Master Thesis

ESP Production Optimization

Supervised by: Dipl.-Ing Herbert Scheibenbauer, SUCO Egypt
Armando Villavona, MSc SUCO Egypt
Univ.Prof. Dr. Herbert Hofstätter, Montanuniversität Leoben

Approval date: 25th November 2010

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

(Thomas Posch)

Leoben, November 2010

Table of Contents

List of Figures

List of Tables

Acknowledgements

This thesis was composed at the Department of Petroleum Production and Processing at the Mining University of Leoben for RWE Dea as the contracting company. I wish to thank the following people for their support and assistance to make the thesis possible:

First, I wish to thank Univ. Prof. Dr. Herbert Hofstätter, head of the Department, for his helpful advice and patience.

I also owe thanks to Dipl.-Ing Herbert Scheibenbauer of the SUCO, who was the spiritual father of this thesis and who supported me with all the data I needed and with his advice. Without his help, this thesis would not have been completed successfully.

Armando Villavona, MSc was of great importance for the success of this thesis. He was my advisor at the Suez Oil Company. He always had an open ear for problems or with data, and he gave me some good advice and ideas around this thesis which helped me to continue. He was the person who gave me orientation when I needed it.

I also wish to thank Dipl.-Ing Bernd König of the SUCO, who arranged meetings, field trips and arranged the very important exchange of knowledge with German engineers possible. The work in the field would have been much more difficult without his assistance.

I owe great gratitude to my parents, Eleonore and Werner Posch. Without their moral support, their patience and their generosity this study would not have been finished. I want to say them a big "**Thank You**!"

1. Abstract

The mature field Ras Fanar was equipped with Electrical Submersible Pumps (ESP) in 1996 due to the low bottom hole flowing pressure (BHFP). Since then new wells in the mature Main Field and in the smaller West Field, which is separated by a fault, have been drilled and equipped from the start with ESP, and the drilling program proceeds.

The thesis shall examine the current ESP operation on the unmanned production platform B in Ras Fanar producing in the Main Field and the West Field. Possible optimization potential and a sustainable economic shall be derived related to the actual forecast.

Since data is not available centrally existing production data like water cut, productivity index, BHFP and static bottom hole pressure (SBHP) are recorded and summarized. The measurements of BHFP by means of an Echometer are started if well conditions are suitable. The platform facilities and the design are evaluated and possible restrictions in the flow line or equipment are investigated.

On this basis new possibilities to increase efficiency are investigated and identified. Although there are no restrictions in regard to platform design the production data do not allow the modelling of an Inflow Performance Relationship, which is fundamental to design an ESP layout. Investigations revealed the production data measured by the offshore test separator must be allocated and the reported gas-oil ratio (GOR) has to be corrected. Furthermore the measured amount of gas is lower than reported by the company EGPC, which processes the production onshore. Using the program Pipesim by Schlumberger for Nodal™ Analysis an improved Inflow Performance Relationship (IPR) based on the corrected data is determined. With this IPR the layout of the ESP can be recalculated well by well and optimization possibilities are stated.

Possible operation alternatives and the required budget are defined. Based on the assumption that the proposals can lead to an increase of pump run life and a production increase due to improved gas handling the economic calculation showed the proposals will be economically valuable, compared by Net Present Value, Pay-out Time and a comparison of Cumulative Cost of the operation modes.

2. Introduction

Ras Fanar is located in the western part of the Gulf of Suez 300 km South-East of Cairo. The field named “Main Field” was discovered and declared commercial in 1974 by a Shell-BP-Deminex co-operation. It commenced production in 1984 with six wells drilled successfully from platforms A and B.

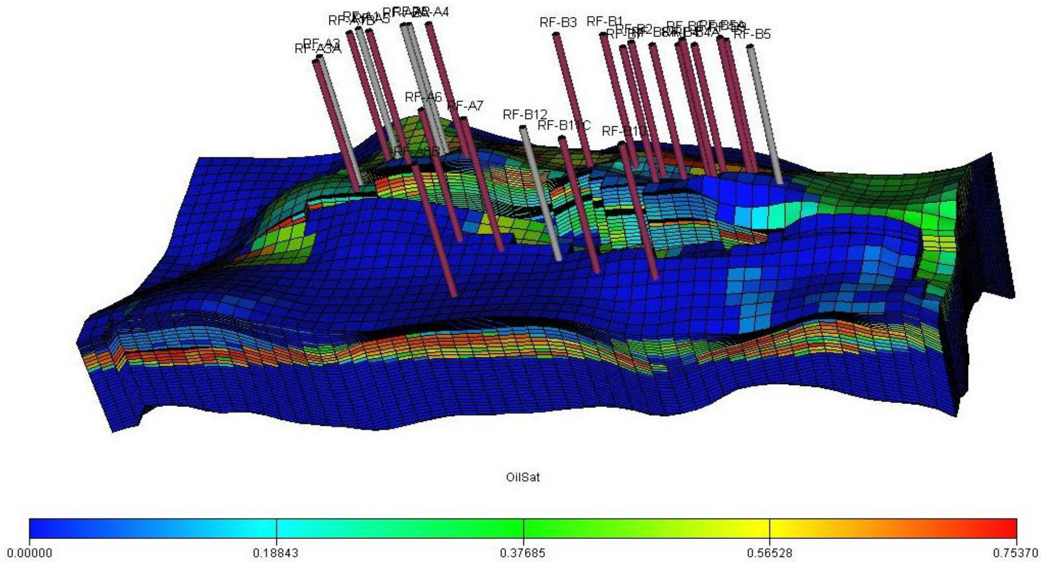

Figure 1: Geological structure[1]

Production began in January 1984 on natural flow and a peak production rate of 22 [MSTB/D] was achieved by October 1993. Production can be divided into four phases.

- Natural Flow with wells located along the main axis of the reservoir near the crest except A3, which was located on the NW toe of platform A in a down thrown fault block. This period ended in May 1992.
- Infill drilling of A4 and B4 along the main axis at the crest again using natural flow
- The other wells were drilled in 1996. Artificial lift method had to be chosen due to the relatively low pressure of the reservoir. ESPs were installed and led to a production boost as well as a rapid increase in water production afterwards. This was attributed to water coning due to the production increase. However an integrated field study in 2002 showed the rising of the water cut as a result of a general increase of oil-water contact (OWC) due to reservoir properties.
- Southeast of the fault a new reservoir named “West field” was explored and production started in June 2004, produced by six wells drilled from platforms A and B. The main fault completely isolates the West Field from the Main Field, which has a separate aquifer too. In 2009, A10 was drilled with deviations to West field PVT properties.[2]

3. Theory

Many high-volume wells are equipped with an Electric Submersible Pump (ESP) to lift the liquid and decrease bottom-hole well flowing pressure. The ESP is a multistage centrifugal pump and applicable to a wide area of pumping operations. The pumping system can be used for very high liquid rates up to 64000 [bbl/d] and small rates like 250 [bbl/d], hence it is the artificial lift system with the broadest producing range. ESPs can be installed up to 13000 [ft] in any deviations, although there are special designs for horizontal applications. Dogleg is a problem because of its mobile shaft. With the introduction of variable speed drives and newly designed gas administration devices, the ESP was able to broaden its area of application. It was thus able to manage up to 75 [%] of gas volume fraction, while furthermore becoming more flexible in its run life.[3] Improved production in deeper wells compared to sucker rod pumps and a small footprint make it a good and highly efficient decision for offshore operations, especially where lifting gas for gas lift operations is not available, although it is possible to combine the ESP with a common gas lift system to improve reliability of the production.

3.1 Parts of an ESP

Placed on the surface is the Ammeter, which records motor consumption, electrical equipment like the transformer and the switchboard. The motor is connected with the pump and the discharge head via the protector, which protects the motor from the well fluid,. The discharge head is mounted on the tubing at a certain depth in the well and hung on the wellhead.

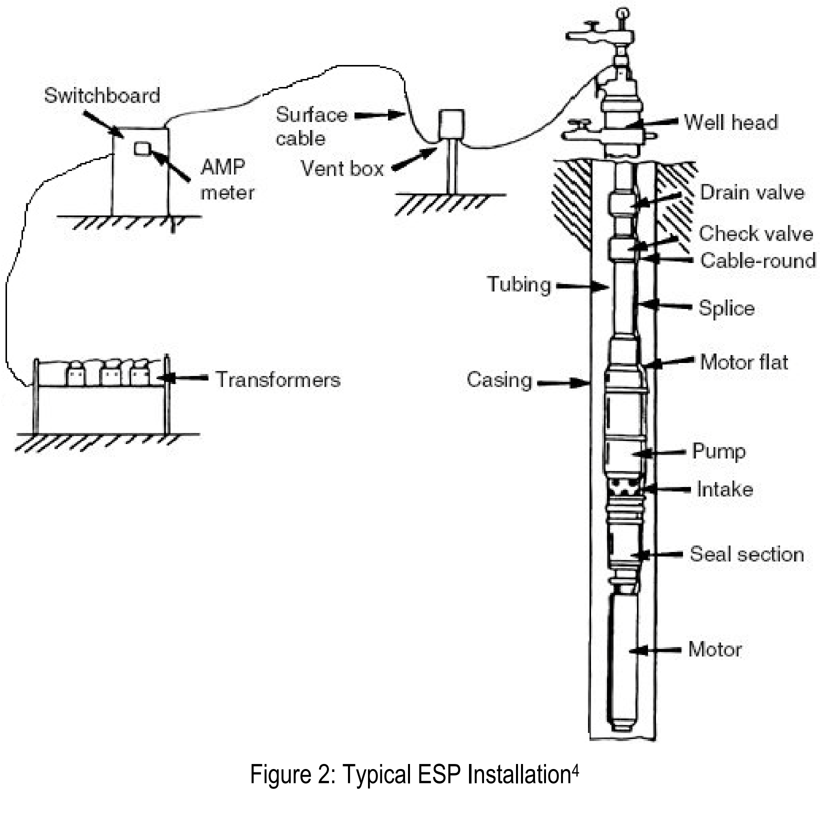

Figure 2: Typical ESP Installation[4]

The motor receives power through a cable with a three phase power source from the surface. It is operated at 60 Hz AC in the US; in the rest of the world the power supply is usually 50 Hz, depending on national power grid standards. But together with the later described VSD it is possible to change the frequency and consequently the production rate. As the motor must be cooled, it is usually placed below the pump intake and above the perforation to ensure that the passing liquid cools the motor. If this is not possible, a shroud can be used to force the liquid stream to flow around the motor. The annulus is either vented or tied into the well's flow line, so that as much gas as possible can be separated.[5] An advisable security system is the backspin relay. A check valve can be installed two or three joints above the pump to maintain a full tubing column after a shutdown and to prevent the fluid from flowing down, which could cause reverse rotation of the pump. In this case, a restart attempt could break the shaft, so without a check valve it is recommended to wait at least 30 minutes for another restart attempt. If a check valve is installed a drain valve has to be included to avoid pulling a wet tubing string. If the completion includes a packer without a conduit through the packer formation treatments cannot be applied by pumping down the annulus. Instead the liquids must be pumped through the tubing string. In this case a check valve cannot be installed because it would block automatically.[6]

Unlike positive displacement pumps such as Progressive Cavity Pumps (short PCP) ESP creates a more constant amount of pressure increase to the flow stream - the pumping head.

Several design options make the ESP capable of producing in corrosive environments like H_2S containments as well as in abrasive environments like sand production or combined with high temperature operations like Steam Assisted Gravity Drainage (SAGD), where it can stand temperatures of 425[°F] (218 [°C]). Late in 2009, Centrilift tested its UltraTemp ESP, which is designed for reservoir fluid temperatures up to 572 [°F] (300 [°C]), the results have not been published yet[3]

3.1.1 Motor

The prime mover of the submergible system is the downhole installed motor, which is a two pole three phase, squirrel cage induction type. Motors run at a nominal speed of 3500 [rpm] or 2915 [rpm], depending on the national power grid frequency. Because of diameter limitations the required horsepower is gained by increasing length. The three windings are continuous throughout the length of the stator; the rotors are short and keyed to the shaft to centre the field. The motor is placed in a steel housing, lubricated by high quality mineral oil, while the by-passing well fluid acts as a coolant. A minimum fluid velocity of 1[ft/sec] is recommended to provide adequate heat transfer. For this reason, a motor should never be placed above the perforation or below but, as a rule of thumb, at least 100 [ft TVD] above the perforation, unless the motor is shrouded. This means the pump intake is covered and the fluid is forced to flow down the outside of the shroud, entering the shroud section and flowing upwards to the pump intake, passing the motor.[6]

3.1.2 Pump

Electric submersible pumps are multi-staged centrifugal pumps. Each stage is constructed out of a rotating impeller and a static diffuser. An increase of pressure is generated as the liquid being pumped surrounds the impeller and the rotating impeller imparts a rotating motion to the liquid. The radial part of the motion points from the centre to the outside of the impeller, which is caused by centrifugal forces. The axial part of the motion moves tangentially to the outside and together they form the actual direction of the flow. The function of the diffuser is to utilize part of the kinetic energy of the fluid in order to increase pressure.

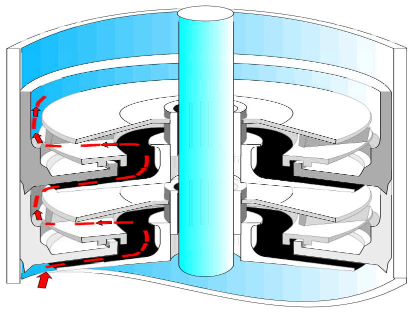

Figure 3: Design and flow path of a pump stage[7]

There are two design categories, radial and mixed flow stages. The first one is preferably used for smaller flow rates up to approximately 1900 [bbl/d] for 4" OD pumps and the other one 3500 [bbl/d] for larger diameters. The difference between the design concepts, is the increased axial direction of the fluid in the mixed flow impeller.

In a floating stage design, the impeller is to float axially along the shaft and the thrust of every impeller stage is absorbed by pads found on the diffuser. The thrust bearing in the seal section has to support the thrust of the pump shaft only. The advantage of this design is that many stages can be stacked together without fixing it to the pump shaft axially, which requires precise manipulation. So the pump can be manufactured with several hundred stages.

The compression design is suitable for pumps with outside diameters beyond 6" and for mild abrasive environments. Instead of allowing the impeller to float individually in the diffusers, the impellers are stacked on one another. This prevents the downthrust forces of the impeller from rubbing on the diffuser thrust pad. These forces are transferred down to the thrust bearing instead to the pump shaft. The pump itself will suffer no downthrust wear, but radial wear, because there is no additional radial support in the standard stage casting.

Impellers are fully enclosed curved vane designs and their maximum efficiency is a function of impeller design and type. The operating efficiency is a function of design capacity and actual capacity.

Centrifugal Pumps are constant head devices, so it is common practice to convert any pressure into the term head, given in feet.

$$BHP = \frac{Q \times H \times SG}{Pump\ Efficiency}$$

Where

Q – volume [bb/d]

H – head [ft], vertical feet of a liquid a given pressure can support

SG – specific gravity of the pumped liquid

BHP – Break Horse Power [hp]

The size and design of the impeller determine the degree of acceleration energy that is transmitted to the fluid. The size of the impeller is restricted by the outer diameter of the housing and the diameter of the pump shaft, which must be strong enough to transmit the power of the motor to all the stages.

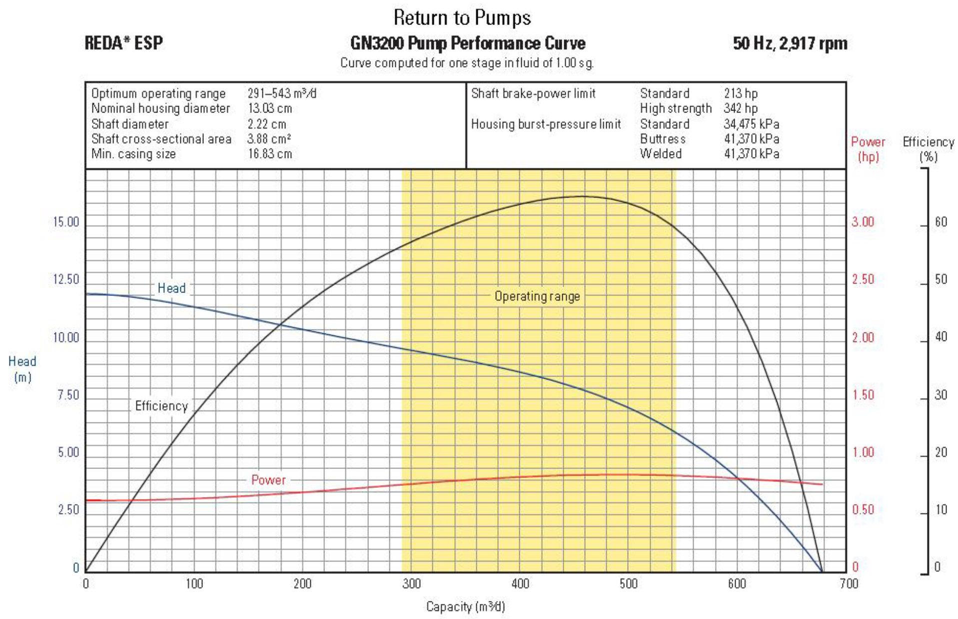

Figure 4: One stage pump performance curve[8]

Neither the head capacity curve nor the efficiency curve must be adopted with changing specific gravity of the pump, because the curve is only a function of the volumetric flow rate. This makes different pumps comparable with the help of pump curves offered by the vendor, even if different pumping conditions occur. Only viscosity has an impact on that pump, but that will be discussed in detail at a later point. The discharge rate of an ESP depends on the rotational speed [rpm] or frequency [Hz], stage design, the dynamic head, which includes the specific gravity of the pumped fluid, against which the pump is operating and the physical properties of the pumped fluid.

