Screening possible applications of Electrical Submersible Pumps Technology within changing Gas Oil Ratio regimes

Master Thesis

by

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Conceptual formulation

Mr. **Ralph Stephan** is assigned to elaborate a Master Thesis with the topic

"Screening possible applications of Electrical Submersible Pumps Technology within changing Gas Oil Ratio regimes"

Compared to other Artificial Lift systems, ESP pumps are a state of the art artificial lift application to gain high volumes. Nevertheless they are normally constrained to adapt changing flow regimes and rates due to their narrow operational performance window. It is common that new installed ESPs show highly increasing GORs already after a short time of production life which cannot be dealt ideal with the built-in ESPs optimally.

The focus of this thesis is the investigation of state of the art ESP technologies to handle changing GOR regimes and the possible adaption of existing ESPs.

In the first part of the thesis the theoretical background, which is necessary to work on the given topic, has to be elaborated. This concerns the main technical parts of actual ESP pumps technology and the functional principles of them. Moreover, special attention should be given to the latest developed ESP pumps technologies for high gas applications and design requirements.

Within the practical part of the thesis a review of actual design processes should be done. In addition, the potential for improvement should be identified and the findings incorporated into a new design concept. For already operating ESP pumps the impact of the change of major operating parameters should be examined and a best practice for the operation of these pumps developed. Finally the available equipment at the market and different case studies should be presented to identify solution options for the presented problem.

Vienna, September 2013 — Dipl.-Ing. Christoph Marschall

Leoben, September 2013 — Univ.- Prof. Dipl.-Ing. Dr. mont. Herbert Hofstätter

AFFIDAVIT

I declare in lieu of oath, that I wrote this thesis and performed the associated research myself, using only literature cited in this volume.

EIDESSTATTLICHE ERKLÄRUNG

Ich erkläre an Eides statt, dass ich diese Arbeit selbstständig verfasst, andere als die angegebenen Quellen und Hilfsmittel nicht benutzt und mich auch sonst keiner unerlaubten Hilfsmittel bedient habe.

(Ralph Stephan)

Leoben, 21th of January 2014

Abstract

To meet the future demand after Oil, new technologies and strategies have to be applied. Artificial Lift technologies such as centrifugal pumps (Electrical Submersible Pumps) will be a key technology to fulfill the needed requirements. The Master Thesis "Screening possible applications of Electrical Submersible Pumps Technology within changing Gas Oil Ratio regimes" deals with the application of ESP pumps in oil wells which have a varying amount of free gas. The operation of ESP pumps under these circumstances has a certain complexity and requires a detailed knowledge of the expected operating parameters. This requires a deep knowledge base, which a design engineer needs, to find the right pump equipment and related to that the ideal completion strategy. This Thesis serves to build up this knowledge base. First, the main components of an ESP pump and their functionality are described in more detail. After a classification of the different design parameters a concept is developed which enables the estimation of future parameters using a calculation spreadsheet and probabilistic methods. If, during the operation of an ESP pump, the free gas content is fluctuating, the possibilities to react on are extremely limited. In this work, a strategy is presented which can be applied. A simulation of this strategy was performed for three different wells and it has been shown that the applicability of the strategy is given. By changing two important operating parameters, an ESP pump which is in unstable operation conditions due to fluctuating free gas can be returned to a stable operating condition. A research of different papers and case studies showed that the operation of ESP pumps in oil wells with high free gas content is an often discussed problem in the industry. Due to new developments of pump manufacturers and the application of new completion strategies and continuous monitoring instruments the operation of ESPs under these conditions is not any more out of scope.

Kurzfassung

Um die zukünftige Nachfrage nach Erdöl bewältigen zu können bedarf es des Einsatzes neuer Technologien und Strategien. Artificial Lift Technologien wie zum Beispiel Tauchkreiselpumpen (Electrical Submersible Pumps) werden hierbei eine immer wichtigere Rolle einnehmen. Die Masterarbeit "Screening possible applications of Electrical Submersible Pumps Technology within changing Gas Oil Ratio regimes" beschäftigt sich mit der Anwendung von ESP Pumpen in Erdölsonden die einen wechselnden Anteil an freien Gas aufweisen. Der Betrieb von ESP Pumpen unter diesen Umständen weist eine gewisse Komplexität auf und erfordert eine detaillierte Kenntnis der zu erwartenden Betriebsparameter. Dies erfordert eine fundierte Wissensbasis welche ein Design-Ingenieur benötigt um das richtige Pumpen-Equipment und damit verbunden die richtige Komplettierungsstrategie auszuwählen. Diese Arbeit dient zum Aufbau dieser Wissensbasis. Zunächst werden die Hauptkomponenten einer ESP sowie deren Funktionsweise näher beschrieben. Nach einer Klassifizierung der verschiedenen Design-Parameter wird mithilfe eines Berechnungsspreadsheets und probabilistischen Methoden ein Konzept entwickelt, welches die Abschätzung zukünftiger Parameter ermöglicht. Kommt es während des Betriebes einer Pumpe zu Schwankungen des freien Gas Anteils sind die Handlungsmöglichkeiten äußerst eingeschränkt. In dieser Arbeit wird eine Strategie vorgestellt welche unter diesen Umständen angewendete werden kann. Eine Simulation dieser Strategie anhand von drei ausgewählten Sonden wird ebenfalls beschrieben und es konnte gezeigt werden dass eine Anwendbarkeit der Strategie gegeben ist. Durch die Veränderung zweier wichtiger Betriebsparameter kann eine ESP Pumpe welche, bedingt durch einen schwankenden freien Gas Anteil, einen unstabilen Betriebszustand aufweist wieder in einem stabilen Betriebszustand übergeführt werden. Eine Recherche verschiedener Papers und Case Studies zeigte dass der Betrieb von ESP Pumpen in Erdölsonden mit hohem freien Gas Anteilen in der Industrie ein weitverbreitetes und viel diskutiertes Problem ist welches jedoch durch Neuentwicklungen der Pumpenhersteller und durch die Anwendung neuer Komplettierungsstrategien und Monitoring Instrumente nicht mehr länger außerhalb der Möglichkeiten ist.

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List of abbreviations

°F	degree fahrenheit
AC	alternating current
API	American Petroleum Institute
bbl	barrel
bbl/d	barrels per day
BEP	best efficiency point
BFPD	barrel fluid per day
BHP	brake horsepower
BHP	bottom hole pressure
cp	centipoise
DC	direct current
ESP	Electrical Submersible Pump
etc.	et cetera
FBHP	flowing bottomhole pressure
ft	feet
ft/sec	feet per second
GLR	gas liquid ratio
GOR	gas oil ratio
GVF	gas void/volumetric fraction
HP	horse power
Hz	Hertz
ID	inner diameter
in	inch
IPR	inflow performance relationship
m	meter
MD	measured depth
mil.	Million
min	minutes
MTBF	mean time between failure
MTBP	mean time before pull
OD	outer diameter
PI	productivity Index
PIP	pump intake pressure
ppm	parts per million
Psi	pounds per square inch
rpm	runs per minute
RTTC	real-time torque command
SCADA	Supervisory Control and Data Acquisition
Scf/stb	standard cubic feet per standard barrel
SCSSSV	surface controlled sub-surface safety valve
SSD	sliding sleeve door
SSSV	sub-surface safety valve
STOIIP	stock tank oil initially in place
TDH	total dynamic head
TRSV	tubing-retrievable safety valve
TVD	true vertical depth
VSD	Variable Speed drive

1 Introduction

To meet tomorrows demand for oil, technology advances were made such as directional drilling, advancements in artificial lift and advances in refining. This allows the production of more difficult oil wells. While the technology advances allow production in more challenging environments, the additional technology comes at additional costs. The chance of finding any significant quantity of new cheap oil is very low and the new exploration areas are going to be very expensive. To choose an artificial lift system is nowadays mandatory to allow the production of all the reserves.

Artificial lift is a big business, about 93 % of the total number of oil wells worldwide use some form of artificial lift. This percentage varies in the different geographical areas, being 95 % in mature regions as North & South America, Far East and East Europe and the Former Soviet Union, 80% in West Europe and only 50 % in the Middle East and 45 % in Africa. The most widely used type of artificial lift system is sucker rod pumping with a share of 74 %. The second most common type are Electrical Submersible Pumps (ESP), which also represents the system with the highest sales and fastest growing form of artificial lift pumping technology. [1]

Found in operating environments all over the world, ESPs are very versatile. They can handle a wide range of flow rates from 70 bbl/d to 64 000 bbl/d or more and lift requirements from virtually zero to as much as 15 000 ft of lift. A limitation of ESP is the inability to handle significant volumes of gas. The implications of this limitation becomes even more critical if the fluid production rate is at or below the minimum rate required for cooling of downhole equipment. Given their high rotational speed of up to 4000 rpm and tight clearances, they are also only moderately tolerant of solids like sand. If solid-laden production flows are expected, special running procedures, pump design and placement techniques are usually employed. When very large amounts of free gas are present, downhole gas separators and/or gas handlers may be required in lieu of a standard pump intake. [2]

For wells with high gas volume, production is limited by the ESP pumps ability to handle free gas. Different technologies have been implemented to achieve the production goals. However, as downhole conditions continue to change, the gas-handling capability of the installed technology is of major importance. The following thesis provides a detailed description of actual technologies, design procedures and operating strategies to design and operate nowadays ESP equipment in challenging free gas environments.

1.1 Structure of the Thesis

Basically the Master Thesis consists of two parts, in the first part the theoretical fundamentals are formulated and in the second the practical and scientific work is described.

The theoretical fundamentals start with a general explanation of the major components of ESP pumps. The functional principle of centrifugal pumps is described in more detail and also the major equipment for gas handling and gas separating is presented.

The next chapter, chapter 3, gives an overview of ESP design procedure especially for applications in wells with high gas contents. The required data are reviewed and listed and common concepts for well inflow calculations presented. Furthermore the calculation of free gas and natural separation efficiency is described. A special focus was given to the influence of free gas to the pump and therefore the degradation of head. Finally the selection process of gas handling devices or gas separation devices was reviewed and the benefits of a VSD design were pointed out.

The practical part starts with chapter 4. In this chapter a newly design-concept was developed, based on the prediction of future parameters and risk analysis. Therefore all the required parameters used by nowadays design software were evaluated and described in more detail. Finally a design spreadsheet was developed and the results for a common example are presented.

Chapter 5 investigates the operation of ESP pumps during changing conditions. A best practice strategy to operate ESP pumps under these circumstances is described. Followed by a description of the Habban Field in Yemen and the history of three wells were the applicability of the strategy had been checked. After a detailed description of the methodology, the results are discussed in more detail.

The next chapter 6 presents some case studies of companies sharing their gained knowledge in the operation of ESPs in difficult environments. Common completion architectures are also described and finally a description of actual available equipment at the market is given.

Chapter 7 is the final chapter and summarizes the results and outcome of this work.

2 The Electrical Submersible Pump

In the early stages of their lifetimes, oilwells usually flow naturally to the surface and are called free flowing wells. This means that the pressure at the well bottom is sufficient to overcome the hydrostatic backpressure and the pressure losses occurring along the flow path. When this criterion is not met, the natural flow will end and the well dies.

To overcome this problem artificial lift methods are used to produce fluids from wells that are already dead or to increase the production rates from free flowing wells. There are several artificial lift systems available at the market that can be rough distinguished into gas lifting and pumping. All versions of gas lifting use high-pressure natural gas injected to the wellstream at some point to add energy to the fluid and move the fluid to the surface. Pumping of the fluid always expect an installed downhole pump to increase the pressure in the well to overcome the sum of flowing pressure losses. There are several criteria to classify the pump types but the most widely accepted classification is based on the way the downhole pump is driven. So a differentiation between rod and rodless pumping is made.

As the name implies, a rodless pumping method do not have a rod string to operate the downhole pump from the surface. Electric or hydraulic devices are used to drive the downhole pump. A variety of pump types like centrifugal, positive displacement, or hydraulic pumps are utilized with rodless pumpings. [1, p. 3]

The ESP utilizes a submerged electrical motor driving a multistage centrifugal pump. Power is supplied by an electrical cable run from the surface to the motor. ESPs are ideally suited to lift high liquid volumes. The further chapters will describe the main parts and functionality of an ESP in more detail.

2.1 Components Overview

The long history of ESP pumps showed that the system proved to be an efficient means of producing liquid from oil and water. First developed by a Russian in the late 1910s and patented in the USA in 1926, the ESP showed its potential early, when first installations were successful operated. Due to their conception, ESP units have excelled in lifting much greater liquid rates than most of the other artificial lift types. Today they are used in a broad range of applications.

The first ESP units were equipped and driven by a three-phase two-pole electric induction motor of $5^3/_8$ in. or $7^1/_4$ in. outer diameter (OD). At this time, the maximum power outcome of the motor was about 105 HP. A seal unit was attached directly above the motor to prevent the leakage of well fluids into the motor. On top of the seal unit, a multistage centrifugal pump was installed to lift the fluids to the surface. The complete ESP unit was run on the bottom of a tubing string right into the well. Power supply is realised from the surface to the motor by a special three-conductor cable and a surface control unit. During today, these presented components are the main components of an ESP pump. Over the years ESP units underwent a continuous improvement and a steady increase of lifetime and capacity. The next chapters will present the main components of an ESP pump in more detail. Figure 1 shows an overview of the main components. [2]

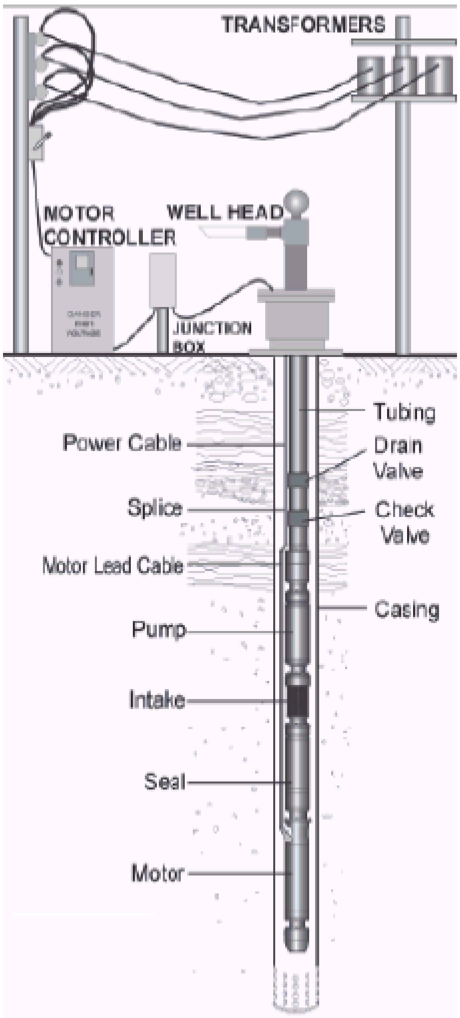


Figure 1: Main Components ESP [2, p. 627]

2.2 Motor

The motor of an ESP pump is usually a two-pole, three-phase induction design motor with a squirrel cage. Due to the two pole design the motors run at a nominal speed of 3500 rpm at 60 Hz or 2915 rpm at 50 Hz. It operates on three phase power at voltages between 230 – 5000 V and amperages between 12 and 200 A. Generally the diameter and length determine the HP rating of the motor. Normally the motor can be manufactured slightly larger in diameter than the pumps because there is no cable running along its length. Typical motor sizes are given by the nominal diameter of the ESP. Common sizes are 3.75 in., 4.50-4.56 in. and 5.40-5.62 in. The manufacturer name the product line to the nominal diameter and call it then the 375 series, 450 series or 540 series. The minimum casing sizes would be $4^1/_2$ in. for the 375 series, $5^1/_2$ in. for 450/456 series and 7 in. for the 540/562 series.

An electrical motor consists of a wound rotor that comprises an unwound stator, electrical windings and an insulation and encapsulation system. Insulated copper wire is wound into each slot of the laminations mounted on the unwound stator. The wounding is separated into three phase coils, displaced by an interval of 120 °. After winding is complete, the whole stator is encapsulated by a solid-fill epoxy or varnish coating. The length of the wound stator determines the number of rotors and finally the total resulting horsepower. For different wounding lengths there are numerous combinations for voltage/amperage possible.

The torque produced by the rotors is transmitted by the shaft. It is generally made out of tubular material with a hollow core. This core is needed for lubrication of radial bearings and rotor areas. Because the shaft is normally completely immersed in clean oil, there is no need for exotic corrosion resistant materials.

An ideal rotor should be one continuous component that runs the length of the stator lamination bore. Due to the very large rotor length, required for borehole installations, enormous dynamic instability problems would occur. To overcome these problems, rotors are constructed in short segments with radial support bearings.

A sleeve-type-bearing system provides the alignment and radial support. The stationary part of the bearing has a bore in which the sleeve runs and the sleeve itself is keyed to the shaft and rotates with it. Between the stator-lamination inside diameter and the bearing outside diameter is a small clearance and sometimes it is equipped with an elastomer ring or a locking key to avoid any relative rotation of the bearing. If this rotation occurs, the bearing may start wearing into the stator and an electrical short can happen.

The so called motor head contains the electrical termination for the connection of the windings to the electrical power cable coming from the surface. These connections are made in an insulated cavity by a male/female plug in design or a splicing of the motor-wire to power-cable. The main components and their arrangement can be seen in Figure 2. [2, p. 648ff]

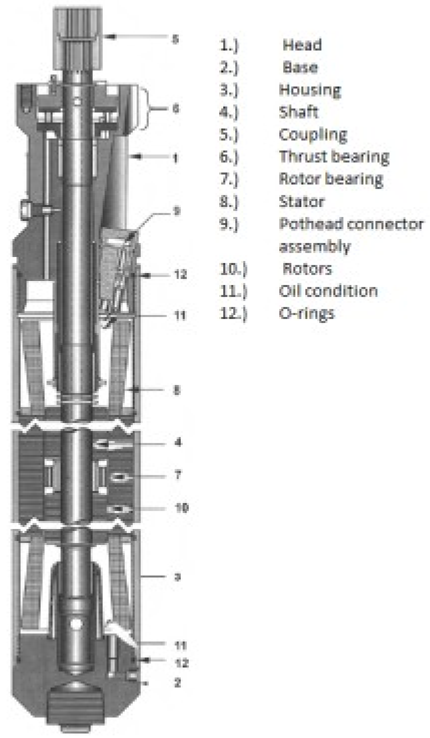


Figure 2: Motor components [2, p. 649]

The performance of a motor is usually characterized by the performance curve, supported by the manufacturer. To get the data, a motor is equipped with a dynamometer and loaded across a broad range of HP load range. The measured data include three-phase voltage, amperage, kilowatts, rpm, motor torque, motor temperature behaviour and fluid velocity passing the motor.

One of the easiest parameter to measure is the motor current. Due to its property, that it is nearly linear with the HP loading, it is the most useful parameter for determining the actual loading of the motor. To determine the output HP of the motor, the percentage of name-plate amps in which the motor runs has to be calculated. Also the rpm can be read from the motor characteristic curve by knowing the percentage of nameplate amps.

Normally the motor is placed in a steel housing, lubricated by a high quality mineral oil. ESP motors are very sensitive to operating temperature and their run lives can be drastically shortened if they were run above their design specifications. To ensure sufficient cooling of the motor, the bypassing well fluid act as a coolant and a minimum fluid velocity of 1 ft/sec is recommended. In most installations the motor is set above the wells perforation to ensure enough fluid flowing past the motor. For wells that have a high water cut, motor cooling is greater because of the higher heat capacity that water has. [1, p. 65ff]

2.3 Protector or Seal Section

The connection between the motor shaft and the pump or gas separator is made by the important seal section or protector. This component has several functions that are critical to the operation and the run life of the ESP system and the motor in particular.

- At first its main purpose is the isolation of the dielectric motor oil against the well fluid. Motors are filled with a high-dielectric mineral or synthetic oil to ensure electrical protection and lubrication. If well fluids migrate into the motor they can cause a premature electrical or mechanical failure through the reduction of the dielectric and lubricating properties.
- It also allows for pressure equalization between the interior and the wellbore. This pressure equalization needs to be done because ESP motors run at elevated temperatures and, if they would be completely sealed, would burst their housing due to the great internal pressure developed by the heated oil.
- It also absorbs the axial thrust produced by the pump and dissipates the heat generated by the thrust bearings.

Selection of the shaft is usually based on the fluid environment and the HP that has to be transmitted. The top end of the shaft is exposed to the well fluid and this part has to be made out of a material that can resist. Typically special alloys are used that protects the integrity and function of the shaft.

There are two main designs available for protection chambers. The labyrinth protection chamber features a direct fluid interface between the wellbore fluid and the motor oil. It is designed to have several concentric annular volumes that form a U-tube-type communication path for the fluids traveling from the top to the bottom of the chamber. It is a very effective protection design but there are some weaknesses that have to be considered. There is a direct fluid interface between the motor oil and the wellbore fluid in the top chamber and this allows the motor oil to be slowly wetted through a wicking action of the wellbore fluid. Also gasses can permeate into the motor oil causing potential corrosion problems and excessive losses of motor oil if there is a sudden decompression. Due to the fact that the labyrinth`s effective volume decreases as the chamber is inclined, the applicability for deviated wells greater than 30° from vertical is not recommended.

The second design type of a chamber is a so called Positive-Barrier-Protection Chamber. This chamber incorporates a positive barrier between the wellbore fluid and the motor oil. Usually an elastomeric or rubber bag is used to provide the barrier. The bag forms a seal between the motor oil inside the bag and the wellbore fluid outside the bag. By expanding and contracting the bag it allows for pressure compensation.

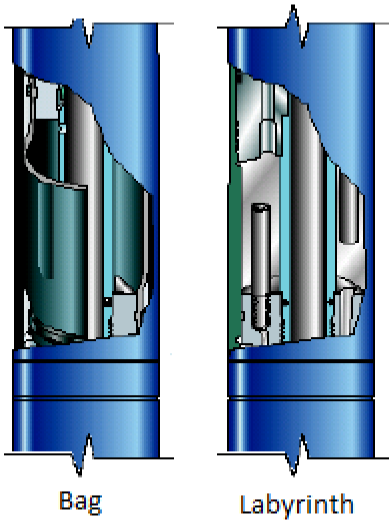


Figure 3: Chamber Types [3]

Each chamber has a rotating mechanical face seal located at the top of the protection chamber. The rotating part is sealed to the shaft by elastomeric bellows and the stationary part is sealed into the stationary component of the seal-chamber section. An installed spring keeps the rotating stationary seal faces in contact. Once the unit starts rotating, a hydrodynamic fluid film is developed on the face to carry the load, prevent wellbore fluids from crossing the face by the pressure-differential setup and cools the loaded face.

The axial thrust bearing carries all of the axial thrust produced by the pump and seal-chamber section. Dependent on the loads they have to carry, different bearing styles are provided. Usually sliding-shoe hydrodynamic types are used because of their robustness and ability to function totally immersed in lubricating fluid. [4, p. 17]

2.4 Pump Intake

The intake section functions as a suction manifold feeding well fluid to the pump. Depending on fluid parameters of the well the intakes can be generally divided into a standard inlet, a gas separator or a gas handler. The standard intake is for wells with a very low free gas to liquid ratio (GLR). It has several fairly large ports, allowing fluid to flow into the lower section of the pump and enter the bottom stage of the pump. Mostly the holes are approximately 1 in. in diameter and the intake could be equipped with a screen to filter solids. A major drawback of using screens and filters is that they tend to plug off which restricts flow into the pump.

The gas separator intakes can be divided into static and dynamic type. A gas separator is needed in wells were excessive free gas is present at the pump intake. This may cause the pump to gradient lock and create thrusting problems. Separator efficiency varies with the design, well conditions and velocity contrasts between the rise of the gas bubbles and the well fluid to the intake of the pump. Different types of gas separators and their functionality will be discussed in more detail in chapter 2.6

Gas separation and venting over the annulus is not applicable for wells or even not allowed in some countries. Therefore gas handling devices were developed to produce the gas together with the liquid through the tubing. These systems can be divided into centrifugal gas handlers and axial-flow technology. A more detailed description will be given in chapter 2.7.

2.5 Pump

2.5.1 Functionality

ESP pumps are multistage centrifugal pumps driven by a prime mover providing a rotary motion. A single-stage consists of two basic components:

- Impeller — a rotating set of vanes
- Diffuser — the stationary part, containing the casing of the impeller, as well as bearings and seals required for proper operation

Figure 3 shows a single stage of a common multistage centrifugal pump. Liquid from the previous stage enters the impeller in an axial direction. The liquid has at the intake a relatively low velocity. Due to the high speed of the impeller`s vanes, kinematic energy is applied to the fluid which relates to a high velocity at the outtake of the impeller. After discharging, the high-velocity fluid stream enters the diffuser, where the conversion from kinetic energy to pressure energy takes place. The liquid is now at a higher pressure than it was before the stage, so the flowing pressure was increased. Since the discharge of any stage is related to the inlet of the next stage this is an on-going process and the pressure of the liquid pumped is accordingly increased.

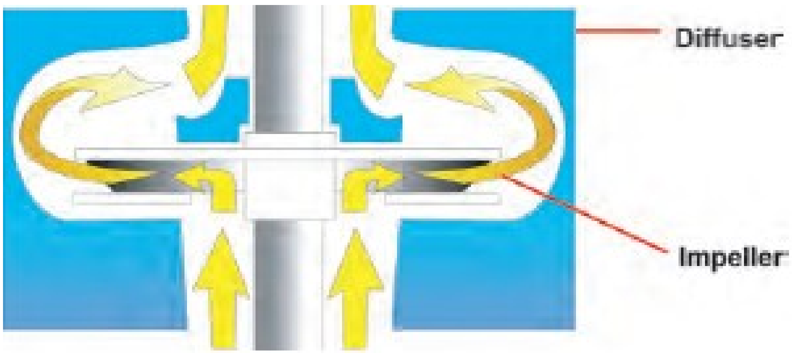


Figure 4: One stage [2, p. 633]

Centrifugal pumps can be classified according to the discharge direction of the impeller. radial, axial or mixed flow pumps are available. In ESP service, however, only radial and mixed flow pumps are used. Radial flow is used for smaller capacities up to 3,000 bbl/d liquid. Mixed flow pumps are used at higher rates and to handle high GORs. The difference between this two design concepts, is the increased axial flow of the fluid in a mixed flow pump. Figure 5 shows the differences between radial and mixed flow type.

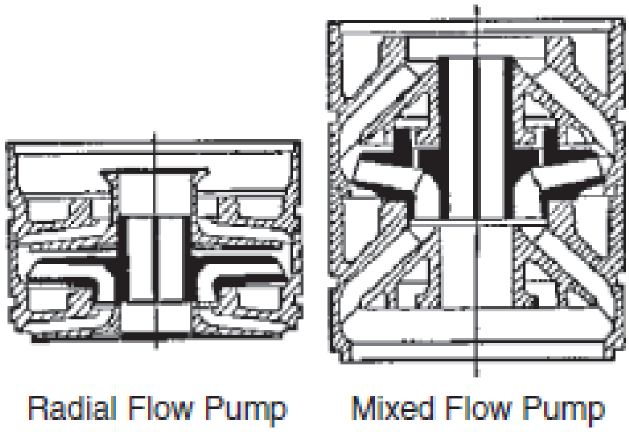


Figure 5: Radial vs. Mixed Flow Pump [1, p. 26]

Another important factor of stage design is the method by which they carry their produced axial thrust. Usually, pumps smaller than 6 in. diameter, are built as floater stages. There the impeller is allowed to move axially on the pump shaft between the diffusers. Contrary to the name, given to this configuration, the impellers never truly float. Typical they run in a downthrust position, and at high flow rates they may switch into upthrust position. To carry this thrust, on each impeller synthetic pads or washers are mounted. These washers transfer the thrust load from the impeller through a liquid film to the smooth thrust pad of the stationary diffuser. General, there are three forces involved to determine even an impeller runs in upthrust or downthrust mode. The first is the downward force which is a result of the impeller discharge pressure acting on the area of the top impeller shroud. In the upward direction, there are two forces acting. On the one hand, the force, produced by the momentum of the fluid, making its turn in the impeller passageway. On the other hand, the resulting forces of a portion of the impeller discharge pressure that is acting against the bottom shroud of the impeller.

Specially built smaller pumps and pumps larger than 6 in. have normally impellers that are fixed or locked to the shaft. These pumps are also called fixed impeller or compression pumps. In this configuration the whole thrust is transferred to the shaft and not to the diffuser and the seal thrust bearing carries the load of the impeller plus the shaft thrust. For this type of pumps, particular care should be exercised during the selection of the bearings because these loads could be very high. [1, p. 61]

2.5.2 Pump Performance

As described before, a centrifugal pump transforms mechanical energy, applied by the motor driving it, to the kinetic energy of the transported liquid. Due to the fact, that kinetic energy is proportional to the term density times velocity squared (ρv^2), a pump running at a given speed and hence having a constant discharge velocity from its impeller, transmits different amount of energy to liquids of different density. Therefore, the pressure increase in one stage or in the whole pump is also dependent on the density of the liquid. Dividing the pressure increase developed by the pump, with the density, delivers a constant called head. In dealing with centrifugal pumps, head is used instead of pressure due to the fact that head is constant for any liquid.

The head developed by an impeller under ideal conditions with an infinite number of vanes is calculated with the Euler equation. In real pumps, the number of vanes is limited and the liquid contained between two vanes develops a circulating flow. This modifies the velocity distribution and therefore the theoretical head developed. The actual head, developed by the pump is always less than the theoretical one. Different losses like hydraulic losses, shock losses or leakage losses influence the performance of a real centrifugal pump stage. In Figure 6 the performance of a real pump stage after considering all the head losses can be seen.

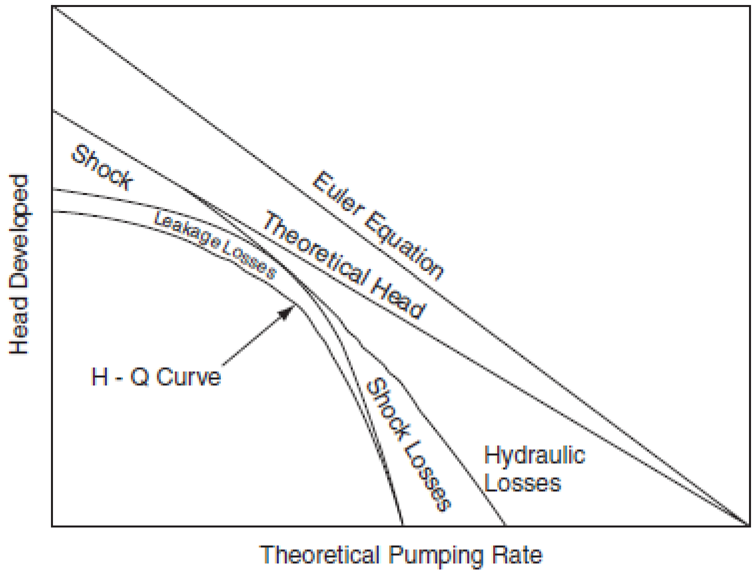


Figure 6: Head-Pumping Rate curve (H-Q curve) [1, p. 28]

The power required to drive a pump is represented by a factor called brake horsepower (BHP). It has to overcome the energy needed to pump the given liquid rate including all the energy losses. The useful hydraulic power is proportional to the product of the head, the liquid capacity and the density and can be derived from the H-Q curve. It could become zero at a liquid rate of zero and at the pumping rate were the head is zero. The centrifugal pumps energy efficiency can be derived from the required brake horsepower and the hydraulic power spent on liquid transfer. Plotting the efficiency curve in function of the liquid rate, the curve follows the shape of the hydraulic power. These circumstances can be seen in Figure 6 and Figure 7.

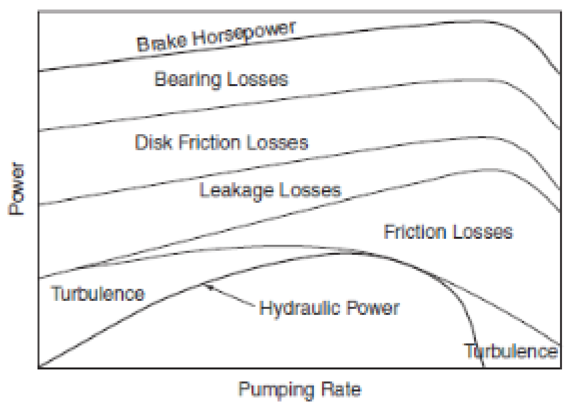


Figure 7: Power conditions [1, p. 29]

Centrifugal pumps are tested by running them at a constant speed while varying the pumping rate by throttling the flow at the pump discharge. The flow rate, suction and discharge pressure and the brake horsepower required to drive the pump are measured. Based on measurement the three parameters shown in Figure 8 are plotted versus pumping rate. The performance tests are based on API RP 11S2 standard and must be based on pumping fresh water with a specific gravity of 1.0 at 60°F and a rotational speed of 3,500 rpm at 60 Hz or 2915 rpm at 50 Hz.

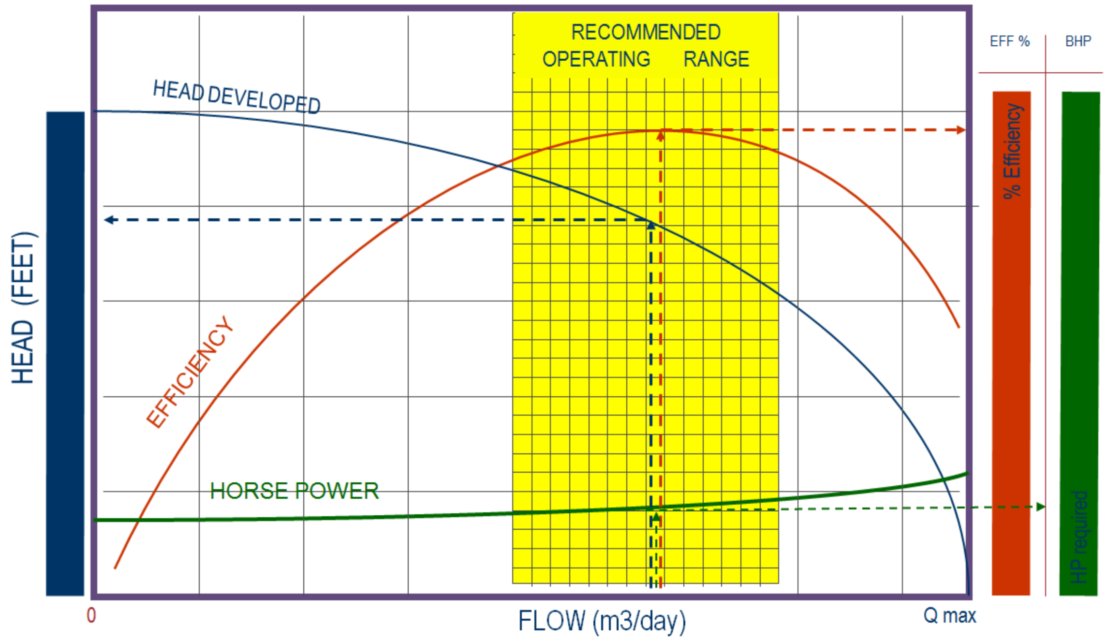


Figure 8: Performance curve [6]

Every ESP has a best efficiency point (BEP) where the performance parameters represent the criteria for an optimum utilization of the pump. Around this BEP the recommended operating range is indicated. The operating range of pumping rates is strictly related to the variation of axial forces occurring in the pump and may take the form of downthrust or upthrust. Axial forces developed in ESP pumps, have to be compensated, otherwise the axial movement leads to mechanical damages.
Downthrust is determined by the head developed, because its main component comes from the pump`s discharge pressure and its shape follows the one of the pumps head rate performance curve. It is at a maximum at shut-in conditions and diminishes to zero when the pump head is zero. Upthrust is the result of changes in inertial forces and are proportional to the kinetic energy of the pumped fluid. Thus their variation with pumping rate follows a second-order curve. The design of the stages should have a slight downthrust, because upthrust is more dangerous for the pumps operation. As can be seen in Figure 9, a safety zone in the pumping rate is created and this defines the upper boundary of the pump`s applicability. The pumping rate belonging to the maximal absorbable downthrust forces of the washers and thrust bearings, defines the minimum recommended pumping rate of the ESP. [1, p. 29]

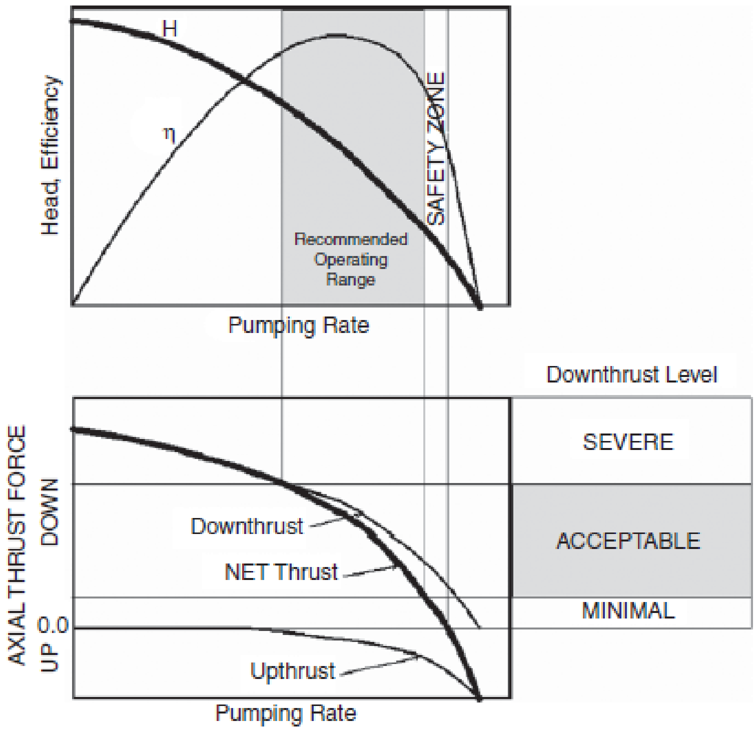


Figure 9: Axial thrust forces and the operating range [1, p. 59]

2.6 Gas Separation

There are many solutions available to mitigate gas interference in ESP operations. To detain free gas from entering the pump two main solutions and the ideas behind them are:

1. **Static Gas Separation**
   By utilizing the natural separation of the liquid and the gas phase in the annulus less free gas is able to enter the ESP system. This kind of separation and the methods of it are also often called static gas separation

2. **Dynamic Gas Separation**
   When natural separation is insufficient and free gas enters the ESP system, separate and expel free gas into the annulus with the help of dynamic gas separators

2.6.1 Static Gas Separation

The simplest static gas separator design increases the gas separation by forcing the fluid to flow reverse in the wellbore. This characteristic is the reason why they are called "Reverse Flow Gas Separators" or also "poor boy" design. This type is still the simplest one and used in wells with low to moderate liquid gas rates of about 10-15 %, where the low separator efficiency is sufficient. The fluid moves up along the outside diameter of the gas separator and then must reverse its flow as it enters the perforated holes of the separator. Then it changes its direction and must go back down to the pickup impeller. There a portion of gas breaks out due to naturally separation efficiency and travels up into the annulus area of the well. The remaining fluid goes through the pickup impeller and moves up to the first stage of the pump.

