 | 0.00 | 6/30/2005 | 4042 | 635.17 |
| 12/31/2000 | 3808 | 0.00 | 7/31/2005 | 3843 | 933.30 |
| 1/31/2001 | 3860 | 0.00 | 8/31/2005 | 3594 | 843.77 |
| 2/28/2001 | 3946 | 0.00 | 9/30/2005 | 3254 | 903.07 |
| 3/31/2001 | 2998 | 0.00 | 10/31/2005 | 3588 | 1023.76 |
| 4/30/2001 | 0 | 0.00 | 12/31/2005 | 3391 | 1123.89 |

| Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) | Date | Cu. Oil (BBL/D) | Cu. Water (BBL/D) |
|---|---|---|---|---|---|
| 1/31/2006 | 3525 | 1390.19 | 6/30/2010 | 1570 | 3029.98 |
| 2/28/2006 | 3410 | 1504.28 | 7/31/2010 | 1469 | 3118.90 |
| 3/31/2006 | 3070 | 1417.53 | 8/31/2010 | 1458 | 2934.57 |
| 4/30/2006 | 3181 | 1363.39 | 9/30/2010 | 1479 | 2655.10 |
| 5/31/2006 | 3091 | 1497.54 | 10/31/2010 | 1339 | 1732.22 |
| 6/30/2006 | 2886 | 1653.11 | 11/30/2010 | 1499 | 1545.49 |
| 7/31/2006 | 2718 | 1558.05 | 12/31/2010 | 1403 | 1855.97 |
| 8/31/2006 | 2476 | 1719.23 | 1/31/2011 | 1434 | 2008.82 |
| 9/30/2006 | 2498 | 1955.04 | 2/28/2011 | 1398 | 1745.35 |
| 12/31/2006 | 2539 | 1791.24 | 5/31/2011 | 1431 | 1794.14 |
| 1/31/2007 | 2614 | 2078.06 | 6/30/2011 | 701 | 845.05 |
| 2/28/2007 | 2590 | 2268.20 | 7/31/2011 | 0 | 0.00 |
| 3/31/2007 | 2498 | 2265.20 | 9/30/2011 | 0 | 0.00 |
| 4/30/2007 | 2397 | 2318.78 | 10/31/2011 | 225 | 464.64 |
| 5/31/2007 | 2457 | 2191.73 | 11/30/2011 | 1666 | 3998.56 |
| 6/30/2007 | 2463 | 2095.72 | 12/31/2011 | 1710 | 5045.25 |
| 7/31/2007 | 2389 | 2111.13 | 5/31/2012 | 1095 | 3449.99 |
| 8/31/2007 | 2339 | 2247.17 | 6/30/2012 | 1089 | 3431.74 |
| 9/30/2007 | 2298 | 2025.94 | 7/31/2012 | 1107 | 2973.18 |
| 10/31/2007 | 2195 | 1792.71 | 8/31/2012 | 1070 | 3044.85 |
| 11/30/2007 | 2192 | 2750.49 | 9/30/2012 | 0 | 0.00 |
| 12/31/2007 | 2211 | 2795.62 | 10/31/2012 | 1024 | 1344.86 |
| 1/31/2008 | 2181 | 2754.92 | 11/30/2012 | 1345 | 1446.67 |
| 2/29/2008 | 2154 | 2890.22 | 12/31/2012 | 859 | 1167.94 |
| 3/31/2008 | 2154 | 2880.39 | 1/31/2013 | 1253 | 2177.04 |
| 4/30/2008 | 2124 | 2544.18 | 2/28/2013 | 1261 | 2172.04 |
| 5/31/2008 | 1993 | 2489.95 | 3/31/2013 | 1194 | 3080.75 |
| 6/30/2008 | 1783 | 2653.72 | 4/30/2013 | 1594 | 4724.84 |
| 7/31/2008 | 1851 | 2765.47 | 5/31/2013 | 1088 | 4051.04 |
| 8/31/2008 | 1847 | 2510.69 | 6/30/2013 | 859 | 3243.99 |
| 9/30/2008 | 1843 | 3024.08 | 7/31/2013 | 730 | 2751.57 |
| 10/31/2008 | 1836 | 3038.84 | 8/31/2013 | 878 | 3488.47 |
| 12/31/2008 | 1743 | 3054.78 | 9/30/2013 | 535 | 1879.60 |
| 1/31/2009 | 1088 | 1968.19 | 10/31/2013 | 994 | 3355.62 |
| 2/28/2009 | 0 | 0.00 | 11/30/2013 | 0 | 0.00 |
| 4/30/2009 | 0 | 0.00 | 12/31/2013 | 0 | 0.00 |
| 5/31/2009 | 1903 | 1989.93 | 1/31/2014 | 826 | 2751.89 |
| 6/30/2009 | 2090 | 2318.86 | 2/28/2014 | 850 | 3093.94 |
| 7/31/2009 | 1893 | 2085.32 | 3/31/2014 | 154 | 463.65 |
| 8/31/2009 | 1805 | 2586.31 | 4/30/2014 | 0 | 0.00 |
| 9/30/2009 | 1769 | 2427.09 | 6/30/2014 | 0 | 0.00 |
| 10/31/2009 | 1851 | 2936.66 | 7/31/2014 | 772 | 3056.67 |
| 12/31/2009 | 1840 | 2745.30 | 9/30/2014 | 914 | 3621.71 |
| 1/31/2010 | 1766 | 3164.95 | 10/31/2014 | 1150 | 4748.53 |
| 2/28/2010 | 1776 | 3265.62 | 11/30/2014 | 199 | 922.66 |
| 3/31/2010 | 1715 | 3055.47 | 12/31/2014 | 0 | 0.00 |
| 4/30/2010 | 1532 | 3090.29 | 7/31/2015 | 0 | 0.00 |

- **PCP production history for well XX-16 during first period of operations**