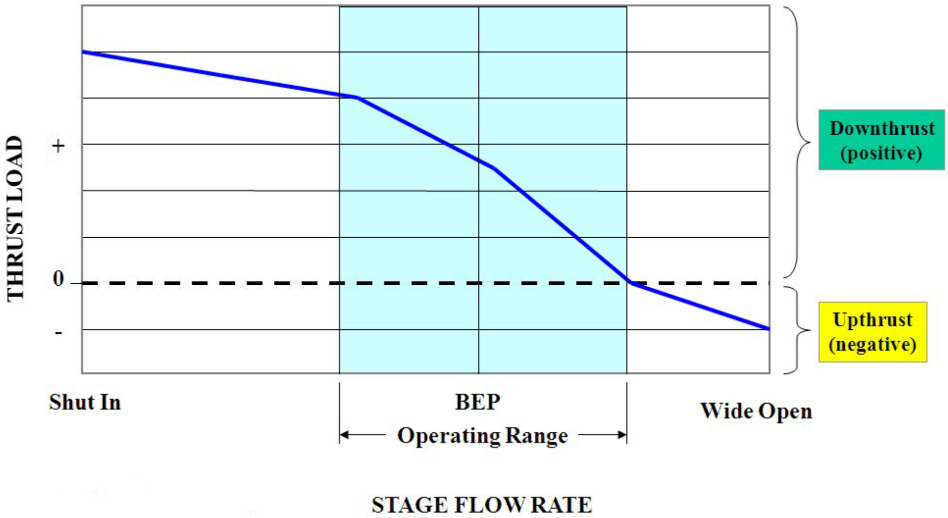

Figure 5: Impeller thrust versus flow rate[7]

Stages are designed to have a slight downthrust force on the impeller in the operating range proposed by the constructor. At the maximum operating point, the downthrust force is designed to be very low or with increasing downthrust force toward the operation minimum. If the design were in the region of no thrust the impeller would oscillate up and down, and this would lead to instable flow and excessive wear. To ensure stable hydraulic operation and minimizing thrust wear, the pump should be operated within the limits specified by the constructor to provide optimal pump run life. For sand producing operations it is recommended to operate on the right side of the best efficiency point, because with lower thrust the sand is acting as an abreast with increasing pressure. Operations outside the recommended range will have a detrimental effect on the pump and other ESP components; the result is reduced run life.[6]

3.1.3 Protector or Seal Section

The very important seal section connects the motor drive shaft with the pump or gas separator. The main purpose of this section is to isolate the dielectric motor oil from the well fluid and to balance well flowing pressure and the motor's internal pressure. This equalisation of pressure across the motor helps to keep well fluid from leaking past the sealed joints of the motor. The well fluid would contaminate the clean motor oil and this would lead to insulation failure.

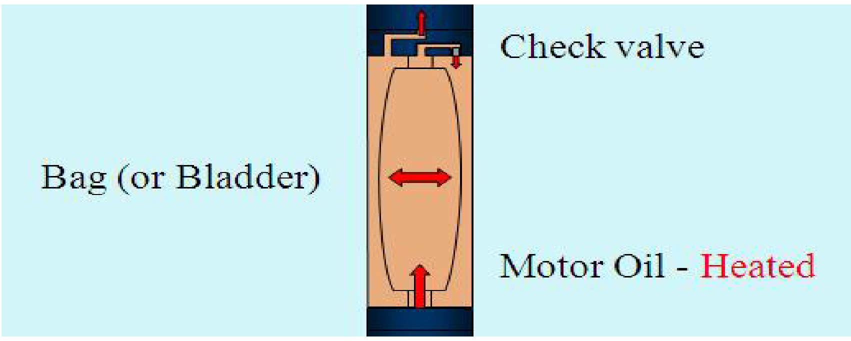

Figure 6: Expansion of the heated motor oil[9]

One of two design options is the positive seal section, which is an elastic rubber bag to provide additional isolated space for the thermal expansion of the motor oil caused by ambient temperature and heat generated by the motor and for the thermal contraction after shutdown. With every thermal expansion, a small amount of motor oil is pressed irreversibly out of the bag through the check valve. This leads to the important issue of restricted expansion and contraction cycles. If many shutdown situations are expected more positive seal sections should be considered in the design to ensure a sufficient amount of motor oil to enhance possible run life.

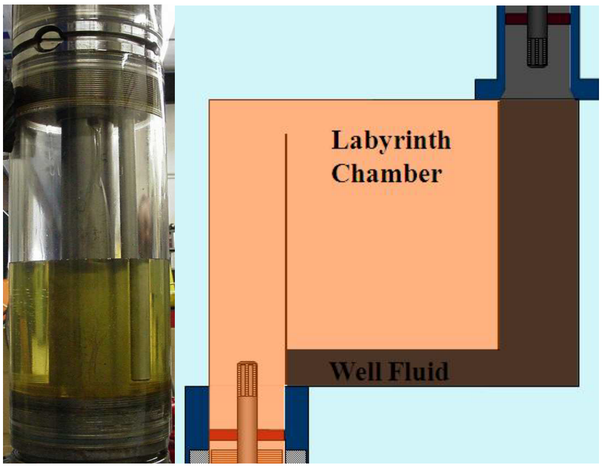

Figure 7: Labyrinth chamber[9]

The other design option is the labyrinth chamber which benefits from the different densities of the well fluid and the motor oil to get the fluid past the upper seals. This is achieved by allowing the well fluid and the motor oil to communicate through tube paths connecting segregated chambers. It provides expansion and isolation volume in vertical or near vertical wells, however in deviated wells the chamber will not work.

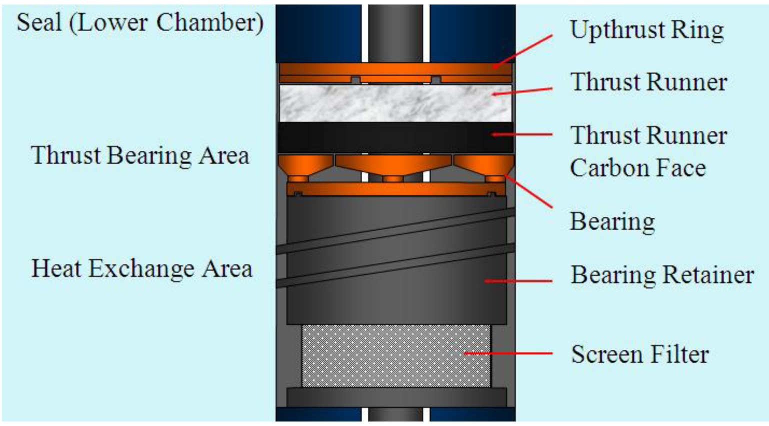

Figure 8: Thrust bearing[9]

Another purpose of the seal section is the thrust bearing which absorbs the axial load of the pump shaft, the longitudinal hydraulic load on the pump shaft and any unbalanced longitudinally fixed impeller load. All those loads are transferred to the seal shaft from the pump shaft and in turn the seal shaft transfers those loads to the thrust bearing section to protect the motor shaft against excessive high load.

Figure 9: Shaft seal[9]

There are several possibilities to equip the protector, like code BSBLB-HL, which stands for the combination bag(B), another bag(B) in series(S), labyrinth(L), bag(B) and a high load(HL) thrust bearing. One design option is to place components parallel(P) to each other like the code BPB where two bags are placed parallel. Between every section a seal is placed at the shaft to isolate each part from one another. Tandem protectors or even more protectors are further options, for instance, to increase motor oil storage capacity in order to ensure a satisfying number of restart attempts.

So the labyrinth chamber provides expansion and isolation volume in vertical or near vertical wells, the bag provides expansion volume and isolation for clean motor oil, the mechanical seal prevents fluid migration down the seal shaft and the thrust bearing carries the thrust load of the pump shaft. [9]

3.1.4 Pump Intake and Downhole Gas Separator

There are two possibilities for the well fluid to enter the pump; standard intake and gas separator intake. The average ESP can cope with up to 10 % free gas in the pump, from 10-20% head degradation takes place and above 20% the risk of suffering a gas lock is very high. A gas lock will damage the pump if there is no automatic shut-down sequence in case of under balance. Nevertheless, there is a loss of production and a reduction in run life, as every stop results in a loss of motor oil.

There are two kinds of gas separator intakes. The static gas separator reverses the flow direction, which creates lower pressure at the entry ports and allows the gas to separate. The gas moves up the annulus and is vented at the wellhead into the flow line, the fluid moves downwards into the stand tube. The rotating impeller picks up the fluid and creates a vortex. This forces the fluid, which is denser than gas, to the outside and the gas moves up the shaft and is vented to the annulus.

The rotary gas separator's core part is an inducer centrifuge. The fluid enters the intake and the inducer, which increases the fluid pressure discharged into the centrifuge. Again the denser fluid is forced to the outside, gas rises from the centre through the flow diverter into the crossover section, where fluid is flowing into the first stage of the pump and gas is vented to the annulus.[10]

To handle additional gas many methods were introduced, like sumps, shrouds and bottom feeder intakes. They were partially successful similar to the mentioned rotary gas separator. Better understanding of multiphase flow led to e.g. Schlumberger's Advanced Gas Handler Pump, which can handle up to 45% of gas volume fractions and Poseidon Multiphase Axial Pump, which can handle up to 75% gas volume fractions.[3] Modern equipment uses the gas as additional lifting energy by transforming gas slugs into bubble flow.[10]

3.1.5 Switchboard

The ESP can be controlled by a Fixed Speed Drive (FSD) or Variable Speed Drive (VSD). The FSD controlled system keeps the voltage frequency fixed at 50 Hz and production must be controlled by a surface choke. A solid state circuit for overload and underload protection is usually built in. Underload or some type of pump off protection is required as the motor needs adequate cooling. During the start up phase of an ESP, the motor can draw five to eight times its rated current, which allows the motor to produce several times more torque than rated. In addition, excessive heat is generated which will damage the plastic components. This can cause electrical and mechanical stress on the installed equipment and is a serious problem in shallower applications. For this purpose a soft starter module was introduced, which decreases the voltage to the monitor during initial start-up.

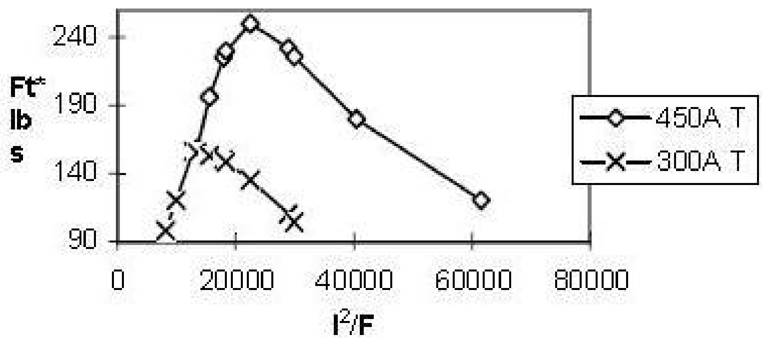

Figure 10: Starting Torque versus Frequency and Current[11]

With a constant current, the motor torque increases linearly with frequency until the output transformer saturates. Reaching this condition any additional current circulates in the transformer primary only and does not produce torque in the motor.[11]

The VSD has several advantages compared to the FSD, like the capability to change the voltage frequency to the motor, which results in less rpm generated by the motor, so the capacity of the pump is changed linearly. The pump curve can be transformed by the later discussed affinity laws into the so called tornado chart. From this chart the production rate can be estimated for different frequencies as well as the operating range at a certain frequency. This ensures that the pump is suitable in a broader production range as the field declines. In addition pump changes due to capacity changes are reduced.

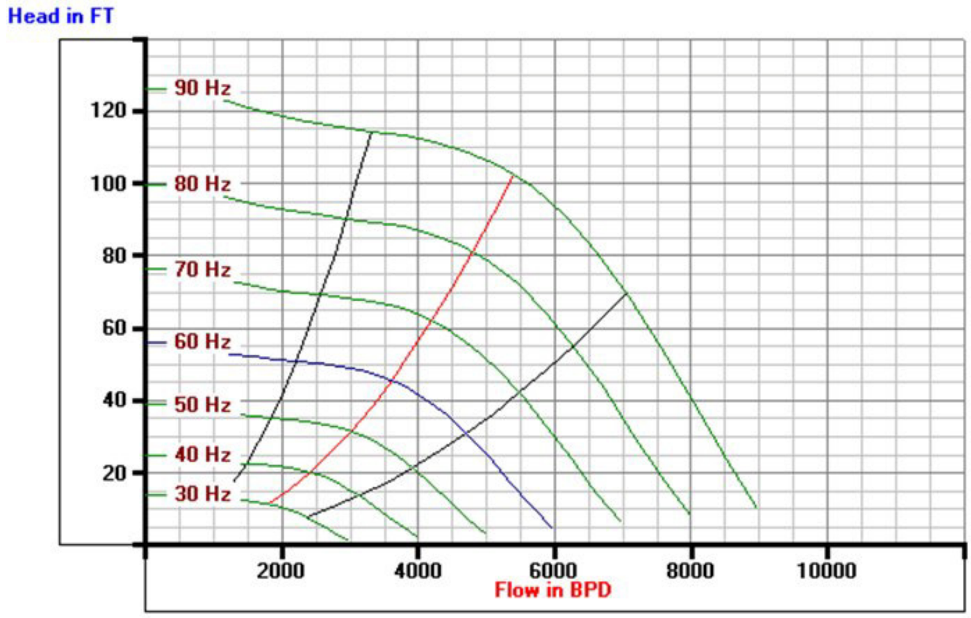

Figure 11: VSD curve, also known as tornado chart[7]

Poor quality electric power can be handled by using VSD. It is quite insensitive to incoming power quality by transforming the incoming frequency and voltage AC into DC and rebuilding it to a six-step wave form AC. It provides closely regulated and balanced output and will not put power transients down to the downhole motor, of course only in a limited range. The VSD can be damaged or even destroyed by transients but it is much easier and cheaper to deal with problems on the surface than downhole.

Previous VSD Systems used six or twelve pulse diodes and reflected harmonic distortions of 25 [%], which continued to create problems for the power supply stream. Schlumberger introduced a new system with integrated 18 pulses, phase shifting auto transformer that shrinks the unit by skipping the additional transformer and reduces the harmonics to less than 3 [%].

Soft starts provide two major advantages; first, it reduces the drain on the power system at start-up and second, the strain on the pump shaft is lower than at the standard starting procedure. This is a real benefit for gassy or sandy wells and in some cases damaging the pump can be avoided by a slow start of the pump.[3]

3.1.6 Power Cable

Round cables are used all the way down the pump; only in the lowest part a flat cable profile is necessary, due to the limited clearance situations at the protector and motor. Attached to the motor there is the so called pothead, which allows the entry of electric power into the motor while isolating it from well fluids. The standard conductor size is from 1/0 to 6 AWG (American Wire Gauge). It meets virtually all motor amperage requirements and is usually made of copper. In harsh environments, like H_2S contamination, lead cables are common. The cable is constructed with one conductor for each power phase and power loss tables are available for the loss of amperage per length unit. In low temperature wells combined with a bottom-hole pressure lower than 1500 [psi], unarmed cable design is the most economical solution, but there are special cable designs for nearly all applications like high temperature wells up to 500° [F] (260° [C]) or gaseous environment.[10]

3.1.7 Pump Housing Limit

Housing strength is normally stated as the limiting value for the housing threads at the discharge of the pump. If operated above this limit, the threads could be damaged and burst. When operating at high frequencies, the shut-in or no-flow pressure generated by the pump may exceed this limit. Therefore, it is advisable to take precautions in order to avoid this situation. Since the normal underload detection is too slow, a properly sized, surface over-pressure shutdown switch is recommended.[11]

3.2 Factors affecting pump design

The pump curves published by vendors usually refer to the performance at a fixed frequency and a specific gravity of the pumped liquid of 1[-] and viscosity is equal to 1 [cp], tested with fresh water. As the pumps are not only used for water, the pump performance under operational conditions had to be predicted as well.

3.2.1 Influence of speed, specific gravity and diameter

To calculate the effect of changing three variables like speed, diameter of the impeller or the specific gravity of the pumped liquid we can use the Affinity laws.

$$Q_2 = Q_1 \times \left(\frac{F_2}{F_1}\right) \times \left(\frac{D_2}{D_1}\right)$$

$$H_2 = H_1 \times \left(\frac{F_2}{F_1}\right) \times \left(\frac{D_2}{D_1}\right)^2$$

$$BHP_2 = BHP_1 \times \left(\frac{F_2}{F_1}\right)^2 \times \left(\frac{D_2}{D_1}\right)^2 \times \left(\frac{SG_2}{SG_1}\right)$$

Where

Q - capacity [bbl/d]

D - diameter of the impeller [in]

F - frequency [Hz]

SG - specific gravity [-]

The power required to overcome all the losses is named brake horsepower. This includes friction of the flow through an impeller and turbulent losses, the disk friction or the energy used to move the impeller through the liquid, leakage of the liquid flowing back from the outside of the impeller back to the centre and mechanical friction losses. Fluid horsepower is the power consumption of the liquid leaving the pump, while brake horsepower is the power consumption of the pump per time unit.[12]

The laws were derived from non-dimensional analysis of rotating machines, valid for dynamically similar or relatively common conditions, where certain dimensionless parameters were kept constant. They are experimentally correct and confirm that capacity is linearly proportional to speed and diameter, the head is proportional to the square and the brake horsepower is proportional to the cube of speed or diameter.

The stated relations are only true if the effect of speed on turbulent and frictional losses is neglected, which can be done because the effect of the losses compared to the total loss is minimal.