Another way to ensure natural gas separation is to set the pump below the perforations. By running it below the well perforations the effect of natural separation can be improved. Separation by gravity occurs if fluid downward velocity is lower than the rising velocity of gas bubbles. This setup is only applicable when casing and equipment sizes allow and case free gas is automatically directed to the surface without entering the pump suction. Also the pump intake pressure increases due to the greater pump submergence causing the amount of free gas to decrease or even diminish. The foundation to apply this solution is the existence of a rathole or sump in the well. The main drawback of placing the motor below the perforations is the insufficient cooling of the motor because of the lack of liquid flow along the ESP unit. To overcome this, high temperature motors or an additional auxiliary situated between the protector and the ESP pump can be used.

Additionally the usage of motor shrouds can force natural separation. The shrouds are short sections of pipe, fixed around the length of the ESP. Motor shrouds provide liquid flow along the ESP motor`s length to ensure proper cooling.

There are different motor shroud designs available:

1. The simplest one is an opened end shroud installation where the ESP unit is run below the perforations. The motor shroud is a pipe section that is closed at the top and mounted above the pump intake. This setup forces well fluids to flow downward in the casing/shroud annulus. It has to be considered that the annular space have to have a sufficiently large cross-sectional area to ensure a low fluid velocity to ensure a proper naturally separation effect. The shroud also guarantees that produced fluids flow along the motor`s length for cooling.

2. A more complicate design for higher gas production rates is the additional use of a gas separator. Here the shroud is mounted just above the separator intake holes and vent tubes direct the separated gas into the annulus. This installation can be seen at the left side in Figure 10. Often a dip tube (also called tale pipe), connected to the bottom of the regular motor shroud, is used to improve natural separation of the free gas. The improvement is realized due to the increased annular cross-sectional area available for downward flow, relating to a lower flow velocity and therefore higher natural separation. With this installation it is also possible to produce well fluids from a restricted section of a vertical or inclined hole where the ESP unit would not pass. Also production from a horizontal well with an installed ESP in the vertical section would be possible. A motor shroud with a dip tube can be seen at the right side in Figure 10: Motor Shrouds Figure 10.

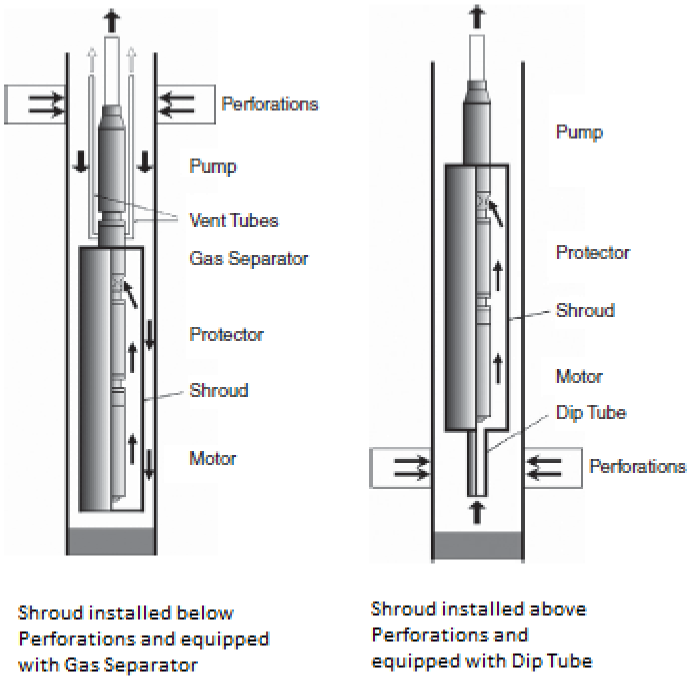


Figure 10: Motor Shrouds [1, p. 59]

2.6.2 Dynamic Separation

The next step in handling free gas with an ESP involves downhole dynamical separation devices. These devices are generally called Rotary Gas Separators and work on the principle that a multiphase mixture, if spun at high speed in a vessel, is separated to its constituent liquid and gas phases. The Rotary Gas Separator is a part of the whole ESP installation and the rotational speed is provided by the separators shaft which is connected to the motor. Due to the application of centrifugal forces onto the liquid and gas phase, the liquid is forced to the inner wall of the separator while the gas is concentrated near the shaft. A flow divider at the top of the separator ensures that the separated gas phases take different paths and a crossover device directs the gas into the annulus and the liquid to the first pump stage.

The first rotary gas separators appeared in the 1970s and were called paddle wheel type. They contain usually five axial vanes that run parallel along the length of the separator`s shaft. Well fluid containing free gas is sucked at the bottom and enters the chamber where the rotating paddle wheel impellers put centrifugal forces on it. The high centrifugal forces, acting on the liquid particles, force them against the chamber wall, while the gas collects near the shaft. Although the paddle wheel separator provided a much better performance in comparison to a reverse flow gas separator, it has some operational weaknesses that limit its efficiency. The main weakness is the fact that the tips of the impellers, turning at high speed, pick up part of the liquid from the inner wall of the separator body and mix it with lower density fluid situated closer to the shaft. The reason therefore is that the velocity near the separator wall is almost zero and therefore remixing is inevitable. Another disadvantage is the abrasion between the tips of the impellers and the separator wall.

To eliminate the remixing of the paddle wheel type separator a rotating chamber type was developed. For this type the rotating impellers were isolated from the stagnant liquid layer present on the inside wall of the separator body. Usually they contain of four impellers that are enclosed by a rotor shroud and create four separation chambers where the fluid rotates as a solid body and effects responsible for remixing are minimized. Inside the separation chambers centrifugal acceleration of up to six times the acceleration of gravity is applied and ensures the separation of the phases. A main factor to ensure a good separation is a sufficient long retention time. This is the time the fluid stays in the separator. By maximizing the cross-sectional area of the chambers, axial fluid velocity can be held at a low level which leads to an increased retention time. At higher fluid rates, retention time will decrease and a drop in separation efficiency can be recognized. Because it involves the maximum acceleration possible for an effective gas-liquid separation, the rotating chamber gas separator is good for wells producing high liquid rates and/or highly viscous liquids.

Another rotating separator is the vortex separator. It is a very simple device that has just one active part, a single axial flow impeller which induces a vortex in the otherwise empty chamber. The created vortex forces liquid against the separator wall but the gas will stay near the shaft. Centrifugal forces are lower for this type and the generated vortex spins at lower speeds than that of the separator shaft. The lost efficiency due to this way is compensated by the complete elimination of the remixing of gas and liquid phases. A vortex separator can be successfully applied in wells producing sand but is not so effective in viscous fluids and emulsions. Figure 11 presents the three different designs of rotary gas separators schematically.

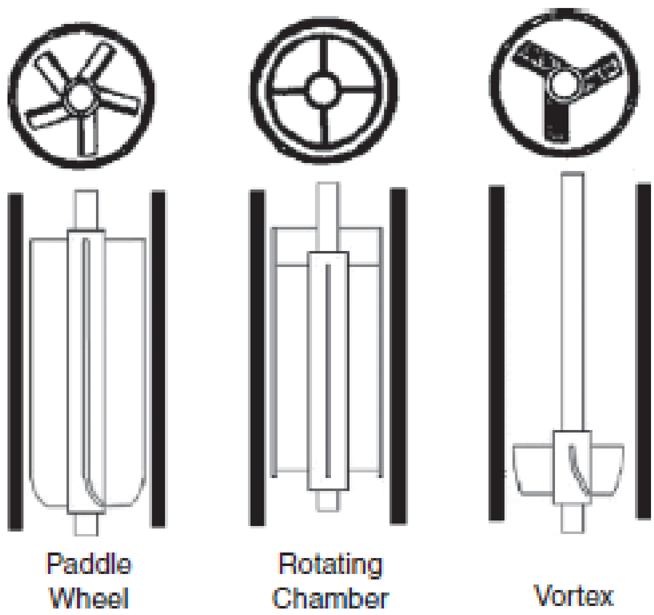


Figure 11: Separator Types [1, p. 146]

The efficiency of gas separation is strongly dependent on retention time and the magnitude of turbulence that occurs in the separator and causes the remixing of the phases. Today`s rotary gas separators can be very effective when they are run at the right conditions. The performance curves are published by the manufacturers and based on laboratory measurement. Figure 12 shows exemplary one of this performance curves. There are different investigations made in the history to learn more about separation efficiency and different mechanistic models were developed. In chapter 3.3.1 the models for calculating separation efficiency will be described in more detail. [1, p. 140ff]

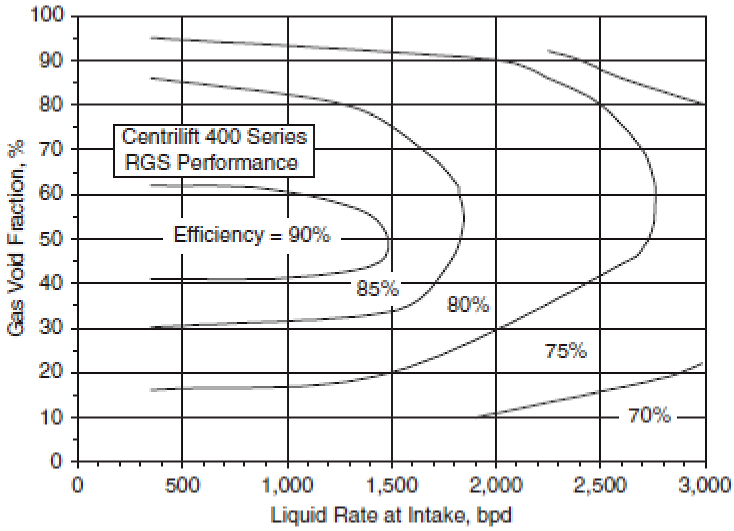


Figure 12: Separator Efficiency Curve [1, p. 149]

2.7 Gas Handling

Sometimes separation of gas cannot be applied or the application is not recommended for some reasons. For example, gas venting and producing over the annulus is restricted in many countries and therefore gas separation isn`t an applicable procedure. In such cases free gas inevitable reaches the ESP pump and has to be handled by special equipment or modifications.

The earliest solution was to use pumps equipped with more stages than needed to compensate for the smaller heads developed by the first few stages due to gas problems. These pumps eliminated the overloading of the upper pump stages that is usually associated with free gas production. The oversizing of the pumps also helps to carry greater amounts of free gas through the pump. The common drawback of oversizing a pump is that different stages usually operate at different liquid rates which may be outside the recommended range of the given pump. This leads to higher wear and finally to mechanical damages.

The next approach was to use Tapered pumps, what is a successful and energy efficient solution for handling free gas. A Tapered pump is an ESP made up of several different stage designs with the capacities of the successive stages decreasing upward. This design allows the lower stages to compress gassy fluids and continuously decrease the total volumetric flow rate. These stages increase the pressure only to that level that is needed to compress the free gas and force it back into solution with the oil. The upper stages receive a much reduced fluid rate and can be used to develop the head necessary to lift the fluids to the surface. During the design of a Tapered pump it has to be ensured that all stages in the pump operate inside their optimum capacity ranges. This requires the use of computer programs that are able to calculate every single stage of the pump. The accuracy of the design relies heavily on proper well data. If conditions differ from the assumptions for this design some or all stages will be operating outside their ranges and a failure of the ESP is the unavoidable result.

Another problem-solving approach is the modification of the stage design since radial discharge pumps are most likely to get gas locked. The design attempt the recirculation of liquid in the pump stage to break up gas pockets and increase the homogenization of the fluid flowing through the stage. Therefore matching holes are drilled into the diffuser and impeller to provide a path for the fluid to flow back from the diffuser into the impeller. The flow created greatly reduces the gas segregation caused by centrifugal forces in the impeller and the circulating fluid can also break up the gas pockets accumulated in the eye of the impeller. The big disadvantage of this design is the drastic reduction of pumping efficiency related to the backflow path of about 20-30 % or even more.

To overcome the lack in efficiency and provide systems which require no pinpoint design, special devices were developed. These multi-phase pumps are similar to charging pumps. Usually it's a short lower tandem pump with high capacity stages added below the main pump. They pump the gassy fluids entering the pump suction and compress the mixture so that the fluid can be lifted easier by the pump. They also disperse free gas in the liquid and create smaller bubbles which lead to a more homogenized fluid. One system of a main manufacturer consists of helico-axial vanes and diffusers providing a smooth axial flow. Due to the axial flow, gas cannot accumulate and the forming of gas pockets is avoided. This kind of devices are able to handle up to 75% of free gas content at the pump intake and can effectively prevent gas locking of ESP pumps. Flow ranges up to 9,000 bbl/d are reachable.

2.8 ESP-Cable

The important process of transmitting electric power from the surface to the ESP motor is done by the ESP cable. They have to work under extremely harsh conditions and must meet different requirements. At first they have to have a small diameter so that they can fit in the annulus along the well tubing. Furthermore they must maintain their dielectric properties in a very harsh environment of high temperatures, aggressive fluids environments and the presence of oil and/or gas. Also they have to be well protected against mechanical strain applied on it during running and pulling as well as normal operations. The proper choice of the type and size has in many cases a direct impact on the life of the ESP installation. A properly designed cable system may be able to stay operational for many years, presumed all handling and other recommendations are strictly followed.

An ESP cable normally consists out of the following parts:

- Three metal conductors for power transmission, usually made of copper
- Individual insulation of each conductor preventing short circuits and leakage currents between the conductors
- a jacket, the protective cover of the three conductors that provides structural strength and mechanical protection
- additional coverings over the insulation providing additional strength and protection to cable components
- an optional metal armor providing enhanced mechanical protection during running and pulling operations

ESP cables are, depending on the available space, obtainable in a round or flat configuration. Round cables are generally used along the tubing string where enough annular space is available and the cable can fit between the tubing coupling OD and the casing`s drift diameter. Flat cables have a much smaller radial space requirement, see Figure 13, and are necessary for small annular configurations or along the ESP. [1, p. 103f]

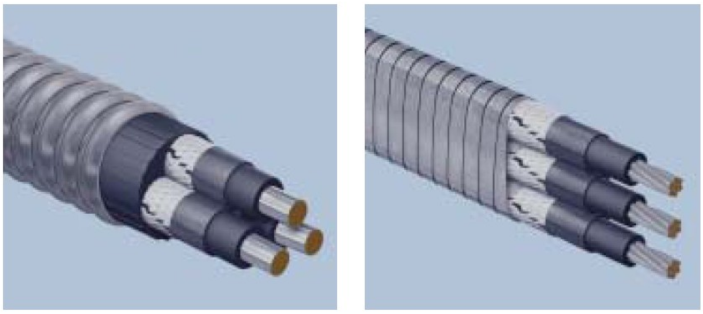


Figure 13: Round & Flat Cable [6]

2.9 Other Downhole Equipment

Besides the equipment described so far there are several additional pieces of equipment to be run into the well. The motor lead extension is the part of the ESP cable running along the pump, gas separator and protector. It is directly connected to the motor using a pothead connector. Since radial distance is very restricted along the ESP unit a motor lead extension is usually a flat cable. The heat load is at a maximum on top of the motor. This is usually the point where the pothead connector is attached and therefore the position where the cable temperature is the greatest. To strap the power cable to the tubing and avoid mechanical damage of the cable during running and pulling, cable bands are used. The common distance between cable bands is about 15 ft.

In the majority of cases, wells produced by ESPs do not have a packer and continuously vent the produced gas to the surface. If a packer is used it will be installed with the production tubing and set above the pumping system. This requires that all fluid passes through the pump and a feed thru and power cable connectors will be required. For special applications (e.g. high gas environments) the packers have additional ports for gas venting valves or chemical injection lines. Packers can also be set below the pump. In this case, the pump intake is normally stung into the packer and special cable feedthrough systems are not necessary.

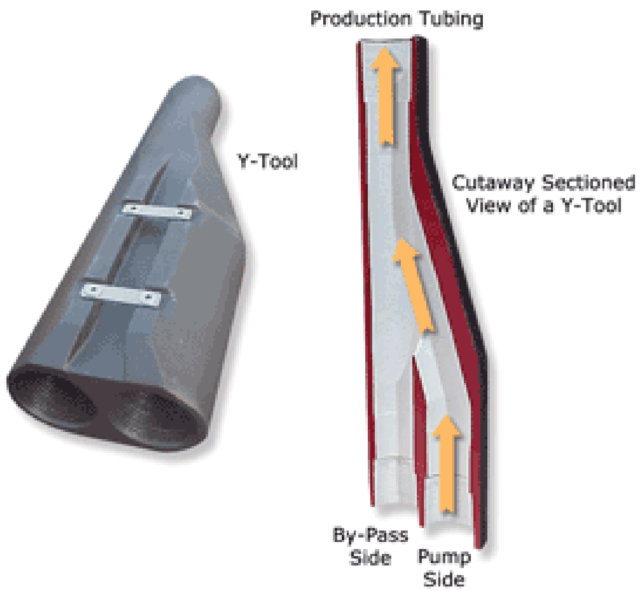
A check valve is installed above the tubing to maintain a full liquid column in the tubing string during equipment shut-down periods. It is a simply gravity valve and prevents leaking of the fluid from the tubing down through the pump when the pump is not operating. Backwards flowing of fluid should be avoided because when the pump turns in the wrong direction and gets started at the same time severe damages can occur.

Whenever a check valve is installed a drain valve is recommended above the check valve. It prevents pulling a wet tubing string and contains of a break-off plug that, after being sheared, opens a hole in the tubing through which liquid can flow back to the well bottom.

Backspin relays are useful when no check valve is installed. For example, ESP plugging with scale or sand could not be cleaned when a check valve is installed. When fluid flows down the tubing during equipment shutdown the ESP is turned in the wrong direction and the motor switches to a generator. The induced current can be detected by the backspin relay and a restart of the unit is avoided.

Centralizers are used to center the motor and the pump in the wellbore to prevent rubbing of the power cable against the casing and proper cooling. They are very useful in deviated wells where the ESP unit tends to stick to one side of the casing. They also prevent damage of the coating applied to the outside of ESP equipment in corrosive environments.

A special tool to provide access to the wellbore sections below the ESP pump is the Y-tool. It’s a special crossover assembly of an inverted Y shape installed at the bottom of the tubing string with one side being in line with the tubing and the other side being offset. The By-Pass side or straight section provides a straight run down the hole while the ESP unit is attached to the pump side. With a Y-Tool it is possible to achieve operations like formation treatment, perforation of new zones or well logging tasks. Figure 14 shows a typical Y-tool and a cross section of the tool. [1, p. 110]



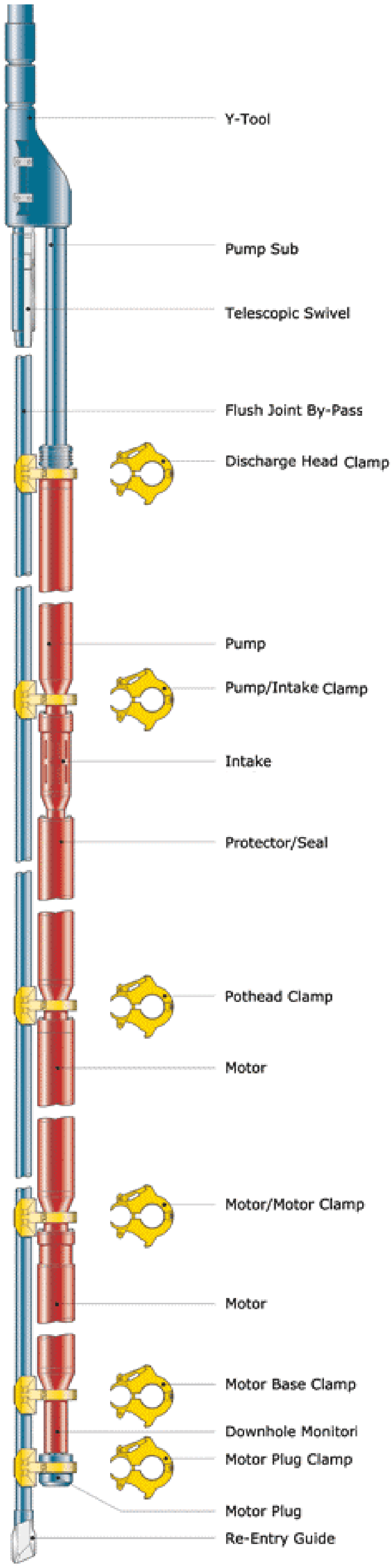


Figure 14: Y-Tool [6]

2.10 Downhole Instrumentation

The tools used for downhole instrumentation are usually installed below the ESP motor and consists of different measuring devices to continuously monitor downhole pressure and temperature as well as other parameters. Data signals are sent to the surface by adding a DC signal to the AC motor power or by a special cable added to the power cable. Modern downhole instrumentations packages are solid-state units and use extremely accurate transducers. For example, strain gauges for pressure and resistivity thermal devices for temperature. The data can be stored in the unit`s memory or displayed in graphical format. A continuous monitoring of downhole parameters gives valuable information on inflow properties and allows a detailed analysis of the ESP units operational conditions. Monitored parameters can vary but usually include pump intake pressure, temperature, motor oil or winding temperature, pump discharge pressure, mechanical vibration, electrical current leakage etc.

2.11 Surface Equipment

2.11.1 Wellhead

Special wellheads are used for ESP applications to support the weight of the subsurface equipment and maintain annular control. A positive seal around the tubing and around the cable has to be provided. There are different solutions at the market available and they differ in the style the cable is fed through the wellhead.

2.11.2 Junction Box

A junction box or vent box is recommended to provide the electrical connection between the downhole and the surface electric cable. A junction box is a simple ventilated weatherproof box. Besides providing the electrical connection it vents any gas to the atmosphere which may be migrated towards the cable. This venting operation eliminates the danger of fire, explosion and H_2S accumulation in the switchbox. It also acts as an easily accessible test point for electrical checks.

2.11.3 Switchboard

The switchboard acts as the control centre of an ESP installation. It provides a controlled on/off switching of the ESP equipment to the power supply using high capacity switch disconnectors or vacuum contactors. It protects the equipment from a wide variety of problems and monitors and records the most important parameters.

Standard switchboards work under a constant frequency and vary in design, size and power ratings depending on the requirements of the installed ESP. Devices with variable frequency are called Variable Speed Drives (VSD) and will be discussed in chapter 3.10. In addition to on/off switching from the electric network a switchboard can protect the ESP from different problems like over- or underloading of the motor, unbalanced currents and excessive number of starts. Also several malfunctions of the surface power supply may cause problems and can be eliminated by the switchboard. In case of malfunctions the switchboards performs an automatic shutdown and restart after a defined delay time. It also provides monitoring of different operational parameters like line currents and voltages. Nowadays installation enables the user to define setpoints to trigger different alarms.

2.11.4 Transformers

The available surface voltages are not compatible with the required motor voltages in most of the cases. Therefore a transformer has to be used to support the right voltage level. Power distribution in the oilfield ranges from 6,000 volts or even higher but most of the ESP requires voltages between 250 and 4,000 volts. Selection of the transformer is based on voltage levels and power ratings. The required levels strongly depend on the setting depth of the ESP equipment due to increasing voltage drop with length in the power cable. This voltage drop plus the required motor voltage give the necessary surface voltage.

3 Design of ESP Installations in Gassy Wells

The design process for ESPs that are producing liquid only is a quite simple task. This is because the ESP pump operating conditions are ideal and normally simple hand calculations would be sufficient to describe the pressure conditions in the well. However, the usage of modern design programs or computer calculations is a standard today and every ESP design will be performed with the usage of this tools.

ESP design for wells with high amounts of gas production is more difficult and the equipment selection can be challenging. As discussed already in Chapter 2.6 and 2.7 there are two ways to eliminate gas interference in ESP installations.

- Separating the free gas from the liquid before it enters the pump
- Using special devices to handle gas and move it along with the liquid

For applications in very high GOR Environments with Gas Void Fractions (GVF) greater than 75% installations are common that make usage of both technologies.

The flow chart below illustrates the entire design process after API RP11S4. It illustrates the design process as a linear process but it has to be considered that during the design process a few iterations can be necessary. For example, the usage of an additional gas handling device would influence the Horse Power requirements of the whole system and therefore a larger motor has to be installed.

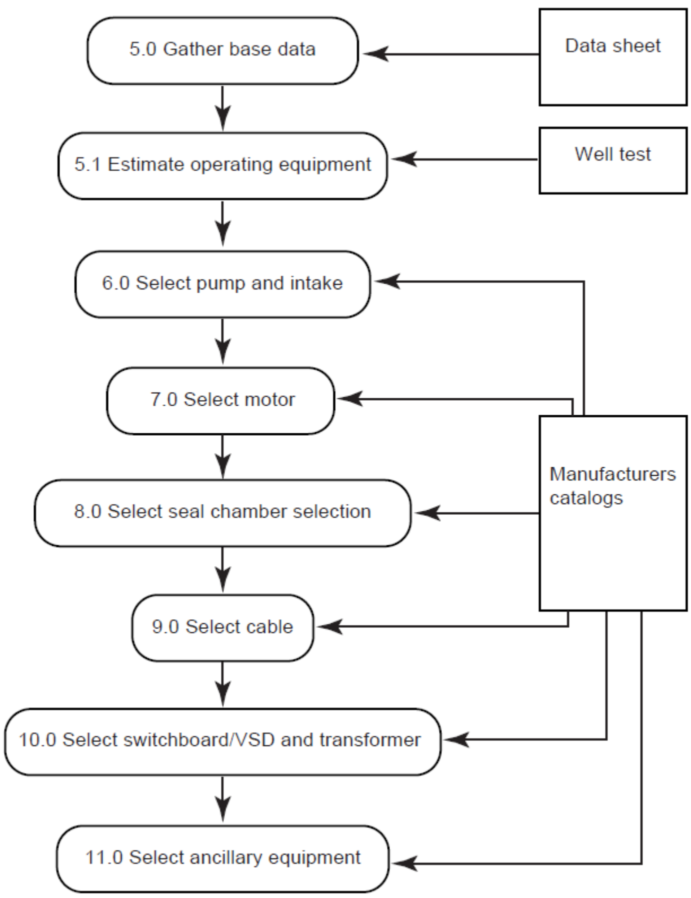


Figure 15: Design Flow Chart [7, p. 2]

The most important steps, even for installations in high gas environments would be step 1 and 2. An accurate base data with reliable quality and forecasts of future parameters is most important to design the ESP properly. Also the estimation of the operating environment and equipment is most important. Therefore not only stable values should be considered. Moreover the behaviour of all the influencing parameters during the expected lifetime of the ESP pumps has to be evaluated. The following chapters will describe the design process for ESP pumps in more detail with a special look on the influence of high Gas Oil Ratios.

3.1 Data Requirements

A successful ESP Design prerequisites the knowledge of many different data in an acceptable quality. Perhaps the most important of them is the information on the well`s productivity so that the desired fluid rate can be achieved from this information. Generally the desired fluid rate is one of the most determining factor in the design of an ESP pump because the selection of the pump and related to this, the number of stages can only be accomplished in the knowledge of the desired rate. Also the desired fluid rate influences the drawdown and therefore the volume of produced gas and free gas at the pump intake.

The required data can be grouped into six categories:

- General Information
- Well physical data
- Well performance data
- Fluid properties
- Surface Infrastructure
- Design criteria

3.1.1 General Information

The general information identifies the well (location, well name, reservoir, field etc.). Also the engineer who collected the data and is responsible for the design should be included.

3.1.2 Well physical data

The well physical data includes following data:

- Well trajectory, inclination and total well depth (especially Dog Leg Severity)
- Depth of perforations and/or open hole interval
- Casing and liner size as well as weights and setting depths
- Tubing size, type, weight, coating and thread

3.1.3 Well performance data

Well performance data are very important because they have a huge impact on the final design of ESP pumps. Data to be collected include:

- Static bottomhole pressure or static liquid level
- Flowing bottomhole pressure or dynamic liquid level
- Productivity data (PI, or q_{0max} for Vogel method)
- Producing water cut or water oil ratio
- Producing gas oil ratio

- Bottomhole temperature
- Flow assurance issues like production of abrasives (sand), paraffin deposition, emulsion formation, corrosion and extreme well temperatures

3.1.4 Fluid properties

Also the fluid properties of the producing liquids are very important. To ensure a proper design following data have to be known at least.

- API gravity or specific gravity of produced oil
- Specific gravity of water and produced gas
- Gas composition (CO_2, H_2S)
- Bubblepoint pressure
- Viscosity of produced oil
- Volume factor
- Solution GOR
- Water Analysis

usually in pVT data included

3.1.5 Surface Information

Surface Information especially for power supply has to be collected. Information regarding to primary voltage, frequency, availability and stability are necessary.

3.1.6 Design criteria

Design criteria include the desired liquid production rate, tubinghead pressure at the desired rate as well as casing head pressure.

3.1.7 Design Data Sheet

Every company dealing with ESP design or equipment provides a data sheet were all the needed data can be filled in. Following graphic shows the style of these common data sheets.

APPENDIX B—ESP DESIGN DATA SHEET

Operator: ____________ Lease: ____________ Well: ____________
Location: ____________ Field: ____________ Resvr: ____________
Prepared by: ____________ Company: ____________
Date: ____________

WELLBORE GEOMETRY
Deviation: Yes | No (if yes, include deviation survey and indicate following depths as TD or MD)
Prod. interval Top: ________ ft | m Bottom: ________ ft | m
Casing min. ID: ________ in. | cm Wt: ________ lb/ft | kg/m PBTD: ________ ft | m
Liner min. ID: ________ in. | cm Grade: ________ lb/ft | kg/m TOL: ________ ft | m
Tubing OK: ________ in. | cm Wt: ________ lb/ft | kg/m
Grade: ________ Thread: ________
Tubing ID: ________ in. | cm Burst: ________ psi | bar | kPa
Limiting factors in wellbore (y-tools, packers, etc)?

SURFACE INFORMATION
Flowline ID: ________ in. | cm Length: ________ ft | m Elevation: ________ ft | m
Separator/Wellhead pressure: ________ psig | bar | kPa Temperature: ________ °F | °C
Casing pressure: ________ psig | bar | kPa Vented? ________ Yes | No
Primary power: ________ Volts Frequency ________ Hz
Amperage Limitations? ________

FLUID PROPERTIES
Oil specific gravity: ________ Water specific gravity: ________
Paraffin? ________ Asphaltenes? ________ Scaling? ________
Detailed information on above: ________

Gas specific gravity: ________ H_2S content: ________ ppm CO_2 content: ________ ppm
Water cut: ________ % CLR | GOR: ________ scf/bbl | m^3/m^3
Sand? ________ Yes | No Shape of sand grains: Round | Angular
Bubble pt pressure: ________ psia | bar | kPa

PVT & Viscosity Data

P (psia | bar | kPa)	T (°F | °C)	B_o (bbl/stb | m^3/m^3)	B_g (bbl/stb | m^3/m^3)	R_s (cf/scf | m^3/m^3)	μ_{od} (cP | SSU)	μ_o (cP | SSU)

Emulsion Viscosity Correction Factors ________ Inversion point ________ % water
Water cut: ________ ________ ________ ________ ________
Factor: ________ ________ ________ ________ ________

INFLOW CHARACTERISTICS
Test datum MD: ________ ft | m TVD: ________ ft | m
Static pressure: ________ psig | bar | kPa Temperature: ________ °F | °C
Test rate (oil | liq): ________ ________ ________ ________ bpd | m^3/d
Test pressure: ________ ________ ________ ________ psig | bar | kPa
Productivity Index ________ bpd/psi | $m^3/d/kPa$

DESIGN CRITERIA
Desired flow rate (oil | liq): ________ bpd | m^3/d
Desired pump intake pressure: ________ psig | bar | kPa
Minimum fluid over pump: ________
Desired pump setting depth MD: ________ ft | m TVD: ________ ft | m
Switch gear/trans. rating: ________ KVA Min Hz: ________ Max Hz: ________
Available voltage taps: ________
Comments: ________

Figure 16: Design Flow Chart [7, p. 33]

3.2 Well Inflow Calculations

A proper installation design can only be achieved if the well`s inflow performance is known exactly. Without the knowledge of the delivered liquid rate and the corresponding dynamic liquid level an ESP pump cannot be selected. These parameter are interrelated and they can be calculated with the well`s inflow performance curve.

The common methods for describing well inflow would be the productivity index method (PI) or, depending on whether Flowing Bottomhole Pressure (FBHP) is below bubblepoint, the Vogel method or composite IPR curve.

3.2.1 Productivity Index Equation

The Productivity Index (PI) method was developed using simplifying assumptions to solve the Darcy`s equation. The constant parameters are collected into a single coefficient called productivity index:

$$q = PI * (p_r - FBHP)$$

PI = productivity index
p_r = reservoir pressure [psi]
$FBHP$ = flowing bottomhole pressure [psi]

The equation states that liquid inflow into a well is directly proportional to pressure drawdown. The endpoints of the PI line are the maximum potential rate at a FBHP of zero and the average reservoir pressure p_r at a flow rate of zero. The use of the PI method is very simple. If average reservoir pressure and the productivity index are known the flow rate for any FBHP can be calculated.

Applying the PI concept the FBHP can be easily calculated by following formula:

$$FBHP = SBHP - \frac{q}{PI}$$

$SBHP$ = static bottomhole pressure [psi]
q = liquid rate [STB/d]
PI = productivity index [STB/d/psi]

3.2.2 Vogel method

The Vogel method was developed with a numerical reservoir simulator to study the inflow performance of solution gas drive reservoirs. Different combinations were simulated and Vogel found that the calculated inflow performance relationship curves exhibited the same general shape. Then he approximated this shape by a dimensionless equation given as follows:

$$\frac{q}{q_{max}} = 1 - 0.2 * \frac{p_{wf}}{p_R} - 0.8 * \left(\frac{p_{wf}}{p_R}\right)^2$$

q = liquid rate [stb/d]
q_{max} = maximum production rate [stb/d]

Vogel established this correlation for solution gas drive but the use of this equation is generally accepted for other drive mechanisms as well. To use this correlation, reservoir pressure needs to be known along with a single stabilized rate and the corresponding FBHP. By knowing this data the IPR curve can be constructed and the FBHP for a given production rate can be read off.

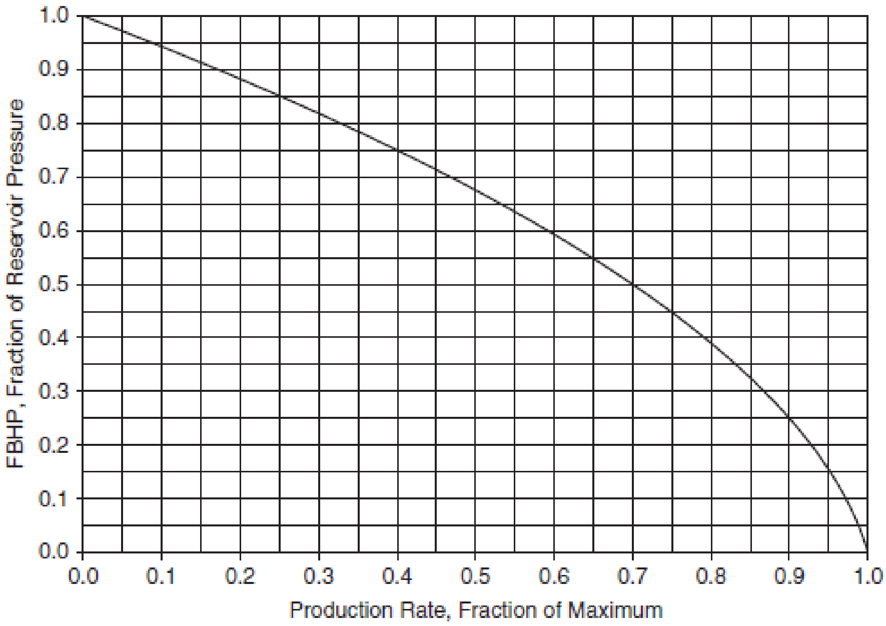


Figure 17: Vogel IPR Curve [1, p. 14]

3.2.3 Composite IPR curve

The applicability of Vogel correlation is limited to two main constraints. The well`s FBHP is below bubblepoint pressure and only oil is produced. To overcome this restrictions the composite IPR curve was introduced. If inflow conditions are greater than the bubble point pressure the PI method is valid. This is still applicable if the well produces 100 % water. Wells producing liquids with water cut of less than 100% and with pressures below the bubble point pressure should have IPR curves somewhere between the curves of the Vogel method and the PI method.