The specific gravity has no influence on the head produced by an impeller, because the centrifugal pump is a volumetric machine, hence the head of the pump is only a function of the volumetric flow rate. This allows for the concept that the head capacity curve and efficiency are independent of the specific gravity. Only brake horsepower depends directly on the density of the pumped liquid.[12]

3.2.2 Effect of viscosity

Usually the ESP is used to pump liquids with a relatively low viscosity, since the production of unconventional resources like heavy oil in the Orinoco Belt, Venezuela or tar sands of Alberta, Canada is economically profitable. Therefore the effect on the performance curve at high viscosity on a centrifugal pump must be applied sophisticatedly as ESP proved to work well with high temperature production techniques. Viscous fluids have a high internal resistance to flowing, so frictional losses and disk friction are increased. This leads to reduced head capacity and higher brake horsepower. Experience has shown that the Best Efficiency Point (BEP) of a pump is lowered significantly and flow capacity decreases.

$$Q_{visc} = C_q \times Q_w$$

$$H_{visc} = C_H \times Q_w$$

Where

C - correction factor

The subscript w stands for water, visc for the viscous fluid

Correction factors are developed to calculate the performance based on the performance with water, which can be seen on a performance correction chart published by Courtesy OiLine-Kobe.[11]

3.2.3 Pump Shaft Horsepower Limit

The Horsepower (HP) capacity of the shaft is proportional to speed and the [HP] required by the pump is a cubic function of speed; there will be a speed above which the maximum rating of the shaft will be reached. Manufacturers normally state the shaft limit as an [HP] capability at 50 or 60 Hz. This rating should then be checked at maximum operating frequency to ensure that the pump shaft capacity is not exceeded.[11]

3.2.4 Vibration and wear

Higher than normal speed operation increases radial vibration due to imbalance in the rotating assembly, this is usually not a significant factor in determining pump life span. Manufacturers usually only initiate the first step of dynamically balancing impellers, when constructing large diameter pumps. If abrasives are contained in the fluid, equipment wear due to abrasive grinding and erosion at high speeds can be a serious problem. In such situations, a VSD can be used to operate the pump at a lower speed in order to reduce wear and erosion. Usually, in order to maintain a required flow rate, a larger sized pump and motor will be required, which is not always possible due to limited casing sizes.[11]

3.3 Nodal™ Analysis

A method for analysing a well which will allow determination of production capacity for any combination of components is called Nodal™ Analysis. This method can be used to determine pressure drops or flow resistance in any part of the system. The method is applicable in many aspects like electrical circuits and complex pipeline systems. Using this method with production systems was first proposed by Gilbert[13] and discussed by Nind[14] and Brown[15].

All components upstream of the node are called inflow section, components downstream of the node are called outflow. Some basic assumptions have to be confirmed, so that the flow rate through the system can be determined.[16]

1. A relationship between flow rate and pressure drop must be available
2. Outflow and the Inflow at the node must be equal
3. Only one pressure at the node

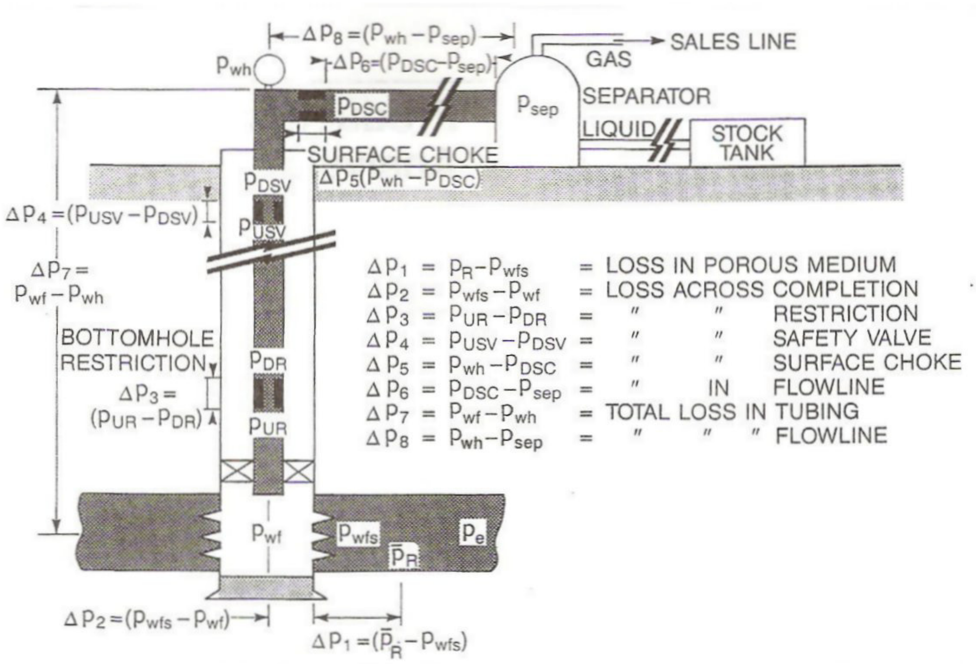

Figure 12: Possible pressure losses in a complete production system[13]

Every possible pressure loss of a production system is determined. There are always two fixed pressures in the well, which do not change with the varying flow rates. One is the average reservoir pressure $p_{r,}$ the other one is the system outlet pressure, usually the separator pressure p_{sep}, and in systems with a choke the pressure at the wellhead p_{wh}. Afterwards, a specific note can be selected, usually at the intake of the well or at the wellhead.[16]

Henceforth the pressure at the node, called p_{node} can be calculated as follows:

$$\text{Inflow to the node: } p_r - \Delta p \text{ (upstream)} = p_{node}$$

$$\text{Outflow from the node: } p_{sep} - \Delta p \text{ (downstream)} = p_{node}$$

The pressure drop, Δp_r, in any component is related to the flow rate through the system including gravitational, frictional and elevation terms. Finding the flow rate and pressure that fulfil the basic assumptions can be illustrated graphically by plotting node pressure versus flow rate.

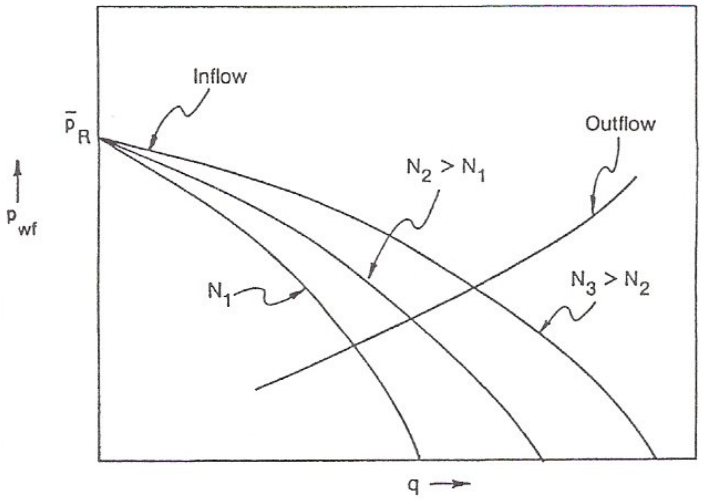

Figure 13: Node pressure p_{wf} versus flow rate q[16]

At the intersection of the two curves the argument that the inflow must be equal to outflow is valid. This is the flow rate which shows the producing capacity of the system with the current configuration. Now the effect of any change in well configuration can be shown graphically by recalculating node pressure versus flow rate. If a change is made upstream the outflow curve will change and the inflow curve will remain constant and vice versa, if the change is made in the inflow section. This is indicated in figure 13 by three different Inflow curves N_1, N_2 and N_3. The intersection will change indicating a new node pressure and flow capacity. The curves are shifted if one of the two fixed pressures change, for example with depletion of a field the reservoir pressure p_r will decline and the inflow curve will shift downwards.

The nodal system analysis can be used to analyse the production of oil and gas wells, naturally flowing or equipped with artificial lift systems. Through modification of the inflow and outflow expressions the method can also be used for injection wells furthermore.

There are several different flow correlations to calculate the pressure drop in a pipe. The most accurate one to the investigated system must be identified and used for the pressure drop in the tubing section. [16]

4. The Ras Fanar Field

4.1 General Characteristics of the Reservoir

The total production is pumped via one 12 [in] production pipeline to onshore facilities. Pipeline samples indicate the average API of both West Field and Main Field is at 27.8° including 5.26 [WT%] asphaltene and 8.35 [WT%] paraffin wax with a pour point of 48° [F] (9° [C]). An API study of the well A8, located in the West field, performed on 21.02.2006 by the Chemical Lab in Zeit Bay, indicated that it produces crude oil at 24.4°, 13.75 [WT%] asphaltene and 7.85 [WT%] paraffin. This difference is due to the different field conditions of West and Main Field. The crude oil of the Main Field has an API of 32°, that of the West Field only 26° and asphaltene is mainly a component of West Field crude oil.

The average reservoir temperature of 120° [F] (48.8° [C]) is valid for both fields.

The average gas composition of both fields measured in the onshore slug catcher 30-V-2 and 30 –V-7 indicate impurities of 13 [Mol %] H_2S, 1.55 [Mol %] N_2 and 3.7 [Mol %] of CO_2. Methane content is 52 [%]; the rest consists out of C+ components leading to the specific gas gravity of 0.88 [-].

	Main Field	West Field
Mean depth	2200 [ft TVDss]	2350 [ft TVDss]
Pressure gradient	0.231818 [psi/ft]	0.276596[psi/ft]
Initial Reservoir Pressure (below Bubble Point Pressure)	812 [psia]	832 [psia]
Actual Reservoir Pressure	500-510 [psia]	605-615[psia]
Temperature gradient	0.050909 [°F/ft]	0.04766[°F/ft]
Specific Gravity of Gas	0.865443 [-]	0.898413 [-]
Oil Viscosity	2.1000 [cp] @515 [psi]	4.98777 [cp] @600 [psi]
Avg. Stock Tank Oil Gravity	32° [API]	26° [API]
Formation Volume Factor Oil	1.1419 [rb/stb]	1.158 [rb/stb]
Formation Volume Factor Gas	5.310 [Mcf/Mscf]	2.490028[Mcf/Mscf]

Table 1: Average Reservoir Fluid Properties

4.2 Reservoir Geology

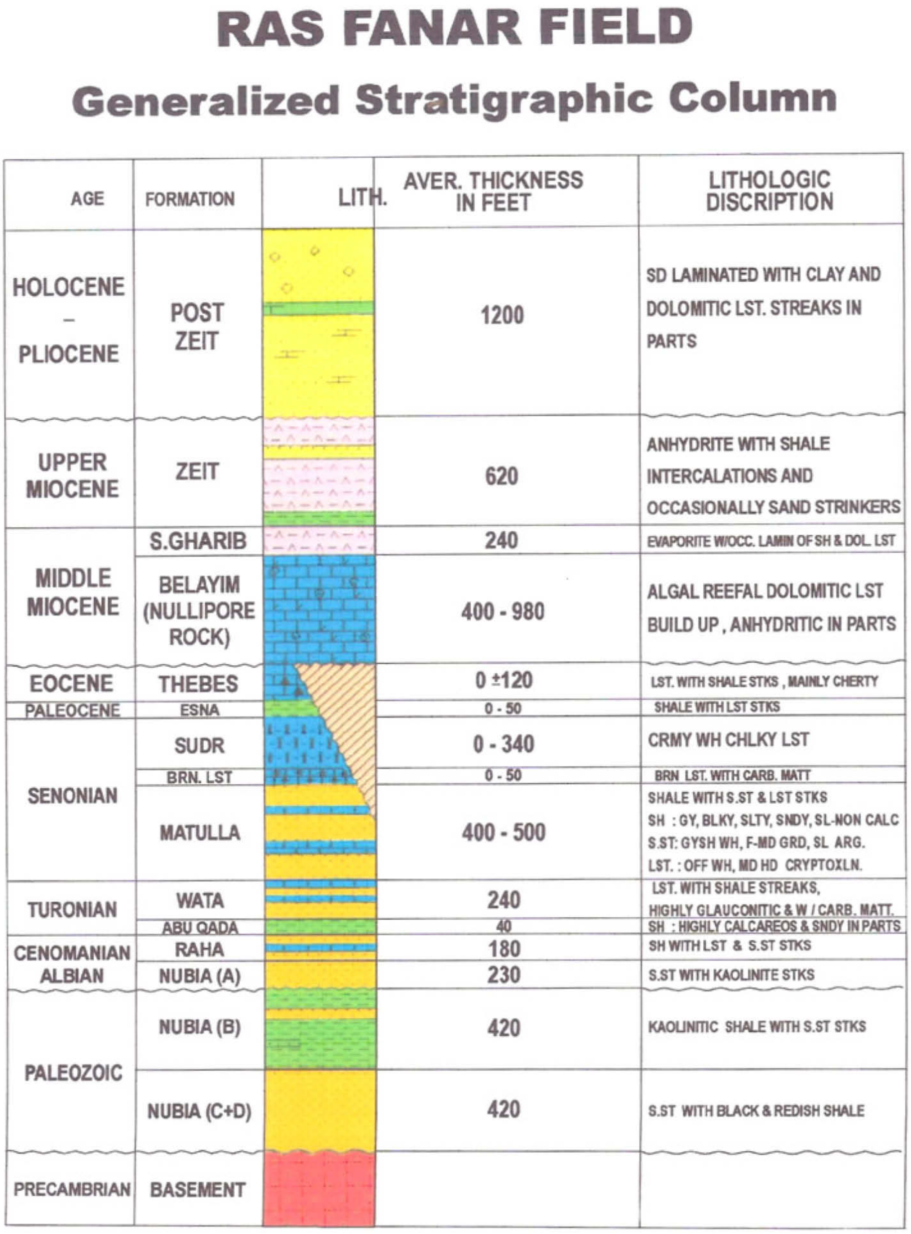

Figure 14: Strartigraphic Column[2]

The field is comprised of a highly heterogeneous reservoir, namely the Belayin Formation, which contains low energy carbonate platform sediments of the Miocene Age. Between the top of the pay zone and base of pay the reservoir is in hydraulic communication without sharp boundaries marine shales or bedded anhydrites segregating it vertically.

The oil bearing formation is the above mentioned Belayim Formation, which is also referred to as Nullipore rock. It has an average thickness of 400 to 980 feet. The reservoir consists of algal dolomitic limestone with anhydritic parts. The top of formation is at 2200 [ft ss] for the Main Field, in the West ield it is about 2350 [ft ss] with the same lithology.

4.3 Production History

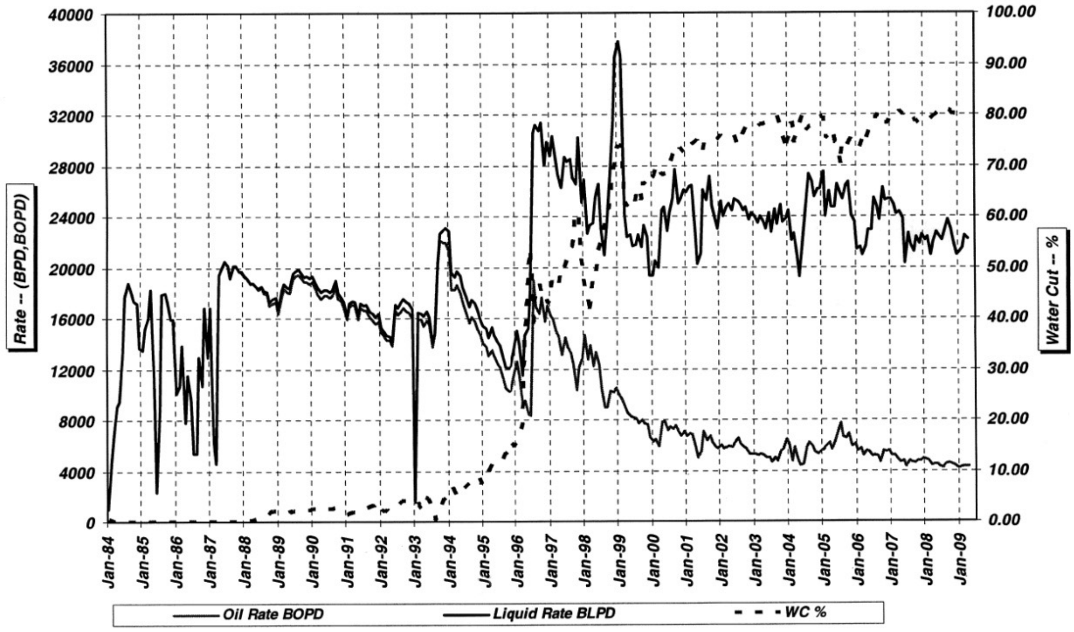

Figure 15: Cumulative Production of Ras Fanar[1]

During 25 years of production the Main Field reservoir pressure has declined from 812 psia to 505 psia. Figure 15 illustrates the production history of the Main Field with peak oil production in 1994 and a sharp increase of gross production and water cut in 1996, when the first ESP applications were started. First, the rise of the water cut was assumed to be the result of the massively increased production by the ESP, but a reservoir study in 2002 indicated that the sharp rise of the water cut was not linked with the ESP operation but is due to the reservoir. The water cut stabilized at 80% in 2003 and gross production is slowly declining due to depletion. It presently varies between 50000 and 60000 [bbl/d].

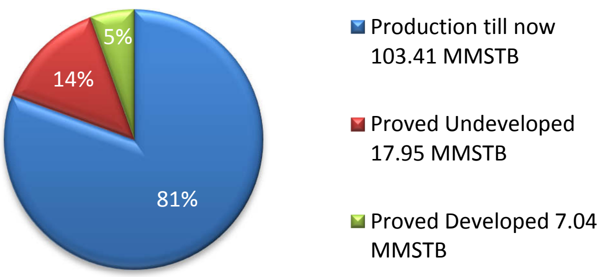

Figure 16: Ras Fanar Oil Reserve Distribution June 2008

The total reserve estimation for Ras Fanar combining the West Field and Main Field indicates that 81 [%] or 103.41 [MMSTB] were already produced until the middle of 2008, 17.95 [MMSTB] were proved undeveloped and will be a point of interest in the next few years. By June 2009 5 [%] of the total reserves were developed; consequently 7.04 [MMSTB] will be produced under current conditions.