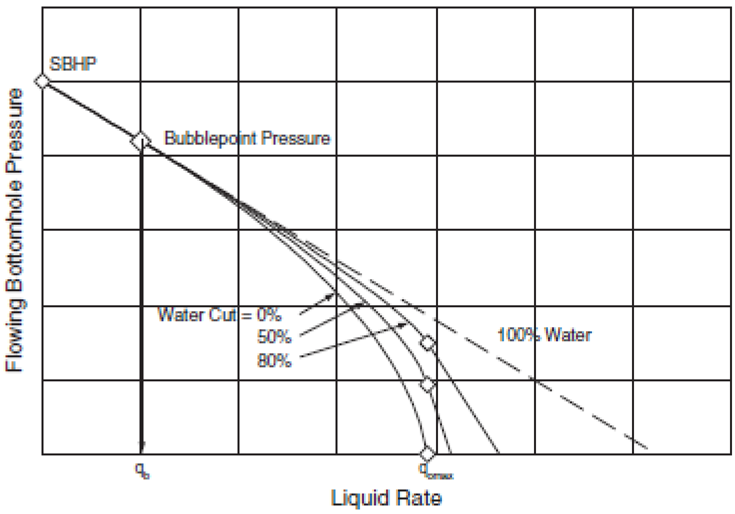


Figure 18: Composite IPR Curve [1, p. 16]

3.2.4 Pump Intake Pressure calculation

Based on FBHP at the perforations the pressure at the pump suction, also pump intake pressure (PIP), is calculated using the top of perforation, pump setting depth and fluid gradient in the annulus.

$$PIP = FBHP - \left(L_{perf} - L_{set}\right) * grad_l$$

L_{perf} = TVD of perforations [ft]
L_{set} = TVD of pump setting [ft]
$grad_l$ = fluid gradient in the annulus [psi/ft]

For gassy wells it is common that a substantial amount of free gas enters the pump. Therefore it is very probable that multiphase flow takes place. If so, there has to be done several multiphase flow calculations to find the PIP. The goal of this calculations is to find the multiphase pressure drop between the pump setting depth and the perforations depth for the well`s current production parameters. Different correlations have been developed in the last decades to calculate the pressure drops. One of the most common in the oilfield industry is the Hagedorn & Brown correlation which was developed in 1965 using a 1500 ft test well with 1 in, 1.25 in and 1.5 in tubing. Usually this correlation applies to cases where the Gas Liquid Ratio is below 10 000 scf/stb and it is among the most accurate vertical flow correlation. For deviated holes some other correlations have to be considered, for example Mukherjee & Brill, Beggs & Brill or Ansari Mechanistic. [8, p. 25f]

3.3 Free Gas Calculation

With the help of the calculated pump intake pressure the amount of free gas at the pump suction can be calculated. Therefore the solution gas/oil ratio at pump intake conditions has to be known. If there are no sufficient PVT data available, the bubblepoint pressure correlation after Standing can be used by substituting bubblepoint pressure with pump intake pressure: [9, p. 5]

$$R_s = \gamma_g * \left(\frac{PIP}{18 * 10^{\gamma}}\right)^{(0.00091*T - 0.0125*°API)}$$

PIP = pump intake pressure [psi]
T = suction temperature [°F]
γ_g = gas specific gravity
$°API$ = API gravity

Matching this value against the wells producing GOR it can be established whether there is free gas entering the ESP or not. If there is a substantial part of free gas available (GVF > 15 %) additional calculations have to be performed. To perform this calculations several thermodynamic properties of the liquid and the gas phase must be known at the pump suction conditions. However, measured thermodynamic properties at pump intake conditions are seldom available and therefore general oilfield correlations have to be used. In the following Standing correlations will be further used to calculate gas and oil volume factor and Papay formula is used to determine natural gas mixtures deviation factor. However, it should be clear that correlations always have an amount of error. Therefore the design engineer should use common PVT, Nodal Analysis or ESP design software where different correlations are implemented and select those that give at least the smallest error.

After Standing the gas volume factor B_g can be calculated by following formula: [10]

$$B_g = 0.0283 * \frac{Z*T_a}{PIP}$$

Z = gas deviation factor
T_a = intake temperature [°R]

The deviation factor Z can be calculated by different methods. The Papay formula is pretty simple as follows: [11]

$$Z = 1 - \frac{3.52 * p_{pr}}{10^{0.9813 * T_{pr}}} + \frac{0.274 * p_{pr}^2}{10^{0.8157 * T_{pr}}}$$

p_{pr} = pseudo reduced pressure
T_{pr} = pseudo reduced Temperature

The pseudo reduced pressure p_{pr} = PIP/p_{pc} and temperature $T_{pr} = T_a/T_{pc}$ can be calculated from the Hankinson-Thomas-Phillips correlation: [12]

$$p_{pc} = 709.6 - 58.7 * \gamma_g$$
$$Tpc = 170.5 + 307.3 * \gamma_g$$

γ_g = gas specific gravity

After knowing these parameters, the volume factor of oil B_o can be obtained from Standing correlation: [10]

$$B_o = 0.972 + 1.47 * 10^{-4} * F^{1.175}$$
with
$$F = R_s * \left(\frac{\gamma_g}{\gamma_o}\right)^{0.5} + 1.25 * T$$

γ_o= oil specific gravity
T = suction temperature [°F]
B_o = oil volume factor at pump suction pressure [bbl/stb]

Knowing the thermodynamic parameters the free gas volumetric rate can be calculated as follows: [1, p. 130]

$$q_{free} = q_o * (GOR - R_s) * B_g$$

q_{free} = free gas volumetric rate [ft³/d]
q_o = oil volumetric rate [stb/d]
GOR = production gas/oil ratio [scf/stb]
R_s = solution GOR at PIP [scf/stb]
B_g = gas volume factor at PIP [ft³/scf]

The in-situ liquid volumetric rate that has to be handled by the ESP pump is found from oil and water flow rates. The volume factor for water is often taken as unity: [1, p. 132]

$$q_l = q_o * B_o + q_w * B_w$$

q_l = liquid volumetric rate [stb/d]
q_w = water volumetric rate [stb/d]
B_w = water volume factor at pump suction pressure [bbl/stb]

Finally the gas void fraction (GVF) can be calculated at the pump intake:

$$GVF = \frac{q_{free}}{(q_{free} + q_l)}$$

Depending on the amount of the GVF the engineer has to decide if gas separation equipment or gas handling equipment will be installed or not.

As already mentioned in chapter 2.6 there is a substantial amount of natural separation that takes place in the well. In a majority of ESP wells the annulus is open or equipped with a vented packer. Therefore the annular space acts as a natural gas separator. The topic natural gas separation of free gas from a produced liquid is well discussed in the literature and an accurate description of the process is not yet available. Following chapter should give a brief overview about models and correlations developed for calculation of natural gas separation efficiency.

3.3.1 Natural Separation Efficiency

For pumped wells the natural phase separation, taking place in the tubing-casing annulus is an integral part of the overall bottomhole separation process. In ESP systems the natural separation influences the amount of free gas entering the pump and thereby strongly influences the overall pumping efficiency.

Lea and Barden performed experimental studies of ESP performance were the pumped fluid contained free gas. Their main purpose was to investigate head degradation due to free gas but they also performed a detailed discussion regarding to the natural separation process. The founding of their experimental data was that the annulus separation efficiency increases as more free gas is fed into the system and decreases as liquid flow rate increases.

The natural separation process in conjunction with utilizing a gas anchor in beam pumping was discussed by Schmidt and Doty as well as Podio. However, there is no detail theoretical explanation that is applicable for ESPs. [12, p. 1f]

Alhanati developed a mechanistic model to predict the efficiency of rotary gas separators. Part of this model was a simple model to predict the natural separation efficiency in ESP systems. Alhanati stated two main assumptions: [13, p. 2f]

- A uniform void fraction exists within the region surrounding the motor section up to the gas outlet ports
- A no-slip condition exists between the gas and liquid phases for the region in front of the gas separators intake ports

Based on these assumptions the following equation can be obtained for natural separation efficiency: [13, p. 4]

$$Natural\ sep.efficiency = \frac{v_\infty}{v_\infty + v_{sl}}$$

v_∞ = terminal bubble rise velocity [ft/sec]
v_{sl} = liquid superficial velocity [ft/sec]

The terminal bubble rise velocity can be calculated as follows after Harmathy: [14]

$$v_\infty = \sqrt{2} * \left[\frac{\sigma * (\rho_l - \rho_g) * g}{\rho_l^2}\right]^{0.25}$$

σ = surface tension [lb/s²]
ρ_l = liquid density [lb/ft³]
ρ_g = gas density [lb/ft³]
g = gravitational acceleration [ft/s²]

And the liquid superficial velocity, the in-situ velocity of the liquid phase in the annulus, is calculated in that way: [1, p. 131]

$$v_{sl} = 6.5 * 10^{-5} * \frac{q_l}{A} * \left[\frac{B_o}{1 + WOR} + B_w * \frac{WOR}{1 + WOR}\right]$$

q_l = liquid volumetric rate [stb/d]
A = annular area [ft²] $A = 0.0055(ID_c^2 - OD_t^2)$
ID_c = Casing inner diameter [ft]
OD_t = Tubing outer diameter [ft]
WOR = water oil ratio

Alhanati gathered some experimental data by using a full-scale water air experimental facility. The model described above showed reasonable agreement with his experimental data for GVF ranging between 20 to 70 percent. Some further investigations, mainly the effect of fluid properties were performed. Some data were gathered from a field scale system run with mineral oils. A comparison of this experimental data with the model of Alhanati showed that the model can still be applied to viscous fluids having viscosity values between 18 to 50 cp at 60°F.

The effect of inclination had also been studied for GVF up to 15 % and this experimental work showed up that the void fraction across the annulus is different from the void fraction that goes into the pump. In the last years some further mechanistic models were developed and the comparison of the models showed a good performance. After performing sensitivity analysis to these models following statements can be made: [13, p. 5]

- **Effect of Geometry:** A larger annulus area should improve the natural separation efficiency. This circumstance is also for inclined wells true. Models indicated that there is a minimum liquid flow rate below which all gas is separated or the system can reach 100% efficiency. Remember that the annulus area is directly related to the superficial liquid velocity.

- **Effect of Gas:** The natural separation efficiency increases as the in-situ free gas increases and the flow rate decreases. Since these two parameters are sensitive to each other, the combining effects of operating conditions and the geometrical set-up may produce different trends.

- **Effect of pressure:** Pressure has an indirect influence to natural separation efficiency due to its influence in GVF calculations.

- **Effect of inclination angle:** Some models were developed which used a general drag coefficient correlation. Using this correlation the models indicated that the efficiency increases as inclination angle decreases.

3.4 Calculation of Total Dynamic Head

The total head to be overcome by the ESP pump consists of three components. TDH calculations are needed to calculate the required number of stages that the pump has to have. The total dynamic head is the sum of following components:

- the required wellhead pressure at a given flow rate
- the net hydrostatic pressure acting on the pump
- the frictional pressure drop that occurs in the tubing string at a given liquid rate

The net hydrostatic pressure acting on the pump reflects the true vertical depth (TVD) of the dynamic fluid level. In other words, the depth of the stabilized fluid level in the casing annulus while producing the desired liquid rate. It can be easily calculated from the PIP under the assumption that an oil column exists above the pump setting depth.

$$L_{dyn} = \frac{L_{set} * \ grad_o + CHP - PIP}{grad_o - \ grad_g}$$

L_{dyn} = dynamic liquid level [ft]
L_{set} = TVD of pump setting depth [ft]
CHP = casinghead pressure
$grad_o$ = oil gradient [psi/ft]
$grad_g$ = gas gradient in the annulus [psi/ft]

After knowing the dynamic fluid level and the frictional head loss in the tubing string the total dynamic head TDH can be calculated.

$$TDH = \frac{2.31}{\gamma_l} * (WHP - CHP) + L_{dyn} + \Delta H_{fr}$$

γ_l = specific gravity of the produced liquid
WHP = producing wellhead pressure [psi]
ΔH_{fr} = frictional head loss in the tubing string [ft]

For gassy wells the calculation of total dynamic head is a little bit more difficult. In a well with a high GOR a multiphase mixture is flowing in the tubing. Therefore no constant gradients can be applied and a proper design includes the calculation of multiphase pressure drops. The necessary pump discharge pressure is the sum of the wellhead pressure and the multiphase vertical pressure drop in the well tubing. By knowing the pump discharge pressure p_d the TDH can be calculated as follows:

$$TDH = \frac{144 * (p_d - PIP)}{\rho_l}$$

p_d = pump discharge pressure [psi]
ρ_l = average fluid density in the pump [lb/ft³]

3.5 Selection of Pump

3.5.1 General

The most important selection criterion for a pump is that the pump must fit in the casing string of the well. Centrifugal pumps are manufactured in different outside diameters and the pump series number always refers to the outside diameter. Because the manufacturing of small pumps is more expensive than for larger OD, the selected pump should be as big as possible. After the pump series has been chosen the type can be selected. As already mentioned in chapter 2.5 there are different design of stages, number of vanes etc. available. Pump type selection is based on the operating regimes as well as the desired liquid production rate. Therefore the selected pump should have the required liquid rate within its optimum capacity range and this rate should be as close to the best efficiency point (BEP) of the pump.

For a pump that's operated under ideal conditions the individual stages all deliver the same head. So a pump with a given number of stages develops a head equal to the sum of all heads developed by every single stage. Since the TDH is already known it is a simple calculation to find out the number of needed stages. The formula therefore is: [7, p. 5]

$$Stages = \frac{TDH}{head/stage}$$

$head/stage$ = head developed by one stage of the pump [ft]
usually provided by vendor

For a pump operated in a gassy well the calculation is not as easy as shown above. It must be taken into account that the stages will be influenced by the gas and will work inefficiently. The following chapter will describe the effect of free gas in a pump in more detail.

3.5.2 Influence of Free Gas

The presence of free gas at the pump intake affects the performance of the ESP pump in several ways. As there are two different phases present, multiphase flow occurs and the head delivered by the pump changes. The first study on two-phase performance of ESPs was done by Lea and Barden in 1982 and they identified four regimes. These regimes were: [16]

- Non-gas interference
- Gas interference
- Intermittent gas lock
- Gas lock

The regimes are depending on the gas volumetric fraction (GVF) and the increase of the GVF leads to a more deteriorating performance. As can be seen in Figure 19, the GVF has a strong influence in the head degradation of the stages. The efficiency of the first stages in a pump is strongly decreased. Due to the fact that the pressure increases after every pump stage, the free gas will be compressed and can be better handled by the stages. This means that the gas goes back into the fluid and the GVF will be decreased.

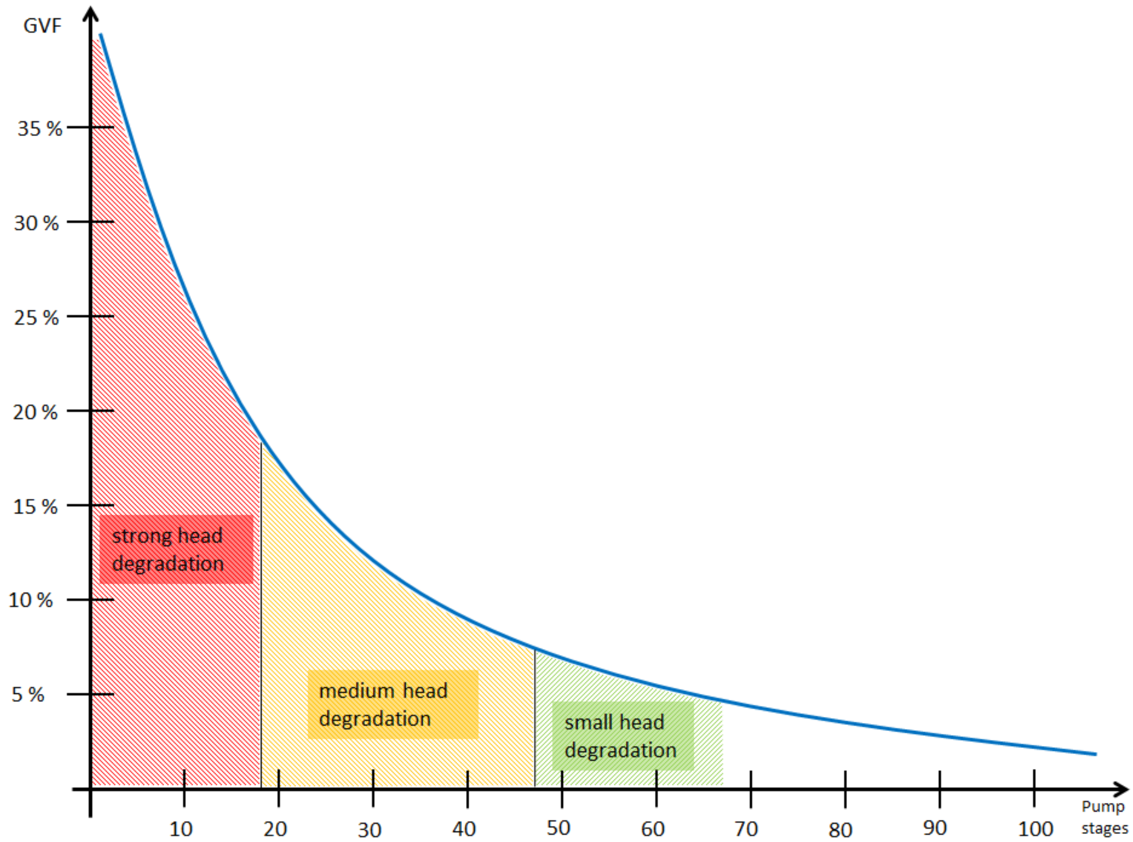


Figure 19: Gas interference head degradation [courtesy of SLB]

If the GVF is very high and the pump is not equipped with proper gas equipment a point can be recognized where a sudden performance breakdown can be observed in the pump head curve. This operating condition is called surging point and by reaching this point the likelihood of gas locking the pump is strongly increased. Following figure shows the changing of the pump`s head performance curve.

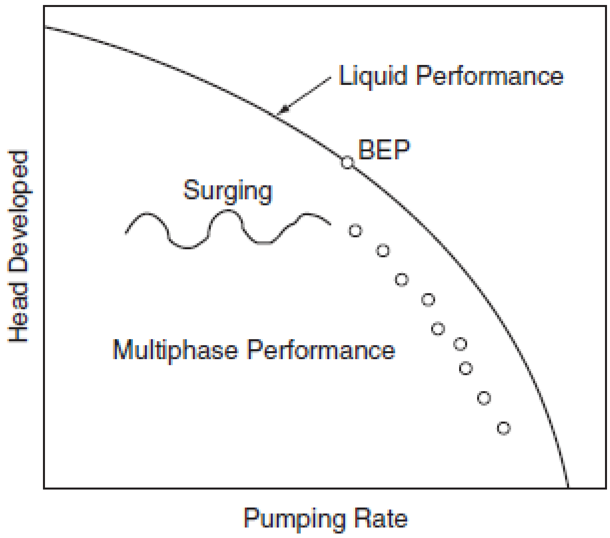


Figure 20: Multiphase head performance [1, p. 137]

When a pump reaches the surging point a gas accumulation takes place in the low pressure area of a vane and in the impeller eye. This accumulation hinders the fluid to pass the stage and the head is decreased. If the accumulation continues the complete vane or stage can get gas locked and the pump will operate in an unstable region. A gas lock of a pump can be seen in the ampere chart, consumed by the electrical motor.

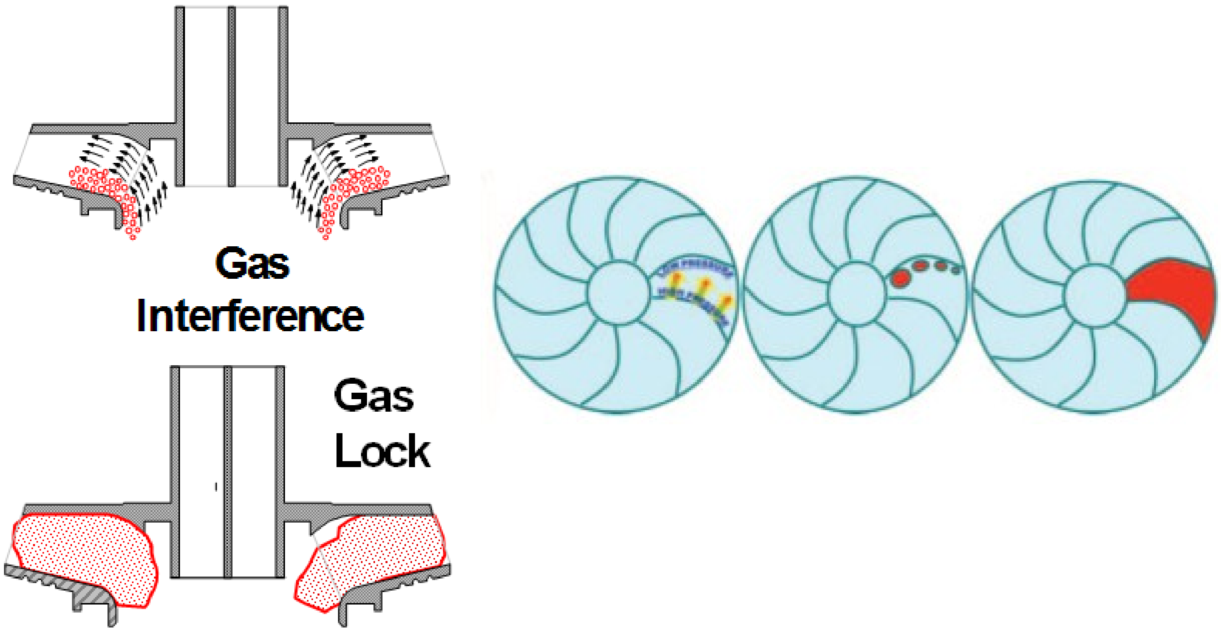


Figure 21: Gas locking [17]

Since the early 1980 different correlations were developed to find the surging point and describe the behavior of ESP pumps during multiphase conditions. The lack of a theoretical basis is a limiting factor for the applicability of these correlations. A proper alternative therefore are mechanistic models. However, the poor understanding of the physical mechanisms that cause surging hinders the development of exact mechanistic models.

One common correlation to define the ability of ESP pumps to handle gas is the Turpin correlation or criteria. The Turpin correlation relates pump performance to the in-situ gas and liquid volumes and the PIP. Turpin defined a formula to find the limits of a stable pump operation. The formula looks like this:

$$\Phi = \frac{2000 * \frac{q_g'}{q_l'}}{3 * PIP}$$

Φ = Turpin criteria
q_g' = gas volumetric rate at suction conditions [bpd]
q_l' = liquid volumetric rate at suction conditions [bpd]

Stable pump operations can be expected for values Φ < 1.0, while gas interference and deterioration of pump performance occurs for cases Φ > 1.0. As seen from the formula and in the graphic bellow, the amount of free gas that can be handled by an ESP pump increases with increasing PIP.

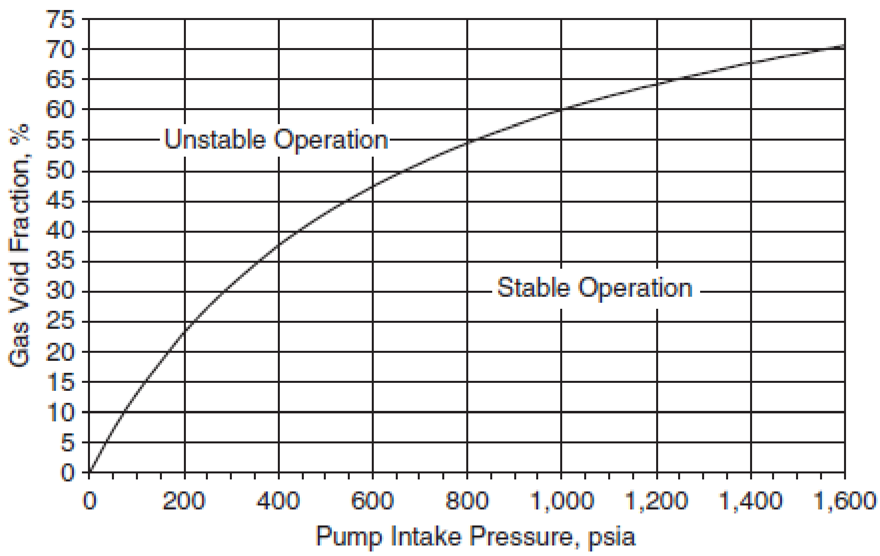


Figure 22: Turpin criteria [1, p. 139]

3.6 Selection of Gas Separator or Handler

The decision process of installing additional gas equipment or not starts with the calculation of the GVF influencing the pump. Therefore the natural separation efficiency has to be taken into account. Using the calculated free gas and the natural separation efficiency following formula can be applied:

$$q_{ing} = \frac{q_{free}}{5.61} * \left(1 - \frac{\eta_n}{100}\right)$$

q_{ing} = gas entering the pump
η_n = Natural separation efficiency

By using the already presented formula for the GVF, the resulting GVF that's present at the pump can be calculated. Together with the Turpin criteria the decision whether to install additional gas handling equipment or not can be made. Today the production of gassy wells with high free gas contents is no longer outside the application range of the ESP system. Every ESP vendor has equipment, to handle gas or separate it, in his portfolio. Following table gives an overview of the technologies and their applicability ranges.

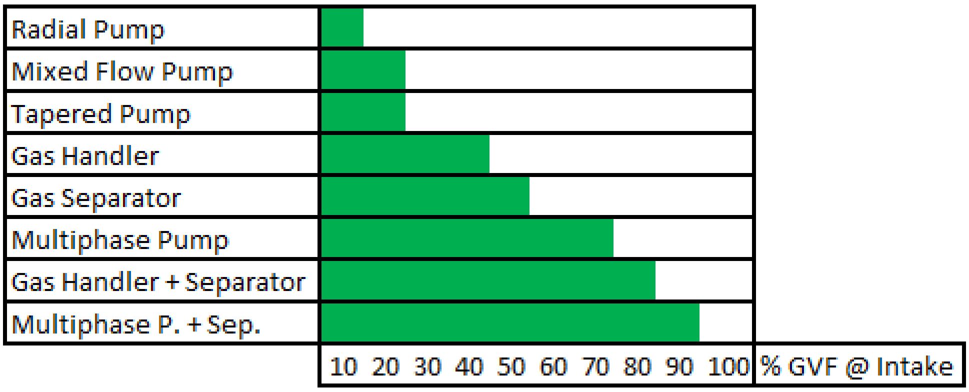


Figure 23: Application Ranges [17]

Normally every vendor has this kind of tables and recommendations which equipment should be installed are based on them. The ranges can differ from vendor to vendor. The decision between gas handling and separation is a very fundamental one and dependent on government regularities and company standards as already mentioned. If a gas separator is chosen, the ingested gas can be calculated in the following way. [1, p. 220]

$$q_{ing} = \frac{q_{free}}{5.61} * \left(1 - \frac{\eta_n}{100}\right) * \left(1 - \frac{\eta_{sep}}{100}\right)$$

η_{sep} = gas separator efficiency

Again the GVF and the Turpin criteria can be checked with the already presented formulas. If the GVF and the Turpin criteria is still out of range additional equipment or a deeper installation of the pump should be taken into consideration.

3.6.1 Separator Efficiency

Investigation of artificial separation was done by Alhanati and Harun at Tulsa university in the late 1990`s and early 2000`s. They tested different models and developed a mechanistic model. Also some leading pump manufacturers and a team at the Russian State Oil & Gas University carried out some similar research work. It has been found out that artificial separation efficiency is affected by the following parameters: [18, p. 3]

- Two phase performance of the separator inducer – The inducer is a component of a gas separator that creates additional pressure inside the separator to remove extra gas into the annular space
- Separator GVF at the intake
- Separator load or liquid flow rate
- Separator rotational speed

The performance of the inducer is dependent on the construction type of the separator. The other factors can be seen as external to the separator. Therefore it is essential to vary the fluid rate, gas rate and rotor frequency in bench tests to obtain correlations between the separation efficiency and this parameters. Only a few software packages afford setting artificial separation efficiency by bench test correlations. Most of the software packages are developed by the vendors who are producing also the equipment. Thus they only allow a calculation of the efficiency value for their own products and they are using data obtained from their own tests. The testing conditions are not published and the software user is not able to see the used correlations. [19, p. 5]

3.7 Selection of Protector

One of the most important functions of the protector or seal section is the absorbing of the axial thrust developed by the pump. For this reason the protectors are selected after the calculated thrust load developed by the pump. Besides the thrust load capacity several other factors have to be considered. It is self-explaining that the right size has to be chosen and the protector shaft should be capable to transfer the required power. Also the oil expansion capacity should be sufficient. The capacity of the thrust bearing strongly relies on the operating temperatures because the viscosity of the motor oil decreases at elevated temperatures. This makes the oil film on the bearings thinner. ESP protectors are available with different oil expansion capacities. Selection of the right design depends on well deviation, temperature and the density of the produced fluid. In deviated wells the usage of labyrinth-type protectors is not satisfactory and therefore bag type protectors have to be used. The operation of the protectors consumes a definite amount of power which should be provided by the ESP motor. Most manufacturers include this power in the pump horsepower requirement of their published data.

3.8 Motor Selection

Selection of the submersible motor should be done after the selection of the pump and additional equipment has been finished. Also for the motor the most important factor is that the OD of the motor fits into the casing. Like for the pump the motor series denotes the OD of the motor. The required horsepower (HP) should be based on the highest load conditions. Generally the HP is the sum of the requirements for the pump, the protector and if used the gas separator and/or handler. As already mentioned the motor is cooled by well fluids flowing past the housing and the minimum recommended flow velocity is about

1 ft/s. [7, p. 7] The flow velocity is a function of liquid rate and the cross sectional area between the casing and motors outside diameter and calculated like shown below:

$$v_l = 0.0119 * \frac{q_l'}{ID_c^2 - OD_m^2}$$

v_l = liquid velocity [ft/s]
q_l' = in-situ liquid flow rate [bpd]
ID_c = inside diameter of the casing string [in]
OD_m = outside diameter of the motor [in]

The electrical power requirements can be read of the technical data published by the manufacturers. For selection of motor voltage the prime factor is the running depth. Deep installations require longer cables and this means an increasing voltage drop and a greater amount of wasting energy. For these conditions the selection of a motor with a higher voltage rating means lower current flows through the cable causing a lower voltage drop. Also for high temperature wells the usage of higher voltages is advantageous because less current means less operating temperature of the cable and cable life is increased. Overall it can be stated that in most situations the motor with the highest voltage requirement is the right choice. This decision allows the use of a smaller and related to the size less expensive power cable and reduces the total power consumption of the system.

3.9 Cable Selection

ESP cables are manufactured in a wide variety of types and sizes. The design parameters for an electrical cable would be the length, type and size. A proper selection of a cable is not just based on technical parameters also economic considerations have to be done.

The length of the cable is determined from the running depth of the ESP motor including a sufficient length needed for the safe connection to the surface equipment. Cables are manufactured in a variety of types with different insulation and conductor materials. A proper choice of the right materials depends on the well fluids, temperature, gas content and corrosiveness of the well fluid.

3.10 Usage of Variable Speed Drives

A conventional ESP system running at a constant speed is very inflexible compared to other artificial lift methods. The reason for this is the narrow recommended liquid rate range. An operation out of this range reduces the system efficiency and can lead to early equipment failures. To avoid this, good knowledge of well inflow parameters is necessary for a proper design and the use of improper data leads to wrong designs. But even in cases were accurate data are available and the installation design is fulfilling all requirements, the inevitable changes in well inflow parameters (reservoir pressure, fluid rates etc.) with time can lead to different operation conditions and therefore an eventual system breakdown.

These disadvantages of an ESP system are eliminated if the submersible pump is driven with widely variable speeds. Since the pump is directly driven by the motor the pump speed can be controlled by changing the motors rotational speed. Also motors directional speed is a direct function of the frequency of the alternating current. This means an adjustment of the frequency of the supply current has a direct influence on the motor and related to this pump speed. This circumstance can also be described with the affinity laws expressed in function of the frequency:

$$Q_2 = Q_1\left(\frac{f_2}{f_1}\right)$$

$$H_2 = H_1\left(\frac{f_2}{f_1}\right)^2$$

$$BHP_2 = BHP_1\left(\frac{f_2}{f_1}\right)^3$$

f_1, f_2 = AC frequencies [Hz]
Q_1, Q_2 = pumping rates at f_1 and f_2 [bpd]
H_1, H_2 = developed heads at f_1 and f_2 [ft]
BHP_1, BHP_2 = required brake horsepowers at f_1 and f_2 [HP]

These formulas enable one to construct pump performance curves for any given electric frequency if the standard performance curve is known. Following graph displays the head performance curves at different frequencies.

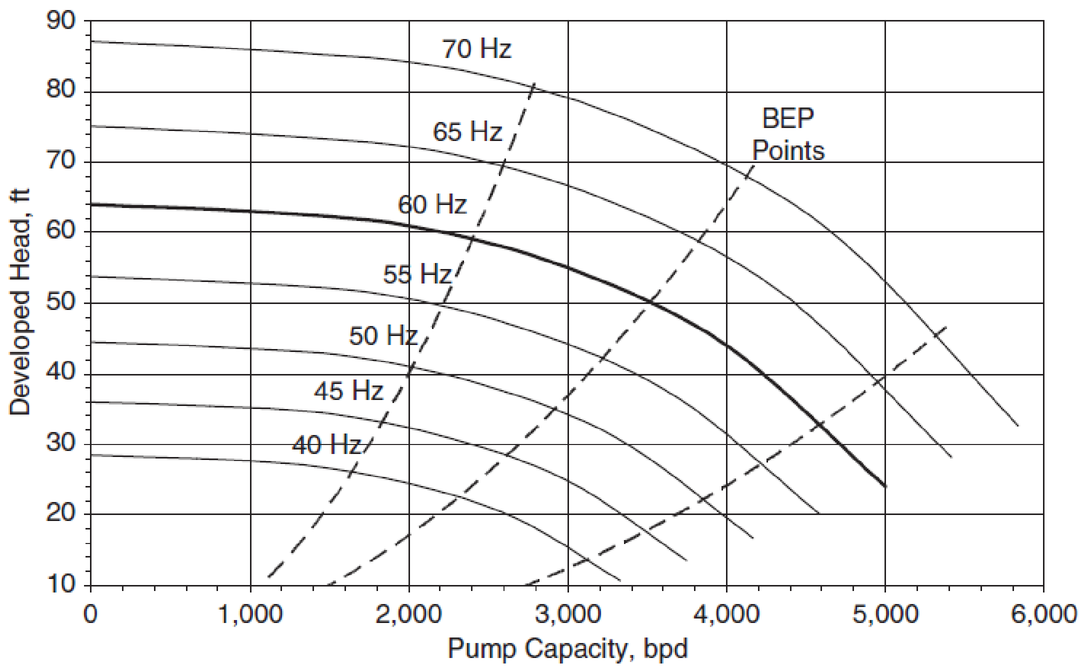


Figure 24: Head performance curve at different frequencies [1, p. 169]

3.10.1 Benefits of VSD-Systems

Compared to a conventional ESP installation with constant speed the installation of a variable speed drive system has several advantages. The most important one is that uncertainties or extensive changes in well inflow conditions can easily be accommodated during the run life of an ESP. Variable frequency units also facilitate nowadays a soft starting function. This feature reduces start-up currents and extends the operational life of the ESP system. Also well testing operations can be performed and the possibility of a closed-loop control is given, if motor frequency is varied according to well inflow rate, sensed by downhole instrumentation. Another advantage is the eliminating of gas lock problems. The pump can be slowed down when gas pockets start to lock the impeller and therefore avoid a complete gas lock.

3.10.2 Design of a VSD installation

As mentioned before a VSD installation can significantly stretch the operating range of an ESP pump and is therefore a valuable tool in meeting the production objectives from wells with changing conditions. The selection of the pump is accomplished by utilizing the variable speed performance curves of the pump and the expected minimum and maximum liquid rates should fall inside the recommended operating range of the pump. By using the head performance curves of the selected pump at different frequencies, the frequency where the pump produces the maximum liquid rate at its BEP can be found. After reading the head developed by one stage, at this condition, the amount of stages can be calculated as shown in chapter 3.5.1. The power required to run the pump and additional gas handling equipment, must also be calculated with this frequency. The ESP motor should develop the power requirement at the maximum driving frequency.

3.11 Design Software

ESP design should be performed with actual software packages which are able to perform different calculations. Most of the software packages are provided by the main pump manufacturers. For example Schlumberger`s Design Rite or Baker Hughes AutographPC. There is only one software package available that is neutral and unbiased. This is the SubPump ESP design software from IHS which provides a huge equipment database with about 3000 components. The design software from the pump manufacturers sometimes also provide catalogues with products from other vendors but the user is not able to identify if the vendor prefers its own products in the software or not.

Actual system analysis software or nodal analysis software (e.g. PROSPER) also provide the design of ESP pumps but they are not specialised on it. Therefore it stated out that their provided simulations and calculations are not sufficient to do a proper ESP design. For example PROSPER has not included any gas separators in its catalogue and is not able to calculate shrouded designs. The user has to enter a static value for the separation efficiency. Also it is not able to calculate the effect of shrouds or regard any natural separation efficiency effects. The independent SubPump is able to calculate the natural separation efficiency after the model of Alhanati. Also some separators of the best-known manufacturers are included with efficiency curves for different liquid rates.

The actual provided software of the manufacturers is also able to perform this kind of calculations and beyond that they are much more detailed in their calculations. They perform stage-by-stage simulations and are able to calculate multiphase pumps. Also they can simulate the system conditions from the start-up of the operation until the time the system stabilizes.

4 Risk-Based Design Concept

The design process of ESP pumps is always an iterative process. During the first installation in a wellbore or field a lot of unknowns are present. To identify these unknowns and assess the risks coming up with them, a risk based design concept has been developed.

4.1 Prediction of Future Parameters

For a proper selection of pump equipment the well performance must be estimated. Fundamentally, well performance estimates define what additional energy must be supplied by the pump. Ideally, this behaviour should be taking into account not only for the current well data, but also for forecasted changes in the reservoir or system performance. The timeframe for this should be the expected lifetime of the ESP, usually a 3-5 year period. Specific attention should be paid to expected changes in average reservoir pressure, water cut, producing gas-oil ratio, required wellhead pressure and inflow performance. [7, p. 3]

To define well performance and considering sensitivity to changes over time, nodal analysis techniques can be applied. These techniques can be used numerically and graphically to provide a good understanding of the differential pressure or head that the pump has to deliver. To estimate future operating conditions different cases with different changing variables are defined and investigated. These single operating point calculations with defined cases values can be effective for defining operating requirements. Therefore the provided data should be sufficient and the well behaviour is stable over time. Also the produced fluid is a single phase fluid. When multiphase flow occurs, well behaviour is not stable and data quality is not reliable. For these cases further investigations have to be done. To perform this investigations a more detailed knowledge of the term uncertainty and how to measure it is required. [3]

4.1.1 Uncertainty

Whenever dealing with bad or not reliable data the design engineer has to deal with uncertainty. In broad terms, uncertainty may be defined as being any deviation from the unachievable ideal of completely deterministic knowledge of a relevant system. [20]

Measurement of uncertainty can be done with a set of possible states or outcomes where probabilities are assigned to each possible state or outcome. This also includes the application of a probability density function to continuous variables. The reasons for uncertainty may be listed as follows:

- Lack of information
- Disagreement about what is known or even knowable
- Quantifiable errors in data
- Ambiguously defined terminology

To overcome uncertainty different solution approaches were developed. A very common one is the uncertainty quantification. This method tries to determine how likely certain outcomes are if some aspects of the system are not exactly known. There are two major types of problems in uncertainty quantification. One is the forward propagation of uncertainty and the other one is the inverse assessment of model uncertainty and parameter uncertainty.

Forward uncertainty propagation can be explained as the quantification of uncertainties in system outputs propagated from uncertain inputs. Therefore it focuses on the influence on the outputs from the parametric variability listed in the sources of uncertainty. The assessment of the complete probability distribution of the outputs, defining the main design parameters for ESP pumps, can be useful to estimate operation conditions and choose the right equipment.

4.2 Influencing parameters

After the evaluation of common ESP design software packages a list with the influencing parameters was prepared. Following graph shows the main influencing parameters. The parameters can be divided into:

Constant factors:	Factors were no or very minor changes over the lifetime of an ESP are expected
Variable factors:	Factors were significant changes are expected or data quality is not sufficient or reliable
Design:	Factors that are chosen by the design engineer

Figure 25: Influencing parameters - ESP design

4.3 Risk Analysis

After the identification of the main influencing parameters for an ESP design the following description should provide an estimation of the related risks. The analysis gives a short overview and points out the main influencing factors.