4.4 Reservoir Pressure Decline

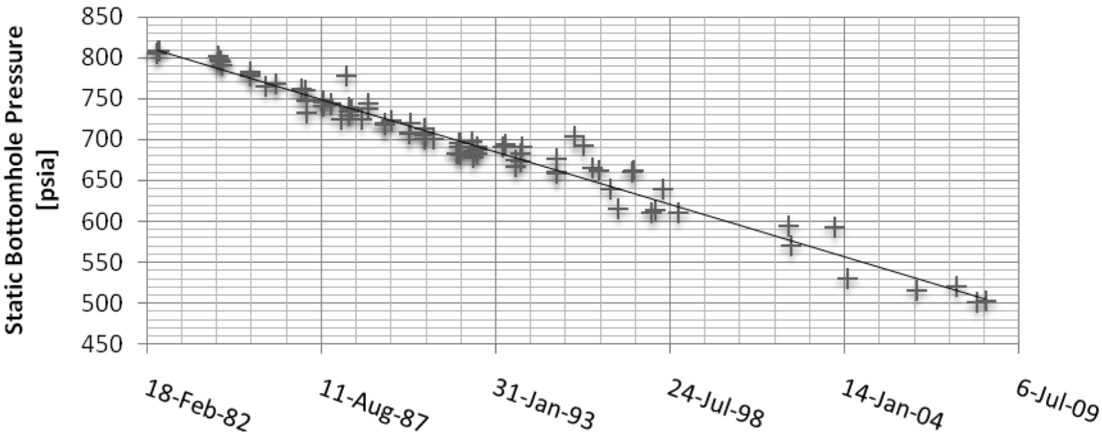

Figure 17: Static Bottom-hole Pressure – Main Field

Pressure is equalized within and between each platform of Ras Fanar. This indicates high overall permeability and reservoir continuity. The bubble point pressure, which is also the initial pressure of the Main area, was about 812 [psia], for the west area it is stated as 832 psi. Over the years the static average pressure in the Main Field declined to around 510 [psia] at 2200 [ftss].

Pressure tests in the Main Field had been stopped with the installation of the first ESPs from 1996 to 1998. Very few tests have been carried out again since 2004 but the few results match the historical trend. No downhole pressure sensors have available since 2009.

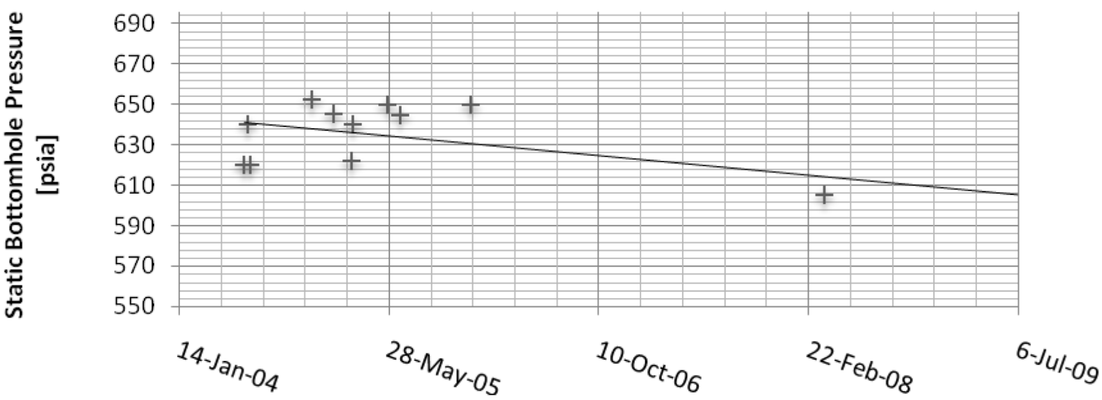

Figure 18: Static Bottom-hole Pressure – West Field

At the beginning of the development of the West Field several pressure tests were performed, and these indicated an initial reservoir pressure of about 650 psia. Only one test was performed afterwards, but it matched the reservoir model, which predicted a reservoir pressure of 600 [psia]. More pressure surveys are recommended for the West Field, because a regression line based only on a few measurements may be inaccurate and would lead to wrong reservoir models and furthermore to inaccurate reserve estimations.

5. Evaluation of the Current Situation

5.1 Nominal Platform Layout

One task was to check unnecessary flow paths or equipment due to former modifications and an up to date platform layout including installed equipment. The nominal layout of the production is rather simple, which is quite usual for unmanned platforms. For batch treatments a high amount of diesel is required, which is pumped through an 8 [in] pipeline to the platforms from onshore, where the offshore pump delivers it to a tank and perform the batch treatment pumping operation for each well. The pump can manage 3 [bbl/min] at 3000 [psig] according to the maximum wellhead and flowline pressures, and the diesel tank can take up 120 [bbl] of non corrosive fluids. The air compressor supplies air to any facility on the platform similar to the safety shut down valve system and the control valve systems downhole and on the surface by keeping up the pressure on it all the time. If any pressure is released, the valves will close automatically. The chemical tank is divided into a 1000 litres demulsifier and a 3000 litres corrosion inhibitor tank.

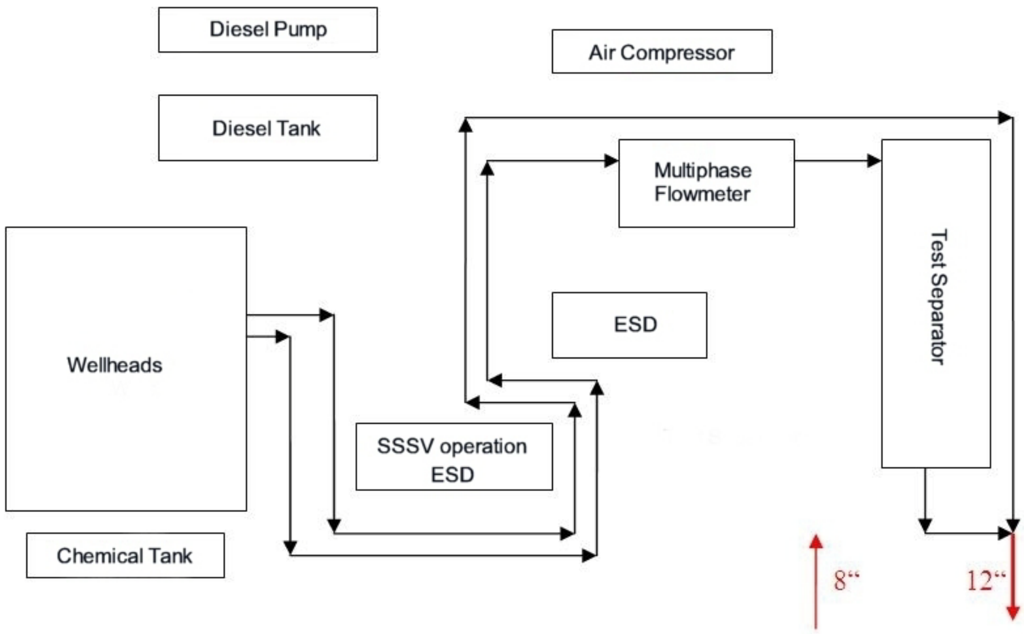

Figure 19: Platform Layout

A 4 [in] liquid and a 2 [in] gas flow line from the wellhead are gathered in two 6 [in] lines with an average pressure of 5 to 5.5 [bar] at the wellhead, one to gather the production and pumping it with the production of platform A with a 12 [in] pipeline to the onshore process facilities, and the other one to lead the production of a single well to the test facilities. A Multiphase Flowmeter is installed via a bypass right before the test separator, but further calibration is necessary to ensure optimal test results. Onshore treatment of the production is performed by the neighbouring national oil company EGPC, which uses the produced gas to run two turbines and in return delivers electricity to the offshore production platforms.

5.2 Wellhead

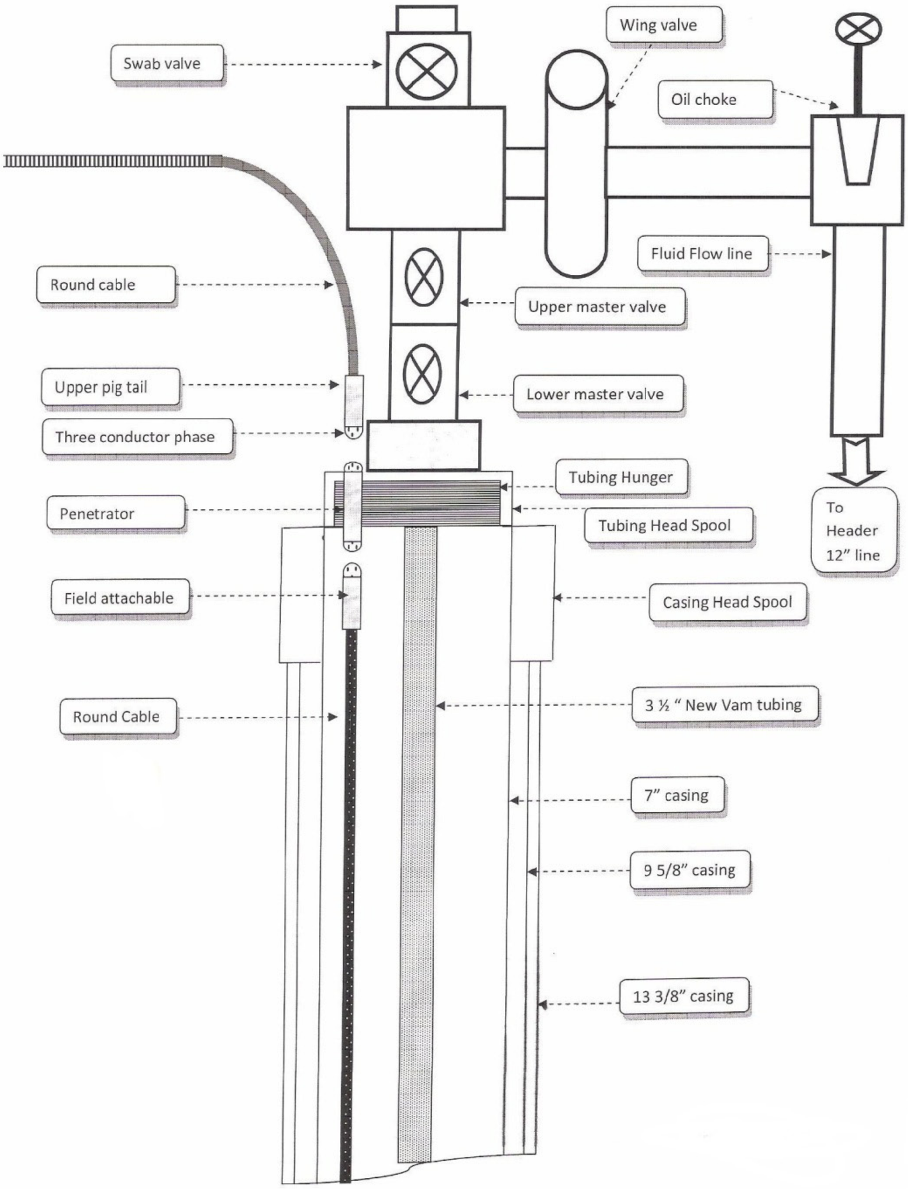

Figure 20: Wellhead Design[17]

The wellheads are from two different companies, Cameron and FMC, but they show the same layout. Pressure gauges are available at the annulus, right of the wellhead and below the variable choke. The annulus is vented to the flow line, where a gauge is installed right before the valve to monitor casing pressure.

After passing the variable choke the flow can be diverted and enter the 6 [in] gathering line, which would be the first exit or the 6 [in] test separator line, with which every well can be measured separately by the test separator. Test samples from the well are taken at the bottom right before the split of production and separator line. No unnecessary flow path or broken gauge could be found and therefore the flow path is already optimal.

5.3 Wellbore Completion

For completion, N80 API steel quality is used for tubing and L80 API steel quality for the production casing. That means ordinary material because H_2S does not cause crack corrosion due to low partial pressure in the production casing.[17, 19] Other types of corrosions do not occur due to an absence of Oxygen. To protect the tubing string from corrosion, a corrosion inhibitor is injected downhole via a chemical injection line.

A typical completion string design can be seen in figure 21. On the production tubing the standard ESP configuration is mounted, which has a vortex gas separator and an advanced gas handler to cope with high gas fractions. The separated gas is vented into the annulus, which is connected to the flow line in order to produce the gas. The gas separator is followed by two protectors and the motor. Below the motor 1 to 2 perforated pub joints allow the well fluid to pass the permanent packer and enter the annulus. The SCSSV is placed between the perforated joints and the permanent packer to prevent well fluid entry in the annulus in case of emergency. A Multisensor Type 1 is mounted below the motor in B11c and B12. The pump is fixed with a permanent packer to ensure the pump is placed in the centre of the hole to provide adequate cooling of the motor on all sides via the passing production fluid. It is additionally fixed by a permanent packer and in this way decreases vibration of the pump caused by rotating parts.

Some completion designs include a 5” liner and B7 is an open hole completion. The pump setting depth is at least 100 feet above the top perforation to ensure well fluid is passing the motor, if a well section with a dogleg severity less than 1 deg/100ft is available.[20]

In Ras Fanar, nearly all the wells are producing in the downthrust region. In order to minimize the detrimental effects of downthrust, compression pump design is used instead of floating. Additionally, best practice recommends the use of a compression pump design if there are problems with solids or gas production. Although corrosion problems are not reported a disassembly in the workshop of the vendor indicated that this problem existed. In combination with the compression pump design the protectors have to bear more forces, so the high load design version must be used and the mechanical seals must be strong because of the solids that the wells produce.

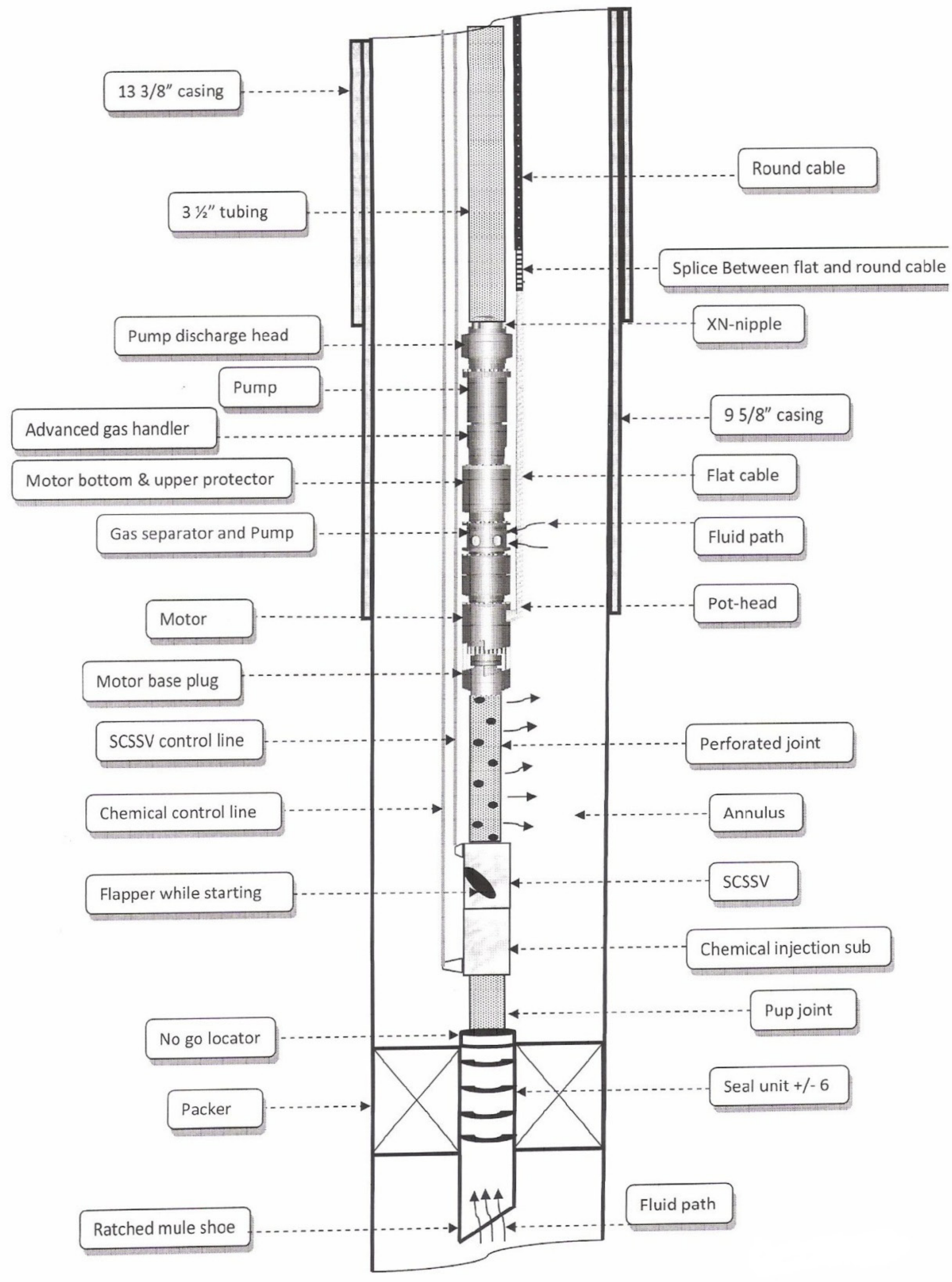

Figure 21: Completion Diagram[17]

5.4 Wellbore installation

The installation reports provided by Schlumberger Reda are generally in poor condition. Several lines were left blank or some items were not even reported, like what kind of Advanced Gas Handler (AGH) is used in wells B3 and B9 or the constraints of the VSD drive used for well B1. This is marked in Table 2 with a question mark. The GN series of Schlumberger Reda is used, which has a 5.13" outside diameter and the number indicates the point of best pump efficiency. The high amount of provided horsepower (HP) by the motor is needed due to the AGH, which consumes roughly 25-30 [HP] additionally to the pump. Remarkable is the GN 4000 with 25 stages, which was installed as an AGH in B7. The current setting of FSD and VSD drives is marked in Table 3 and can be changed according to operational needs.