Power availability

Secure power availability is a critical parameter for the run life time of an ESP. An unstable power source can reduce the pump run life time significantly. However, the influence into the design of the ESP is not very high. Reliable generators with backup systems and preventive maintenance should be used to mitigate this risk.

Wellbore geometry & Downhole equipment

The installed downhole equipment (Tubing, Packer, SSSV etc.) can have different influences. The installed tubing and related to that the final wellbore geometry has an influence to the natural separation efficiency and the flow velocity in the annulus. To ensure a proper cooling of the motor the flow velocity range should be analysed and never be below 1 ft/sec. If a vented packer in combination with a gas separator is installed it may be possible that the packer is a bottleneck for the separated gas.

Fluid & gas characteristics/PVT

PVT behaviour has a direct influence to the GOR that is present at the pump intake. Therefore a detailed knowledge of the PVT data is essential. Wrong interpretation of the data can lead to wrong design values.

Reservoir temperature

A wrong estimation of reservoir temperature has a direct influence to the temperature regime in the wellbore. This influences the cooling behaviour of the motor and can have a significant influence to the altering behaviour of the electrical cable.

Presence of solids

The presence of solids higher than ~200 ppm can lead to a failure of the ESP and has therefore an impact into the design phase. If high sand production is expected maybe another artificial lift method would be more preferable. It also has to be considered that a higher drawdown and therefore increased flow rate can lead to sand production. Also scale deposits within the pump or in the tubing lead to pressure losses and reduce the efficiency of the ESP. If problems with scale are expected a continuous inhibition with a chemical injection sub is required.

Bottom hole static pressure

Changes in bottom hole static pressure are related to reservoir depletion. Therefore it is normal that the pressure will decrease during the production period. As a consequence thereof the operating envelope will change and this has to be considered during the design phase. In the risk based design concept a consideration of the change of the reservoir pressure should be implemented by defining a range with a probability function.

Productivity

A wrong estimation of the productivity of the well can lead to a wrong pump design and therefore to a reduction in ESP performance and loss of production. The design should be performed with a defined range, covering the minimum and maximum expected PI from the well.

Water cut

Changes in water production are common during field production life for water driven reservoirs. An increase in water cut leads to reduction in ESP performance. To mitigate this risk the design should be performed with the most expected watercut for the reservoir. For a risk based design the expected range for the water cut should be defined.

Producing GOR/GVF

The producing GOR or GVF of the well is one of the main influencing parameters for a gassy well. If the FBHP is lower than the bubble point pressure and/or wrong data of GOR are used, the expected free gas that must be handled by the pump exceeds the amount that the pump can handle. To define the capacity, the gas handling equipment has to handle, a range for the producing GOR should be defined that covers all scenarios.

4.4 Software @ Risk

Performing a quantitative risk analysis can be done in different ways. Nowadays ESP design software can perform different cases where different single-point estimates for values are used. Using this method, an analyst may assign values for discrete scenarios to see what the outcome might be in each. For example, in the ESP design process, an analyst examines three different cases: worst case, best case and most likely case scenario which can be defined as follows:

- Worst case scenario: GOR is the highest possible value, also the water cut would increase to a high level over the time
- Best case scenario: GOR in the expected range, water cut stable
- Most likely scenario: Values are chosen in the middle of the expected ranges

This kind of approach can bring up several problems:

- Only a few discrete outcomes are considered
- It gives equal weight to each outcome, so no attempt is made to assess the likelihood of each outcome
- Interdependence between inputs, impact of different inputs relative to the outcome and other nuances are ignored. This oversimplifying of the model reduces its accuracy.

A better way to perform quantitative risk analysis is by using Monte Carlo simulation. In this simulation method, uncertain inputs in a model are represented using ranges of possible values known as probability distributions. With the usage of probability distributions, variables can have different probabilities of different outcomes occurring. Probability distributions are a much more realistic way of describing uncertainty in variables. Common distributions used by the software are normal, lognormal, uniform, triangular or discrete.

During a Monte Carlo simulation, values are sampled at random from the input probability distribution. This process is called iteration and the resulting outcome from that sample is recorded. The simulation does this hundreds or thousands of times and the result is a probability distribution of possible outcomes. Hence the Monte Carlo simulation provides a much more comprehensive view of what may happen. The results tell not only what could happen but how likely it is to happen.

The most common way to perform quantitative risk analysis is the spreadsheet model. By using @Risk in Microsoft Excel it is very easy to make usage of a Monte Carlo simulation. @Risk adds the needed functions to Excel to define probability distributions and analyze the results.

4.5 Design spreadsheet

To implement the model of a quantitative risk analysis for the design of an ESP pump a spreadsheet in Excel was implemented. With the following input variables different calculations, following the design procedure in chapter 3, were performed. Following data are necessary:

- **Reservoir Data:** The most important data from the reservoir have to be inserted. These include reservoir pressure, reservoir temperature, water cut and productivity index. The water oil ratio will be calculated automatically
- **Test Data:** If no PI value is added the user is able to insert the Test data like static BHP, flowing BHP, test rate and the PI or qmax after Vogel will be calculated. Test data also include the value for the GOR and dependent on the watercut the GLR will be calculated.
- **PVT Data:** Mandatory are values for the oil density, gas specific gravity, water specific gravity and the bubble point. The gradients and specific gravities are calculated automatically. The spreadsheet provides a calculation of the volume factors and solution GOR after Standing. There is also the possibility to insert the values manually at the pump intake conditions.
- **Wellbore & Completion Data:** Here the data for top of perforation and bottom of perforation are needed. With this values the mid depth of perforation is calculated which marks the inflow point into the well. Also the tubing size, casing ID and pump setting depth has to be inserted for the calculation of PIP and annular area.
- **Desired Rate & Pressures:** The desired production rate, required wellhead pressure and casing pressure have to be inserted. With this the rate for oil, water and gas are calculated. Also the PIP will be calculated.
- **Natural Separation:** The value for the interfacial tension is needed. With the concept of Alhanati natural separation efficiency is calculated. For artificial separation efficiency a value can be inserted. The spreadsheet will calculate the amount of gas ingested by the pump and the total liquid volumetric rate the pump has to handle. After these values are known the gas void fraction is calculated. This value is very important for the estimation of the needed gas handling equipment. Also a check of the Turpin criteria and the Dunbar pressure is calculated.
- **Total dynamic head:** By adding the friction losses in the tubing the frictional head losses and the total dynamic head are calculated. Also the dynamic liquid level and the fluid over the pump are calculated.
- **Pump specifications:** By inserting a value for the head per stage and the break-horsepower, the needed stages and required BHP are calculated.
- **Motor Cooling:** Finally a check of the motor cooling behavior is performed. As already mentioned, the flow velocity in the annulus should be above 1 ft/sec. If this value is below one it will be automatically highlighted red.

The following graph shows the spreadsheet. Yellow cells are input cells and the total ingested volume by the pump as same as the GVF are highlighted in green.

Reservoir Data		
Reservoir Pressure	2900	psi
Reservoir Temp.	200	°F
Water Cut	10	%
Water Oil Ratio	0,111111	
PI	0,71	bopd/psi

Test Data		
Static BHP	2900	psi
Flowing BHP		psi
Test Rate		bpd
PI calc	0	
qmax Vogel	0	bpd
Production GOR	1150	scf/bbl
Production GLR	1035	scf/bbl

PVT Data		
Oil density	39	°API
Oil gradient	0,359352	psi/ft
Oil specific gravity	0,829912	
Gas gradient	0,33774	psi/ft
Gas specific gravity	0,78	Air 1
water gradient	0,47197	psi/ft
Water specific gravity	1,09	
Fluid gradient	0,370614	psi/ft
Fluid specific gravity	0,855921	
Bubble Point	3360	psi

Oil volume factor	1,345696		
Water volume factor	1		
Gas volume factor	0,007521	ft³/scf	
Solution GOR	557,79	scf/bbl	Enter @ PIP

Oil volume factor	1,345696		
Gas volume factor	0,007521	ft³/scf	Calculated
Rs	557,79	scf/bbl	after
F	790,76		Standing @ PIP
Z Factor	0,839292		2084,22 psi

Wellbore & Completion Data		
Top of Perforation	7291	ft TVD
Bottom of Perforation	7291	ft TVD
Perforation Mid Depth	7291	ft TVD
Tubing Size	2,875	in.
Casing ID	9,625	in.
Pump Setting Depth	6990	ft TVD

Desired Rate & Pressures		
Desired Production Rate	500	bpd
Desired Oil Rate	450	bpd
Desired Water Rate	50	bpd
Desired Gas Rate	517500	scf/d
AOF	2059	bpd
FBHP	2195,774648	psi
Required Wellheadpress.	900	psi
Casing Pressure	20	psi
Pump Intake Pressure	2084,21992	psi

Gas Interference		
Gas Volumetric Rate	2004,41	scf/d
Converted to bpd	357,29	bpd

Natural Separation		
Annular Cross Sectional Area	0,464	ft²
Superficial Liquid Velocity	0,12	ft/sec
Density gas @ pump suc. cond.	7,92	lb/ft³
Density liquid @ pump suc. cond.	41,44	lb/ft³
Interfacial tension	0,04	lb/sec²
Bubble Rise velocity	0,56	ft/sec
Natural Separation efficiency	82,36	%
Gas Separator Efficiency	0	%
Gas ingested by pump	63,01	bpd
Liquid Volumetric Rate	655,56	bpd
Total In-Situ volume	**718,57**	**bpd**
Gas Void Fraction	8,77	%
Turpin Criteria	0,174327983	<1 okay
Dunbar	657,53	psi

Total Dynamic Head			
Dynamic LL (TVD)	1245,715	ft	100% oil
with negleted gas gradient			
Fluid over Pump	5744,285	ft	100% oil
Fluid over Pump	6990	ft	act. Liquid
Frictional Losses Tbg	80	ft/1000ft	
Frictional Head Loss	559,2	ft	
TDH	4179,901	ft	100 % oil

Pump spec.			
Head/stage	15	ft/stage	
BHP/stage	10	HP/stage	
minimum needed stages	278,66	stages	100%oil
BHP requ.	2786,6	BHP	100%oil

Motor Cooling			
Motor OD	5,4	in	recommen
Flow velocity in Annulus	0,122891	ft/sec	ded

Figure 26: Design Spreadsheet

4.6 Example

The following example shows the usage of the Excel spreadsheet and the @Risk software tool. It should demonstrate the additional value generated through the usage of quantitative risk analysis. In the presented example the 4 variable factors for an ESP design were substituted by a probability distribution.

In a first step the reservoir pressure was substituted with a beta general probability distribution. The range of the values should be between 2400-3000 psi. This distribution can be clearly seen in Figure 27.

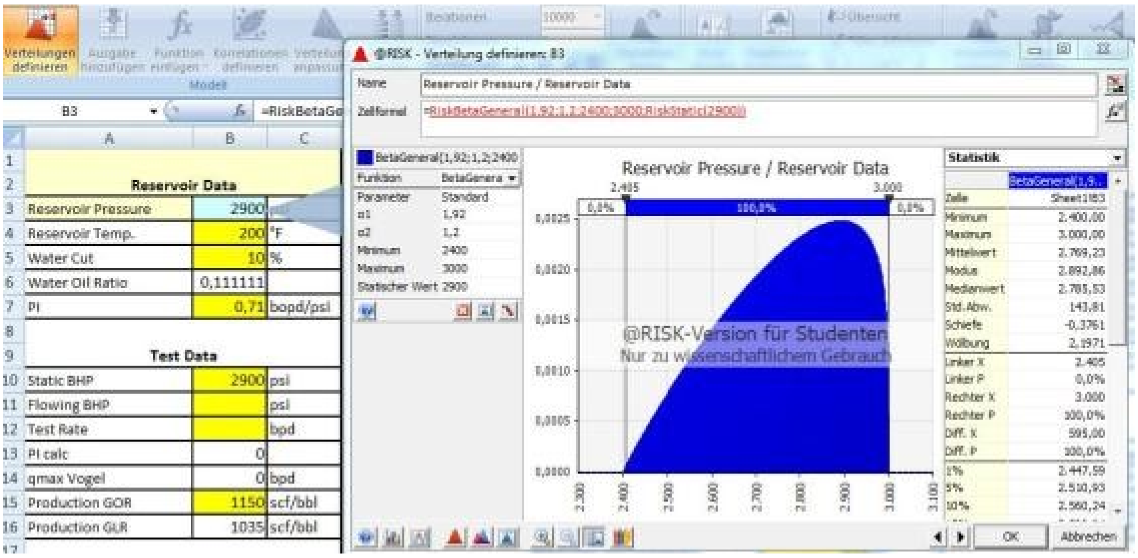


Figure 27: Probability distribution reservoir pressure

Also the water cut, which can increase over the lifetime of an ESP well, was substituted with a probability distribution. Here a uniform distribution was used, defining a range between 7-35 %. Figure 28 shows the distribution of the water cut.

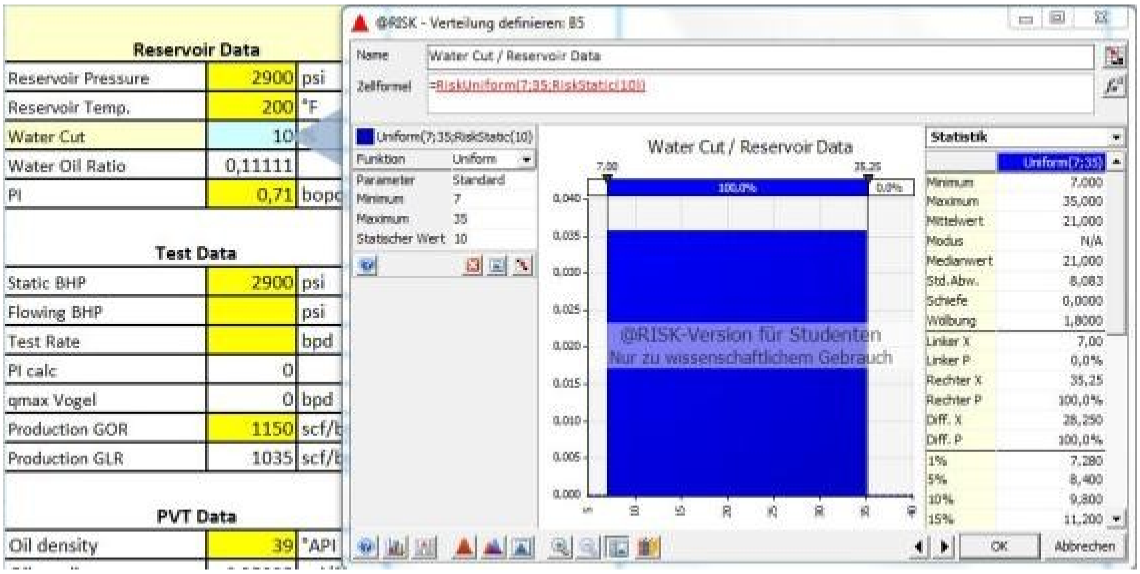


Figure 28: Probability distribution water cut

Also for the productivity index a uniform distribution was used. The expected range for the PI is between 0.6 to 0.75. Figure 29 shows the distribution of the productivity index.

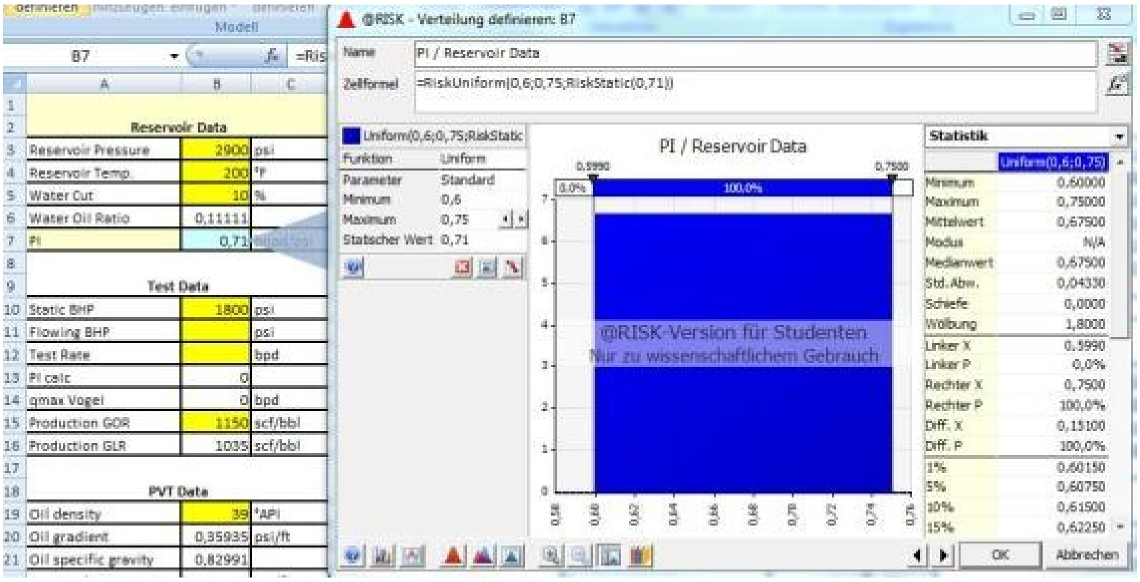


Figure 29: Probability distribution productivity index

The last substituted variable is the production GOR. Here a beta general distribution was chosen defining a range between 750 – 5000 scf/stb. The shape of the distribution can be seen in Figure 30.

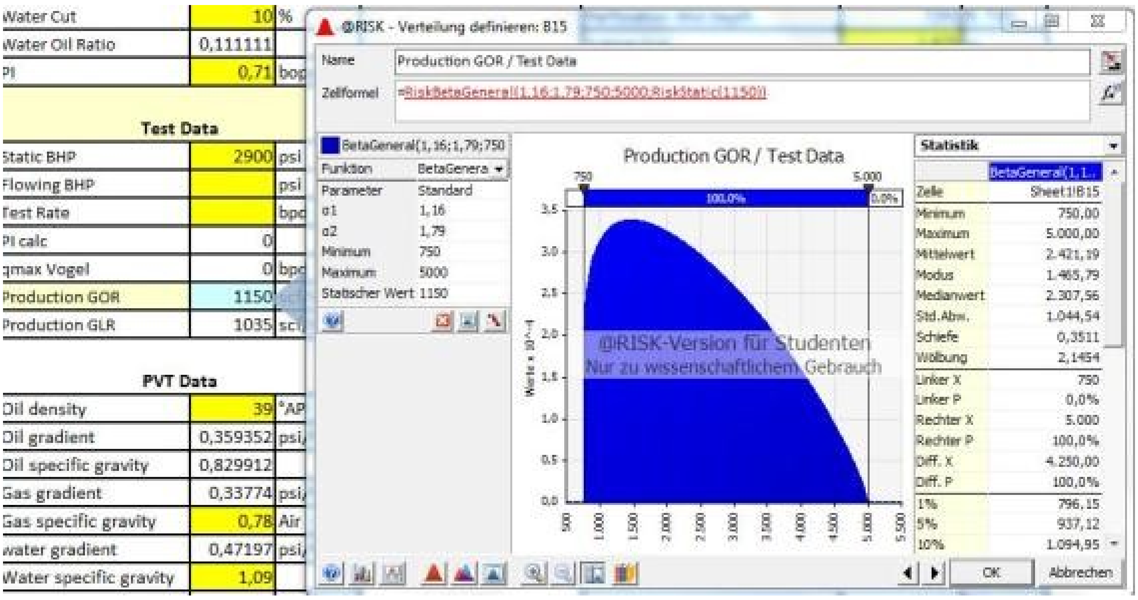


Figure 30: Probability distribution production GOR

After the definition of all distribution functions for the input variables the output variables have to be defined. For a risk based design concept for ESPs that will operate in a gassy environment the most important factor will be the gas void fraction. This value is the base of any decision related to selection of gas handling equipment. @Risk allows you to define different output variables. After defining the output variables the simulation can be started.

The amount of iterations, that the software will calculate, is also selectable. For a good accuracy a simulation with 10 000 iterations was chosen.

As can be seen in Figure 31 the distribution of the gas void fraction in dependency of the input variables was simulated. For this example it can be clearly seen that the GVF will be in a range between 0-35%. The probability, that the GVF will be higher than 25% is 15.7% or vice versa the probability that the GVF will be between 0-25% is 84.3%.

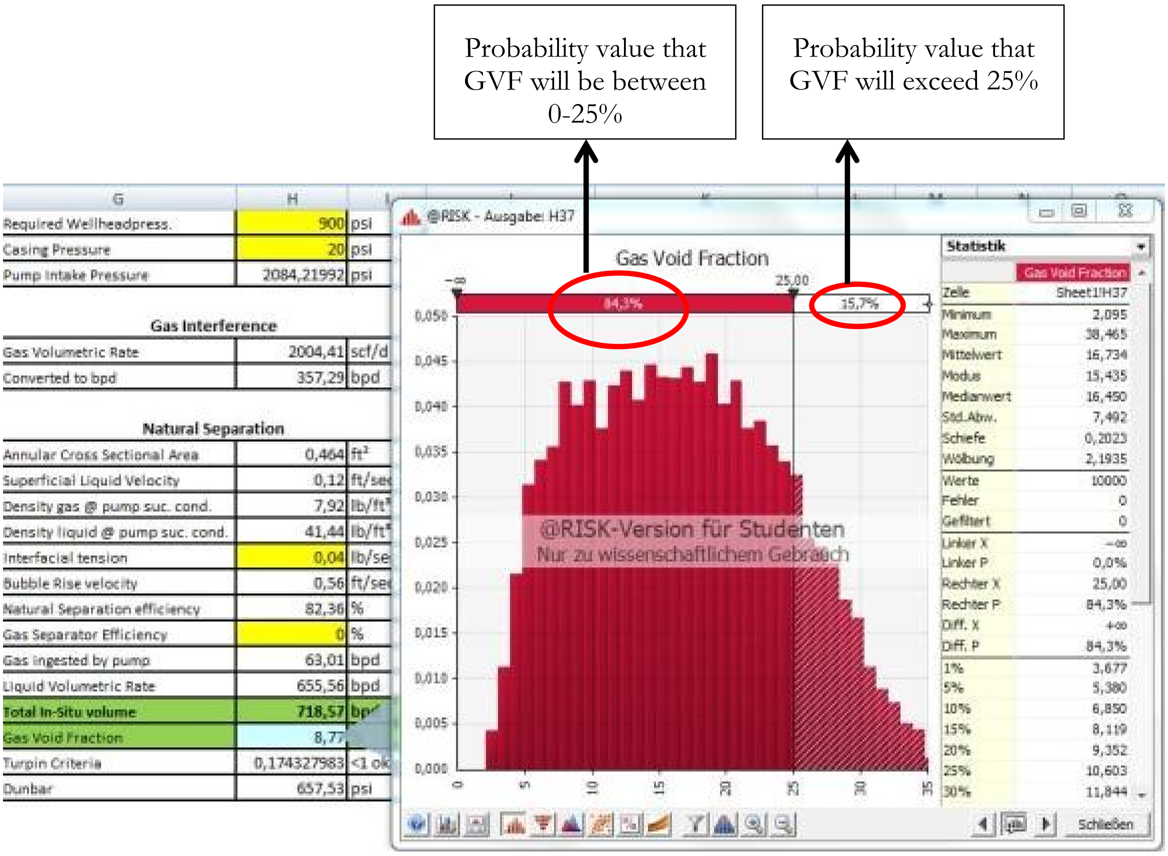


Figure 31: Outcome - Distribution Gas void fraction

By knowing the probabilities of the defined output variables, the design engineer is able to choose the right equipment. For the presented example the likelihood that the GVF will be above 25% is about 84%. If the engineer decides to install an ESP that is capable of handling 25% there will be a remaining risk of 16% that the ESP will fail. If the engineer wants to eliminate the risk of gas locking he has to choose equipment that's able to handle a GVF up to 35%.

4.7 Summary and Conclusion

With the development of the risk based design concept could be shown that the quantitative risk analysis concept is applicable for the ESP design process. For a better understanding the presented example had been kept very simple. In a more complex model more than four factors can be substituted by probability distributions. Also the probability distributions can be more complex. It would be possible to use historic datasets to define a probability distribution or use a correlation developed of data provided by other wellbores in a field. Also the simulation of more than one output variable is possible. With the investigation of more variables the decision making process can be performed more accurate. The knowledge of ranges for design values and the likelihood of single values support the engineer with additional information. With this information it is possible to choose the right equipment that is needed to operate an ESP over the whole life time in a changing environment.

The developed spreadsheet also could be further improved. In the actual version no multiphase correlation for the pressure drop in the tubing and the annulus was used. By implementing a common correlation the accuracy can be raised. The usage of an accurate model for the pressure drop is important for the calculation of the pump intake pressure.

5 Operation of ESPs during changing conditions

Whenever an ESP is installed it cannot be expected that the conditions will stay constant over the whole lifetime. Nowadays industry standard for the lifetime of ESPs is about 3-5 years. During this period different parameters will change significantly and will have a direct influence to the operation regime of the ESP. Also during the design phase it is often very difficult to estimate the right operating regime for an ESP. This uncertainty sometimes leads to wrong ESP pump design that operate inefficiently. Whenever an installed ESP is dealing with changing conditions or operating in a wrong estimated regime the actions that an engineer can take are very limited. The following chapter will concentrate on a strategy applied for wells dealing with high GOR.

5.1 Background

ESPs are a state of the art artificial lift technology to produce high volumes. Due to their narrow operational performance they are constrained to adapt to changing parameters. In OMV some projects showed highly increasing GORs during the production of wells equipped with ESPs. This increased GOR rates cannot be handled optimally with the built in ESPs. Besides a review of the design concept and a screening of the actual state of the art technology provided by vendors a possible adaption of existing ESPs to handle changing GOR regimes was conducted. After some research work and a consultation with an engineer from a major ESP vendor a strategy was found that supposed to be applicable. To estimate the applicability of this strategy to existing OMV wells an investigation of three wells was performed.

5.2 Strategy

A major strategy to minimize shutdowns related to free gas fluctuations in gassy ESP wells is the adjustment of the frequency and the choke setting. For wells equipped with variable speed drives and adjustable chokes following strategy is applicable.

By reducing the choke setting the FBHP can increase and the trapped gas in the pump can flow to the surface. Additionally the frequency should be increased to force liquid production. The adjustment of the choke size and frequency increases the pressure regimes in the pump and forces the gas back into solution. Also the higher liquid production can force the gas to flow through the pump and therefore avoid gas locking.

5.3 Field description

5.3.1 General

All the investigated wells are in the OMV operated Block Yemen S2 (Al Uqlah). The block is located in the province of Shabwah in central Yemen. The license lies along the northern border of the Shabwah province, immediately south and west of the Hadramauwt province.

Figure 32: Geographic location Block S2

In March 1992 the exploration well Kharwah-1 proved oil discoveries in the Lam and Kohlan formations in Block S2. Subsequent exploration wells, Al-Nilam-1 and Habban-1, confirmed the discovery of producible hydrocarbons also in the fractured basement.

End of 2005 OMV embarked on a phased field development of the Habban Field which holds an estimated STOIIP of 1000 mil. bbl. As part of the phase 2 development a total of more than 30 wells were drilled and permanent production facilities with oil export were installed.

5.3.2 Geology

The current production comes mainly from the fractured basement reservoir and its overlying sedimentary Kohlan unit. The primary development philosophy is to intersect fracture corridors with highly slanted/subhorizontal wells. Fractures are mostly associated to structural features and hence the wells have been designed mostly based on seismically identifiable features and discontinuities. The well locations and depth can be seen in the basement depth map in Figure 33.

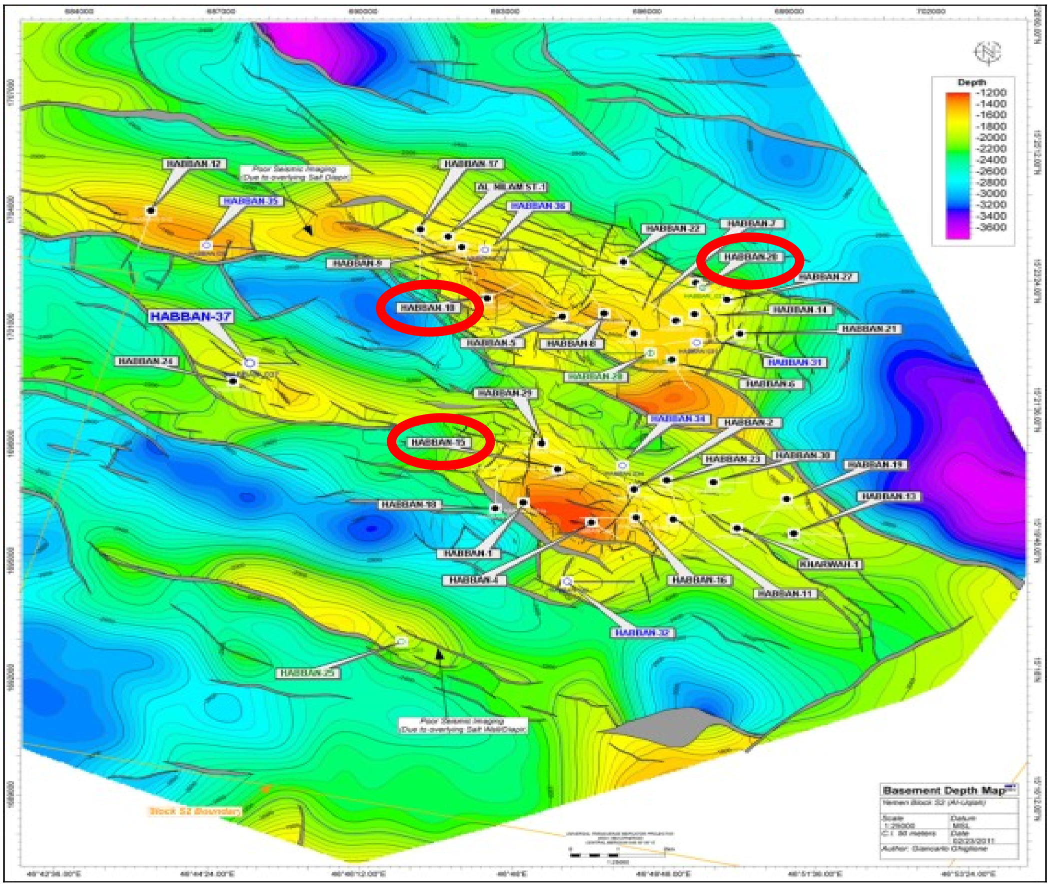


Figure 33: Well locations – Basement depth map

5.3.3 Reservoir fluids

The Habban field produces light sweet crude, which has been sampled in three wells. The following table summarizes key fluid parameters:

Property	Kohlan (Habban 1a)	Kohlan (Al Nilam 1)	Kohlan (Kharwah 1)
Solution Gas, R_s	1156 scf/stb	1210 scf/stb	1262 scf/stb
Saturation Pressure, P_b	3365 psi	3595 psi	3600 psi
Gas Gravity (air=1)	0.78 @ P_b	0.79 @ P_b	0.761 @ P_b
Formation Oil Factor B_o	1.683 bbl/stb @ P_b	1.683 bbl/stb @ P_b	1.72 bbl/stb @ P_b
Oil Viscosity	0.3 cp @ P_b	0.27 cp @ P_b	0.29 cp @ P_b
Gas Viscosity	0.022 cp @ P_b	0.022 cp @ P_b	0.022 cp @ P_b

Table 1: Key fluid parameters – Habban field

The fluid composition shows that the reservoir fluid has low impurity contents (N_2 and CO_2 mole % less than 1%) and no H_2S. The reservoir pressure at initial conditions encountered in Al-Nilam 1 was 4172 psia @ Datum depth (1952m TVD) substantially above the bubble point pressure. With continuous pressure depletion as production of the field continues the producing GOR will increase. The increasing GOR will have to be managed and wells with excessively high GOR`s were shut in to preserver reservoir energy.

Water production has been seen in various wells (Hab-13, Hab-19, Hab-10). These wells usually intersect deep fracture zones, which are connected to downthrown fault systems and pull up water.

5.3.4 Reservoir outflow

From production start wells have been produced from open hole completions on natural flow. Four wells have been equipped with ESPs to test the viability of this artificial lift method in this reservoir which exhibits high GOR`s.

No sand problems are expected from basement wells. Over the life of the field changes in well fluid composition may occur, but significant changes in contaminates are not expected.

5.4 Investigated wells

For the investigation three wells of the Habban field were chosen. All the three wells are equipped with ESP´s. The locations of the investigated wells and depth can be seen in the basement depth map in Figure 33 (highlighted with red ellipse). All three wells had a significant increase and high fluctuation in free gas during the production. Following chapters provide a more detailed description of the wells.

5.4.1 Habban 10

Habban 10 was drilled in 2008. The 20” surface casing shoe was set at 449 m-MD, the 13 3/8” intermediate shoe at 1384 m-MD and the 9 5/8” intermediate casing shoe at 2223 m-MD. An 8.5” open hole section was drilled to total depth at 3143 m-MD. At the beginning the well was flowing naturally with an initial production of 1250 bbl/d with water cut less than 1%. The produced water increased over the time and reduced production.

In January 2011 the well was equipped with an ESP, GE-Woodgroup TE-1500, 52 stages. The well was completed with a vented packer at 100m-MD and a Y-Tool at 2123 m-MD. A completion schematic can be seen in the appendix. The ESP was set at 2127m-MD and equipped with a gas separator, gas handler and a downhole gauge, providing measurement of intake pressure, discharge pressure, motor amperage, intake temperature and motor temperature. Also a VSD had been installed. After commissioning the ESP worked well but was shut in for almost 6 months due to external reasons. A restart of the ESP after this period was not successful.

The production data showed cycling GOR values between 300-3800 scf/bbl. The average GOR was about 1000 scf/bbl., average watercut was 20 % and the average oil rate was 500 bbl/d. The pump operated most of the time under cycling conditions due to the fluctuating GOR. Due to these circumstances this well is a good candidate to investigate the potential of the former presented strategy.

5.4.2 Habban 15

Habban 15 was also drilled in 2008. The 20” surface casing shoe was set at 219 m-MD, the 13 3/8” intermediate shoe at 1439 m-MD, the 9 5/8” production casing shoe at 2079 m-MD and the 7” production liner at 2416m-MD. An 8.5” open hole section was drilled to total depth at 4100m-MD. The average of initial production was 1200bbl/d with less than 13 % WC. The well was completed with an ESP, GE Woodgroup TD-300, 201 stages. A vented packer was installed at 102m-MD. The completion schematic can be seen in the appendix. The ESP was set at 2117 m-MD and equipped with a gas separator, gas handler and a downhole gauge, providing measurement of intake pressure, discharge pressure, motor amperage, intake temperature and motor temperature. The control unit was equipped with a VSD system. After commissioning the pump had problems to deliver a sufficient discharge pressure. During start up, the pump had a period with cycling conditions. After this period the pump gained no additional pressure and showed also a cycling behavior. The pump was shut in for some external reasons for four months and was restarted in January 2013. After the restart the pump showed the same cycling behavior like before but finally gained a discharge pressure at the beginning of March 2013. The pump showed a constant behavior for approximately one month and started to cycle again. After strong cycling of the pump it failed in mid of May 2013. A work over showed that the ESP cable failed. However, during the production period the ESP had problems to gain a sufficient discharge pressure and showed also a cycling behaviour like Habban 10.

The production data showed cycling GOR values between 450-4500 scf/bbl, average water cut of 57% and the average oil rate was about 90 bbl/d.

5.4.3 Habban 20

Habban 20 was expected to be a natural flow producer and it was drilled in 2009. The 20” surface casing shoe was set at 252 m-MD, the 13 3/8” intermediate shoe at 1474 m-MD and the 9 5/8” production casing shoe at 2495 m-MD. An 8.5” open hole section was drilled to total depth of 3987 m-MD. It stated out that Kohlan formation does not exist in this well. The well was completed with an ESP, GE Woodgroup TD-650 with 201 stages in January 2011. A completion schematic can be seen in the appendix. Many trials were made to get the pump started but it did not work out. After that the well was shut in for a long time due to external reason. Finally the pump got started but due to some restrictions on the surface the well had to be shut in again. Afterwards many trials were made to re-start the pump but all the trials were unsuccessful. Maybe the pump got stuck due to precipitation of sand. Originally the ESP was set at 2030 m-MD completed with a vented packer at 105 m-MD, a Y-Tool at 2021m-MD, a gas separator, a gas handler and a downhole gauge were also installed. The downhole gauge failed from start on and provided only measurement of intake pressure, motor temperature and motor amperage. The control unit was equipped with a variable speed drive.

Due to the fact that Habban 20 ESP only had a runtime of about 30 days and the downhole gauge failed, the dataset is very limited. Based on the behaviour of the motor temperature in this short period it could be possible that the pump cycled.

The production data in this period showed a GOR range between 1000-2800 scf/bbl, average water cut of 18% and the average oil rate was about 200 bbl/d.

5.5 Methodology

To apply the former presented strategy to the investigated wells the nodal analysis software PROSPER was used. In a first step PROSPER models of the wells were set up. This includes the input of all the main data like PVT, Inflow Performance, downhole equipment etc. After this the ESP equipment and choke setting was chosen. With the analysis summary tool "System" the accuracy of the well models was checked. To ensure that the well models coincide with the real wells, matching data were used. This includes PVT match data as well as a match with historic production data. After a good match of data was founded different cases were defined. In the single cases the two variables choke size and frequency were changed. By changing these parameters the former presented strategy was simulated and the behaviour of the well observed. To get accurate results and find the borders of the strategy more than 50 cases for each well were simulated. Following figure shows the "System sensitivity analysis" interface of PROSPER. In this interface the cases were defined and the calculated data analysed.