Wells	Pump		Motor			AGH	VSD			Installation date
	Type	Stage	[HP]	Volt/Amp	Type		min	max	base	
B1	GN3200	54	104	1337/48	540	G 20-40	?	?	50	10.03.2008
B2	GN4000	45	104	1337/48	540	G 20-40	-	-	50	07.06.2009
B3	GN4000	32	125	1337/48	540	?	-	-	50	22.03.2000
B7	GN3200	54	104	1337/48	540	GN4000	-	-	50	02.12.2007
B8a	GN1600	58	83	1038/47	540	G 20-40	-	-	50	26.05.2009
B9	GN1600	73	83	1038/47	540	?	40	55	50	18.05.2007
B10	GN1600	58	83	1038/47	540	G 20-40	40	55	50	20.12.2008
B11c	GN3200	43	83	1038/47	540	G 20-40	40	50	50	21.04.2007
B12	GN1600	73	83	1038/47	540	G 20-40	40	50	50	11.10.2006

Table 2: Configuration of installed pumps

The ESP completion is equipped with two protectors. One with two elastomeric bags connected in series (BSB-HL), the second with two bags and a labyrinth section connected in series (LSBSB-HL). Both are designed with high load thrust bearings as mentioned above. The shaft material has intermediate strength.[8]

Reda LEAD cables with a 4# conductor are used in every well completion using Ethylene Propylene Diene Methylene (EPDM) insulation formulation and an impervious lead barrier, which prevents failure from chemical attack and gas decompression. The round cable (ELBE G4R) from the surface to the top of the pump is spliced and connected with a flat (ELB G4F), which passes the pump to the motor to provide acceptable clearance. The highest measured well temperature of 128° [F] (53° [C]) is far below the maximum conductor temperature of 400° to 450° [F] (204° to 232° [C]). The corresponding maximum conductor current of 140 [A] for the flat cable and 150 [A] for the round cable is far above the motor amperage in the investigated wells.[8]

5.5 Well Behaviour

Twelve wellheads are placed on platform B, nine are producing and three are currently shut in. The current production data can be read on Table 3, gross production being an average of the last few measurements. The wells are quite uniform, except for the high wellhead pressure of B9 and the high amount of gas in B1 and B12. The downhole multisensors read a fluid temperature of 118° to 127° [F] (48° to 53° [C]), which surprisingly corresponds with the average reservoir temperature of 120° [F] (48.8° [C]), but can be explained with the heat of the motor. The flowline temperature at the wellheads, where an ESP is installed, is 111° to 118° [F] (44° to 48° [°C]); the natural flowing wells function at 77°to 86° [F] (25° to 30° [C]). The PED of the company use an Absolute Open Flow Potential (AOFP) of 5000-8000 [stb/d] as a guideline to set up models and define the PI. Where not mentioned explicitly in the detailed well description, the different flow parameters were steady during the investigated time period.

Well	Production [bbl/d]	GOR [scf/bbl]	WC [%]	Oil [bbl/d]	Choke [1/64in]	P_{wh} [bar]	Frequency [Hz]	Drive
B1	2800	800	80	580	22	8	50	VSD Nr.1
B2	3350	250	85	500	24	7	50	FSD Nr.9
B3	2600	200	85	390	32	6	50	FSD Nr.7
B7	3500	350	90	350	22	6	50	FSD Nr.11
B8	1900	300	85	300	16	8.5	50	FSD Nr.8
B9	900	350	60	360	16	32	45	VSD Nr.3
B10	1550	325	90	155	16	9	43	VSD Nr.6
B11c	1150	225	60	460	24	13	43	VSD Nr.2
B12	1150	1200	55	520	32	13	43	VSD Nr.4

Table 3: Averaged Production Data Measured via Offshore Test Separator at 5 [bar] and 45°C

B1

The water cut of B1 has been steady at 80 [%] since April 2005, when the gross rate was 3500 [bbl/d] and 0.2 [MMscf/d] which is a moderate amount of gas. In the first half of 2007 this moderate amount of gas nearly doubled to 0.5 [MMscf/d]. With a declining production rate the GOR increased to 650 [scf/bbl]. Production declined further to 2800 [bbl/d] and the GOR is about 800 [scf/bbl] with peaks up to 1100 [scf/bbl]. Gas locks occur in this well.

B2

The water cut of the well rose from 82 [%] in June 2006 to currently 85 [%]. The amount of gas is constantly below 0.2 [MMscf]. The pump was changed on June 7th 2009 and no further downhole sensor was installed this time. Until then, the multisensor reported an intake pressure of 420 [psia] and an ambient temperature of 118.5° [F] (48° [C]).

B3

Well B3 has been very steady with a gas rate of 0.8 [MMscf/d] and a water cut of 85 [%] since June 2006, only production decreased slightly from 2800 to 2600 [bbl/d]. It has to be mentioned that gross production could possibly be higher, because the pump was installed on March 11th 2000, so pump wear should be kept in mind when analyzing the well by means of Nodal^{TM} Analysis.

B4

The pump in well RF-B4 was resized in February 2005 and the water cut rose from previously 90 [%] to 95 [%] for two samples and after several water cut measurements of 99 [%] the well was shut in for two months. It produced again 99 [%] water at a rate of 3200 [bbl/d] and it was closed in for 7 months. The switchboard was changed to VSD, and at a rate of 42 [Hz] the well produced 1700 [bbl/d] with a water cut of 80 [%]. One month later the water cut rose to 90 [%] again and production decreased to 1400 [bbl/d]. Two months later production stopped. Field staff reported the pump could work in normal parameters, but there was no surface production. The well has been closed since July 7th 2006 due to undefined downhole problems, which will be investigated in greater detail in chapter 6.2.1.

B5

In 2005 well B5 was sidetracked and production started with 500 to 1000 [bbl/d] gross production with a water cut of 5 to 10[%] and 2 to 3 [MMscf/d], but gross production decreased to 10 [bbl/d] at stable gas production within the following 9 days. The well was closed for 4 months without any improvement. After 4 additional months the closed in well was operated for 4 weeks. The only change in well behaviour was a wellhead pressure drop from 430 to 30 [psig]. The well was closed again and 5 months later in August 2006 the last production restart attempt was performed with a negative result. Since then the well has been sealed off.

B7

Since June 2006, a water cut of 90 [%] and 0.1 [MMscf/d] of gas produced has been steady, but with the pump change on November 28th 2007, the wellhead pressure dropped from 130 to 87 [psig] and gross production increased from 3300 to 3500 [bbl/d]. Few wellhead pressure peaks up to 145 [psig] were observed, but without any significant change of other parameters.

B6

Between January 2003 and February 2004 the water cut of B6 increased considerably from a formerly steady 80 to 99 [%] in April 2004 at a production rate of 3000 [bbl/d] and 0.1 [MMscf/d] gas. The reduction of the frequency from 45 to 42 [Hz] only resulted in lower production and the well was closed because of high water cut. Three months later the well was changed into an FSD drive, which led to a gross rate of 3800 [bbl/d] with a water cut of 90 [%]. The amount of produced gas increased to 0.7 [MMscf/d], so the GOR increased from formerly 200 [scf/bbl] to 1000 to 1500 [scf/bbl], including peaks of 1 [MMscf/d] or a GOR <2000 [scf/bbl], especially at the end of the pump run life in November 2005, when the GOR was <3500 [scf/d]. Although the GOR was so high a new pump was installed in April 2006 and operated until two weeks before the well was shut in due to the high water cut of 98 [%]. 10 months later, production was restarted again but decreased within days from 1000 to 600 [bbl/d] gross production with a water cut of 70 [%]. But as the amount of produced gas exceeded to 1.9 [MMscf/d] it was decided to produce periodically through the annulus without the ESP. The water cut dropped to 30 [%] at gross production rates of 500 to 800 [bbl/d] within an interval of only several months.

B8a

The water cut has been stable since June 2006 with a short drop, when the well was shut in for 90 days, because of a downhole problem. Gross production dropped slightly by 100 to 1900 [bbl/d] today. The pump had to be replaced due to a motor short circuit after 611 days on May 26th 2009.

B9

In June 2006 the water cut rose from 50 to 60 [%], the wellhead pressure was 25 [bar] at a daily gross rate of 1550 [bbl] and 0.16 [MMscf] of gas. By February 2007 the gross rate had decreased to 1300 [bbl/d] and the amount of gas decreased to 0.10 [MMscf/d] and has remained steady since then. The pump frequency was amplified from 44 to 45 [Hz] resulting in a higher water cut of 70 [%], but gross production did not increase. Instead, the pump was damaged due to a short circuit in the flat cable on May 18th 2007. The well was restarted and the bean size was changed from 14/64 [in] to 12/64 [in], which reduced the production rate from 1350 to 1100 [bb], the water cut from 67 to 60 [%] and increased wellhead pressure to 32 [bar]. In the following 6 months gross production decreased to 960 [bbl/d] and wellhead pressure increased to 39 [bar], henceforth the bean size was increased again to 16/64 [in] and the frequency of the pump was lowered to 43 [Hz]. The wellhead pressure dropped to 30 [bar] and the gross production of 950 [bbl/d] decreased gradually to 850 [bbl/d] in March 2009. A formation chemical batch treatment by paraffin dis type AP-o10 was carried out and the frequency was increased to 45 [Hz] again. Gross production increased to 950 [bbl/d]; other well parameters did not alter. Gas locks occur in this well. The annulus is vented into the flow line, so casing pressure is equal to flow line pressure of 72 [psig].

B10

When the well was drilled in July 2004 the water cut rose rather quickly to its present value of 90 [%]. Several treatments and two pumps, a GN3200 and a GN 1600 were used until stable production was established in March 2006 with a gross rate of 1700 [bbl/d] and a water cut of 82 [%], which rose again in October 2006 to its current value of 90 [%]. In the earlier production phase gas production posed a problem. At that time the GOR rose from 500 to 800 [scf/bbl] for three months before it decreased to its present value of 325 [scf/bbl]. Production decreased to 1600 [bbl/d] in April 2008 and the pump frequency was heightened from 43 to 45 [Hz]. The next test showed that gross production rose by 150 [bbl/d], but simultaneously a water cut of 5% plus an enlargement of GOR to 600 [scf/stb] occurred. The frequency was lowered again to 43 [Hz] and it took 4 months for the well to return to former performance. A point of interest is the increase in wellhead pressure from 7 to 9 [bar], without any other changes in production data.

B11c

From June 2006 to the workover in April 2007, the installed GN 3200 produced a daily gross rate of 1500 [bbl] with a GOR of 250 [scf/bbl] at 42 [Hz] and a water cut of 50 [%], which rose to 55 [%] in January 2006. During the work over, the pump was replaced by a GN 3200, which has a lower operating limit of 1500 [bbl/d] at a frequency of 42 [Hz]. It was planned to increase production, instead gross production decreased after 3 months to 1020 [bbl/d]. Accordingly pump frequency was increased to 43 [Hz], resulting in a daily gross production of 1450 [bbl/d] in June 2007. At present the gross production rate has declined to 1050 [bbl/d] and the GOR dropped to 200 [scf/stb]. It is very likely that parts of the pump are damaged by high downthrust forces, because of ongoing operation below recommended operating range. As production will not be increased in the future, a new pump design is already available in SUCO PED. Gas locks occur in this well.

B12

A "gassy" well with a GOR fluctuating between 800 and 1400 [scf/bbl]; the motor current has been fluctuated within ranges of 5 to 10 [A] until the water cut rose to 55 [%] in May 2008 and has been constant since. Various chemical treatments and several alterations in pump frequency were performed to improve the poor condition of the well. After the last major chemical batch treatment in July 2008 with diesel and AP-O10 as a paraffin solvent, the motor runs currently only on 32 to 34 [A], but the fluid flow is unstable and gas slugs occur. The gross production rate at 41 [Hz] with about 1100 [bbl/d] decreased within 2 months to 900 [bbl/d] right before the mentioned treatment with chemicals, but rose again to 1100 [bbl/d]. An increase of frequency to 43 [Hz] had no effect on gross production. The wellhead flowing pressure was 100 [psig] until November 2007 and has since increased to 190 [psig] with peaks at 245 [psig]. Gas locks occur in this well too.

6. Investigations

The task of investigations is to review the flow line systems and pressure reductions in order to define bottlenecks in addition to recalculating the ESP set up. First the failure history will be investigated, the flowing pressure data will be verified and a detailed well model will be built with Schlumberger PipeSim™ 2007 to recalculate the ESP design with IHS Subpump™ v.9.11. The operating procedure will be investigated in detail, followed by a short overview of the regular chemical treatments.

6.1 Failure Analysis, Trip History and Run Life

Run life and overall working quality of a pump strongly depend on the challenges affiliated to its installation like abrasive conditions in sand wells or high corrosive environments like H_2S, CO_2 or Oxygen. In 1993 an average run life of 400 days was stated by BP for an offshore operation in Scotland[20,] and in 1999 Husky Energy reported an average run life of 406 days due to sand production[3]. In 2009 customer support of Schlumberger Reda, the manufacturer of the installed pumps, states an average run life of about three years as common today, so the ESP operation in Ras Fanar is about average.

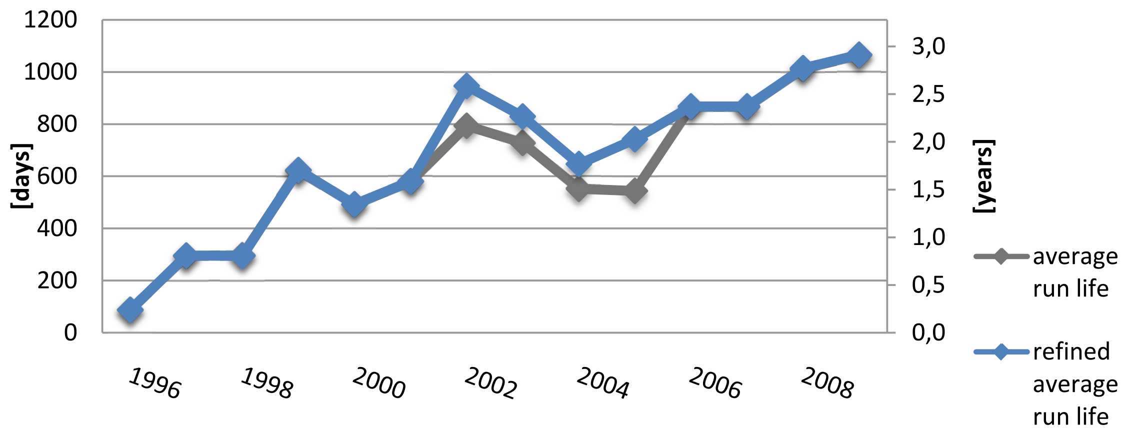

Table 4: Average run life of ESP

The average run life of ESP installations is compared with a refined average run life. The first installations of an ESP are often a 'try and error' procedure, because the exact design conditions are not known when a new well is drilled. Therefore the first year of installation was not considered after 2001, because any new well diminishes the average run life of the existing completions. In 2004 and 2005 failures occurred during the installation and tripping occurred. This problem has been solved and is therefore not of interest when analyzing run life. Run life improved from 2.1 to 2.9 years over the past years.

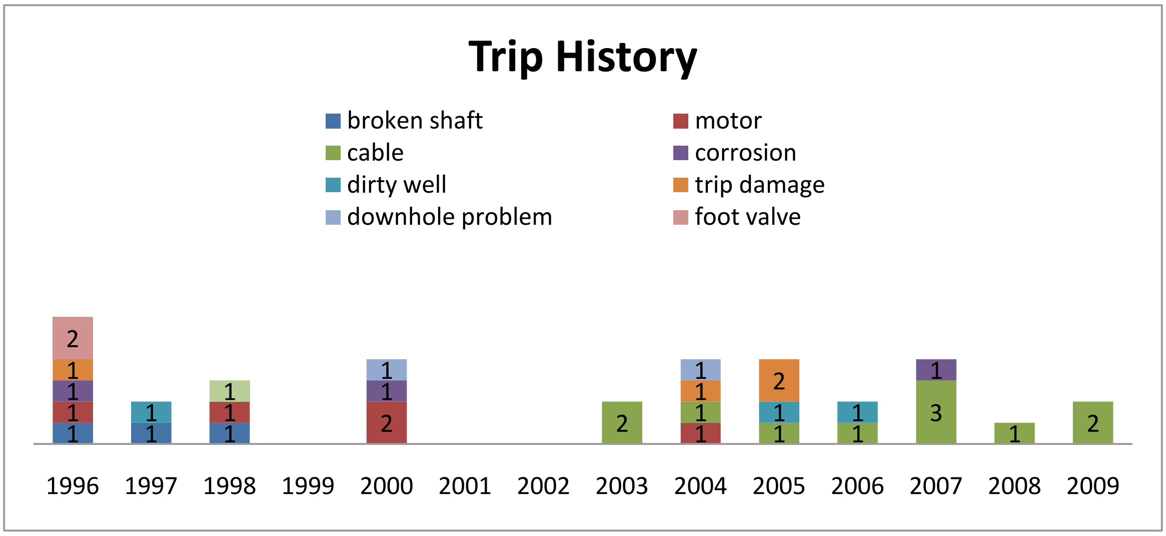

Table 5: Failure history of Ras Fanar B

In the beginning of the operation, pump failures occurred because of design and operating procedures, which is normal and improves in the course of the operation.

Since 2003 the major reason for pump failure has been related to the downhole cable. Such failures can have many reasons, not only the cable itself, though it is one of the weakest points in the assembly. Solid proof for this assumption could only be supplied by the vendor himself, but Schlumberger abandoned this time consuming service method and reports only a simple cable failure due to undefined reasons. Nevertheless, the general electric supply is rather poor, hence this is probably responsible for most of the failures. The average run life of a pump with a failure in its downhole cable is only 805 days.