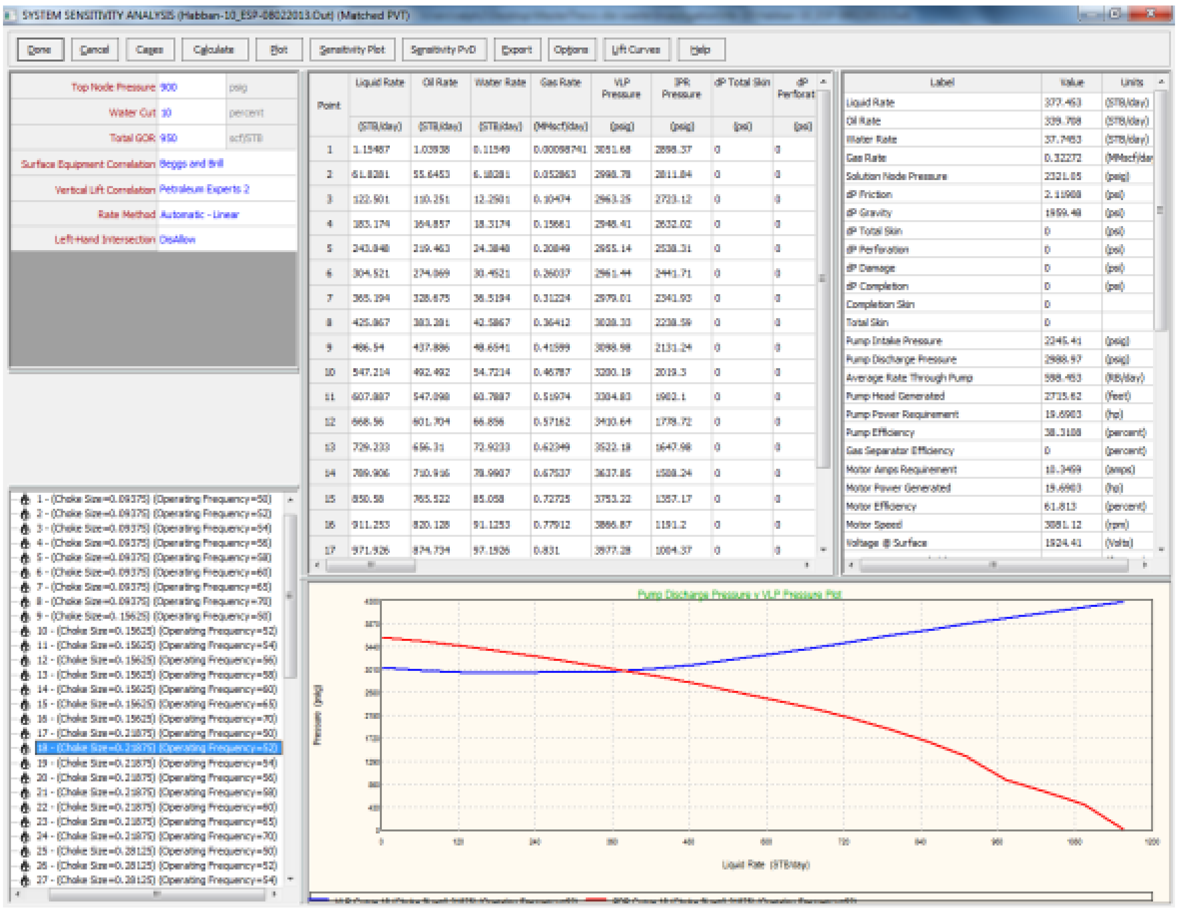


Figure 34: System sensitivity analysis – PROSPER

Analyzing a big amount of data generated through a big amount of cases is not very comfortable in PROSPER. Due to this reason the calculated cases were exported to Microsoft Excel. In Excel it is much easier to perform further calculations, compare the cases and visualize the results.

After importing the data into Excel the cases were filtered to two different tables. One table lists fixed choke size and variable frequency, the other one fixed frequencies and variable chokes. This was needed to calculate the influences of a choke size change and the frequency change to the gas fraction present in the pump. General the value for the gas fraction in the pump was the value of main interest in these simulations because it influences the behavior of the pump during gas interference the most. By applying the strategy and running the different cases an estimate of the potential should be provided. In other words, the main interest was to find out how much the gas fraction can be lowered by choking the well back and raising the frequency.

Frequency	Choke	Gas fraction	diff	cum	Oil Rate
50	26	0.28559	0.28559		455.328
52	26	0.30464	0.01905	0.01905	477.059
54	26	0.32475	0.02011	0.03916	498.92
56	26	0.34655	0.0218	0.06096	520.219
58	26	0.36895	0.0224	0.08336	542.099
60	26	0.39718	0.02823	0.11159	563.097
50	22	0.27038	0.27038		437.978
52	22	0.28808	0.0177	0.0177	458.172
54	22	0.30633	0.01825	0.03595	478.99
56	22	0.32568	0.01935	0.0553	499.829
58	22	0.34654	0.02086	0.07616	520.209
60	22	0.36798	0.02144	0.0976	541.146
50	18	0.23894	0.23894		396.878
52	18	0.25578	0.01684	0.01684	418.906
54	18	0.2729	0.01712	0.03396	440.861
56	18	0.28926	0.01636	0.05032	459.516
58	18	0.30611	0.01685	0.06717	478.739
60	18	0.32388	0.01777	0.08494	498.072
50	14	0.18552	0.18552		318.739
52	14	0.19904	0.01352	0.01352	339.708
54	14	0.21221	0.01317	0.02669	359.155
56	14	0.22586	0.01365	0.04034	379.306
58	14	0.23961	0.01375	0.05409	397.742
60	14	0.25372	0.01411	0.0682	416.198
50	10	0.12611	0.12611		215.522
52	10	0.13335	0.00724	0.00724	228.926
54	10	0.1407	0.00735	0.01459	242.207
56	10	0.14833	0.00763	0.02222	255.987
58	10	0.15624	0.00791	0.03013	270.27
60	10	0.16434	0.0081	0.03823	283.934
50	6	0.069613	0.069613		99.4741
52	6	0.073058	0.003445	0.003445	107.214
54	6	0.07614	0.003082	0.006527	113.899
56	6	0.079016	0.002876	0.009403	119.967
58	6	0.081998	0.002982	0.012385	126.258
60	6	0.085084	0.003086	0.015471	132.768

Frequency	Choke	Gas fraction	diff	cum
50	26	0.28559	0.01521	0.28559
50	22	0.27038	0.03144	0.27038
50	18	0.23894	0.05342	0.23894
50	14	0.18552	0.05941	0.18552
50	10	0.12611	0.056497	0.12611
50	6	0.069613		0.069613
52	26	0.30464	0.01656	0.30464
52	22	0.28808	0.0323	0.28808
52	18	0.25578	0.05674	0.25578
52	14	0.19904	0.06569	0.19904
52	10	0.13335	0.060292	0.13335
52	6	0.073058		0.073058
54	26	0.32475	0.01842	0.32475
54	22	0.30633	0.03343	0.30633
54	18	0.2729	0.06069	0.2729
54	14	0.21221	0.07151	0.21221
54	10	0.1407	0.06456	0.1407
54	6	0.07614		0.07614
56	26	0.34655	0.02087	0.34655
56	22	0.32568	0.03642	0.32568
56	18	0.28926	0.0634	0.28926
56	14	0.22586	0.07753	0.22586
56	10	0.14833	0.069314	0.14833
56	6	0.079016		0.079016
58	26	0.36895	0.02241	0.36895
58	22	0.34654	0.04043	0.34654
58	18	0.30611	0.0665	0.30611
58	14	0.23961	0.08337	0.23961
58	10	0.15624	0.074242	0.15624
58	6	0.081998		0.081998
60	26	0.39718	0.0292	0.39718
60	22	0.36798	0.0441	0.36798
60	18	0.32388	0.07016	0.32388
60	14	0.25372	0.08938	0.25372
60	10	0.16434	0.079256	0.16434
60	6	0.085084		0.085084

Figure 35: Calculation tables – Fixed choke variable frequency (left)
Fixed frequency variable choke (right)

The calculated data in the tables are also the database for the visualization of the results. With the data following graphs were drawn:

• Free gas 3-D graph	Y-Axis: Frequency X-Axis: Choke size Z-Axis: Free gas
• Free gas 2-D graph	Y-Axis: Free gas X-Axis: Choke size
• Surface diagram	Y-Axis: Frequency X-Axis: Choke size Z-Axis: Free gas
• Choke size change influence	Y-Axis: Free gas X-Axis: Choke size
• Frequency change influence	Y-Axis: Free gas X-Axis: Frequency

Following figures give an overview of the created graphs. In total 4 sets of graphs were created. For Habban 10 two matches were performed, for Habban 15 one match and for Habban 20 also one match.

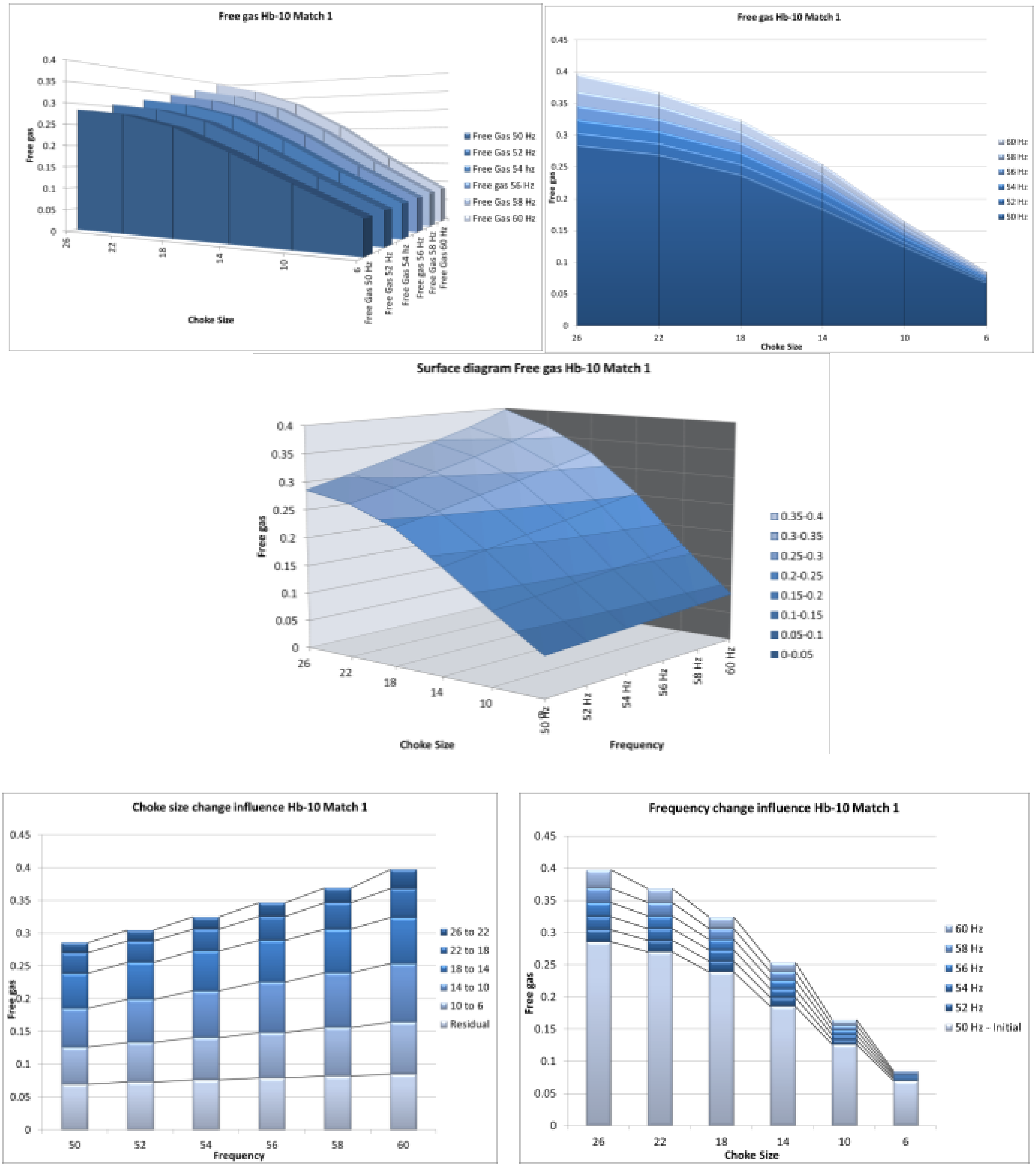


Figure 36: Generated diagrams for data visualization

5.6 Results

In the following chapters the simulation results are discussed in more detail. The matches will be described in more detail and the results of the simulations in PROSPER are presented.

5.6.1 Habban 10

As mentioned before for Habban 10 two matches were performed. The reason therefore is a strong cycling behaviour of the ESP pump. One match was chosen at the beginning of a period were the pump showed a behaviour without cycling for approximately 3 months. The other match was right at the beginning of a phase were the pump showed strong cycling conditions.

5.6.1.1 Match 1

The first match was performed at the 1. February 2013. At this time the pump was running on a frequency of 50 Hz and a choke size of 30 (Choke sizes will be described in 64ths). For this setting the oil rate was about 465 bbl/d and the gas fraction had a value of 28.5%. The simulation showed that a reduction of the choke size to a value of 18 could reduce the gas fraction about 5%. With this reduction the oil rate will be lowered to a value of 395 bbl/d. The frequency had been kept to 50 Hz, a raise of the frequency showed a raise of the gas fraction. For these parameters the pump was still operating in the ideal range. A change of the choke to 14 and a raise of the frequency to 54 Hz could reduce the gas fraction additional 2 % up to 7% total. But for this setting the pump would be slightly out of the operating range.

The maximum accessible reduction of the gas fraction was 30% for a choke size of 6 and a frequency of 60 Hz. It has to be considered that the pump would be out of the recommended operating conditions as can be seen in the pump plot below. If the pump would be operated in this area for a longer time it would be likely that it will fail immediately.

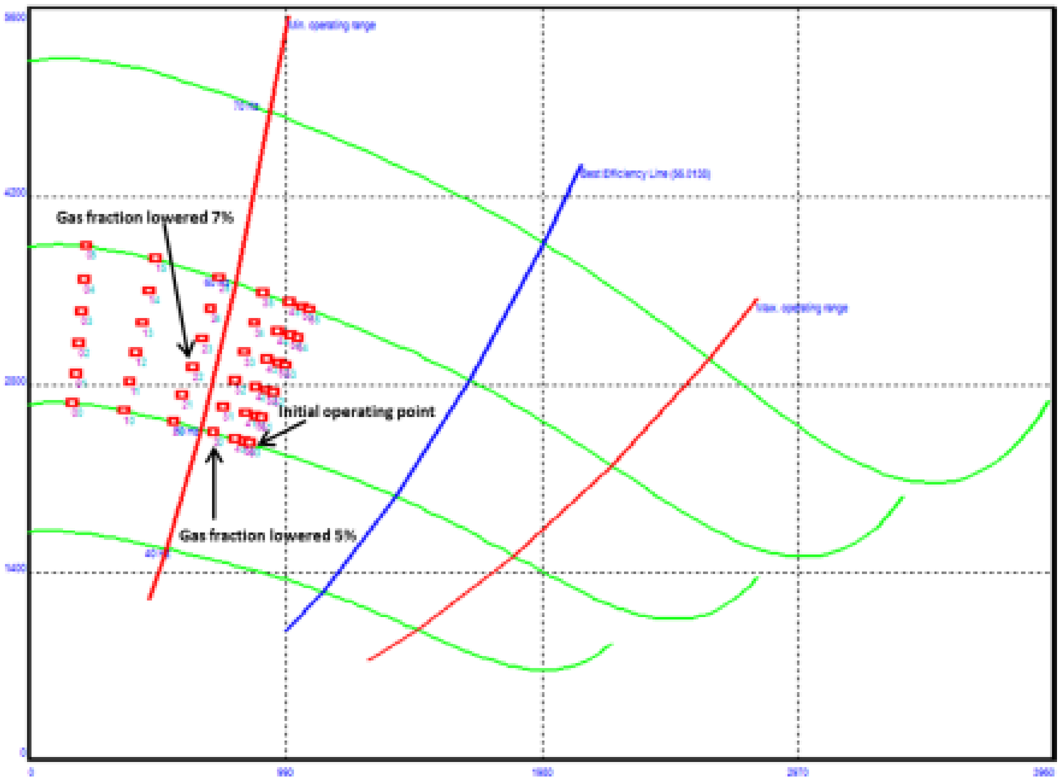


Figure 37: Pump plot Habban 10 – Match 1

Following two graphs show the change of the free gas during the reduction of the choke size in more detail. Also visible is the influence of the frequency change for every choke size. What can be seen very clearly is that the effect of a frequency change gets compacted or squeezed with decreasing choke sizes. In other words, a raise of the frequency has more influence to the free gas conditions in the pump when the choke is more opened. This circumstance can be seen clearly in the right picture. By comparing the free gas values for a choke size of 26 with a choke size of 14 shows that the free gas amount at the highest frequency of 60 Hz can be lowered by ~14%.

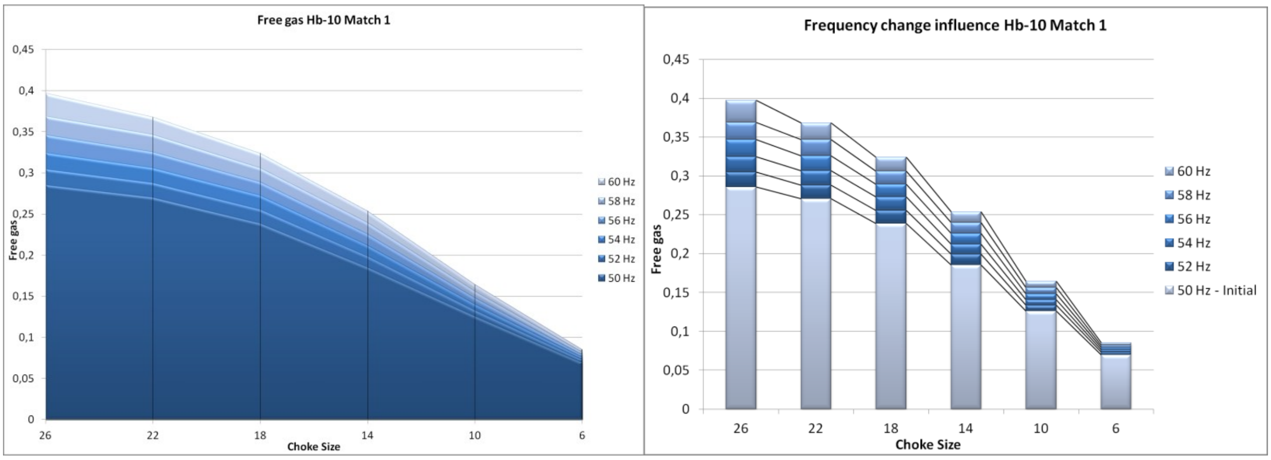


Figure 38: Free gas change and Frequency change influence Habban 10 - Match 1

5.6.1.2 Match 2

The second match was 3 months later at the beginning of May 2013. There the pump started to show up a strong cycling behaviour due to an increase in GOR. At this time the pump was operated at a frequency of 44 Hz and a choke size of 24. The oil rate was about 580 bbl/d and the gas fraction was 54%. Of course this high gas fraction leads to the cycling behaviour of the pump. The simulation showed that a change of the choke size to 18 and a raise of the frequency to 54 Hz could decrease the gas fraction by 14%. The oil rate for these parameters would be about 500 bbl/d. By choking back the well to a value of 14 and increase of the frequency to 58 Hz the gas fraction could be decreased by 25 %. There the pump would have to handle a fraction of 30 %. This is nearly the same fraction at initial conditions of Match 1 and there the pump showed a stable behaviour.

The maximum accessible reduction of the gas fraction for this match was about 40 % for a choke size of 6 and a frequency of 60 Hz. But again, this goes hand in hand with a strong decrease of the oil rate and an operating regime out of the recommended range.

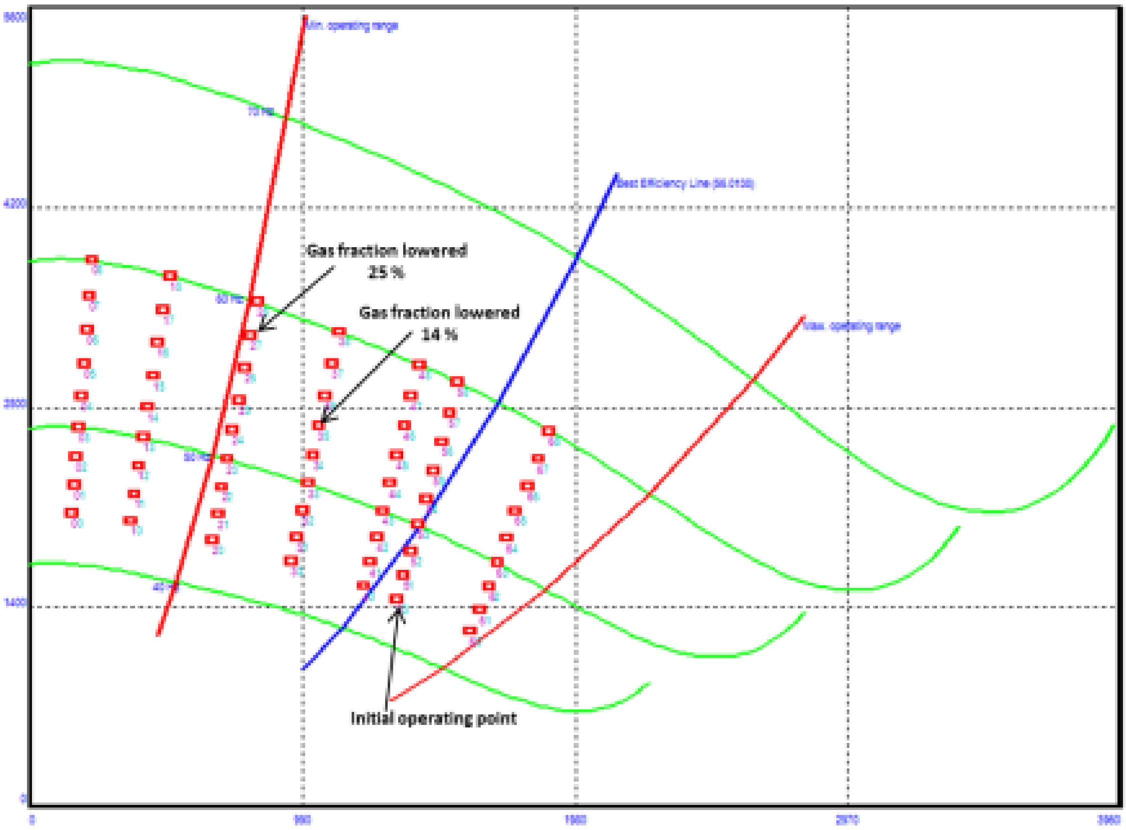


Figure 39: Pump plot Habban 10 – Match 2

Due to the fact that the initial free gas value for this match was much higher than for the first match the surface diagram is steeper. This can be also seen in the frequency change influence diagram on the right side below. An operation of the pump at a choke size of 24 and 60 Hz would lead to a free gas fraction of 75%. At a choke size of 14 the free gas fraction would be about 30% at the same frequency. As described before, the squeezing of the effect related to a change of the frequency is much more pronounced than in the first match. This circumstance leads to the statement that the potential and applicability of the presented strategy is higher for wells with initial high amounts of free gas. To verify these statements and check the applicability of the strategy another well was investigated.

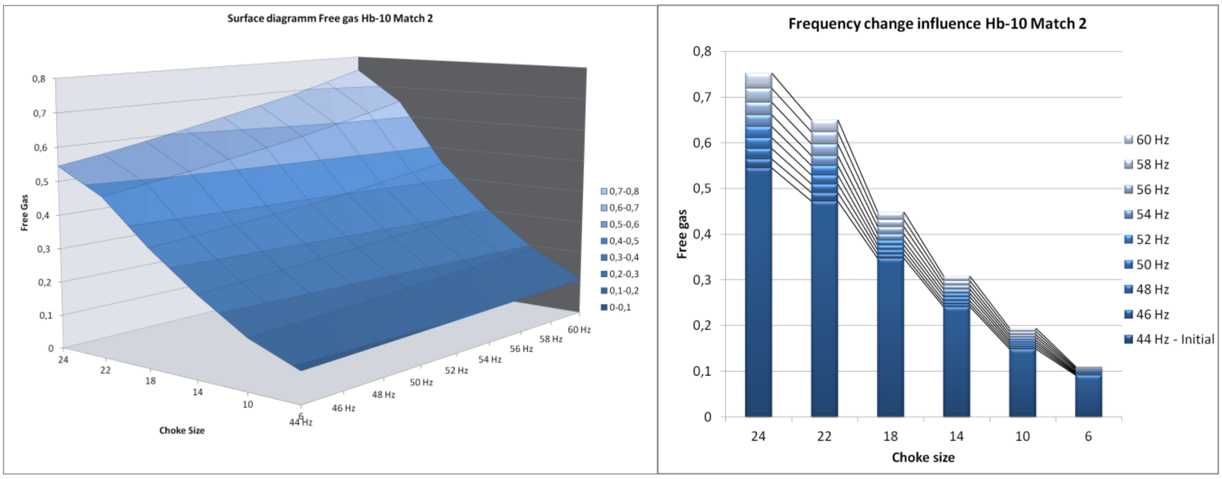


Figure 40: Surface diagram and Frequency change influence Habban 10 - Match 2

5.6.2 Habban 15

The match for Habban 15 was done in April 2013. At this time the pump was running on a choke size of 24 and a frequency of 50 Hz. Like mentioned before, during this period the pump showed a constant behaviour with a sufficient discharge pressure. Shortly after this period the pump started to cycle again. At this time a strong increase of the motor temperature could also be recognized. The production rate at this time was about 90 bbl/d with a gas fraction of 12%. After the import of the data into PROSPER it showed up that the pump was operating outside the recommended operating window. A simulation of the presented strategy and therefore a change of the choke size to 12 and a raise of the frequency to 54 Hz showed that the pump would be in a much more preferable operating condition. For this setting the free gas fraction could be lowered by one percent and the production rate would be decreased to 75 bbl/d. Of course, the relative low savings in free gas is related to the already relatively low amount of free gas inside the pump. However, the change of the parameter would have run the pump in a much more preferable operating condition and therefore may extend the run life of the pump. A further adjustment of the parameters to a choke size of 8 and a frequency of 60 Hz would lead to an additional saving of 1% in free gas fraction. The pump would be still in the recommended operating range and the oil rate would change to 63 bbl/d.

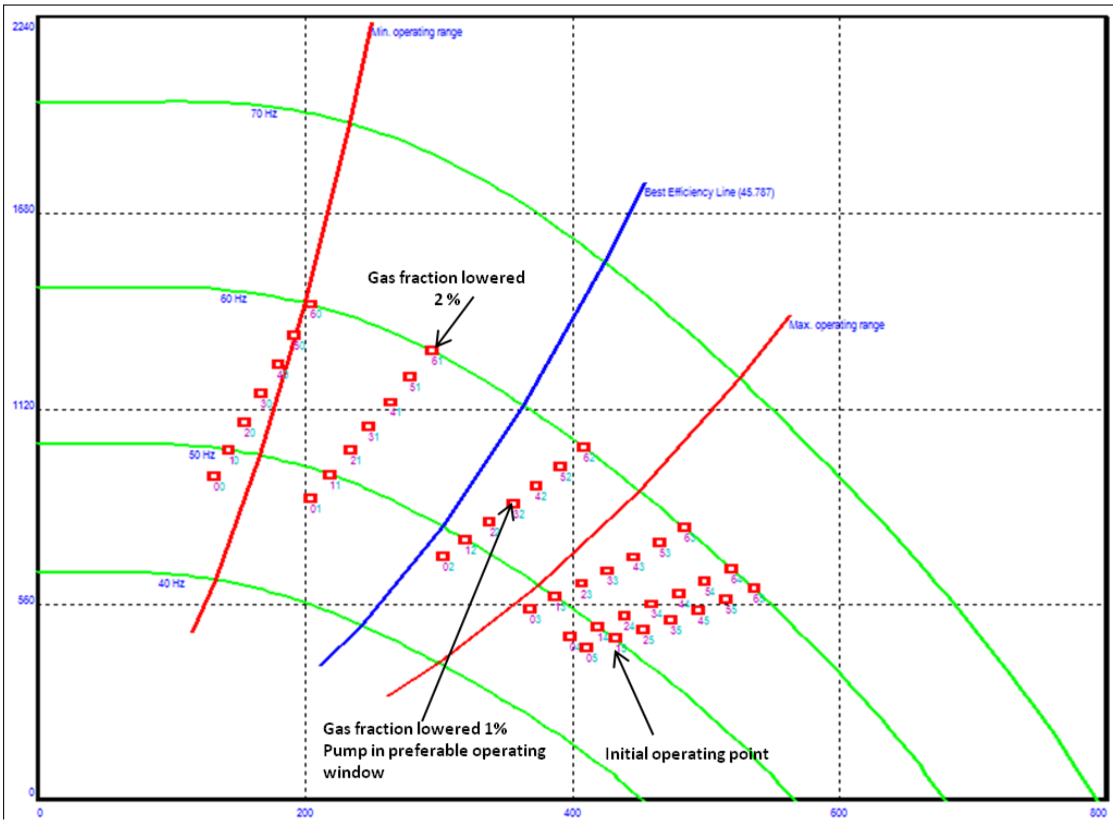
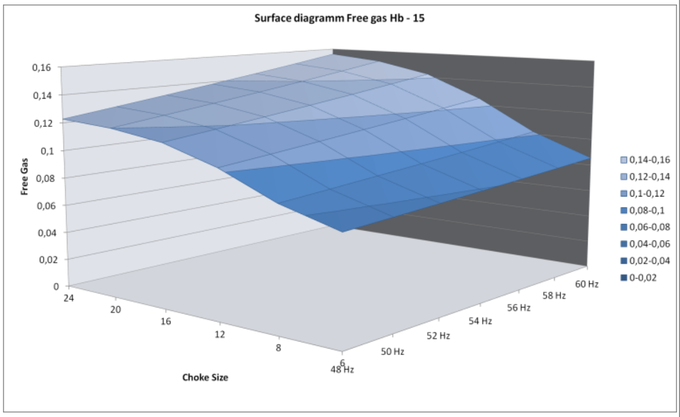


Figure 41: Pump plot Habban 15

Due to the fact that the free gas level for the presented operation conditions was already at a low level of about 13% the surface diagram is relatively flat. Also the reduction potential is relatively limited. This circumstance can also be seen in the frequency change influence diagram on the right side below. An operation of the pump at a choke size of 24 and 60 Hz would lead to a free gas fraction of 15 %. At a choke size of 12 the free gas fraction would be about 12 % at the same frequency. The squeezing effect can be also recognized for this simulation but the single steps of a frequency change are much smaller than for wells with a high amount of free gas. This confirms the above mentioned statement that the potential and applicability of the presented strategy is linked to the amount of free gas present in the well and gets lower with smaller gas fraction values.



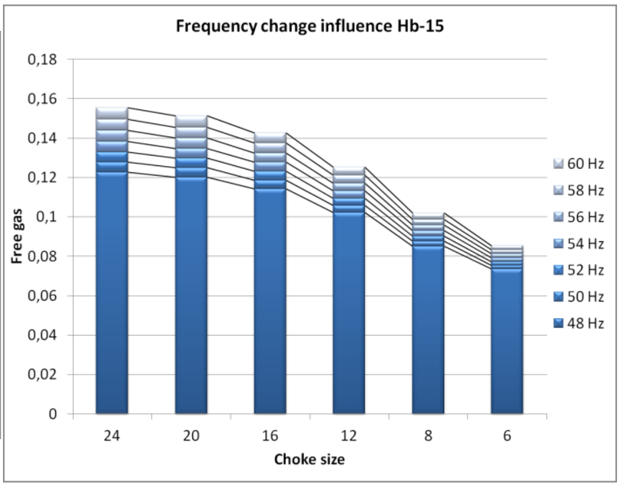


Figure 42: Surface diagram and Frequency change influence Habban 15

5.6.3 Habban 20

The match for Habban 20 was done in May 2013. The pump was operating only for a period of 20 days. Unfortunately the downhole gauge failed from the first day on and provided no data of the discharge pressure. The reading from the motor temperature chart showed some peaks during the runtime of the pump. These peaks can be related to a cycling behaviour or gas interference in the pump. After start up, the pump was operated on a choke size of 24 and a frequency of 48 Hz. The simulation showed that the pump, operated with these parameters, is out of the recommended operating range strongly in the upthrust region. A change of the parameters to a choke size of 12 and a frequency of 60 Hz would have the same gas fraction value of 18 % but be much closer to the best efficiency line. By setting the choke size to 12 and the frequency to 54 Hz a decrease of the gas fraction to 15% can be reached. This operating point would also be closer to the best efficiency line than the initial operating point.

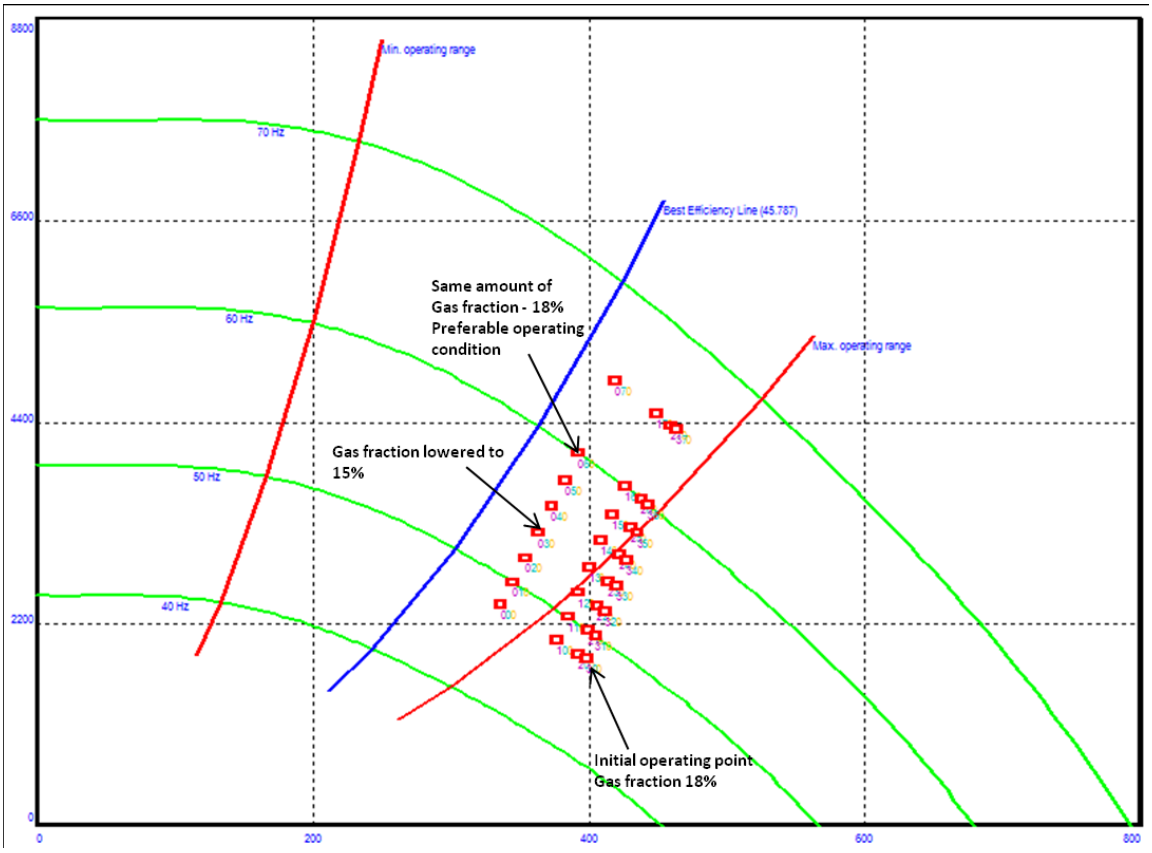


Figure 43: Pump plot Habban 20

Despite the limited set of data the charts for the change of the free gas value and the influence of the frequency change showed the same behavior like in the other matches. The squeezing of the free gas fraction values for smaller choke sizes can also be recognized. An operation of the pump at a choke size of 24 and a frequency of 60 Hz would lead to a gas fraction of 28%. A reduction of the choke to 12 would lead to a gas fraction of 19% at the same frequency.

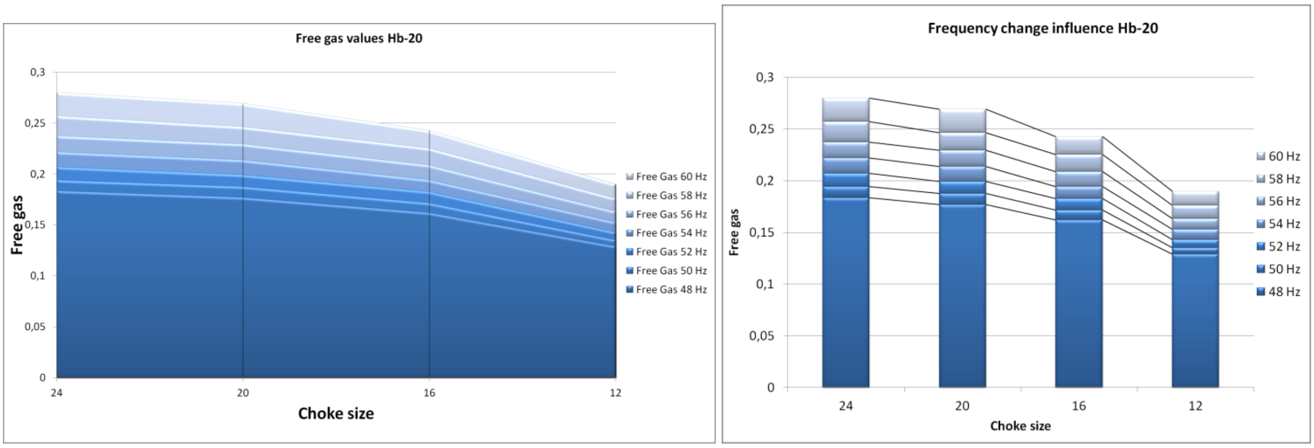


Figure 44: Free gas change and Frequency change influence Habban 20

5.7 Influence of flow regime

ESP performance curves are determined by using water as the working fluid. This leads to specific single-phase performance curves that are describing the relationship between the developed head by the pump and the flow rate through the pump for a certain rotational speed. The head performance curves are then valid for any other low viscosity single-phase liquid, independent of its density. Usually presented on the same chart are brake horsepower and efficiency curves. The performance of multistage pumps handling incompressible fluids is presented on average per stage. As already described and used in this thesis, two vertical lines define the lower and upper limit where it is recommended to operate the equipment.

For low viscosity oil with no free gas or very low free gas fractions (<2%) at pump intake conditions, the sizing of a multi-stage ESP has shown good agreement based on the water performance curves supplied by the manufacturers and corrected by the homogeneous model approach.

As already presented in chapter 3.5.2 the centrifugal pumps suffer from head degradation while handling higher contents of free gas. Therefore the performance based prediction on single-phase water performance curves, corrected by the homogeneous model, are not applicable. Beyond to the performance degradation while handling free gas, the submersible pumps also require a prediction of surging and gas lock conditions. Therefore the homogeneous model is incapable of correctly addressing these problems. [21]

The surging phenomenon was already discussed in this thesis. In other literature it is also known as heading or the term instability is used. For an entire range of liquid flow rates though fluctuation is observed in two-phase flow. Studies from the nuclear industry state that surging appears as a discontinuity in the head performance, and such discontinuity is a consequence of a change in a flow pattern from dispersed bubble or turbulent churned flow to stratified or slug flow. This abrupt fluctuation in performance is most likely for flow rates smaller than the best efficiency point and changes with the amount of gas at the pump intake.

The next deteriorating stage after surging would be the gas lock condition. During this condition the pump stops to deliver head. Once the pump is in this condition it could be brought to normal operating condition by either increasing the intake pressure or shutting down the pump so that gas is pushed out of suction by liquid. An increase of the intake pressure can be reached by the former presented strategy. [22, p. 2]

A reduction of the choke size and a raise of the frequency have two major effects that influence the performance of an ESP. Due to the increase in frequency the rotational speed of the pump is higher. This influences the flow regime inside the stages to be more turbulent and helps to disperse and break up gas bubbles in smaller ones and avoid the formation of gas pockets. The reductions of the choke size leads to a higher pressure regime in the well and therefore to a higher pump intake pressure. This increases the amount of gas that can be handled by the pump.

PROSPER provides an analysis of the flow regime that's present in the well. After the simulation of the different cases the flow regimes were analyzed for the wells. The graph below shows the data for the first match of Habban 10. It can be seen clearly that for choke sizes of 26 and 22 no changes in the flow regime for all frequencies can be recognized. This means that during the operation under these parameters it is very likely that slug flow was present. Of course this can be the reason for the cycling behavior of the pump. The simulation also showed that a reduction of the choke size to 18 can reduce the transition depth from slug to bubble flow to 3800m-MD for a frequency of 50 Hz and to 4600 m-MD for a frequency of 52 Hz. A reduction of the choke size to 14 reduces the transition depth significantly. For the frequency values 50 Hz, 52Hz, 54 Hz and 56 Hz the change of the flow regime would be above the pump which means that a bubble flow would be present at the pump intake. This operating condition is much more preferable than the operation of the pump with a slug flow regime present at the intake.

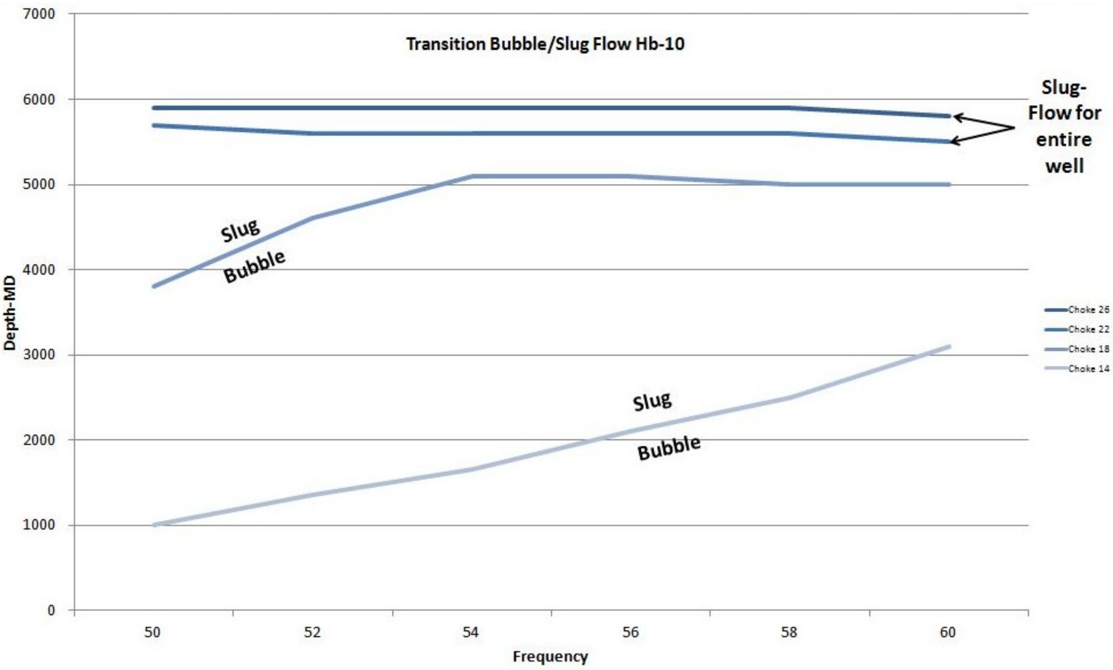


Figure 45: Transition between Bubble/Slug Flow Habban 10

6 Available ESP-Technology for gassy wells

The usage of ESPs for wells with high amounts of free gas is nowadays technically feasible. Over the past years different technologies were developed to meet this challenge. The following chapter should give an overview of these developments and provide a summary of the actual state of the art equipment. Also different case studies were reviewed to present the experience that different companies made after the installation of special ESP systems in gassy wells.

6.1 Case Studies

A lot of companies are struggling with the operation of ESP pumps in difficult environments. The design process for an ESP pump is always an interpolating process and due to changes in the reservoir or other parameters a final design will not be achieved. It will always be a "best fit" solution for the actual circumstances. A company, that can make usage of the knowledge provided by other companies via platforms like ONEPETRO, may be able to avoid design failures for their pumps. The following case studies presents a summary of interesting case studies, sharing the knowledge gained by other companies, with a special focus on the high GOR topic and operation of ESPs in difficult environments.

6.1.1 Successful Implementation of ESPs in a High-GOR, Poorly consolidated corrosive field

The study presented at the SPE Annual Technical Conference in 2005 by engineers of Harvest Vinccler covers 114 ESP wells completed in the Uracoa and Tucupita Fields, located in the state of Monagas, Venezuela. After the installation of the ESP and operation of them for approximately two years several problems were identified:

- Moderate to severe abrasion in the gas separator due to sand production
- Corrosion in the production tubing due to sulphate reducing bacteria, CO_2 and erosion
- Seal failure
- Pump failure
- Electrical problems
- Low run life

The initial ESP design consisted out of abrasion resistant floating stages with a few compression staged pumps. Radial and mixed flow stages were used and the pump capacity ranges were between 650 BFPD and 27 000 BFPD. Also a dynamic gas separation device was used which utilizes natural vortex action to separate the gas. All ESPs were equipped with a VSD with different sizes. After pulling and tear down the first ESPs the design was changed to standardize the design and decrease the pump and seal failure rates. Especially the pump configuration was changed to compression stages with few floating stages and an abrasion resistant configuration. Performance of the ESPs was continually monitored and analysed using nodal analysis software. Whenever the ESP equipment was not working efficiently operational changes to alleviate the situation were made.

For this case study it stated out that the failure analysis procedure has helped to identify the weaknesses in the system and generate ideas for the improvement. The design change reduced seal and pumps failures and extended overall MTBF. An additional injection of corrosion inhibitors and biocides also enhanced the MTBF. [23]

6.1.2 ESP installation in very high gas environment, using Multi Vane Pump and Tail-Pipe in PDO

Petroleum Development Oman presented a paper at the SPE/IADC Middle East Drilling Technology Conference and Exhibition which presented their decision process and experience with the installation of a Multi Vane Pump (MVP) in a well with a high GOR.

The presented well was self flowing but quit after a drop of the reservoir pressure and increasing water cut to 20%. After a long shut-in period the well was put on test in 2007. It flowed for about 10 hours and died out. The objective was to put the well back on production with an ESP capable of a high GOR due to the depleted reservoir conditions and production below the bubble point.

They decided to use the Centurion Multi Vane Pump after exploring all available technologies for handling high GOR in the market. The Multi Vane Pump integrates three principles of gas handling and it tolerates gas fractions up to 90 %. The three principles are:

- Balancing holes that mitigate the pressure difference and thrust loading. If there is the forming of a gas pocket due to low pressure regions the gas can easily escape through those holes.
- A split vane design to get a more homogenous fluid. With a split vane design a turbulent mixing occurs which is favourable for flow capacities to carry the gas without becoming stagnant.
- A steep discharge angle transmits a greater amount of kinetic energy to the liquid. This increases the lift at lower flow rates.

In addition to the MVP a 5.5” shroud cross-overed to a 2 7/8” tail-pipe was installed to produce from below the perforations and minimize the risk of a gas entry into the pump. Also a rotary gas separator was added to reduce the gas entry to the pump.

After commissioning and during the first period of production, the fluid drawdown caused a significant increase in gas migration into the wellbore and related to that an increase in average GOR and casing pressure. This means that a big amount of gas has skipped the pump entry and went to the annulus. Of course this is due to the tail-pipe technique and the installed gas separator. This provided a good flow beyond the expectations of the authors for the first 2 months. Afterwards the well declined and sustained with the same rate for approximately 3 years After more than three years run time the pump failed electrically due to a burnt motor due to water ingress either through the seal thrust chamber or the sensor O-ring. During the run time of the well an interesting action took place. The well started to tripping on high intake temperatures revealed to a gas accumulation in the annulus. It stated out that the casing master valve wasn`t operated properly and therefore a bottleneck. After bleeding-off the casing the well went back to normal operation. The well was restored with the same set-up in 2011 and doing well after commissioning. [24]

6.1.3 ESP design changes for high GLR and high sand production: Apache stag project

A team of Apache Energy Ltd. and Schlumberger presented a paper at the SPE Asia Pacific Oil and Gas Conference held in Melbourne, Australia in 2002.

The paper main focuses on the design changes and lessons learnt of the completion and ESP design, which initially ran for only 191 days but then averaged 511 days. The initial ESP designs for the Stag oilfield, located at the Australian Northwest Shelf, were based on a low GOR, high viscosity crude oil. However, higher than forecasted gas rates and gas-oil separation in the 3300 ft long horizontal production sections resulted in flow from the reservoir in the form of slugs of gas and oil. With the onset production of water, high volumes of produced sand compounded the problems. These two main issues, plus a rapidly declining reservoir pressure, have combined to present a challenging ESP production environment.

The initial design located the ESPs at the start of the horizontal sections of the wells. A production packer was installed below the ESP to provide reservoir isolation during workover. The design of the ESP included a pressure containing shroud that completely enclosed the ESP. The benefit of this design is the elimination of the need for a packer above the ESP to provide isolation of the reservoir from the production tubing/casing. Originally the ESP was equipped with a 28-stage pump and a gas/fluid handling conditioning system designed to handle GOR`s up to 400 scf/stb.

After production commenced it became clear that the producing GOR`s were significantly higher than expected. In addition, a poorer than expected aquifer support resulted in a rapid decline in reservoir pressure which further led to the release of solution gas. Consequently, free gas fractions in excess of 80% were common at pump suction conditions. The high gas fraction was further complicated by the very long undulating horizontal sections in the wells, which caused large, high frequency, gas slugs which continually locked the pumps resulting in numerous shutdowns. At this time the overall production rates from the Field were significantly lower than forecasted and the average run life of the ESPs were 191 days. The failures of the ESP components were due to high gas slugging through the pump wich exerted a cyclic upward thrust on the impellers.

As a second design a vent packer completion in combination with a gas separator was used to reduce the volume of free gas passing through the ESP. Unfortunately this design increased the production only 15-20% and the pumps continued to experience gas locking, albeit to a lesser degree. It stated out that multiphase flow was occurring in the annulus. The liquid was choking flow across the vent packer safety valves and in the annulus flowline at surface. Consequently the gas slugs were not being vented efficiently. Nonetheless, the run life of Design 2 exerted the run life of Design 1. The average run life of the pumps was 385 days.

The next stage in the design evolution was to look at methods of de-bottlenecking the annulus. The primary objective of the new completion design was to enhance the ability of the completions to vent large gas slugs while allowing natural flow oil production up the annulus while reservoir conditions supported it. Therefore the vent packer was removed and the wells TRSV was set down to the production packer/FLD assembly. Above the pump an Auto Flow Sub was installed and the distance between the perforated tubing and the pump intake was increased. The new design enhanced the natural gas separation in the annulus and provided auto gas lift annular production. It also enabled well bore isolation in the event of problems. The Auto Flow Sub was incorporated to provide the facility for natural flow of the well via the tubing whilst by-passing the tubing.

After the installation of this design the expected production rates could be reached and gas-locking of the pumps could be avoided. Due to the higher production massive volumes of sand were produced. Therefore different changes to further improve the endurance of the pumps were made. The changes include different materials for the bearings and the sleeves. Zirconia and silicon carbide were chosen and also a more wear resistant stage material was used. Additionally the cable was changed to a lead sheathed cable to ensure that it would not be the next failure mode.

The design changes extended pump run life to more than 3 years. The authors described five key lessons in their final conclusion:

1. Design your developments with contingency in mind. Reservoir models on new field developments frequently do not match reality.
2. Design wells and completions with flexibility as one of the key components
3. The off-the-shelf solutions that work in most ESP applications are not applicable for high sand and gas slugging conditions.
4. As with many projects incorporating ESPs, the mature economic life will be determined by two main factors; the price of the oil and the run life of the ESP.
5. The achievements highlighted have required a significant level of ingenuity and lateral thinking. Teamwork and perseverance is required across the board to enable significant design changes in extremely short time frames. [25]

6.1.4 High GLR ESP Technologies Comparison Field Test Results

A group of engineers of RN-Purneftegas, Rosneft and M. Prado from the University of Tulsa prepared a paper for the Russian Oil & Gas Technical Conference and Exhibition held in Moscow, Russia in 2008. They presented in their work the results from a field test of the performance of state of the art gas handling technologies based on real well field tests.

Like already mentioned in this Thesis, the three common approaches used when designing ESP systems for gassy wells are to avoid conditions of excessive free gas, separate the excessive free gas and/or handle or condition the free gas. The study concentrated on the third approach, to handle or condition the free gas. This can be accomplished by using special devices specifically designed to have a higher tolerance to the presence of free gas than regular ESP stages.

For their study three different conditioning device technologies from different vendors were selected to be tested:

Technology 1 consisted mainly of a gas conditioning device for ESP. This device is expected to create a homogenous flow and additional pressure increment at high gas fractions. This unit is a centrifugal pump with a set of specially designed mixed flow type stages.

Technology 2 is a pump with axial-design stages. Axial flow stages have a more efficient energy transfer mechanism and supposed to result in trouble-free operation at high free gas fractions. The special designed flow stages ensures a good mix between the gas and liquid. This breaks up large gas bubbles and the gas and liquid mixture is pushed through this device to the regular stages of the pump.

Technology 3 is an ESP completely equipped with specially designed radial-type stages that are able to work with higher gas fractions at pump intake.

The main objectives of the field test were to determine the technical limits of new ESP conditioning devices and to prove the possibility of incremental oil production with the use of conditioning technology. Therefore all operational parameters were recorded during the tests. A mobile multiphase flow meter was used to determine the GOR and flow rates for both phases at the surface. The readings of the multiphase flow meter were verified by comparing the results with standard phase flow meters that consist of mass measuring units. Electronic pressure and temperature gauges were installed at the Christmas tree to measure temperature and pressure at the wellhead and to determine the dynamic liquid level of the fluid in the annulus. Also a downhole measurement of pressure and temperature at the pump intake was performed. To analyse the total downhole gas separation efficiency and the ESP pressure head degradation a procedure was developed.

A total of 78 measurements were made in 41 different wells, including the measurement of new ESP conditioning devices in 12 wells and standard ESP equipment in 29 other wells.

The tests results showed that the multiphase flow meter showed a complicated dynamic behaviour of the liquid flow in the pump and well bore. For the tested wells, the period of liquid rate oscillations or fluctuations varied from 2 to 15 min. The range of changes was rather wide, including short-time interruptions of liquid feed to the surface. Therefore the maximum liquid rate was in some cases twice as large as the reported average. It should be noted that in all cases gas flow rate changes occur several minutes slower as compared with those of the liquid. Probably this is connected with a short time period where conditions at the pump intake exceed that of the critical gas fraction and the gas tends to form big bubbles or slug flow. Such operation of the well and the pump is accompanied by the typical increase of the electric engine current fluctuations also known as "current saw". For some high GOR wells operating under different conditions when the parameters change within several hours the pump intake pressure also changes with time. Such behaviour can be caused by an insufficient head developed by ESP due to the performance degradation. This undesirable behaviour can be eliminated by increasing the frequency.

The test result showed a good agreement between experimental results and the manufacturer specifications. But the authors mentioned that from a practical point of view it is not sufficient to know the ultimate gas fraction to select the most efficient technology. The second important factor is the pump pressure head degradation that indicates how much more stages are required to ensure the same performance as in homogeneous conditions. If ESP pressure degradation is not accounted when selecting and sizing the equipment, it can result in a wrong number of stages which may be insufficient to sustain the design operating conditions.

Finally the capability to increase the oil production was confirmed. The best results were observed in wells equipped with Technology 2. Technology 3 showed the worst results due to the bad performance during a long period of time with high gas fractions in the pump. It showed out that the conditioning device, used in Technology 2, prevented the pumps from a permanent gas lock.

The authors wrote in their conclusion that it is proven that ESP can operate successfully with gas fractions up to 75%. The factors which influence ESP operation like gas fraction, head degradation, water cut and pump intake pressure have to be considered carefully. [26]

6.1.5 ESP Runtime Optimization – Low Volume High GOR Producers

A team of engineers working in the South Fuwaris field and Humma field in PNZ-Kuwait presented a paper at the Abu Dhabi International Petroleum Exhibition & Conference held in Abu Dhabi, UAE 2010.

Both fields are producing from tight carbonate reservoirs with 95% of the wells operated on ESP pumps. The failures of ESP components in low volume – high GOR producers are generally due to the high gas rates passing through the small impeller veins of the pump. When no fluid or to less fluid passes the pump it will either trip on underload and/or the ESP motor will fail on overheat. In such cases the industry practice is to equip the well with gas separators, gas handler, special impeller designs or bottom feed intakes. In very high free gas rate cases this systems may function not properly. The asset team had little or no success with their attempts to improve ESP`s runtime through the installation of such components in their low volume-high GOR open-hole producers.

To reduce the number of underload ESP trips and components failures the following mitigation plans had been historically applied to two candidate wells:

- Implementation of bottom feed intake design
- Installation of the gas handler as part of the production string to compress the gas back into solution and produce it mixed with the liquid through the pump
- Inverted shroud with the primary function of gas separation (no motor cooling)
- Setting the VSD to run in the I-Limit mode
- Installation of regulator valve on the surface to control the rate of casing gas
- Installation of a Back Pressure Valve on the surface for choking and maintaining the well

Representative values of free gas at the pump intake calculated from nodal analysis software and produced GOR measured through field production tests showed values of 65.2% and 77.6% free gas at pump intake for the two wells.

To meet the special requirements the team developed a dual-shrouding system assembled together in one piece that fulfils two functions. A schematic of the dual shroud system can be seen in the Appendix C The primary function was the cooling of the motor and the secondary function the separation of the gas before it enters the pump. Also a perforated tubing serving as an intermediate fluid pathway and as an additional element for further gas separation was installed. The final design can be seen in Figure 46.

The newly designed shroud system, with its built in perforated tail pipe, successfully reduced the number of ESP shut downs, resulting in improved ESP runtime. With increased ESP run life, the newly-designed shrouding system completely eliminated cases of underload shutdown caused by gas locking of the ESP. Also minimal free gas enters the perforated tail pipe, resulting in shielding of the pump from the adverse effects of the annular slug flow. The provision of a large flow area between the perforated tail pipe and its enclosing shroud results in a low annular fluid velocity which consequently improves the overall gas separation efficiency. [26]

6.2 Completion Architecture

The first ESPs were installed nearly 100 years ago and just simply run on a tubing in a cased hole. Since then a lot of new completion architectures have evolved to cater for a wide range of needs. This includes dual barriers for offshore operations, reservoir monitoring, flow assurance, backup gas-lift, back-allocation for multi-layered reservoirs and dual ESP-systems for enhanced run life. These kinds of solutions were made possible by new completion tools and the process of developing new tools is still ongoing.

Decisions related to the choice of completion architecture are taken either during well construction or during workover planning stage. For wells fitted with ESPs, the decisions regarding to the completion equipment effect production operation in many ways. It is the impact on production, which constitutes the value generated either positively by increasing production or negatively by increasing deferred oil. Therefore all factors have to be taken into account that one can generate the production functional requirements of a well equipped with an ESP.

These factors can be summarized as follows:

1. Delivering production or draining the reservoir
2. Safety:
    a. ESP completions with dual barrier systems
    b. Well control (e.g. killing the well)
3. Well integrity: in most cases the protection of the production casing
4. Dynamic Reservoir Surveillance: especially measurement of rates, pressures and temperatures
5. Production optimization: management of drawdown to maximize recovery factor while considering inflow and outflow
    a. Especially gas venting as it can optimize outflow
    b. Production of multi-layered reservoirs as it optimizes the inflow side of the equation
6. Flow Assurance: all deposits which can reduce or stop production
7. ESP redundancy: here the focus is on extending the mean time between failure (MTBF)

The decisions are classified as strategic by most of the operators as it impacts the evaluation of the course of action during both phases of well construction and production. It may also impact the amount of wells that have to be drilled in a reservoir to achieve the targeted recovery factor. The strategic classification is gained due to the fact that there is a limited window of opportunity with respect to time within which the decision has to be taken to realize value for the stakeholders. Besides this, the decisions are usually irreversible, at least for the period between the workovers and sometimes even for the live of the well.

6.2.1 Delivering production

Of course, the most important function of an ESP completion is to deliver production and optimize reservoir drainage without any damage of the reservoir. Of course it is obvious that the tubing and casing sizes have an effect on ESP design and production and there are numerous textbooks and papers available written on the subject of tubing sizing. However, there is one aspect of tubing size selection that is often overlooked and should be mentioned in this work. Although high velocities are typically avoided in the tubing design to minimize frictional pressure drop they are able to improve the flow regime and solid entrainment. Furthermore, higher tubing velocities can increase wellhead temperatures, which can reduce deposits of organic scale. Whereas, low liquid velocities can cause slugging of liquid loading issues as well as sand fall-back on top of the pump or check valve.

Usually any additional friction can be compensated by simply adding stages or running at higher speeds or both. Therefore, the flexibility of adding stages or managing speed associated with ESPs provides the production engineer with the opportunity to optimize the flow regime and flow assurance environment Due to the fact that tubing size is usually standardized across a whole field and that tubing must be ordered in advance to mill lead times the selection of the right tubing size is very important.

6.2.2 ESP completions with Dual Barrier Systems

A common definition for a well barrier is an envelope of several dependent barrier elements which prevent formation fluids from flowing unintentionally from the formation into another formation or to the surface. A single barrier, which consists of the casing, the wellhead and the master valves is normally sufficient for a land-based non-eruptive well. There are a lot of governing authorities who insist on two barriers for wells which are either eruptive or located offshore. The provision of two barriers often complicates ESP completions and, therefore, must be discussed in more detail.

The primary barrier is normally in direct contact with the reservoir fluids. The elements of the secondary barrier only come into contact with reservoir fluids if the primary barrier fails. A common way to realize the dual barrier is the installation of a packer and a surface controlled subsurface safety valve (SCSSSV). It is accepted by most governing authorities and complies with API standards 14A and 14B.

In the Appendix D, 5 different dual barrier ESP completion types are compared and evaluated for different functional requirements. For these common completions the secondary barrier is always the intermediate casing, wellhead and master valves and the primary barrier is the safety valve and the packer. The five architectures can be split into two groups, whether casing protection is required or not. This is important if the reservoir fluid is corrosive and the casing material cannot be exposed to the production stream or the casing is not strong enough to withstand the formation overburden pressure under the expected drawdown conditions. For both challenges there is one solution, setting a packer deeper so that the annulus can be filled with a completion fluid which protects the casing from corrosion and counterbalances the overburden pressure on the casing. Also the ESP cable is not exposed to the well fluids. However, while casing protection is an important first step in the choice of the right completion architecture, a lot of ESP installations do not require this functionality. As with most decisions, there is no right or wrong answer, just a series of compromises. It is nevertheless important to evaluate how all the production functional requirements interact with the dual barrier policy.

6.2.3 Completion optimization

Over the last years multiport packers have become very common. However, compared to a packer arrangement located below an ESP the multiport packers have the following disadvantages:

1. Multiport packers are generally more expensive than monobore packers
2. With the packer above the ESP, it has to be pulled and redressed at each ESP change out
3. Installing a multiport packer above an ESP the need for two additional power splices plus a feedthrough is necessary
4. Gas venting is potentially constrained, although this is dependent on the reservoir conditions. However, in 7 in. casing it is very difficult due to the insufficient space to fit a gas vent valve. [25]
5. For shallow set multiport packer above the ESP, circulating between the tubing and annulus is virtually impossible. In most cases there is no port available in the packer and if there is a port available the orifice limits the pumping rate.
6. Gas Lift back-up is more complex and often not possible
7. Bullheading fluid into the reservoir can only be done down the tubing and not via the annulus.

Because of these disadvantages, many operators have changed their completions to deep set packers below the ESP. Also has to be noted that as and when alternatively deployed ESPs will gain more popularity, the number of completion architectures using a multiport packer below the ESP will increase as placing the packer and SCSSSV below the packer is necessary with cable- or coiled-tubing deployed ESPs. Whenever the packer has to be deployed above the ESP due to field specific or governmental reasons, the above presented potential disadvantages have to be taken into account.

6.2.4 Gas venting

Like already mentioned, ESPs can only handle a maximum GVF of ~20% at the pump intake. This means that gas separation or conditioning is necessary. For gas separation the completion architecture has to make the allowance of gas venting up the annulus. The annulus is than either reinjected to the flow line or flared. With the development of gas conditioning devices like Advanced Gas Handlers (AGH), helicoaxial pump stages and multi-vane pumps the GVF limit has increased to approximately 75%. Besides this there are a growing number of ESP applications which do not permit gas venting for the following reasons:

- Gas flaring is not allowed for environmental reasonst
- It is not possible to reinject gas back into the production flowline, which can be the case for remote wells which have a high wellhead pressure and a high annulus pressure would limit the drawdown
- Subsea wellheads do not permit gas venting
- There are some countries where the governing authorities do not allow fitting gas vent valves in shallow set packers
- Wells where the production casing cannot be exposed to reservoir fluids due to corrosion concerns

Besides the evolution of gas handling technology, gas venting is still an important consideration, especially since separating gas can improve pump efficiency and reduce slugging conditions in the production tubing. For this reason, gas venting is simply a functionality which must be considered when designing the completion architecture.

6.2.5 ESP redundancy

Dual ESP-Systems

Over the recent years a large growth in dual ESP systems driven by the need to increase Mean Time Before Pull (MTBP), for environments in which the cost of workover is high or rig availability is low, could be recognized. The concept is simple that when one ESP fails the production is switched to the second ESP, thereby doubling the MTBP. There are two different concepts available how a dual ESP completion can be realized. The first concept works with Y-tools which allow access below the ESP. The second concept works with a so called POD (also CAN system), a sealed shroud that encapsulates the ESPs. Both systems have advantages and disadvantages and should be taken into consideration during the design process. An aspect that is noteworthy is the opportunity that the installation of the dual system offers to expand the production range. By selecting different pump sizes the production can be optimized to manage inflow uncertainty on wells or manage inflow change over time.

Backup Gas lift

Many ESP applications result from the conversion of gas lift wells and therefore a back-up gas lift is a viable option for reducing deferred production in the event of an ESP failure. However, from the completion point of view the annulus between the tubing and production casing must obviously be made available to gas injection. For wells without a packer, back up gas lift can be still considered. The point of reservoir inflow is an Sliding Sleeve Door (SSD) or an Auto flow sub (AFS) just above the ESP. this architecture is recommended since the flow through an ESP leads to unnecessary pressure losses. However, the depth of the gas lift valve must be set so that its height is such that the pressure drop in the tubing between the SSD and the gas lift valve is greater than the pressure drop across the gas lift valve. With this setting the gas always takes the way of least resistance and enters the tubing over the gas lift valve and not over the SSD. For offshore environments also back up gas lift in combination with dual ESP were planned to maximize the MTBP.

6.3 Shrouds

The usage of shrouds is a simple and effective method to control free gas volumes at the pump intake. The shroud is a simple cylinder fitted around the motor, protector and intake section of an ESP. It is designed to reduce the annular area between the ESP and the casing bore, which allows the velocity of fluid by the motor section to increase and subsequently helps to cool the motor. It is simply constructed with a length of tube, long enough to swallow the motor, protector and intake sections and is bolted with a split clamp unit to the first ESP neck located above the intake. [28]

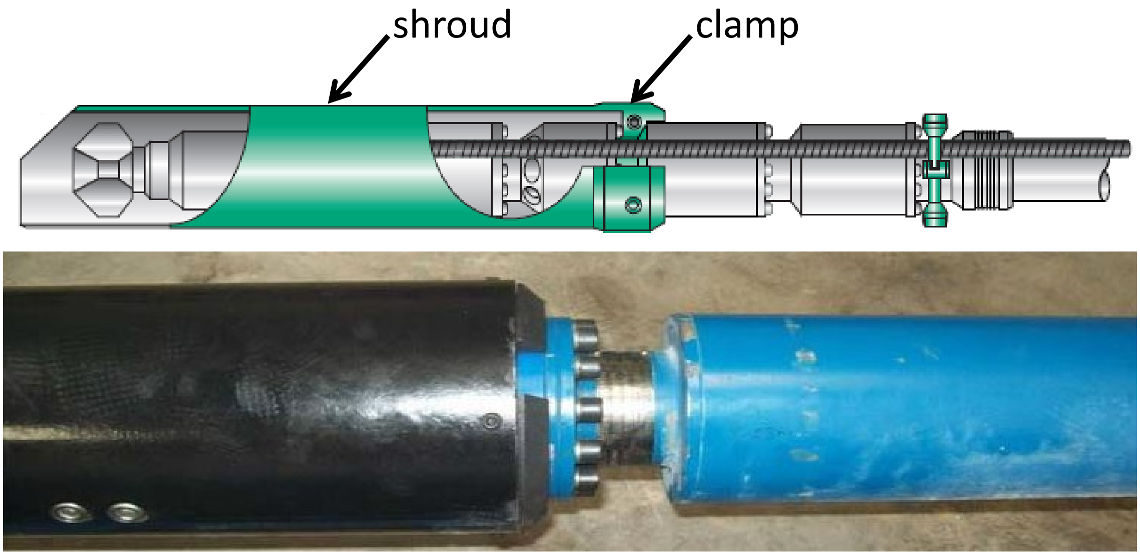


Figure 46: Shroud [28] [24, p. 9]

Shrouds are available from different suppliers and in different designs like inverted shrouds. Every bigger ESP vendor has them in his program and there are also some smaller companies selling shrouds and other ESP completion equipment (e.g. RMS pump tools). To implement a dip tube or tail pipe standard tubing pipes are used.

6.4 Gas avoiding intake systems

Especially for horizontal wells or highly deviated wells free gas can form slugs on top of the well and then move into the intake of the pump. To avoid this, special intake systems were developed where only the heavier liquid phase is able to enter the inlet ports. Schlumberger offers the Bottom Feeder Intake which is constructed in a way that gravity causes the intake ports to orient toward the bottom of the well. This enables the fluid to enter the pump from the bottom and the gas to bypass the intake on the top. A similar technology was developed by Baker Hughes. They offer three different pump intakes designed specifically with gas avoiding capabilities: standard, gravity cup and bow spring. The gravity cup works similar like the device from Schlumberger. With the bow spring intake, 8 bow springs resting on the casing bottom activate mechanically and open intake ports to divert production from the casing bottom. Bow springs on the top keep these ports closed. The standard intakes have a long intake section that encourages natural separation of gas.

6.5 Gas Handlers

The role of gas handling devices is to homogenize the mixture, reduce bubble sizes, put gas back into solution and move gas back into mainstream. They can also be combined with a gas separation device. Schlumberger is offering the Advanced Gas Handling Device for wells having up to 45% gas void fraction. They are available for different flow rates ranging from 500 – 25 000 bbl/d. GE Oil&Gas also offers a gas handling device which use axial flow and proprietary pump stage geometry to homogenize the gas. GE states out that they can effectively manage up to 70% free gas and can be used in conjunction with a gas separator in extremely high-gas environments. Baker Hughes is offering their Multi Vane Pump (MVP) as a gas handling device. When combined with a conventional ESP the MVP acts as a charge pump for a standard ESP system. Special designed impellers with a split vane design and a steep vane exit angle are used for this tool. The MVP is able to operate in fluid conditions exceeding 70% of free gas and it is available in two common sizes, 4 in and 5.38 in. Also the Russian vendors Borets and Novomet have gas handling devices in their programs.

6.6 Gas separators

As already described in chapter 2.6.2 there are different separator technologies available. All the major vendors have rotary and vortex type separators in their catalogues. Schlumberger offers both types, the vortex separators are available from 2000 – 15 000 bbl/d. Baker Hughes sells their separators under the brand name GM performance series. Also rotary and vortex type separators are available and the customer can choose between three different abrasion resistant configurations. Other vendors for gas separators would be GE Oil&Gas, Borets and Novomet.

6.7 Multiphase Pumps

The term multiphase pump is used different by the vendors. Most of them use it to classify their products which have the highest capability of gas handling. Actual there are two different ESP technologies available at the market. Schlumberger has developed the patented Poseidon system. This system has specially designed axial-flow stages which are designed to minimize the radial velocity components of the fluid and reduce the separation of the gas liquid phase. A special hydraulic design of the pump, unlike conventional centrifugal pumps, does not rely on accelerating the fluid in the radial direction to transfer energy to the fluid mixture. Therefore, the gas and liquid phases are both guaranteed to move from one stage to the next inside the pump, gaining energy progressively. The system can be operated at lower intake pressures with GVF in the pump up to 75%. In combination with a gas separation device higher amounts of free gas up to 90% can be handled.

Figure 47: Poseidon Multi-Phase Pump [7]

Also the Russian supplier Novomet is offering a multi-phase pump which design is very similar to the Poseidon system. Novomet claims that the pump is capable of handling 65 % GVF at the pump intake.

Baker Hughes took another path to develop efficient multi-phase equipment. They tried to modify the stages to increase the gas handling capability. The outcome of their research work is the MVP multi-phase pump. The impellers have a split vane design that prevents gas accumulation in the impeller. Also a steep vane exit angle is used to confer high momentum to the fluid exiting the impeller, expanding gas evacuation. Oversized balance holes are used to create turbulences that break up gas bubbles. The MVP can be used alone or employed as a charge pump. Therefore it is able to continually operate while producing substantial lift in fluid conditions exceeding 70 % free gas. It can also be combined with a gas separator for applications with more than 90% free gas.

6.8 Variable Speed Drives

One of the most important equipment to handle high gas fractions and changing conditions in an ESP pumped well is the Variable Speed Drive (VSD). Only a VSD enables the full potential of a pump and makes it possible to change the speed of the pump. An important factor during the selection of a VSD system is the quality of the output signal. The output wave form should be very similar to a true sine wave to reduce harmonic distortion. The reduction of harmonic distortion leads to longer lifetime for the electrical components.

Every bigger vendor is offering VSD systems that can be operated in every environment. The latest developments at the market are VSD systems equipped with special software. For example the Advantage VSD from Baker Hughes is equipped with intelligent production software and a Real-Time Torque command. (RTTC). This system delivers the exact amount of torque that the pumping load requires at any given instant. With the real-time calculated torque values a precise control and protection of the pump against varying loads can be made. Also a real-time cable compensation, that calculates the appropriate surface voltage based on the changing loads, is implemented. This assures that the proper motor voltage is being applied at all times for most efficient operation. It is also possible to load modular customized production-assisting software into the controller which can improve the performance of an ESP system.

6.9 Monitoring Instruments

6.9.1 ESP Monitoring

Operators realized very quickly that motor protection is essential to maximize ESP run lives. Solid state motor controllers have provided the essence of this protection, which has driven their technical development with ever increasing functionality being introduced by manufacturers. Usually these devices rely on stopping the ESP which results in downtime and additional ESP starts. At the same time SCADA systems have also evolved, complemented by data-hosting systems that can be programmed with alarms to enable monitoring by exception. As advances in computer technology and web access generated a vision of oilfield management from a desktop the industry saw a proliferation in demand for real-time and Intelligent-Field projects.

To explain the importance of ESP monitoring and how run life can be improved, all the activities required to operate a field lifted with ESPs have to be reviewed. This is best explained by a block diagram, which is shown in Figure 48. ESP operations involve managing two closed feedback loops, which can be named as the “fast” and “slow” loops. Generically, such feedback loops have the steps listed below.

- Monitoring
    - Data measurement
    - Data Transmission
    - Data Storage

- Surveillance
    - Setting alarms

- Recording alarms
- Analysis of alarmed events, also known as diagnostics
- Recording events
- Decision making or recommendations
- Implementation

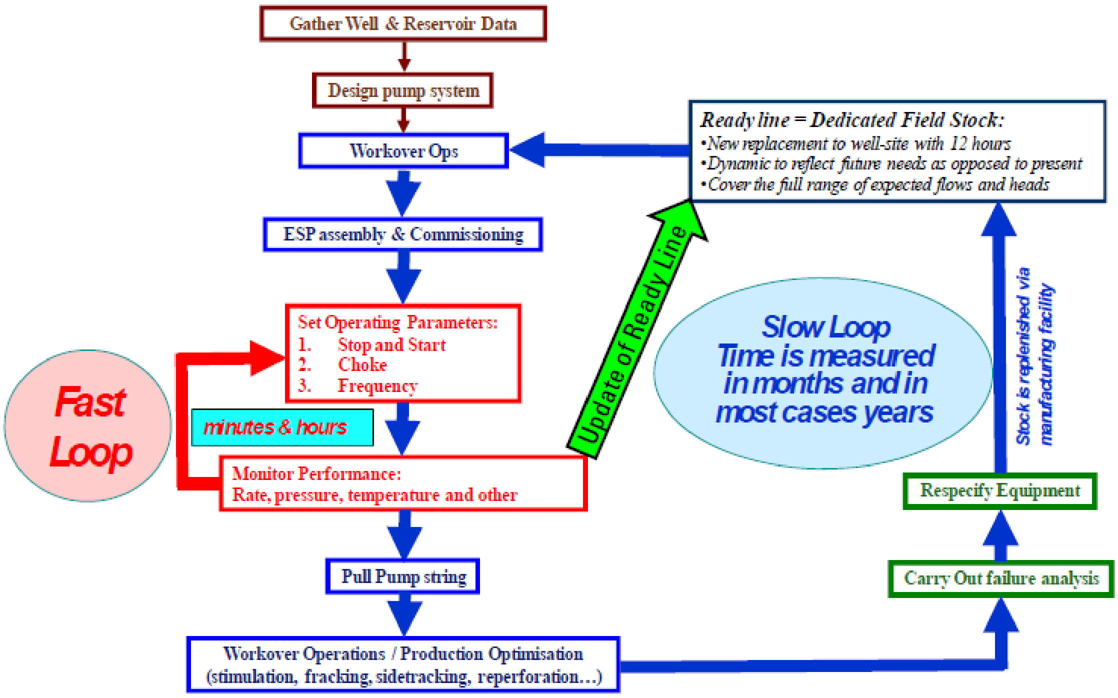


Figure 48: ESP operation block diagram [30]

The principle that the value lies in feedback loops is generally shared in the industry. It rests on the fact that data needs to be transformed into information in order to enable implementation of decisions, which is an age-old management principle. Value is also derived from recording and classification of events, which provide the basis for continuous improvement. Finally, the closed loop constitutes the difference between monitoring and surveillance, where the latter is synonymous with the closed feedback loop and includes monitoring as well as all of the above activities. It is therefore essential to have a thorough understanding of the loops, which are pertinent to maximizing ESP run life and uptime.