More troublesome are failures due to tripping, where the SCSSV control line or the downhole cable is damaged, and the average run life decreases to 47 days. Precautions taken by SUCO include reduced tripping speed and detailed staff training.

The failure category “dirty well” describes the recovery of rubber inside the ESP in a place where such an occurrence was not recorded or officially stated. Average run life with this failure is 518 days.

The reason for failure in connection with downhole problems is not recorded; the only statement being a ground measurement of 0. It may indicate an electrical problem, but additional, helpful information on this topic was not provided.

Of minor importance are failures due to corrosion, recorded in 2007, since the resulting pump run life of 1914 days is above average, hence guarantees continuation of operation. In hindsight to the general well condition, however, corrosion is usually expected. During further investigations by SUCO, it was revealed that the assembling quality of the installed pumps was not adequate at all. The pumps were from the same vendor and were assembled in the same workshop, so it might be that some pump failures originated in the assembly process and were not caused by on-site activities.

6.1.1 Electric Failures

They are caused by:

- surface electrical electronic component failure
- poor power supply
- cable failures due to decompression or high voltage spikes, which causes insulation damages
- overload of the controller or transformer due to changes in downhole conditions

The problem of insufficient electric supply is known in Ras Fanar. Electric power is provided by the neighbouring EGPC, which performs the onshore processing of production. It receives the whole amount of produced gas in return for supplying electric power to both production platforms. The produced but unprocessed gas is used to generate electricity in two turbines. Contamination and a low methane (C_1) fraction in the gas lead to harmonic distortion and voltage spikes generated by the turbines, which harms the ESP equipment offshore. Although a VSD can reflect large amounts of distortion back into the system and a phase shift transformer is connected to the VSD, it must be sized properly to meet current conditions, which may vary in the course of time. Additionally, some wells are still produced using an FSD, therefore are affected more often by the unstable electric supply.

6.1.2 Failures due to Old Age

Old age is the main reason for failure of ESP units world-wide, but this term is relative, because it depends on the well conditions. It is reasonable to call an ESP completion “old” after three years in shallow wells. For deep wells in harsh environments a pump run life of 1 to 1.5 years is reported. Typical reasons for this failure are

- Burned motor due to fluid migration from seal section
- Low production due to pump wear
- Burned motor due to overload
- Down hole fault in the cable or motor lead due to decompression damage

The first listed failure occurs when the clean motor oil in the protector is exhausted. The second occurs because of excessive downthrust, when the pump is operated outside the recommended fluid rates at the end of its designed run life or abrasive well environment. Decompression damage can occur, when the operating procedure is not optimal and the cable is decompressed too fast, consequently insulation failures develope. The insulation of the motor and the cable gradually suffer from voltage spikes or from harsh well conditions. The failures occurring in Ras Fanar after a run life of three years are typical, but can still be reduced.

6.2 Well Test Data

The actual flow rates measured by the offshore test separator are shown in Table 3. The installed multiphase flow meter is not calibrated and gives unlikely results; ergo the test separator data is the only available and reliable source of information. A test period of 4 to 6 hours for a well is rather short and perhaps insufficient, but unavoidable because of operational conditions. The platform is unmanned and workforce is not allowed to stay overnight there for safety reasons, making throughout testing, complete with necessary supervision, almost impossible. The platform can be reached by helicopter, which can only fly a short period of time because of the unfavourable wind and weather conditions. For these reasons, the maximum test duration is 6 hours. As the flow will not be fully stabilized within this short period of time, the procedure leads to inaccurate and insufficient results.

Well	Echometer Bottom Hole Flowing Pressure [psig]	Echometer Pump Intake pressure [psig]	Multisensor Pump intake pressure [psig]	Multisensor Downhole Temperature [°F]
B1	250	185	-	-
B2	308	262	406	117
B3	437	374	-	-
B7	395	253	-	-
B8a	422	318	-	-
B9	-	-	-	-
B10	486	262	-	-
B11c	490	354	416	122
B12	-	-	0	122

Table 6: Echometer Level shot results

Echometer tests were introduced recently, but the reported well flowing pressures were far above initial reservoir pressure. This was illogical and not considered by RF PED. Investigation revealed that the well test procedure was correct, but the data set in the data processing programme “Total Well Management” was not set up properly. Together with the field staff, the data set was revised and corrected for the wells of Platform B. The well deviation data, pump intake depth and the formation depth had to be defined again or corrected. Other unknown variables were estimated, because possible deviations were indivertibly small. This optimization had to be repeated for the set up of Platform A and revised by RF PED.

Echometer test results were not as reliable as the downhole sensor measurements, because the wells were only tested twice so far, so the accuracy of the tests was not guaranteed. Well B9 could not be tested, because the pressure in the Echometer has to be more than 100 [psi] the annulus pressure. This cannot be provided by a portable gas bottle used there. Well B12 gives no reasonable results as the high amount of gas in the annulus produces foam.

Multisensor data were available for Well B2 only until May 26th 2009, because the pump failed and the new completion design did not include a multisensory device. The multisensor installed in B12 reads a pump intake pressure of 12 to 26 psia. The flow was unstable and included gas slugs.

The reported readings of the multisensors in B11c and B2 are not in accordance with the results of the Echometer.

The reservoir temperature measurements by sensors in B2, B11c and B12 are uniform with 117° to 122° [F] in an investigation period of 2 years, with peaks of 128° [F] in well B11c, so the recommended average value by the Reservoir Department can be confirmed.

6.2.1 Tubing Leak in RF B4

Field personnel reported the pump in well RF B4 worked in normal parameters, but there was no surface production when the pump was switched on. The well has been closed since July 14th 2006 and only an undefined downhole problem was recorded. The ESP Troubleshooting Chart indicates that zero production can have following the causes; worn pump, low voltage, tubing leak or incorrect rotation. Low voltage is unlikely judging from ammeter charts, incorrect rotation is excluded by field personnel. The irregular Echometer shot trace indicates a leaking problem.

Figure 22: Outtake of the irregular Echometer shot trace

The big wave on the right side indicates a typical phase change from gas to liquid, but the irregular small wave in front of it may have its origin in a tubing leak.

Keeping the poor well behaviour and the high water cut in mind, further investigations or repair cannot be recommended. It is more economical to plug and abandon the well and to use its wellhead space on the platform for the development of the West Field.

6.3 Optimization of IPR Determination

The current method to determine an Inflow Performance Relationship was disclosed as not according to best practice and thus should be improved. Both the actual and the improved procedures are described. For the Nodal™ Analysis the program Schlumberger Pipesim is used.

6.3.1 Setting up an IPR Model – Current Procedure

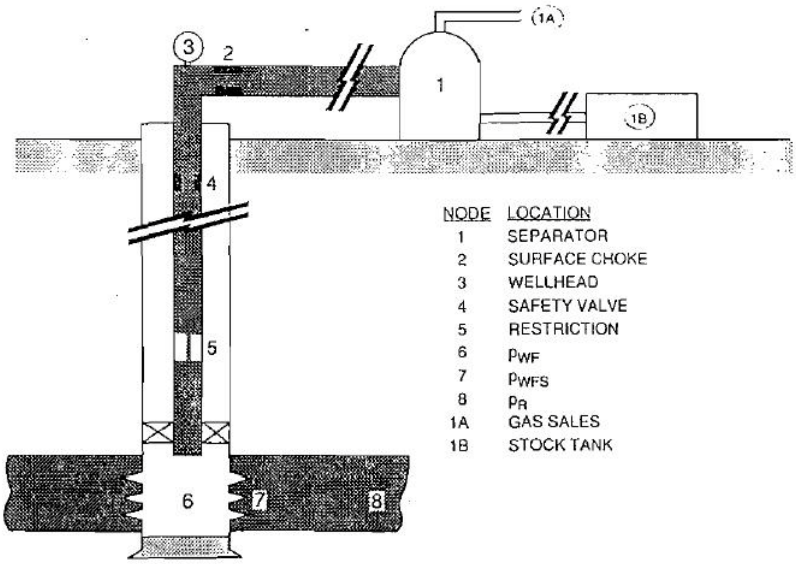

Figure 23: Location of various nodes

The pressure of the flowline (72 [psig]) and separator (65 [psig]) cannot be changed in case of Ras Fanar, and according to Beggs, the outlet pressure is usually adopted as the pressure at the wellhead, if a choke is used in the system.[16] So the model, which is set up in Pipesim, contains nodes 3 to 8.

A model for well B1 was set up with the procedure recommended by RF PED, using data of Table 7. The contamination data is the average of slug catchers 30-V-2 and 30-V-7. For the inflow itself the Vogel correlation was used. For the specific gas gravity the field average was employed. No special set of PVT correlation was exploited and the program's standard parameters were used.

Compositional models are recommended for volatile or light crude oils and gas condensates only, so it is valid to use the black-oil model in Ras Fanar in Pipesim.

Design Data		Design Data	
Gross production	2800 [bbl/d]	Specific gas gravity	0.8654 = average
Water Cut	80 [%]	API	32°
GOR	800 [scf/stb]	Specific gravity water	1.04
AOFP	5000 to 10000 [stb/d]	Deviation data	
Static Pressure	505 [psi]	Wellhead Pressure	116 [psi]
Reservoir Temperature	120° [F]	Tubing ID	2.99 [in] @ 1950 [ft-MD]
Wellhead Temperature	104° [F]	Casing ID	6.186 [in] @ 2840 [ft-MD]
H_2S	13 [%] = average	ESP	GN 3200, 54 stages
CO_2	3.7 [%] = average	Intake ESP	1950 [ft-MD]
N_2	1.55 [%] = average	Frequency ESP	50 [HZ]

Table 7: Input Data to set up a model of RF B1

Initial conditions for the establishment of the model, were a well flowing pressure p_{wf} (required by the program itself) and the absolute open flow potential AOFP (calculated by the program). Actual pressure data was not available for the RF-PED, so the model was set up and tested for an AOFP of 5000- 10000 [stb/d] based on experience and multisensor data of B2. With the "flow correlation option" several flow correlations can be compared and the most accurate with respect to the actual production value chosen. Following this procedure, the IPR was calculated. The result predicts a gross production of 1600 [bbl/d], but it was 2800 [bbl/d] at a well flowing pressure of 469 [pisa], which is too high for operation/production. However, there was also the U-shaped outflow curve, which would suggest a pump off the well, which is NOT the case in reality.

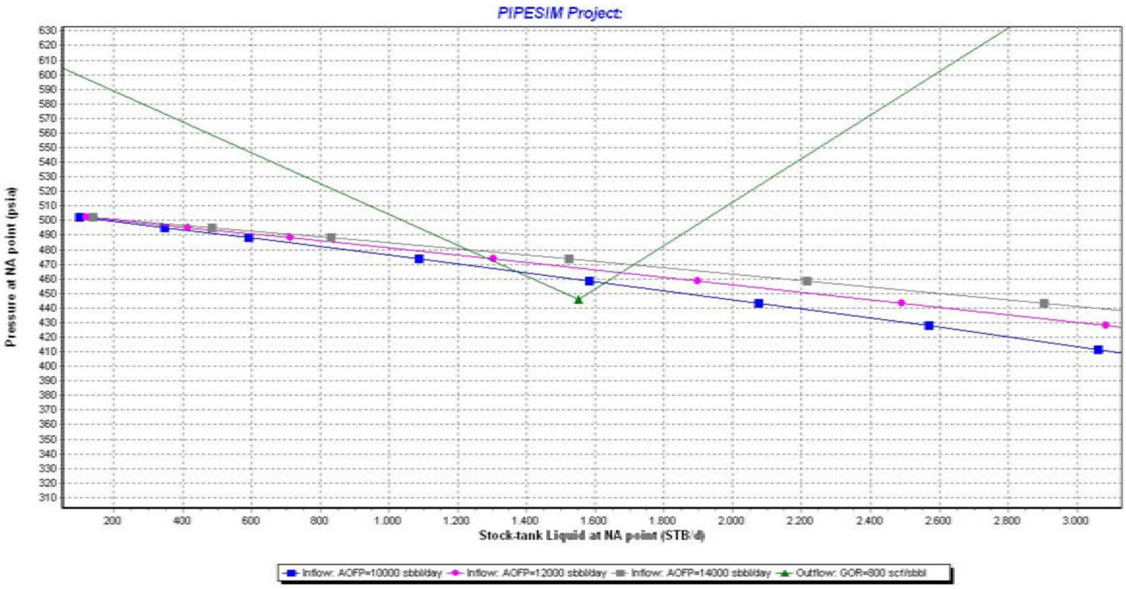

Figure 24: IPR of RF B1 with available data and current design procedure

The problem of production volume is solved rather simply by RF PED by adding more stages to the pump [...] *because the program Pipesim cannot handle ESP pump equipment correctly and therefore it is used only for Nodal^{TM} Analysis and Gas Lift design*. To calculate an ESP design the program Subpump by IHS was used. The problem of the wrongly shaped outflow curve is thereby ignored.

The problem of the gross volume was valid for all wells and no matching IPR for the wells of platform B can be established. Each minor input value was checked by the means of a system analysis, but any deviation leads to a matching IPR. Flow correlation selection has to be done in greater detail and will be discussed later. Obviously, the production data measurement procedure has to be investigated and confirmed.

6.3.2 Investigation of Input Data

As stated above, the test time for test separator measurement is restricted due to operational reasons. On site the well test data processing spreadsheet was checked with the field staff. The amount of gas is measured by means of an orifice plate and the formula to calculate it was checked and confirmed. In this formula the exact gravity of gas is required and was actually entered, although the Chemical Department and PED stated those values were not available, because the test would be too inaccurate and expensive. Further investigations revealed gas analysis for every well of 2003 and for B11 of 2006 were available in the field. Gas samples were taken and a complete gas analysis was carried out for each well by the company owned laboratory.

[%]	B1	B2	B3	B7	B8	B10	B11
N_2	1.23	0.49	1.26	0.50	0.34	1.41	1.87
H_2S	5.70	8.53	13.20	7.90	14.77	8.00	6.90
CO_2	5.24	10.10	6.26	5.81	8.56	4.61	3.09
C_1	58.88	42.97	51.61	58.60	38.29	66.74	60.36
Specific Gravity	0.895	1.012	0.934	0.887	1.085	0.812	0.849

Table 8: Gas Analysis

Two values of the specific gravity were corrected in the well test excel sheet, but the deviation was insignificant. It is recommended to review corrosion inhibitor injection for each well based on this data. Furthermore this data should be used for design purposes as well.

6.3.3 Allocation Factor

The production of each well is measured by means of a test separator located offshore, but gross production is too high compared with the liquid in the stock tank measured by EGPC and SUCO. A so called 'allocation factor' is introduced by dividing the production in the stock tank with the summed up production of the test separator. The allocation factor has been quite stable during the last few years and varies between 0.73 and 0.76 [-].

Test separator production results have to be multiplied by this factor, which is evaluated monthly and used by the finance department only.

The introduction of an allocation factor is common practice, although the factor here is quite low compared to the usual 0.95 to 0.99 [-], which is valid for other fields of SUCO in this region. Hereinafter, the procedure to allocate the liquid production can be confirmed, but there is no reason why this allocation factor should be automatically correct for gas production as well.

Well	Gross Production [bbl/d]	Gas [MMscf]	GOR [scf/stb]	Allocated Production [bbl/d]	New GOR [scf/bbl]	Allocated GOR [scf/stb]
RF-B1	2800	0,47	800	2060	1140	1400
RF-B2	3350	0,16	250	2475	430	550
RF-B3	2600	0,08	200	1920	275	400
RF-B7	3500	0,10	350	2585	385	500
RF-B 8a	1900	0,07	300	1480	315	400
RF-B9	900	0,15	350	665	565	730
RF-B10	1550	0,05	330	1145	440	560
RF-B11c	1150	0,09	225	849	265	345
RF-B12	1150	0,70	1200	849	1965	2370

Table 9: Platform B production with allocation factors

The first three columns represent the actually reported production data used for design purposes. The section for ‘Allocated Production’ represents revised production with the most recent allocation factor of 0.73845. This factor is used for accounting only, but since it signifies the actual gross production, it is recommended to be used for design purposes too.

As mentioned above, there is no reason to discount the amount of gas, so the same amount of gas must be divided by the smaller amount of oil, leading to a significantly higher GOR summed up in the column named ‘New GOR’.

Summing up the average amount of gas produced monthly by platforms A and B during the last 6 months leads to a daily gas production of 2.79 [MMscf/d]. But investigation of the daily reports of the last year revealed that the neighbouring EGPC, which processes the production, reported 3.4 to 3.7 [MMscf/d], averaging at 3.6 [MMscf/d]. This variation supports the idea of introducing an allocation factor for gas, which would be around 1.29 [-]. Needless to say, that this is a rough estimate, because the 2.7 [MMscf] is measured by the offshore test separator at a pressure of 65 to 72 [psig] (4.5 to 5 [bar]) and the conditions of the test routines by EGPC are unknown, but the pressure regime will be lower, so some gas will be dissolved. But this cannot explain the fact of 29 [%] more measured gas. This has to be investigated further to properly design gas handling devices for the ESP.

This significantly higher amount of gas would explain observed gas locks in B1, B9 and B12, because the advanced gas handlers are designed for lower amounts of gas.