- The fast loop involves monitoring of ESP performance and making of decisions like start, stop or change of frequency and/or choke setting. The time frame can be very fast and the duration of each cycle is, therefore, measured in minutes and/or hours because ESPs react quickly to outside disturbance due to their low inertia.
- The slow loop time frame is determined by the mean time between pulls, which ranges from a few months up to 6 years. At each workover, the key decision is wether to rerun an identical ESP or whether to take the opportunity to change the specification with a view to improving the run life or increase production.

It is self evident that monitoring is essential to the fast loop, ensuring correct operation of the ESP much in the same way as the monitoring of a car engine`s water temperature. In itself however, the monitoring in the fast loop cannot explain ESP failure just as a high water temperature cannot explain car engine failure. [30]

6.9.2 Flow measurement with ESP gauges

As real-time technology gained more momentum in the oil industry, more and more wells are equipped with gauges and SCADA systems. Despite the growth in instrumentation, flow-rate measurements and recording have lagged and remain manual. Wells are typically tested once a month with manual data entry into the production system. To overcome this, servicecompanies have developed proprietary interpretation technique that provides real-time flow rate without the need to retrofit additional hardware in the field. Providing real-time well flow rate can improve back allocation and brings a new dimension to well and reservoir performance diagnostics. Superposition analysis is enhanced and can be used to monitor real-time reservoir pressure. With the usage of downhole measurements and interpretation technique production changes as low as approximately 10 bbl/d can be recognized. This granularity cannot be achieved using monthly well tests, particularly when production fluctuates rapidly. [31]

6.9.3 Dynamic fluid level metering

The measurement of bottomhole pressure is of special interest for reservoir and production engineers. While this task is relatively easy for free flowing and gas wells it can be challenging for wells which are lifted artificial. The measurement of the reservoir pressure and the well flowing pressure for these wells is conventionally done with a measurement of the fluid level and a calculation. This measurement is usually nonautomated, personnel and time intensive and not done continuously.

Nowadays automated fluid level measurement tools are available that can improve the run life of an ESP lifted well. An automated fluid level measurement tool can be used to control and optimize the systems more effectively. Some benefits are listed below:

- The tool can assist to protect pumps against running dry. It can be either switched off or be run at a smaller production rate if the fluid level tends to get into an unacceptable region
- It can assist the operator to stray within the recommended operating range
- Due to uncertainties of poor known inflow performance relationships, ESPs are often set up in a conservative production range to avoid equipment damage. The tool can be used to produce a well more efficiently without the danger of equipment damage. Furthermore higher drawdowns are available which will mobilize more oil.
- The continuous set of data can be used to design the replacing ESPs more precise and well specific which will elongate the run life and enable to set the pump more close to the maximum efficiency point. This lowers the consumption of electrical power and operational expense.

Besides the monitoring and controlling of a well during production, with a continuous measuring of the liquid level it is possible to perform pressure transient analysis. For example, the collected data during a shut-in period can be used for pressure buildup analysis. [32]

7 Conclusion

Due to the fact that most of the easy accessible oil is gone, new technology advances become more and more important. In the future, one of the main goals for the oil industry will be the maximum exploiting of known reservoirs. To achieve this goal artificial lift technology will be one of the key components. ESP pumps already have a big share in artificial lift technology and this share will increase in the future due to their operational advances compared to other technologies, especially for offshore applications.

Nowadays ESP technology is already very sophisticated but the development of this technology is a continuous process. The first ESP pumps were installed in the late 1910s which was the starting point of this important technology. At this time the pumps were high technology but compared to today`s one relatively simple. Due to different requirements special pump designs have evolved like helico-axial stages or Multi Vane pumps. Also wear resistant bearings and special designed sealing sections, able to withstand very harsh environments were developed. Pump controlling evolved from a single frequency controller to variable speed drives, able to adjust the pump speed individual. The increasing use of ESPs in wells with high amounts of free gas forced the companies to develop equipment for gas handling. Different gas separators, gas handlers and completion architectures are available to produce wells with high GORs efficiently with ESP pumps.

The main problem with free gas inside an ESP pump is mainly the decreasing of head and efficiency. The range of gas interference can be from small head degradation up to a complete gas lock of the pump. Under this condition the pump will not deliver any head. In the last years the operation of ESP in high GOR wells was very challenging for operators but development in equipment, to overcome this challenge, made it possible to operate pumps in wells with gas void fractions up to 90%.

Performing an ESP design is an iterative process that starts with a detailed evaluation of different parameters. Especially for pumps in high GOR wells a correct design is of major importance and directly related to the run life time of the pump. Besides the recommended API practice 11S4 for "Sizing and Selection of Electric Submersible Pump Installations", different software packages are available. This software packages perform the major calculations and have integrated pump and equipment catalogues for selection of the right components. However, what must always be considered is that the design software always performs a pin-point calculation for the special entered parameters. Of course there is the possibility to perform different cases and sensitivity analysis but the design engineer will always be confronted with uncertainty in the calculation models. Whenever the input data quality is bad or not very reliable, or the change of major parameters over the life time of the pump is expected, the uncertainty will increase. This leads often to wrong designed pumps resulting in short MTBF.

To address this uncertainty in ESP design the Risk-based design concept, developed in this thesis, can be used. The concept is spread-sheet based with an integrated software tool able to perform a Monte-Carlo simulation. The user is able to define expected operating ranges for the entire run life time of the pump. The ranges can be defined as different probability functions. After the calculation of the main design parameters and the Monte-Carlo simulation the spreadsheets delivers an estimation of the future operating parameter ranges and the different likelihood of the parameters. With this knowledge the design engineer is able to perform an ESP design able to handle all operational requirements during the lifetime of the pump.

If despite all efforts the pump is designed wrong or the operating parameters are outside the expected ranges and the pump is already in operation, very limited actions can be made. The goal for these circumstances would be an operating strategy that is able to operate the pump continuously and extend the MTBF. In this thesis an operation strategy was evaluated which allows an extended operation of pumps in high GOR regimes.

The change of the frequency and the choke size for wells that are equipped with a VSD system and an adjustable choke can have a significant influence to the pressure regimes inside the pump and wellbore. By chocking back and raising the frequency of an ESP lifted well the pressure regime raises and therefore forces more gas back into solution and avoids gas lock conditions. This strategy was evaluated for three wells in OMV operated Habban field and showed good results. With the application of the strategy the possibility of getting an ESP lifted well, that's under cycling operating conditions due to gas interference, back in normal operation is raised tremendous. It must be noted that an operation of the ESP pump with this changed parameters comes at the expenses of the energy efficiency of the pump. However, with the application of the strategy an increase of the MTBF for a well is possible that would fail definitely if nothing is changed.

An evaluation of different case studies showed that the operation of ESPs in gassy environments is a common problem in the industry. Over the last years different new equipment was developed to handle this problem. Nowadays the usage of ESPs for wells with high GOR is not any more out of the application range. With the usage of special shroud design, special designed stages and intakes the free gas can be handled and the ESPs are able to operate in environments up to 90% gas void fraction. Despite the selection of the right equipment the completion architecture also has a major influence. Different papers showed that a vented packer placed above the pump can act as a bottleneck and the gas is not vented properly. To overcome this any ESP completion should be designed with an open annulus to force natural separation and provide the free gas an unrestricted path to the surface.

Over the last years ESP monitoring become more and more important because the industry realized that continuous monitoring significantly improves the run life time of ESP pumps. Due the availability and installation of SCADA systems combined with gauges and intelligent controllers a real time monitoring of pumps can be made. In the future the usage of fuzzy logic or other probability based decision tools will further increase ESP monitoring and automated diagnosis. The usage of these tools can help to further improve the MTBF of ESP pumps and avoid pump shut-downs.

7.1 Recommendations

The following recommendations are made for the investigated wells in the Habban field. Generally has to be mentioned that the produced liquid volumes are relatively low. Principally is the usage of ESPs possible but a detailed discussion regarding a conversion to another lift method (e.g. gas lift) should be made.

If the preferred completion strategy is artificial lift with ESP pumps some important circumstances have to be discussed in more detail. For the design of an ESP pump a detailed knowledge of the inflow depth is indispensable. All common design software packages calculate the difference between perforation depth and pump setting depth and use this calculation for an estimation of the intake pressure. If the perforation depth is uncorrect, or the ESP is run in an open hole completion without a detailed knowledge of the exactly inflow depth, the design cannot be made correctly.

To avoid a wrong design a production log should be performed to know the inflow depth. If a log is not possible a different completion strategy should be implemented. The usage of a shroud in combination with a tail pipe/dip tube can solve the above mentioned problem. With the tail pipe it is possible to control the point where the inflow into the pump system takes place. It is also possible to put the inflow point below the perforations and therefore avoid it, that too much free gas can enter the pump. Also a dual shroud system like the design presented in chapter 6.1.5 could be installed. With the knowledge of the inflow depth a more detailed design of the pump is possible which results in an extended MTBF time. Additional a detailed evaluation of the historical datasets should be performed to select the proper gas handling/separating equipment. If any uncertainty in the data set is present, different cases should be calculated. Also the Risk-Based Design concept, presented in this Thesis, could be used to estimate the gas fraction value and operating parameters of the pump. The usage of shallow set vented packers can be a bottleneck for gas venting. A completion with an open annulus is much more preferable due to the fact that the gas is vented with no restriction and the possibility of a liquid level monitoring is given. Generally should a continuous monitoring system during the operation of the pump be implemented and in the case of gas interference the presented strategy applied.

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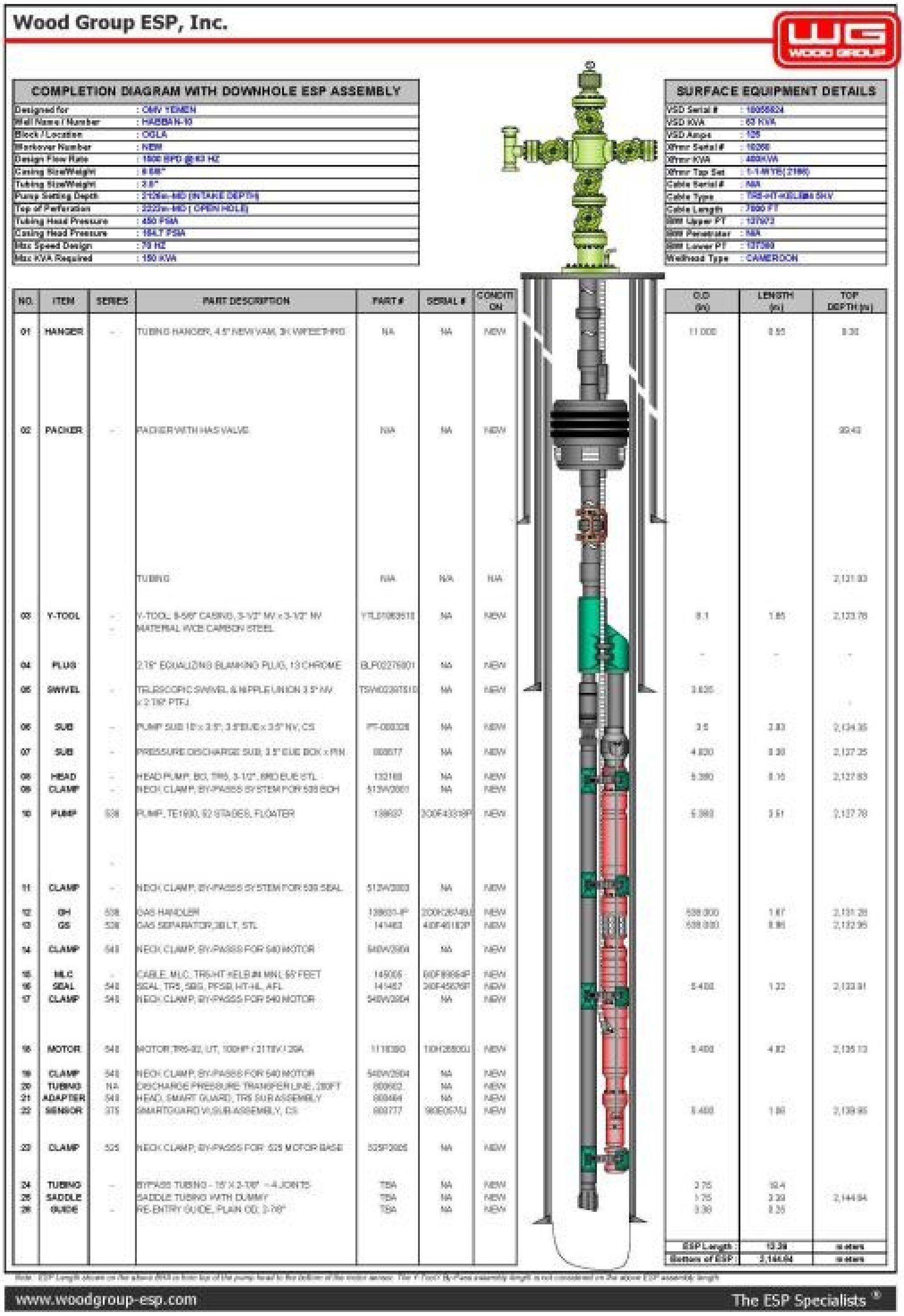
Appendix

Appendix A -	**Wellbore schematic Habban 10** **Wellbore schematic Habban 15** **Wellbore schematic Habban 20**
Appendix B -	**Diagrams Habban 10 – Match 1** **Diagrams Habban 10 – Match 2** **Diagrams Habban 15** **Diagrams Habban 20**
Appendix C	**Dual Shroud System**
Appendix D	**Table – Functional comparison of completion architectures**

Appendix – A

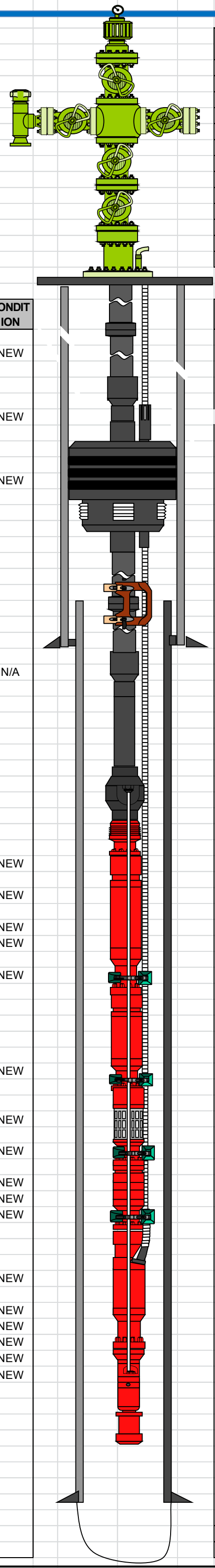
Habban 10 – Wellbore Schematic



Habban 15 – Wellbore Schematic

GE Oil & GAS Artificial Lift System

imagination at work



COMPLETION DIAGRAM WITH DOWNHOLE ESP ASSEMBLY

Designed for	: OMV YEMEN
Well Name / Number	: HABBAN-15
Block / Location	: UQLAH
Workover Number	: 2
Design Flow Rate	: 350 BPD @ 60 HZ
Casing Size/Weight	: 9 5/8" 47# @ 2079 Mmd & 7" 29# @ 2416.5mMD
Tubing Size/Weight	: 3.5" 9.2 ppf L80
Pump Setting Depth	: 1930m-MD (Bottom Of the ESP Dummy Neck)
Top of Perforation	: 2416.5m-MD (OPEN HOLE)
Tubing Head Pressure	: 700 psig
Casing Head Pressure	: 200 psig
Max Speed Design	: 70 HZ
Max KVA Required	: 150 KVA

SURFACE EQUIPMENT DETAILS

VSD Serial #	: 10055622
VSD KVA	: 83 KVA
VSD Amps	: 125
Xfrmr Serial #	: 10262
Xfrmr KVA	: 100KVA
Xfrmr Tap Set	: 1439 VOLTS
Cable Serial #	: N/A
Cable Type	: TR5-HT-KELB#4 5KV
Cable Length	: 6332 FT
BIW Upper PT	: 137972
BIW Penetrator	: N/A
BIW Lower PT	: 137380
Wellhead Type	: CAMEROON

NO.	ITEM	SERIES	PART DESCRIPTION	PART #	SERIAL #	CONDITION	O.D (in)	LENGTH (m)	TOP DEPTH (m)
01	HANGER	-	TUBING HANGER, 4.5" NEW VAM, 3K W/FEETHRG	NA	NA	NEW	11.000	0.55	9.30
			3-1/2 " x 2.81" TR-SCSSSV	N/A	N/A	NEW	5.03	1.38	39.80
02	PACKER	-	PACKER WITH HAS VALVE	N/A	NA	NEW	8.5		102.41
			TUBING	N/A	N/A	N/A			1,900.00
		-							
03	SUB	-	CROO OVER 3 1/2" EUE - 3 1/2 NEW VAMN	N/A	NA	NEW	3.5	0.29	2,111.10
04	SUB	-	PRESSURE DISCHARGE SUB; 3.5" EUE BOX x PIN	800677	NA	NEW	4.820	0.38	2,111.48
05	HEAD	-	HEAD PUMP, BO, TR5, 3-1/2", 8RD EUE STL	132160	NA	NEW	5.380	0.19	2,111.67
06	CLAMP	-	CABLE PROTECTOLIZER FOR 400 SERIES	513W2801	NA	NEW			
07	PUMP	400	PUMP, TD 300, 201 STAGES, FLOATER	130892	2F1A44748P	NEW	4.000	5.36	2,117.03
		-							
08	CLAMP	-	CABLE PROTECTOLIZER TR 5	513W2803	NA	NEW			
09	GH		GAS HANDLER IP PUMP TYPE TD 300 FLT	130883	2F3F30794J-IP				
10	GS	538	GAS SEPARATOR,3B LT, STL	141463	4O1A46460P	NEW	538.000	0.96	2,117.99
11	CLAMP	540	CABLE PROTECTOLIZER TR 5	540W2804	NA	NEW			
12	MLC	-	CABLE, MLC, TR5-HT KELB #4 MNL 55' FEET	145005	6I0E91448P	NEW			
13	SEAL	540	SEAL, TR5, SBG, PFSB, HT-HL, AFL	141457	3I1A46873P	NEW	5.400	1.22	2,119.21
14	CLAMP	540	CABLE PROTECTOLIZER TR 5	540W2804	NA	NEW			
15	MOTOR	540	MOTOR,TR5-92, UT, 70HP / 1265V / 35A, HTI	121884G	1I3F30793J	NEW	5.400	3.57	2,122.78
16	CLAMP	540	CABLE PROTECTOLIZER TR 5	540W2804	NA	NEW			
17	TUBING	NA	DISCHARGE PRESSURE TRANSFER LINE, 200FT	800602	NA	NEW			
18	ADAPTER	540	HEAD, SMART GUARD, TR5 SUB ASSEMBLY	800464	NA	NEW	5.400	0.10	2,122.88
19	SENSOR	375	SMARTGUARD VI,SUB-ASSEMBLY, CS	800777	9I1B7640P	NEW	3.750	0.96	2,123.84
20	Bull nose	562	DUMMY NECK 540 SERIES MOTOR BASE	DNP01525001	NA	NEW	5.62	0.21	2,124.05
								12.95	
							ESP Length :	12.05	Meter
							Bottom of ESP :	2,124.05	Meter

Note : ESP Length shown on the above BHA is from top of the pump head to the bottom of the motor sensor.

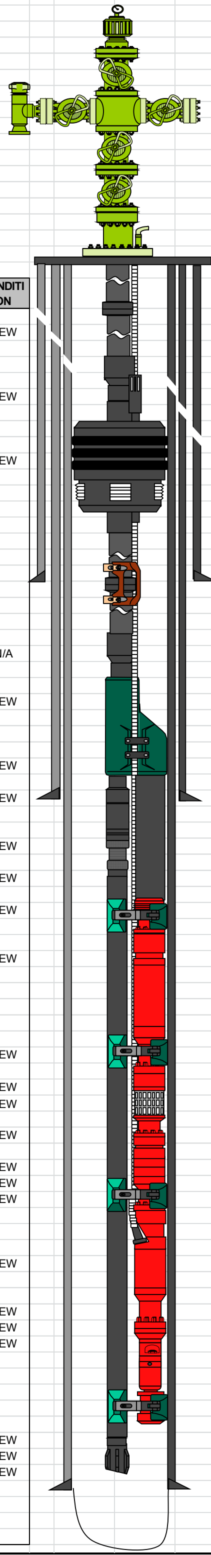
Habban 20 – Wellbore Schematic

GE Oil & GAS Artificial Lift System

imagination at work

COMPLETION DIAGRAM WITH DOWNHOLE ESP ASSEMBLY

Designed for	: OMV YEMEN
Well Name / Number	: HABBAN-20
Block / Location	: OGLA
Workover Number	: 2
Design Flow Rate	: 250 BPD @ 62 HZ
Casing Size/Weight	: 9 5/8"
Tubing Size/Weight	: 3.5"
Pump Setting Depth	: 2030m-MD (Bottom Of the ESP)
Top of Perforation	: 2495 M
Tubing Head Pressure	: 580 PSI
Casing Head Pressure	: 300 PSI
Max Speed Design	: 70 HZ
Max KVA Required	: 70 KVA



SURFACE EQUIPMENT DETAILS

VSD Serial #	: 10055625
VSD KVA	: 83 KVA
VSD Amps	: 125
Xfrmr Serial #	: 10263
Xfrmr KVA	: 100KVA
Xfrmr Tap Set	: 1432 V
Cable Serial #	: N/A
Cable Type	: TR5-HT-KELB#4 5KV
Cable Length	: 8035 FT
BIW Upper PT	: 137974
BIW Penetrator	: N/A
BIW Lower PT	: 137378
Wellhead Type	: CAMEROON

NO.	ITEM	SERIES	PART DESCRIPTION	PART #	SERIAL #	CONDITION	O.D (in)	LENGTH (m)	TOP DEPTH (m)
01	HANGER	-	TUBING HANGER, 4.5" NEW VAM, 3K W/FEETHRG	NA	NA	NEW	11.000	0.26	8.76
			SSSV.5K- 31/2" NVAM	NA	NA	NEW	5.030	1.38	42.06
02	PACKER	-	PACKER WITH HAS VALVE	N/A	NA	NEW		1.68	105.48
			TUBING 31/2" NVAM	N/A	N/A	N/A		1,915.50	2,019.66
03	Y-TOOL	-	Y-TOOL; 9-5/8" CASING, 3-1/2" NV x 3-1/2" NV	YTL01963510	NA	NEW	8.1	2.03	2,021.69
		-	MATERIAL WCB CARBON STEEL						
							-	-	-
04	PLUG		2.75" EQUALIZING BLANKING PLUG, 13 CHROME	BLP02275001	NA	NEW			
05	SWIVEL	-	TELESCOPIC SWIVEL & NIPPLE UNION 3.5" NV	TSW02287510	NA	NEW	3.625		
			x 2.7/8" PTFJ						-
06	SUB	-	PUMP SUB 10' x 3.5"; 3.5"EUE x 3.5" NV, CS	PT-000326	NA	NEW	3.5	2.94	2,024.63
07	SUB	-			NA	NEW			2,024.63
08	HEAD	-	HEAD PUMP, BO, TR5, 2-7/8", 8RD EUE STL	132160	NA	NEW	5.380	0.19	2,024.82
09	PUMP	400	PUMP TD300. 201 STAGES FLOATER	130892	2F1A44747P	NEW	4.000	5.36	2,030.18
		-							
10	CLAMP	-	NECK CLAMP; BY-PASSS SYSTEM FOR 400 SEAL	513W2803	NA	NEW			
11	GIP	400	GAS INTAKE PUMP 49 STAGES	130883	2F0K26751IP	NEW	538.000	1.51	2,031.69
12	GS	538	GAS SEPARATOR,3B LT, STL	141463	4O1A46458P	NEW	538.000	1.10	2,032.79
13	CLAMP	540	NECK CLAMP; BY-PASSS FOR 540 MOTOR	540W2804	NA	NEW			
14	MLC	-	CABLE, MLC, TR5-HT KELB #4 MNL 55' FEET	145005	6I0L91447P	NEW			
15	SEAL	540	SEAL, TR5, SBG, PFSB, HT-HL, AFL	141457	3I1A46874P	NEW	5.400	1.23	2,034.02
16	CLAMP	540	NECK CLAMP; BY-PASSS FOR 540 MOTOR	540W2804	NA	NEW			
17	MOTOR	540	MOTOR,TR5-92, UT, 50HP / 1375V / 22A	111821G	1I1A47437P	NEW	5.400	2.73	2,036.75
18	TUBING	NA	DISCHARGE PRESSURE TRANSFER LINE, 200FT	800602	NA	NEW			
19	ADAPTER	540	HEAD, SMART GUARD, TR5 SUB ASSEMBLY	800464	NA	NEW			
20	SENSOR	375	SMARTGUARD VI,SUB-ASSEMBLY, CS	800777	9I1B7641P	NEW	5.400	1.06	2,037.81
21	TUBING	-	BYPASS TBG - 15'X2-7/8"4JTS+ SHORT JT =20.63M	TBA	NA	NEW	2.75		
22	SADDLE		SADDLE TUBING WITH DUMMY	TBA	NA	NEW	1.75	3.25	2,041.05
23	GUIDE	-	RE-ENTRY GUIDE, PLAIN OD; 2-7/8" = 1.27 M	TBA	NA	NEW	3.38		

ESP+Y TOOL :	21.40	meters
Bottom of ESP :	2,041.05	meters

Note : ESP Length shown on the above BHA is from top of the pump head to the bottom of the motor sensor. The Y-Tool / By-Pass assembly length is not considered on the above ESP assembly length.

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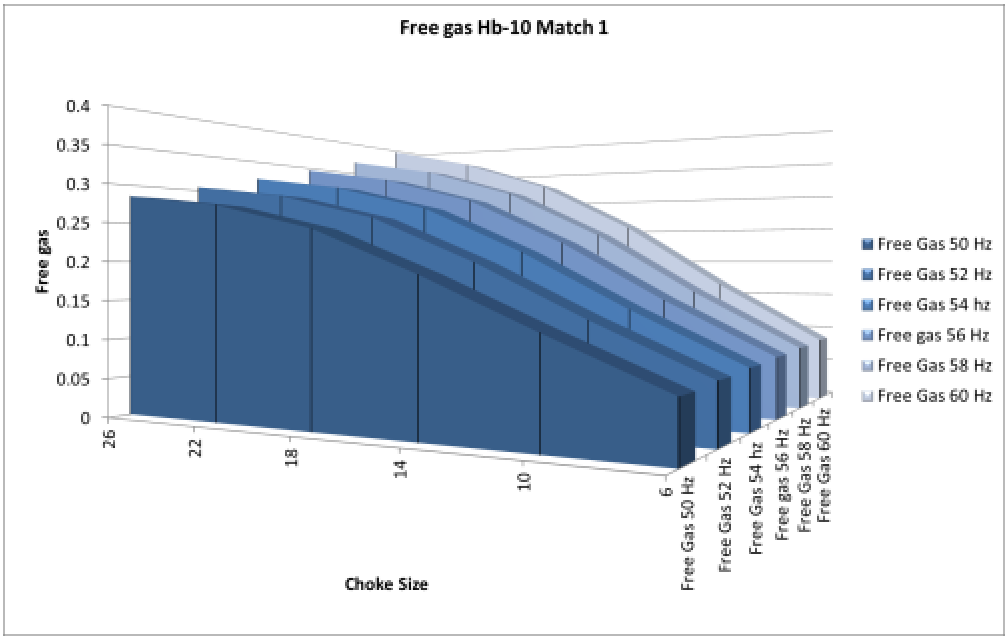
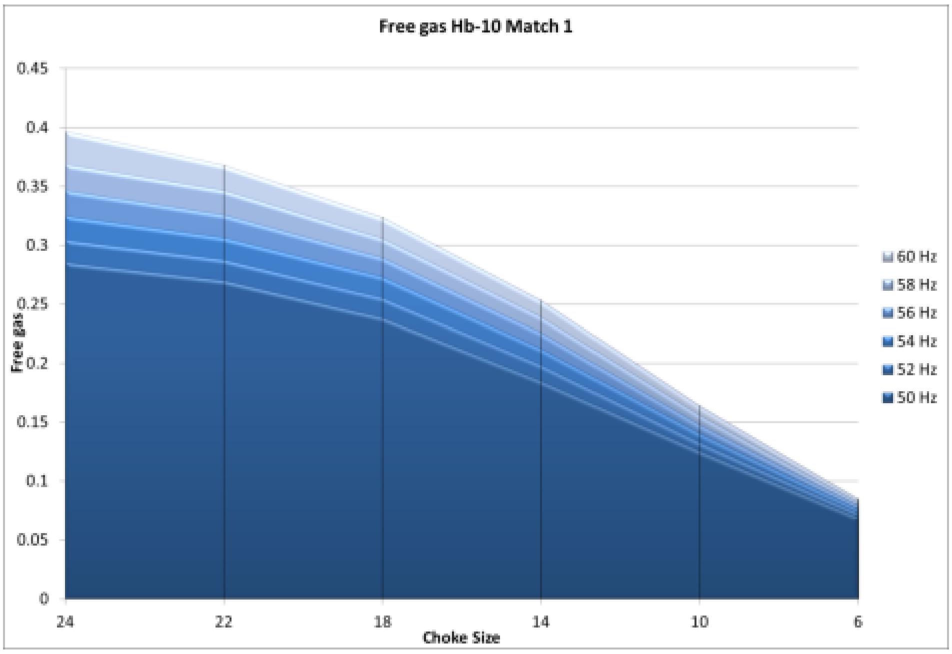
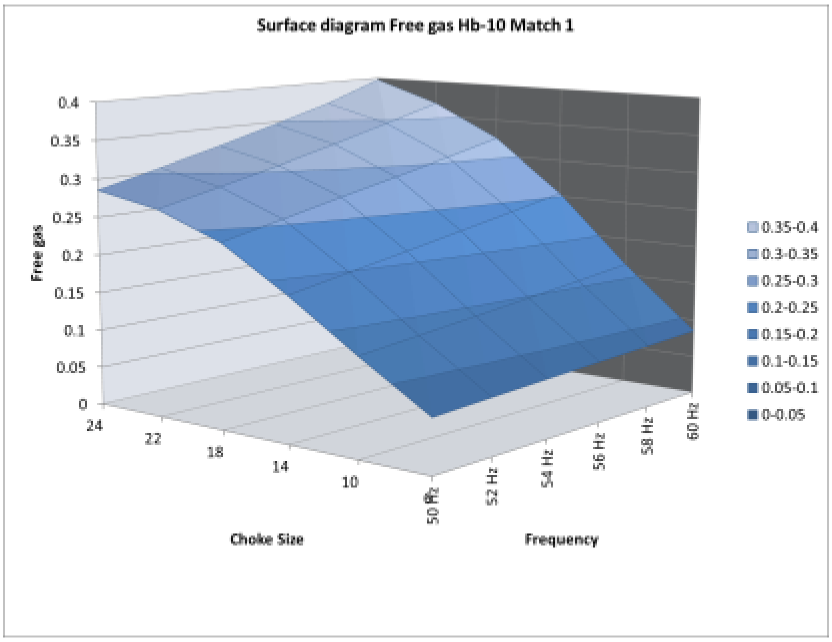
Appendix – B

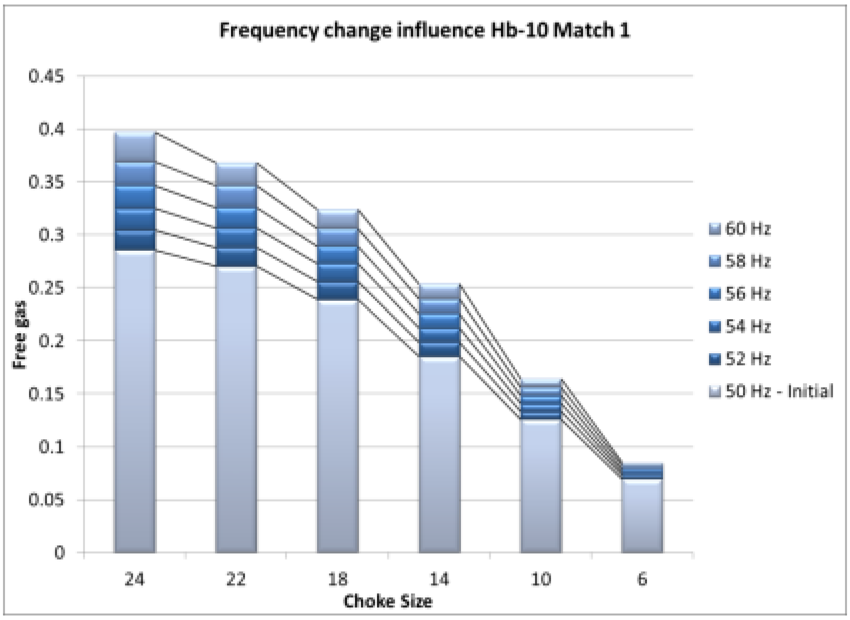
Diagrams Habban 10 – Match 1



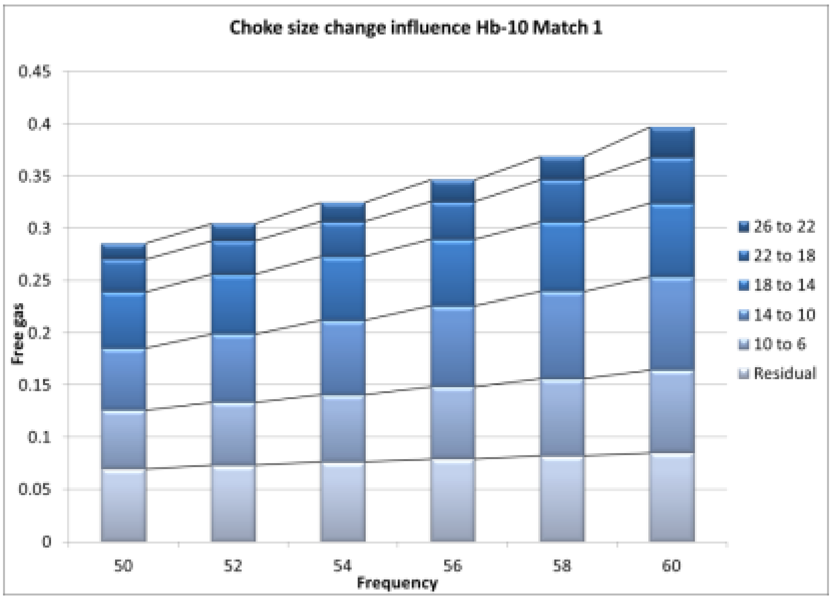




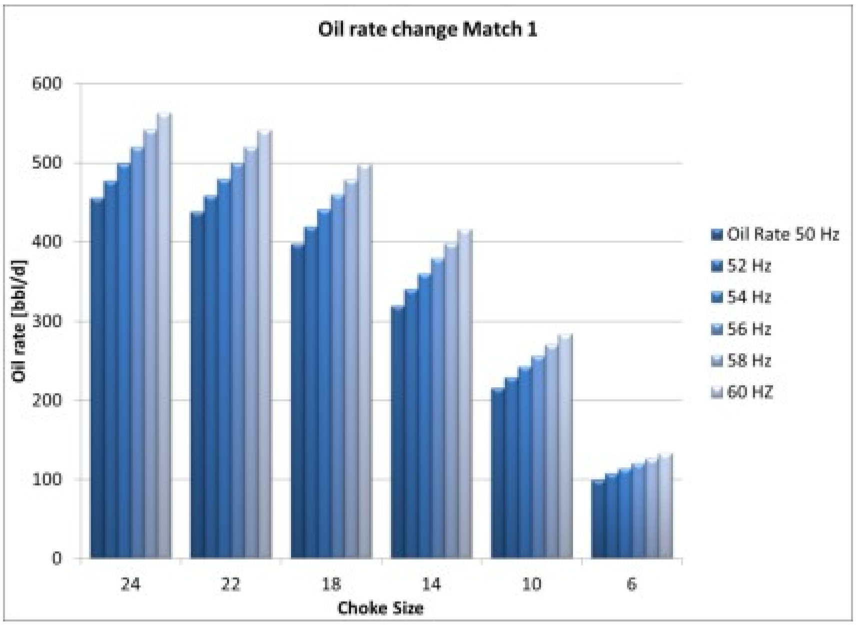
Surface diagram Free gas Hb-10 Match 1
Free gas
Choke Size
Frequency
0.35-0.4
0.3-0.35
0.25-0.3
0.2-0.25
0.15-0.2
0.1-0.15
0.05-0.1
0-0.05



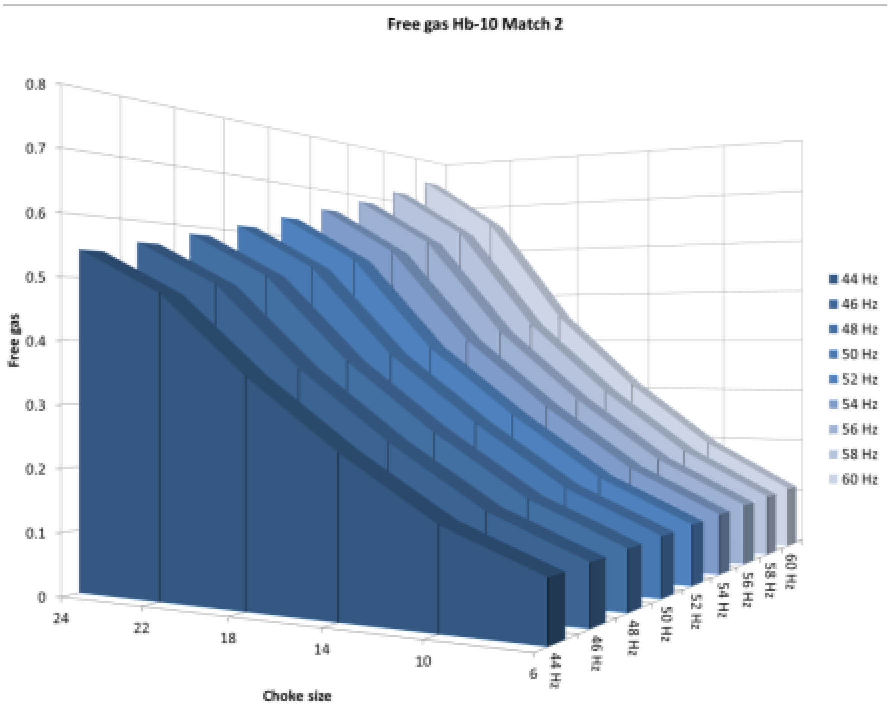
Frequency change influence Hb-10 Match 1
Free gas
Choke Size
60 Hz
58 Hz
56 Hz
54 Hz
52 Hz
50 Hz - Initial