6.3.4 Multiphase Flow Correlation

The only meaningful procedure for evaluating the various pressure-gradient correlations is the comparison of the actual pressure drop with the predicted one. Pipesim has an option to compare several gradients with each other, but the correlations still have to be selected according to their true case conditions.[16]

Applicable in / correlation	Vertical oil wells	Highly deviated wells	Oil pipelines	Gas Condensate wells
Hagedorn & Brown	yes	no	no	yes
Duns- Ros	yes	yes	yes	yes
Orkisziewski	yes	no	no	yes
Gray	no	no	no	yes
Beggs & Brill	yes	yes	yes	yes
Aziz, et. al	yes	yes	yes	yes

Table 10: Applicable Correlations

Hagedorn & Brown

$$\frac{\partial p}{\partial Z} = \frac{f_m \rho_n v_m^2}{2\rho_s d} + \frac{\rho_m \Delta(v_m^2)}{2g_c \partial Z} + \rho_s g$$

Where

ρ_s – slip density [lbm/ft^3]

ρ_n – no slip mixture density [lbm/ft^3]

ρ_m –mixture density [lbm/ft^3]

v_m –mixture velocity [ft/sec]

f – friction factor [-]

d – diameter of the pipe [in]

g – acceleration of gravity [ft/sec^2]

∂Z –vertical distance [ft]

The correlation of Hagedorn and Brown was developed to explain the flow in narrow pipes and was discovered to provide good results over a wide range of wells. It is of great importance to keep in mind Hagedorn and Brown did not measure liquid hold-up. The Hagedorn & Brown revised correlation was introduced to extend the application range. Flow pattern and the liquid hold-up were modified, and those two methods are the most widely used in industry.[21,22]

Gray

$$\frac{\partial p}{\partial Z} = \frac{f\rho_m v_m^2}{2d} + \rho_s g - \rho_m^2 v_m^2 \frac{\partial}{\partial Z}\left(\frac{1}{\rho_m}\right)$$

Gray developed a correlation to describe the flow of gas and condensates in wells only, so this will not be applicable in our case. Although it may give an accurate value when compared by means of Pipesim, however the IPR curve would simply be incorrect.[23]

Duns and Ross

$$\frac{\partial p}{\partial Z} = \left(\frac{\partial p}{\partial Z}\right)_{friction} + \rho_s g + \left(\frac{\partial p}{\partial Z}\right)_{acceleration}$$

Following correlations differ from *Hagedorn and Brown* and *Gray* in the way how they predict flow pattern and liquid hold up, friction and acceleration term for those different flow patterns. The acceleration term is often neglected in bubble and slug flow.

$$slug\ and\ bubble\ flow\colon \left(\frac{\partial p}{\partial Z}\right)_f = \frac{f\rho_L v_m^2}{2d}$$

$$mist\ flow\colon \left(\frac{\partial p}{\partial Z}\right)_f = \frac{f\rho_g v_{sg}^2}{2d}, \quad \left(\frac{\partial p}{\partial Z}\right)_{acc} = \frac{v_m \rho_n v_{Sg}}{p}\left(\frac{\partial p}{\partial Z}\right)$$

Where

ρ_L – liquid density [lbm/ft^3]

v_{SL} – superficial liquid velocity [ft/sec]

ρ_{gL} – gas density [lbm/ft^3]

v_{Sg} – superficial gas velocity [ft/sec]

Duns and Ross performed the first dimensional analysis for multiphase flow in pipes and identified four important variables. The four separate regions are combined in a flow-pattern map, which is often referred to by other correlations. It is considered to be applicable in a wide range, although the updated method (known as the 'Shell method') increases the application range.[25]

Orkisziewski

Orkisziewski compared several correlations and concluded that none were accurate enough for all flow patterns. So he uses *Griffith and Wallis* for bubble flow, *Duns and Ross* for mist flow and established his own correlation for slug flow based on the data of *Hagedorn and Brown*.

$$slug\ flow\colon \left(\frac{\partial p}{\partial Z}\right)_f = \frac{f\rho_L v_m^2}{2d}\left[\left(\frac{v_{SL} + v_b}{v_m + v_b}\right) + \tau\right]$$

Where

v_b – bubble velocity [ft/sec]

The Orkisziewski method is widely used in industry with a wide range of well conditions. In some cases the calculated mixture density is lower than the no-slip density and discontinuities can occur in the pressure transfer curves as the mixture velocity exceeds 10 [ft/sec].[26]

Aziz et. Al

$$slug\ flow: \left(\frac{\partial p}{\partial Z}\right)_f = \frac{f \rho_L H_L v_m^2}{2d}$$

$$bubble\ flow: \left(\frac{\partial p}{\partial Z}\right)_f = \frac{f \rho_S v_m^2}{2d}$$

Where

H_L – liquid hold-up [ft^3/ft^3]

This method uses the flow-pattern map first presented by Govier et. Al.[28] The correlation of Aziz et. al. showed negligible deviations in the result compared to Orkisziewski. For mist flow Aziz, et. Al propose to use the *Duns and Ros* method.[27]

Beggs & Brill

This method was developed to describe multiphase flow in inclined pipe sections and directional wells. The measurements were made for any pipe inclination with air and water.

$$\left(\frac{\partial p}{\partial L}\right) = \frac{\frac{f \rho_n v_m^2}{2d} + \rho_s g \sin\theta}{1 - E_k}$$

$$E_k = \frac{v_m v_{Sg} \rho_n}{p}$$

Where

E_k – dimensionless kinetic Energy [-]

Although it was developed for inclined flow and it can produce good results in vertical oil wells, it usually overestimates the pressure drop, so it should be used for inclined flow mainly.[24]

Comparison Studies

Several authors published evaluation studies provide information about the average percent errors which can occur when a specific correlation for the pressure drop in a well is used. This is done by comparison of the real pressure drop of a well in the field with the predicted pressure drop by the examined method. The results of several studies are summarized below.

[avg. error | scatter]	Author of the study				
correlation	Orkisziewski	Lawson	Aziz	Ibe	Rossland
Orkisziewski	-0.8% | 11	8.6% | 35	8.9% | 15	-0.8% | 35	8.4% | 28
Beggs & Brill		17.8% | 28		19.1% | 32	10.7% | 16
Hagedorn & Brown	0.7% | 24	1.3% | 26	-20.5% | 25	1.2% | 23	-3.5% | 9
Duns&Ros	2.4% | 27	15.4% | 50	-11.1% | 15	13.6% | 33	-5.5% | 13
Aziz, et. al		-8.2% | 35	8.9% | 15		

Table 11: Comparison study[16]

As comparison parameter the average error in per cent was identified, where a positive value means the correlations overestimated the pressure drop and a negative value means it underestimated the pressure drop in the evaluated wells. The scatter of the errors is stated as standard deviation in the table. Of course some studies were performed in a way to emphasize the quality of a specific correlation. For example, Lawson evaluated with a data base of 726 wells, of which 346 were used to develop the correlation of Hagedorn & Brown. Those cases were removed from the study later and the accuracy of Hagedorn & Brown decreased, but still gave the best result.[16]

So the results of the evaluation studies clearly confirm that there is nothing like a general best method for all wells and the best fitting pressure drop correlation must be evaluated with actual field data.

Evaluation of the matching correlation in Pipesim

For most correlations, two codes are available in Pipesim, 'bja' and 'tulsa'. The first has been developed by Baker Jardine, the second, marked with a 'T' in front of the correlation code in the legend below, was developed by the University of Tulsa, USA. This code is usually of high academic quality.

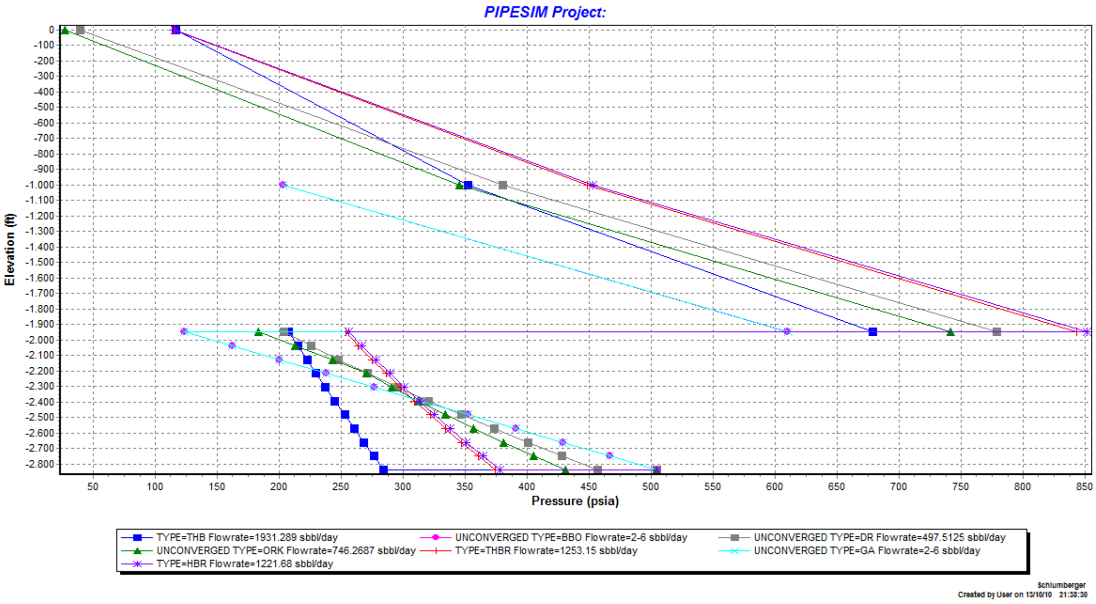

Figure 25: Flow correlation matching B1 – pressure versus depth chart

Based on available field data and following the modelling procedure introduced in 6.3.5, the correlations were evaluated. As can be seen in the pressure versus depth graph Beggs & Brill original (BBO) and Aziz, et al (GA) predicted no production, Duns & Ros (DR), Orkisziewski (ORK) and Hagedorn & Brown revised (HBR and THBR) underestimate the production. Only Hagedorn & Brown original,Tulsa (THB) is within the range of uncertainty of the measured field data of 2060 [sbbl/d]. If not mentioned separately, the two codes predicted the same pressure drops or one was not available.

The best results for Ras Fanar wells were achieved by the correlation of Hagedorn & Brown original, Tulsa (THB) for inclinations up to 45°, changing to Beggs & Brill, Tulsa (TBB) results above this inclination developed.

6.3.5 Setting up an IPR Model – Recommended Procedure

Design Data		Design Data	
Gross production	Table 9 allocated	Specific gas gravity	Table 8
Water Cut	Table 3	API	32° / 26°
GOR	Table 9 allocated	Specific gravity water	1.04
Well Flowing Pressure	Table 6	Deviation data	
Static Pressure Main	505 [psia]	Wellhead Pressure	116 [psi]
Static Pressure West	610 [psia]	Tubing ID	2.99 [in] @ various depth
Reservoir Temperature	120° [F]	Casing ID	6.186 [in] @ various depth
Wellhead Temperature	various	ESP	GN 3200, 54 stages
Contaminants	Table 8	Intake ESP	Various depth
PVT Data Main/West	Appendix Table 1/2	Frequency ESP	50 [HZ]

Table 12: Recommended Input Data

When Table 12 is compared with Table 7, it becomes obvious that more input data should be used. The most important difference is the allocated gross production and allocated GOR of Table 9. Ignoring the allocation factor for liquid would lead to constantly oversized pumps, which would work outside their operating range. This would lead to excessive wear of the pumps due to high downthrust forces and reduces the run life of the pumps. The second important set of values is Table 6, because the Inflow Performance Relationship IPR cannot be set up properly without the values of both tables. Minor increments are expected from the different gas analysis of Table 8, although the difference is within ±50 [stb/d] production in the model. Accurate measurements of the API would be interesting to refine the model, but the increment of ±20 [stb/d], is rather small. PVT Data should be included as well to be as accurate as possible.

The biggest increment on the design procedure has the proposed change of the flow correlations to Hagedorn & Brown original, Tulsa, for inclinations less than 45° and above to Beggs & Brill, Tulsa. This set up is the most accurate pair of correlations for the Ras Fanar field.

With these changes, it is possible to set up matching IPR curves for seven wells out of nine, without changing the number of stages of any pump, nor will unrealistic outflow curves be a result.

The IPR of well B12 could not be modelled, because no stable flow can be achieved due to high slug flow. The pump in well B11c extends so far out of the operating range that neither Subpump nor Pipesim are able to simulate its inflow performance.

6.3.6 IPR Determination

B1

Design Data	
Gross production	2060 [stb/d]
Water Cut	80 [%]
GOR	1400 [scf/stb]
Well Flowing Pressure	250 [psig]
Static Pressure Main	505 [psia]
Static Pressure West	-
Reservoir Temperature	120° [F]
Wellhead Temperature	104° [F]
Contaminants	Table 8
PVT Data Main/West	Appendix Table 1

Design Data	
Specific gravity gas	0.95
API Main / West	32°
Specific gravity water	1.04
Tubing ID	2.99 [in] @ [1950 ft-MD]
Casing ID	6.186 [in] @ [2840 ft-MD]
ESP	GN 3200, 54 stages
Intake ESP	1950 [ft-MD]
Speed ESP	50 [Hz]
Wellhead Pressure	116 [psi] (8 [bar])
Deviation Data	

Table 13: Recommended Input Data B1

The model is quite different to the existing one, because so far the p_{wf} had to be estimated with an absolute open flow potential (AOFP) of 5000 to 10000 [stb/d]. So the p_{wf} was said to be about 420 [psig], which is far too high compared with the Echometer results of 250[psig], which leads to an AOFP of only 3050 [stb/d]. The allocated gross production (GP) is 2060 [stb/d], the predicted with 1930 [stb/d] is quite accurate.

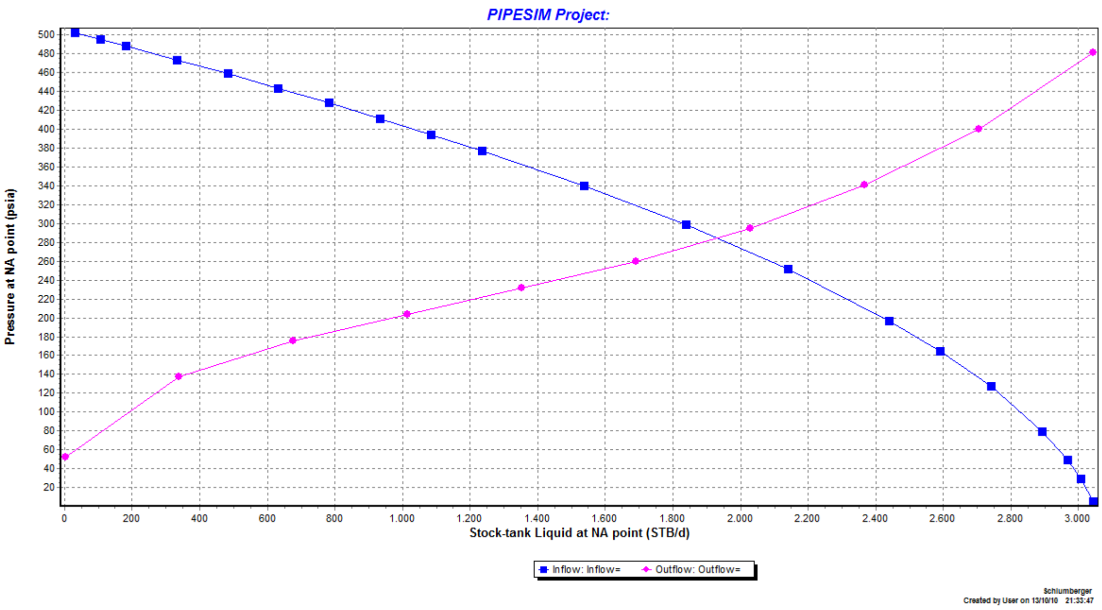

Figure 26: IPR of B1

B2

Design Data		Design Data	
Gross production	2475 [stb/d]	Specific gravity gas	0.95
Water Cut	85 [%]	API Main / West	32°
GOR	550 [scf/stb]	Specific gravity water	1.04
Well Flowing Pressure	420 [psig]	Tubing ID	2.99 [in] @ [2446 ft-MD]
Static Pressure Main	505 [psia]		
Static Pressure West	-	Casing ID	6.186 in @ [2815 ft-MD]
Reservoir Temperature	120° [F]	ESP	GN 4000, 45 stages
Wellhead Temperature	115° [F]	Intake ESP	2446 [ft-MD]
		Speed ESP	50 [Hz]
Contaminants	Table 8	Wellhead Pressure	102 [psi] (7 [bar])
PVT Data Main	Appendix Table 1	Deviation Data	

Table 14: Recommended Input Data B2

The IPR indicates a daily gross production of 2405 [stb/d], which matches the observed GP of 2475 [stb/d]. The p_{wf} indicated by the multisensory was much higher at 420 [psig], than that of the Echometer at 308 [psig], yet downhole sensors are more accurate, hence their usage is highly recommended.