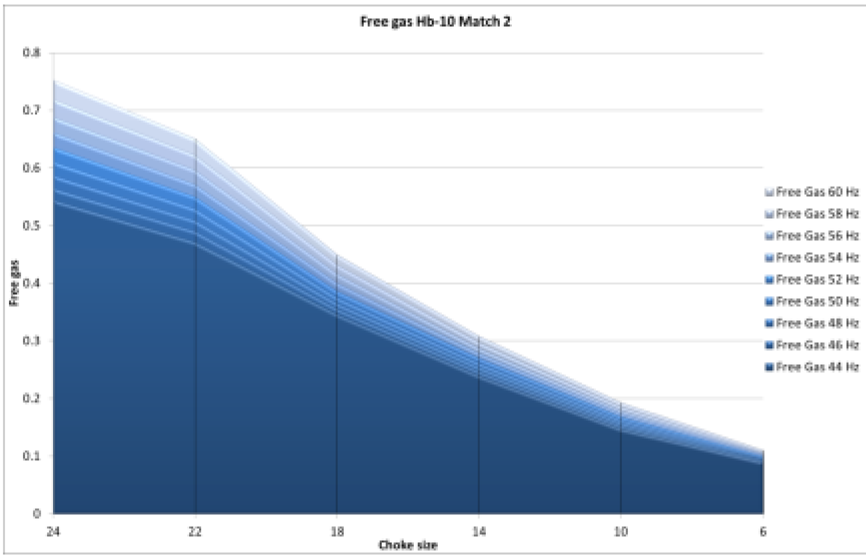


Choke size change influence Hb-10 Match 1
Free gas
Frequency
26 to 22
22 to 18
18 to 14
14 to 10
10 to 6
Residual

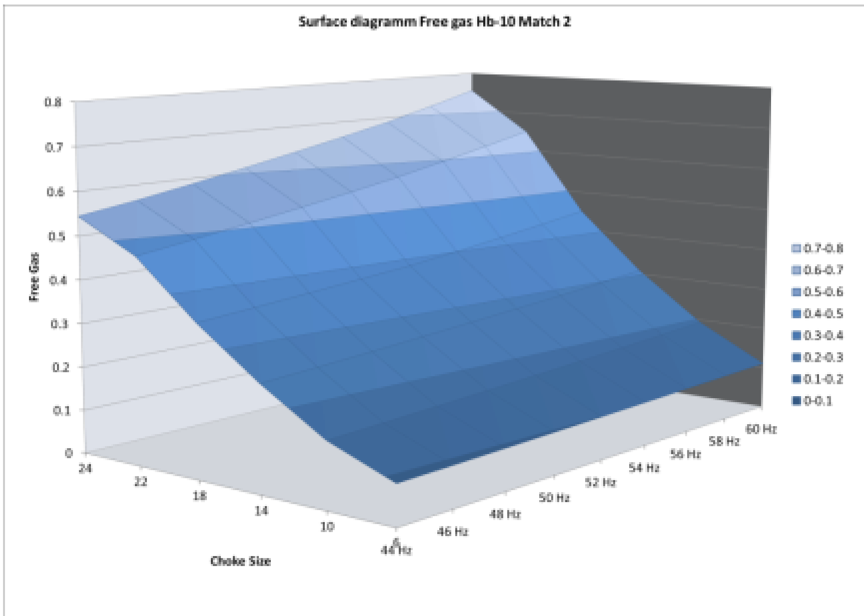


Diagrams Habban 10 – Match 2

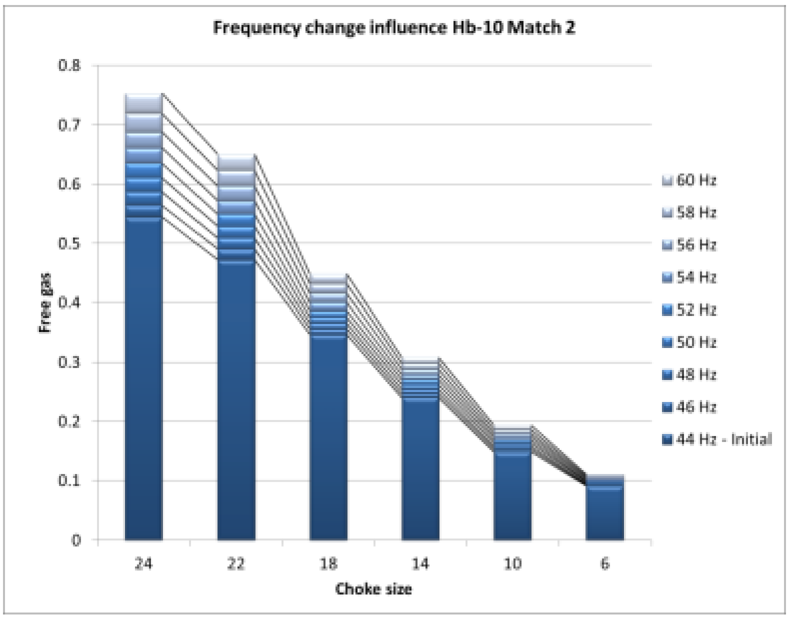




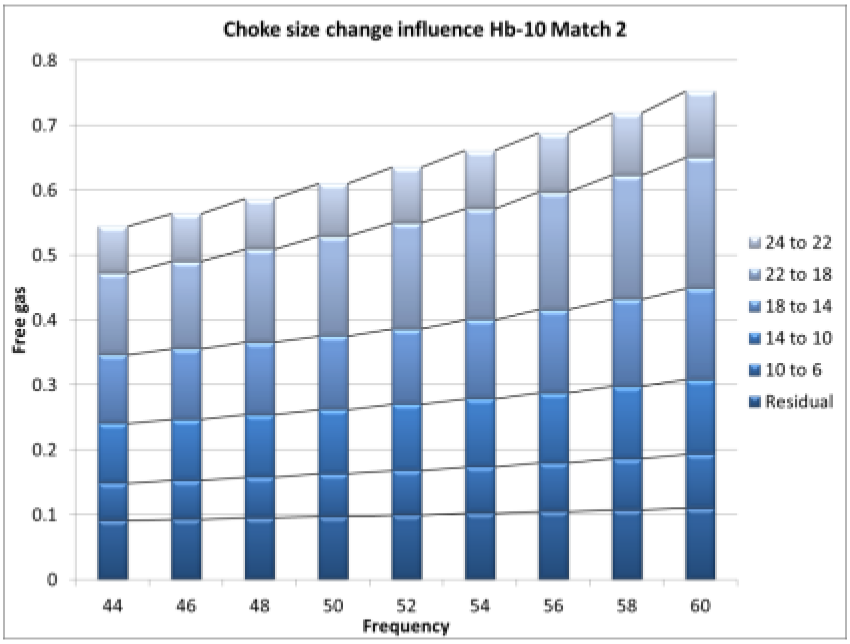
Free gas Hb-10 Match 2
Free gas
Choke size
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
24
22
18
14
10
6
Free Gas 60 Hz
Free Gas 58 Hz
Free Gas 56 Hz
Free Gas 54 Hz
Free Gas 52 Hz
Free Gas 50 Hz
Free Gas 48 Hz
Free Gas 46 Hz
Free Gas 44 Hz

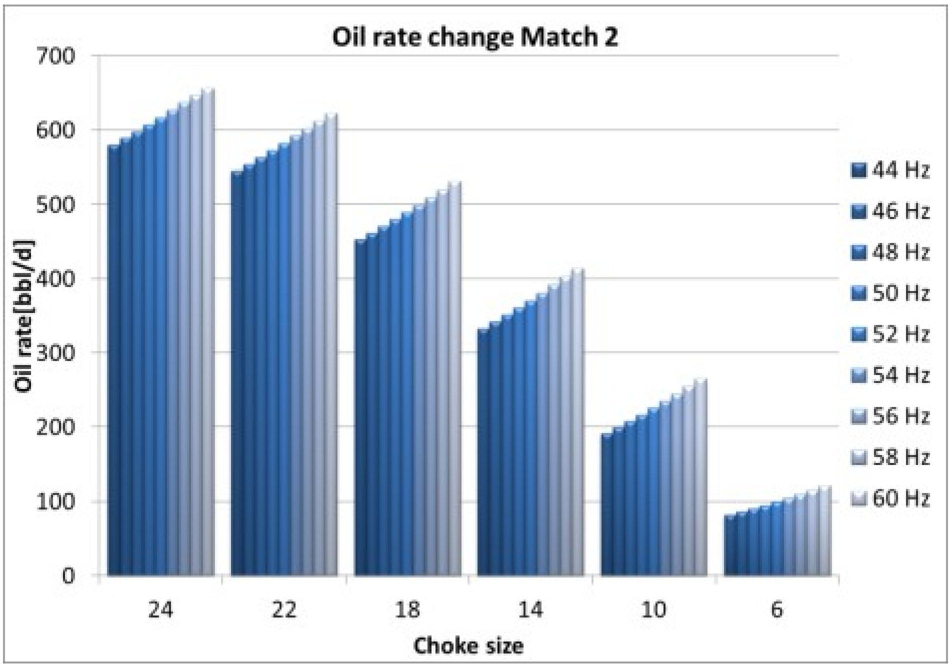


Surface diagramm Free gas Hb-10 Match 2
Free Gas
Choke Size
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
24
22
18
14
10
6
44 Hz
46 Hz
48 Hz
50 Hz
52 Hz
54 Hz
56 Hz
58 Hz
60 Hz
0.7-0.8
0.6-0.7
0.5-0.6
0.4-0.5
0.3-0.4
0.2-0.3
0.1-0.2
0-0.1

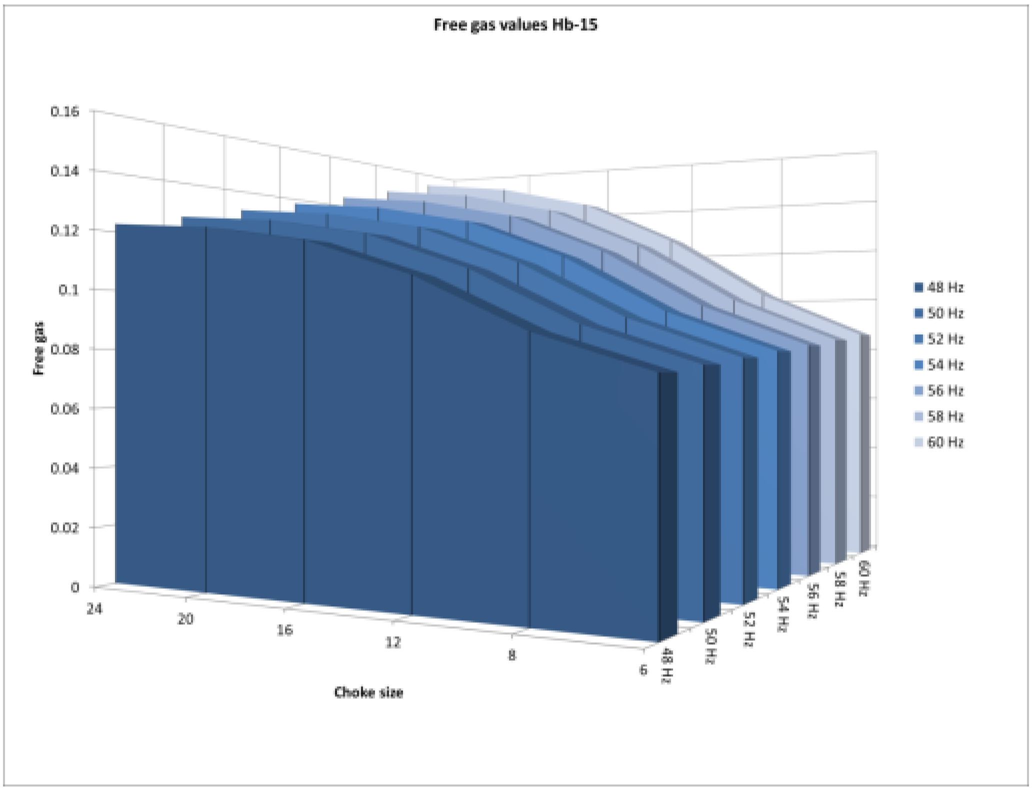


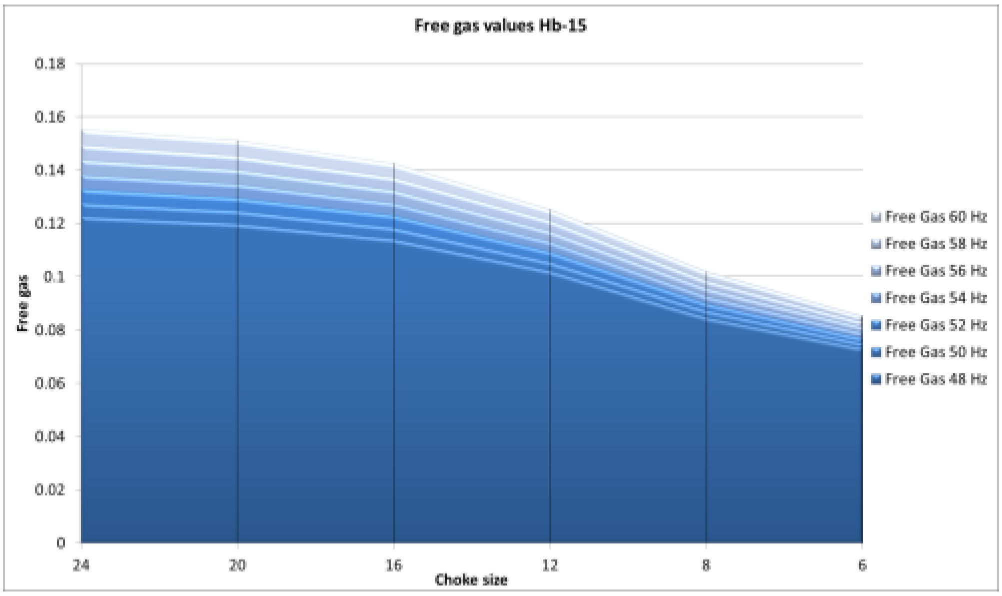
Frequency change influence Hb-10 Match 2
Free gas
Choke size
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
24
22
18
14
10
6
60 Hz
58 Hz
56 Hz
54 Hz
52 Hz
50 Hz
48 Hz
46 Hz
44 Hz - Initial

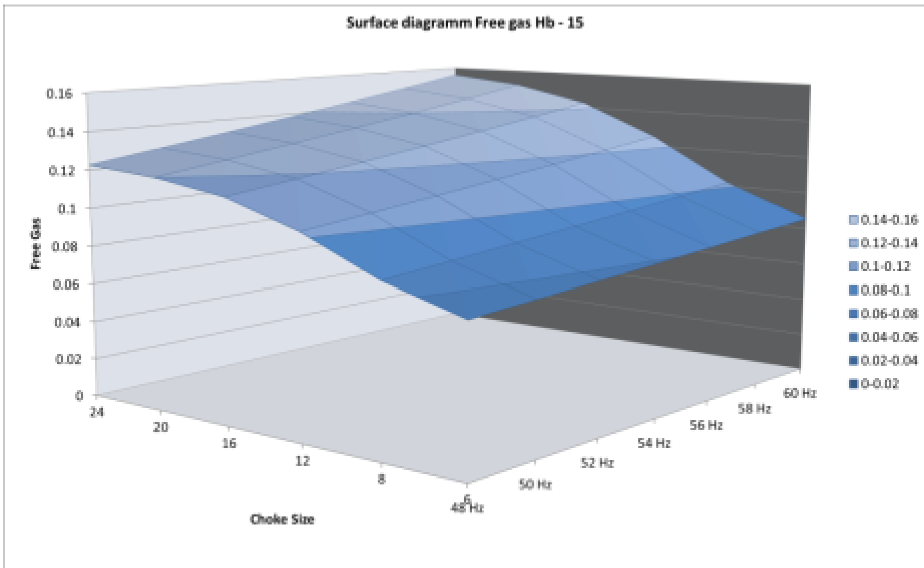

Choke size change influence Hb-10 Match 2
Free gas
Frequency
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
44
46
48
50
52
54
56
58
60
24 to 22
22 to 18
18 to 14
14 to 10
10 to 6
Residual

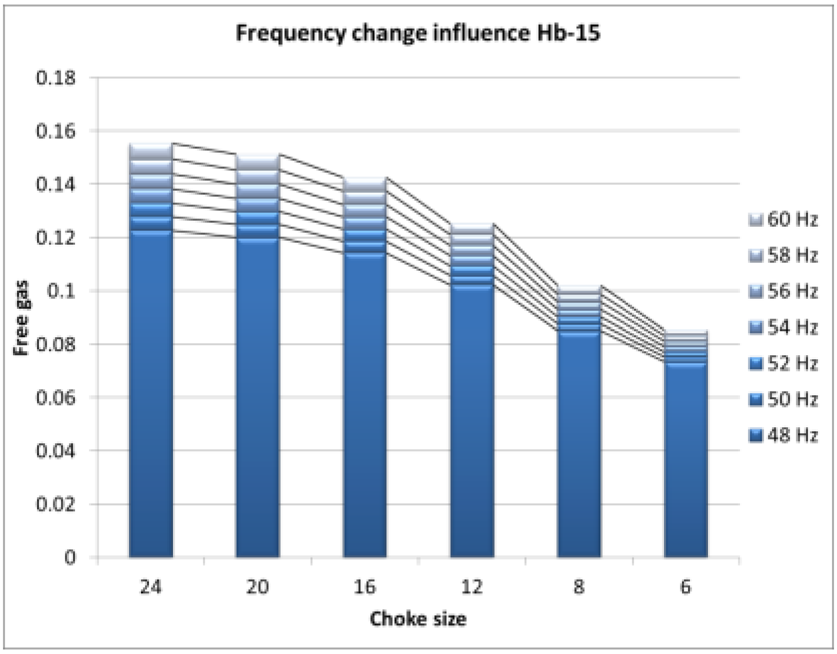

Oil rate change Match 2
Oil rate[bbl/d]
Choke size
700
600
500
400
300
200
100
0
24
22
18
14
10
6
44 Hz
46 Hz
48 Hz
50 Hz
52 Hz
54 Hz
56 Hz
58 Hz
60 Hz

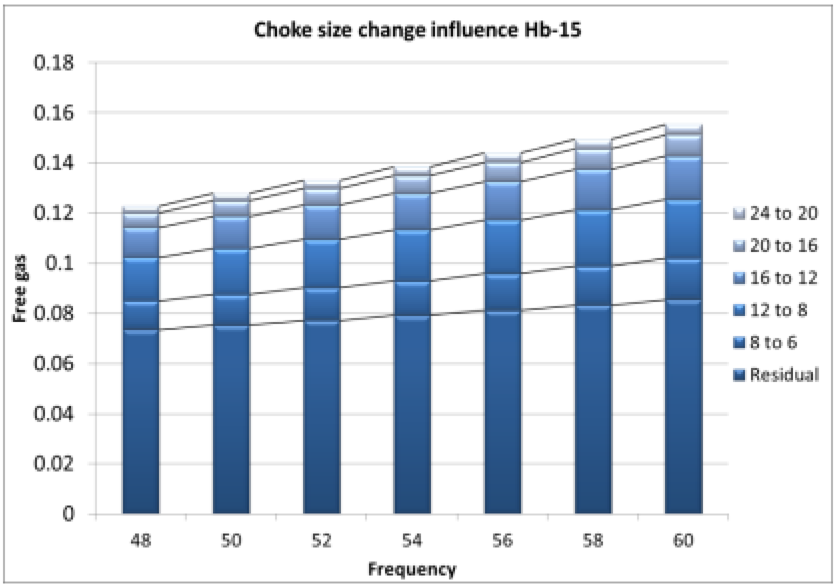
Diagrams Habban 15

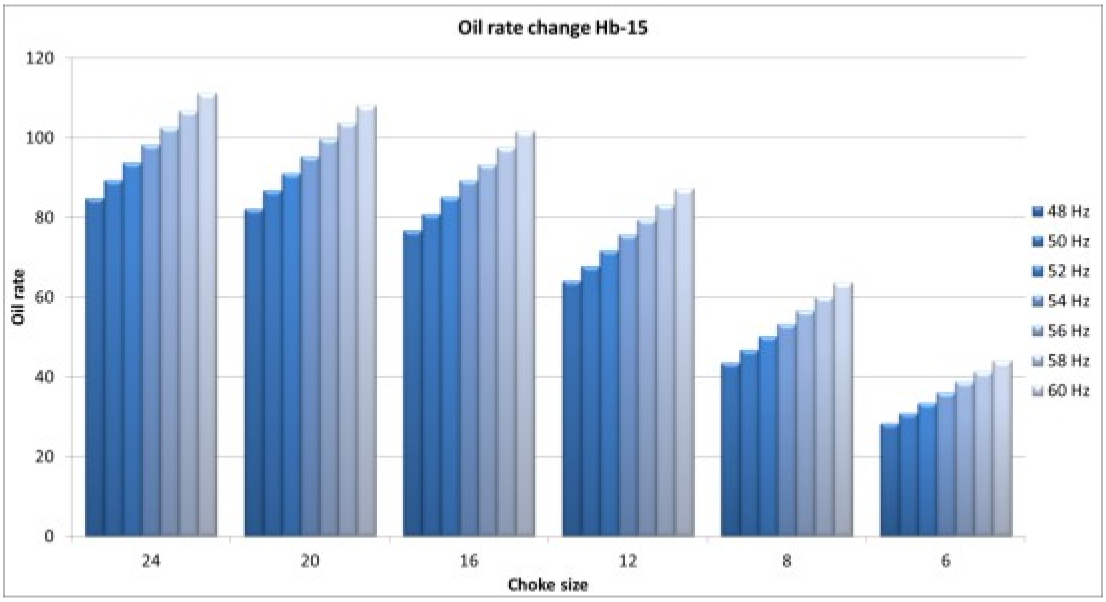




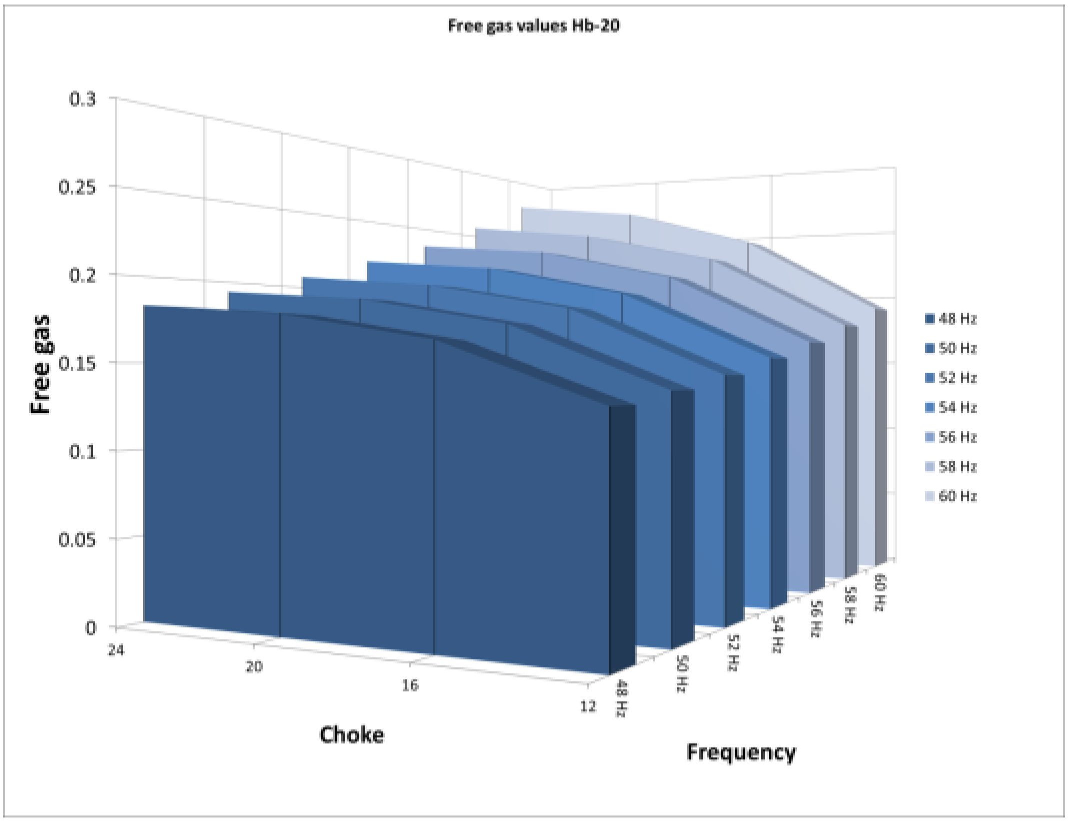

Surface diagramm Free gas Hb - 15
Free Gas
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
24
20
16
12
8
6
Choke Size
48 Hz
50 Hz
52 Hz
54 Hz
56 Hz
58 Hz
60 Hz
0.14-0.16
0.12-0.14
0.1-0.12
0.08-0.1
0.06-0.08
0.04-0.06
0.02-0.04
0-0.02

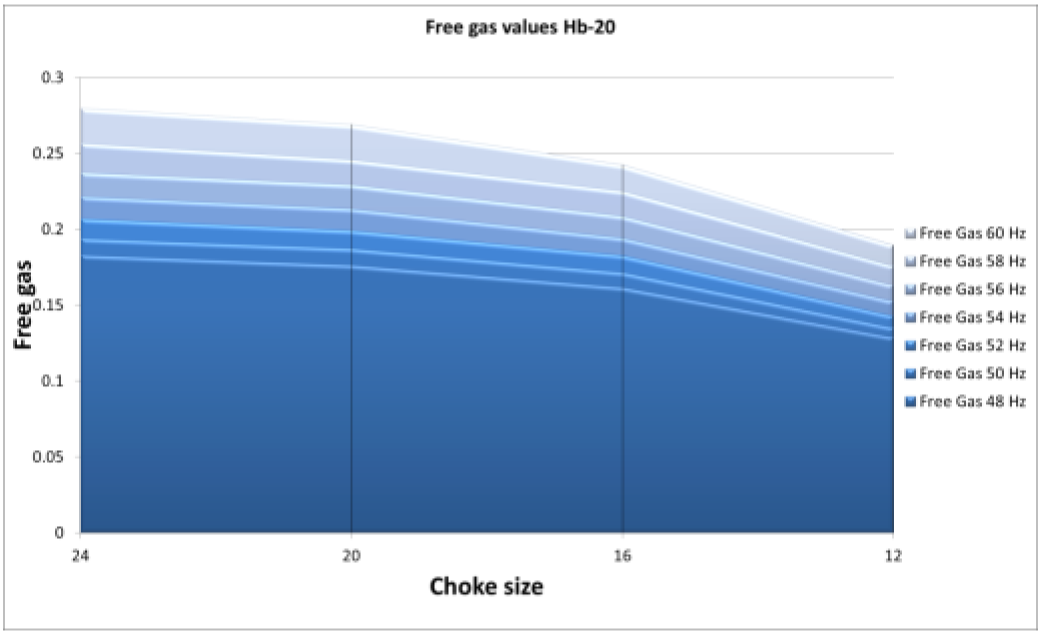

Frequency change influence Hb-15
Free gas
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
24
20
16
12
8
6
Choke size
60 Hz
58 Hz
56 Hz
54 Hz
52 Hz
50 Hz
48 Hz

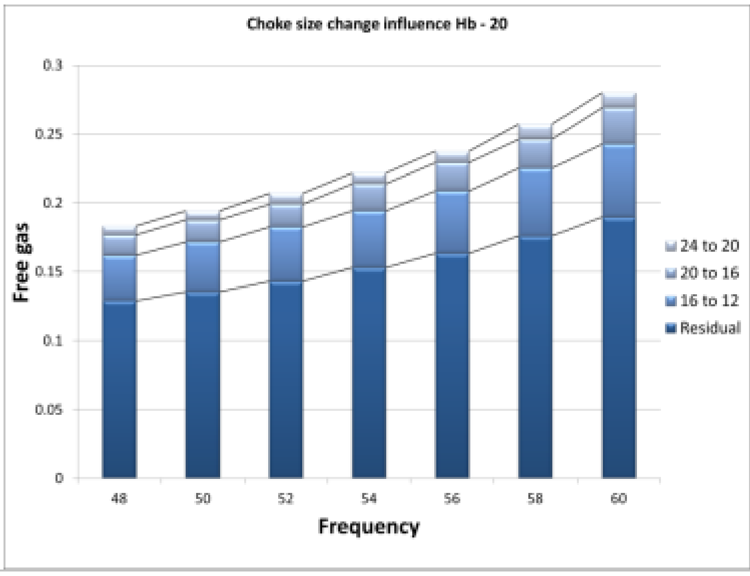

Choke size change influence Hb-15
Free gas
0.18
0.16
0.14
0.12
0.1
0.08
0.06
0.04
0.02
0
48
50
52
54
56
58
60
Frequency
24 to 20
20 to 16
16 to 12
12 to 8
8 to 6
Residual

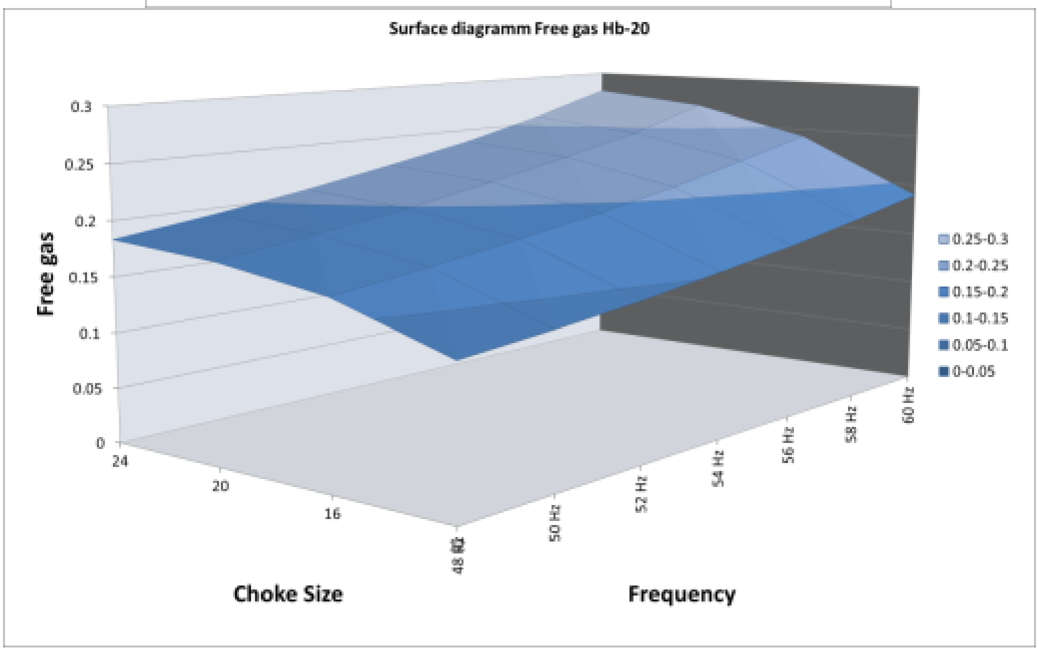


Diagrams Habban 20



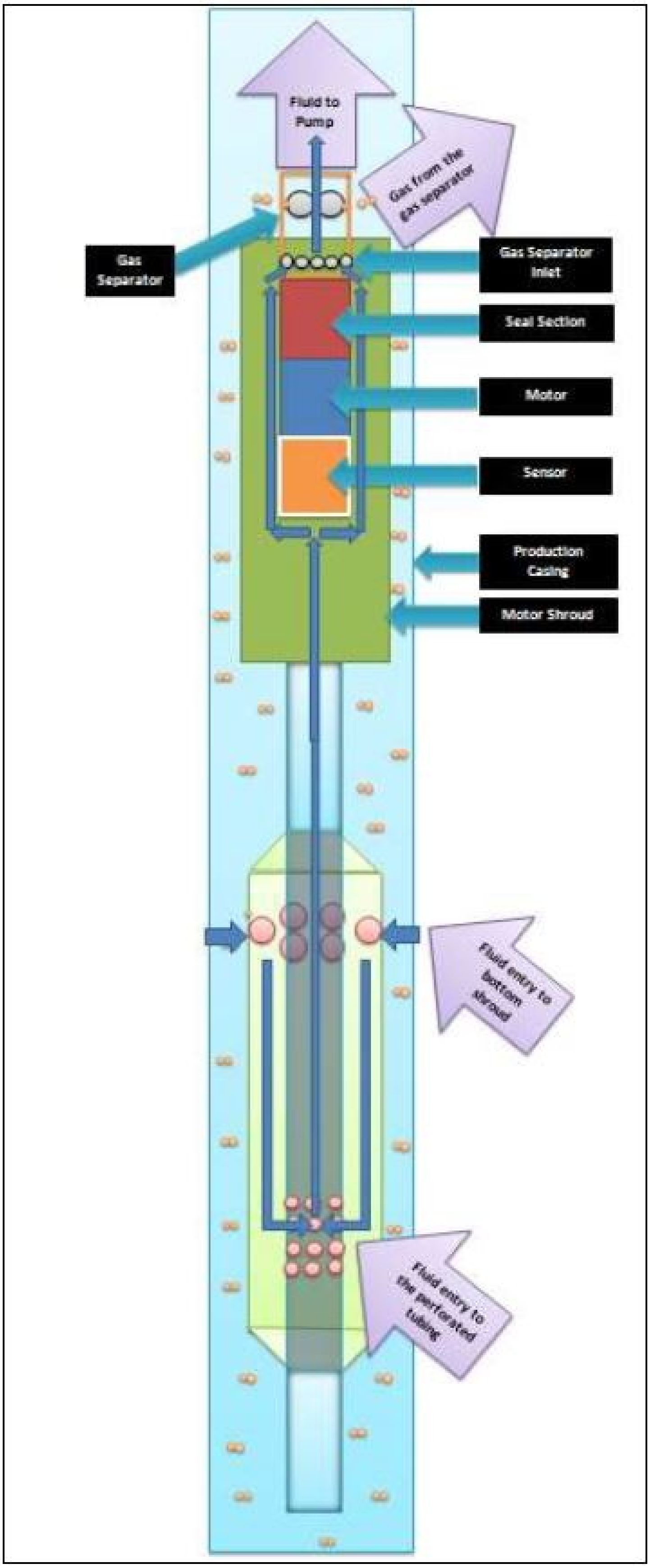

Free gas values Hb-20
0.3
0.25
0.2
0.15
0.1
0.05
0
Free gas
24
20
16
12
Choke size
Free Gas 60 Hz
Free Gas 58 Hz
Free Gas 56 Hz
Free Gas 54 Hz
Free Gas 52 Hz
Free Gas 50 Hz
Free Gas 48 Hz


Choke size change influence Hb - 20
0.3
0.25
0.2
0.15
0.1
0.05
0
Free gas
48
50
52
54
56
58
60
Frequency
24 to 20
20 to 16
16 to 12
Residual


Surface diagramm Free gas Hb-20
0.3
0.25
0.2
0.15
0.1
0.05
0
Free gas
24
20
16
Choke Size
50 Hz
52 Hz
54 Hz
56 Hz
58 Hz
60 Hz
Frequency
0.25-0.3
0.2-0.25
0.15-0.2
0.1-0.15
0.05-0.1
0-0.05

Appendix – C

Dual shroud system



Appendix – D

Functional comparison of completion architectures

Primary Barrier	Not Applicable	Casing + **Shallow Set Multiport Packer above ESP** + Tubing + shallow set SCSSV	Casing + **Deep-Set Multiport Packer above ESP** + Tubing + shallow set SCSSV	Casing + **Deep Set Monobore Packer below ESP** + Short length of tubing+ *deep-set SCSSV*	Casing + **Deep-Set Monobore Packer below ESP** + **POD** + Tubing+ *shallow-set SCSSV*
Casing Protection	NO	NO	YES	NO	YES
Power Cable Downhole Packer Feed-through	NONE	YES – Through Packer	YES – Through Packer	NOT Required	YES Through POD
Total Quantity of Power Cable Splices	**2**	**4**	**2/3** To minimize splices, it is necessary to have packer connector factory molded to MLE	**2**	**2**
Control Line Downhole Feed-through	NONE	YES – Through Packer	YES – Through Packer	NOT Required	NOT Required
Wireline or Coiled Tubing Access to SCSSV	NOT Required	YES	YES	Only if casing size permits by-pass tubing and deviation allows for wireline access to the SCSSV below ESP.	YES
Packer Redress for each ESP Change-out	NO	YES	YES	NO	NO
Bullheading (Well Kill or Stimulation)	YES, Via annulus Does not require wireline	Through tubing via ESP or via SSD after wireline operation	Through tubing via ESP or via SSD after wireline operation or AFS	YES, Via annulus Does not require wireline operation	Yes, via tubing
Circulating (Kill Fluid or Debris Removal in Tubing)	Yes IF SSD fitted and Pr is high to avoid formation losses	NO, Packer precludes such operation	YES, for the volume above the packer. The volume below the packer can only be bullheaded.	YES, without losses to the reservoir if ported sub is replaced with on/off valve and with circulating valve above the ESP.	YES, without losses to the reservoir with circulating valve (e.g., AFS) above the POD
Gas Venting	**YES**	YES with gas vent valve or small SCSSV on packer short string, but not in 7" casing	**NO**	**YES**	**NO**
Gas Lift Backup	Yes but packerless GL	Yes but requires SCSSV on packer short string and is packerless GL (uncommon)	Yes and packer isolates fluid intake and orifice valve	Yes but GL is packerless	Yes and packer isolates fluid intake and orifice valve
Possibility to Use Y-Tool and Run Bypass Tubing	YES	YES	YES	YES	NO – usually not possible as POD takes most of the space in classical casing sizes such as 9 5/8 in.

(green)	**Clear functional advantage**
(orange)	**Clear functional disadvantage**