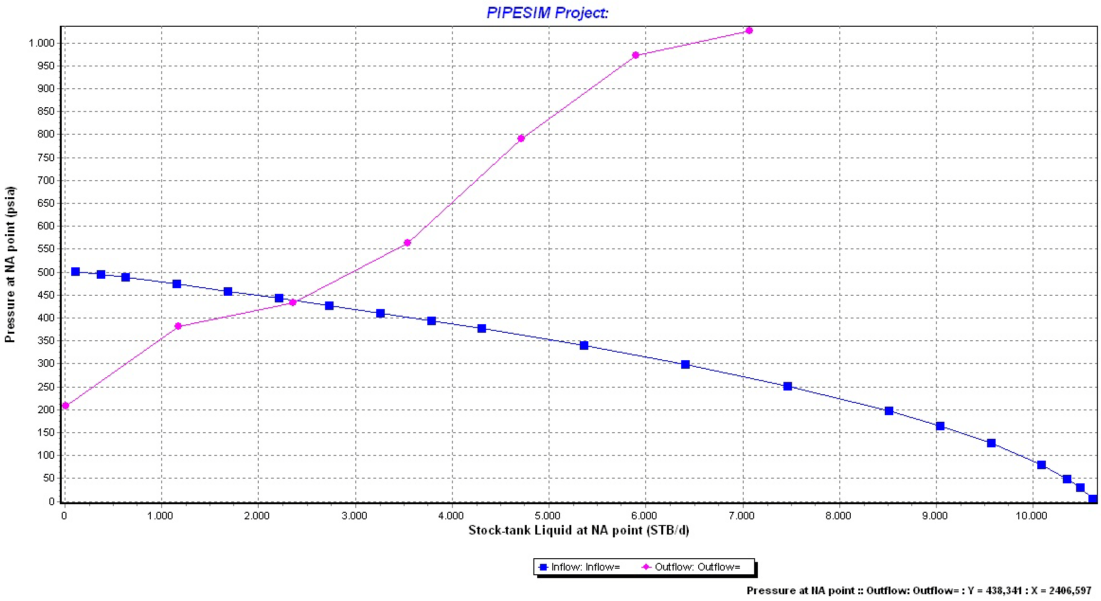

Figure 27: IPR of B2

B3

Design Data		Design Data	
Gross production	1920 [stb/d]	Specific gravity gas	0.943
Water Cut	85 [%]	API Main / West	32°
GOR	400 [scf/stb]	Specific gravity water	1.04
Well Flowing Pressure	437 [psig]	Tubing ID	2.99 [in] @ [2285 ft-MD]
Static Pressure Main	505 [psia]		
Static Pressure West	-	Casing ID	6.186 [in] @ [2780 ft-MD]
Reservoir Temperature	120° [F]	ESP	GN 4000, 32 stages
Wellhead Temperature	120° [F]	Intake ESP	2285 [ft-MD]
		Speed ESP	50 [Hz]
Contaminants	Table 8	Wellhead Pressure	87 [psi] (6 [bar])
PVT Data Main	Appendix Table 1	Deviation Data	

Table 15: Recommended Input Data B3

The pump has been in use since 2000, so degradation would be expectable, but the opposite is the case. If the input data is correct, two adjustments need to be made to create a matching IPR curve. First, gas separator efficiency was lowered from 90% to 80%, possibly the gas separator degraded over time. Second, head fraction was upgraded by a factor of 1.05, because API Specification allows a head variation of ±5% compared with catalogue performance. With these modifications, the IPR predicts a GP of 1840 [stb/d], which is quite accurate compared with the observed production.

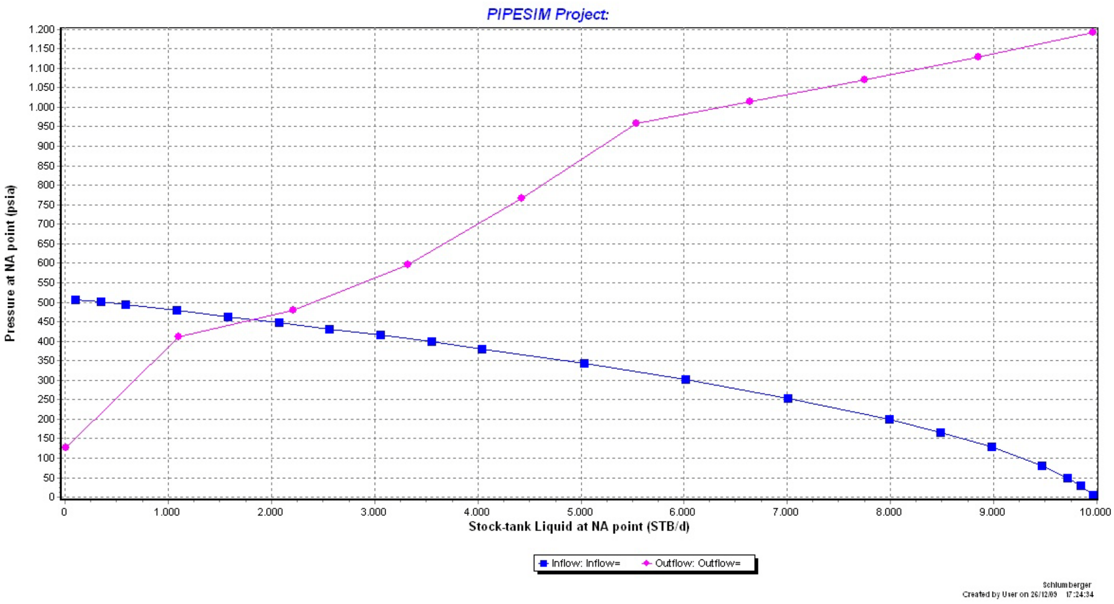

Figure 28: IPR of B3

B7

Design Data		Design Data	
Gross production	2585 [stb/d]	Specific gravity gas	0.887
Water Cut	90 [%]	API Main / West	32°
GOR	500 [scf/stb]	Specific gravity water	1.04
Well Flowing Pressure	394 [psig]	Tubing ID	2.99 [in] @ [2040 ft-MD]
Static Pressure Main	505 [psia]		
Static Pressure West	-	Casing ID	6.186 [in] @ [3439 ft-MD]
Reservoir Temperature	120° [F]	ESP	GN 3200, 54 stages
Wellhead Temperature	118° [F]	Intake ESP	2040 [ft-MD]
		Speed ESP	50 [Hz]
Contaminants	Table 8	Wellhead Pressure	101 [psi] (7 [bar])
PVT Data Main	Appendix Table 1	Deviation Data	

Table 16: Recommended Input Data B7

No adjustments were necessary. The IPR predicts a gross production of 2500 [stb/d], which matches the allocated gross production of 2585 [stb/d].

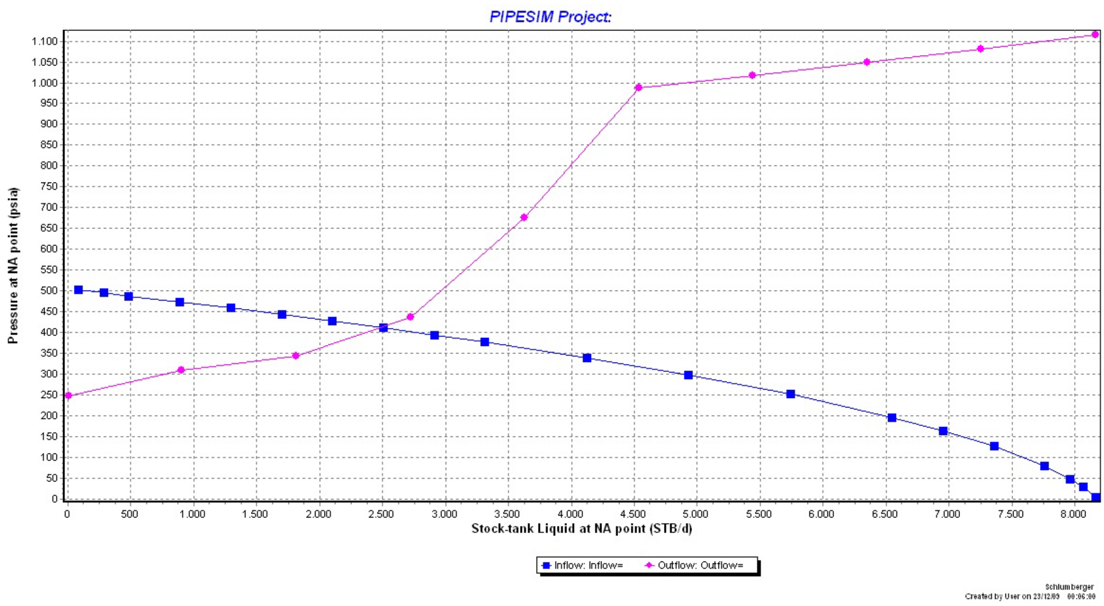

Figure 29: IPR of B7

B8a

Design Data	
Gross production	1480 [stb/d]
Water Cut	85 [%]
GOR	400 [scf/stb]
Well Flowing Pressure	422 [psig]
Static Pressure Main	505 [psia]
Static Pressure West	-
Reservoir Temperature	120° [F]
Wellhead Temperature	118° [F]
Contaminants	Table 8
PVT Data Main	Appendix Table 1

Design Data	
Specific gravity gas	1.085
API Main / West	32°
Specific gravity water	1.04
Tubing ID	2.99 [in] @ [2236 ft-MD]
Casing ID	6.186 [in] @ [4002 ft-MD]
ESP	GN 1600, 58 stages
Intake ESP	2236 [ft-MD]
Speed ESP	50 [Hz]
Wellhead Pressure	101 [psi] (7 [bar])
Deviation Data	

Table 17: Recommended Input Data B8

No adjustments had to be made. The IPR predicts a gross production of 1440 [stb/d], which matches again the allocated gross production of 1480 [stb/d].

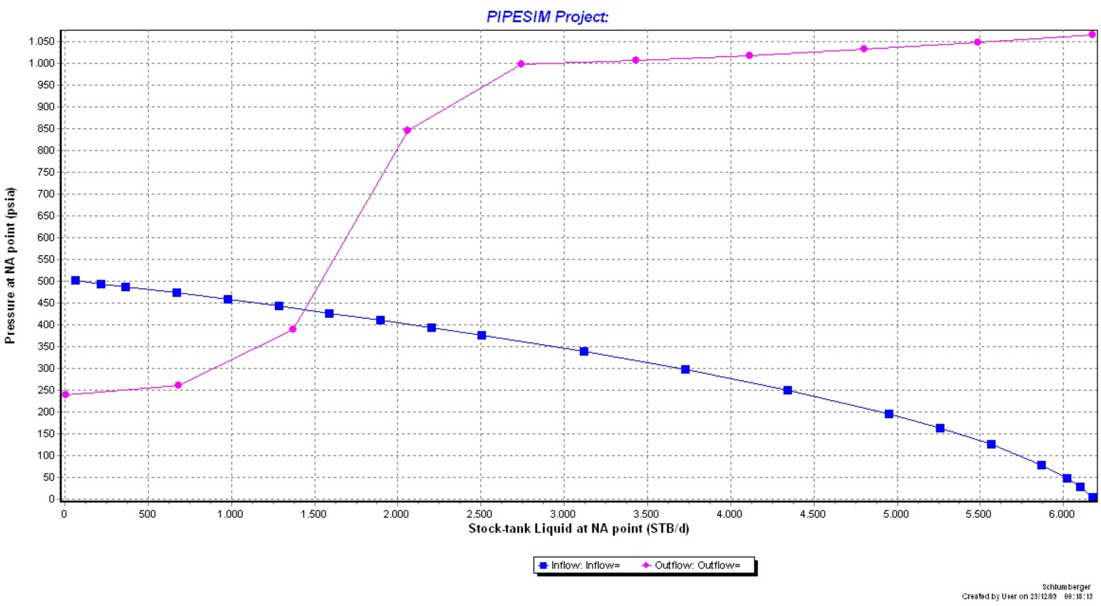

Figure 30: IPR of B8

B9

Design Data		Design Data	
Gross production	665 [stb/d]	Specific gravity gas	0.833
Water Cut	60 [%]	API Main / West	32°
GOR	730 [scf/stb]	Specific gravity water	1.04
Well Flowing Pressure	400 to 450 [psig]	Tubing ID	2.99 [in] @ [3613 ft-MD]
Static Pressure Main	505 [psia]		
Static Pressure West	-	Casing ID	6.186 [in] @ [4315 ft-MD]
Reservoir Temperature	120° [F]	ESP	GN 1600, 73 stages
Wellhead Temperature	113° [F]	Intake ESP	3613 [ft-MD]
		Speed ESP	45 [Hz]
Contaminants	Table 8	Wellhead Pressure	435 [psi] (30 [bar])
PVT Data Main	Appendix Table 1	Deviation Data	

Table 18: Recommended Input Data B9

Due to operational methods no Echometer test could be performed; therefore no measured p_{wf} is available. In order to have an idea of the possible range the output graph contains two IPR lines. The blue IPR line represents the inflow with a p_{wf} of 400 [psia] and the pink IPR line is modelled with a p_{wf} of 450 [psia]. To match the observed gross production of 665 [stb/d] a p_{wf} of 450 [psig] is most likely. Additionally, gas separator efficiency was lowered to 80%, because the well is suffering gas locks anyway. Combining those two issues the created IPR(pink line) predicts 649 [stb/d], which confirms the production mentioned.

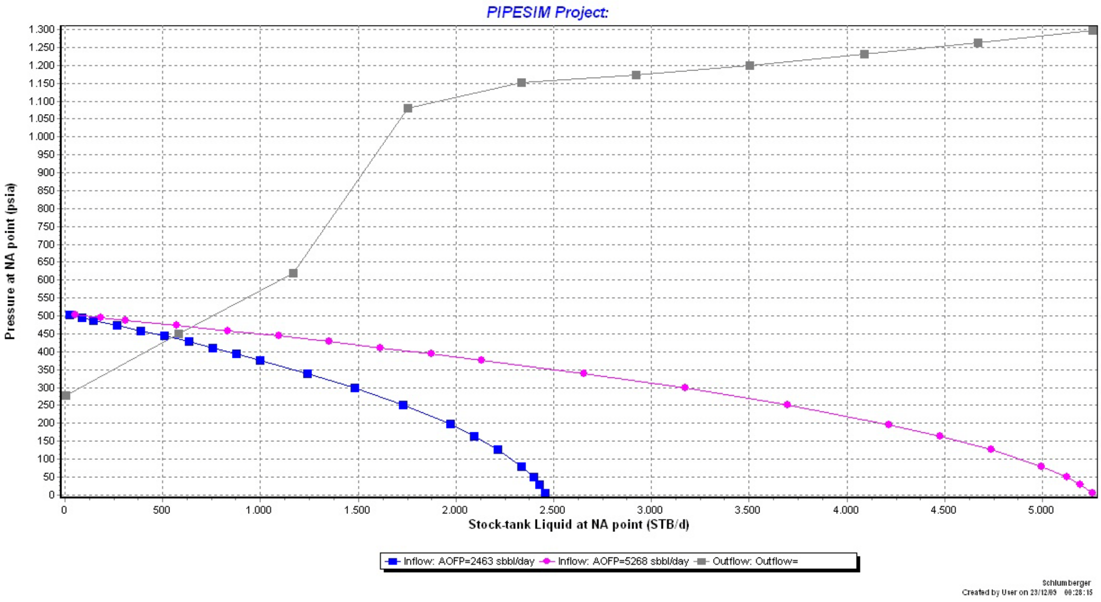

Figure 31: IPR of B9

B10

Design Data		Design Data	
Gross production	1145 [stb/d]	Specific gravity gas	0.812
Water Cut	90 [%]	API Main / West	32°
GOR	560 [scf/stb]	Specific gravity water	1.04
Well Flowing Pressure	486.7 [psig]	Tubing ID	2.99 in @ [1950 ft-MD]
Static Pressure Main	-		
Static Pressure West	610 [psia]	Casing ID	6.186 in @ [2840 ft-MD]
Reservoir Temperature	120° [F]	ESP	GN 1600, 58 stages
Wellhead Temperature	118° [F]	Intake ESP	3778 [ft-MD]
		Speed ESP	45 [Hz]
Contaminants	Table 8	Wellhead Pressure	130 [psi] (9 [bar])
PVT Data West	Appendix Table 2	Deviation Data	

Table 19: Recommended Input Data B10

Again no adjustments had to be made. The IPR predicts a gross production of 1190 [stb/d], which is in agreement with the allocated gross production of 1145 [stb/d].

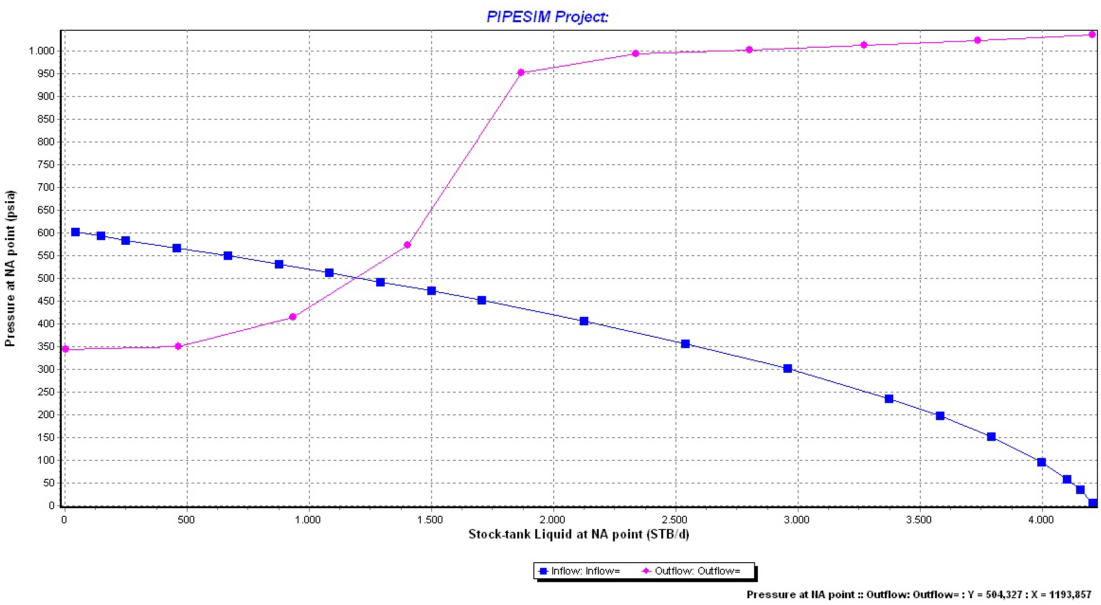

Figure 32: IPR of B10

B11c and B12

The IPR of well B12 could not be modelled because no stable flow can be achieved due to high slug flow. The pump in well B11c is so far outside the operating range that neither Subpump nor Pipesim are able to simulate the inflow performance relationship.

6.3.7 Pressure drop in the choke

The choke size and the corresponding pressure drop could not be calculated for the wells. Only a rough estimate was established for B9, where critical flow occurs according to Gilbert, because the upstream pressure is at least 70% higher than the downstream pressure.

Below that, subcritical flow is valid and the choke size, the corresponding pressure drop and the liquid rate in given conditions were calculated applying the Ashford-Pierce correlation and the mechanistic correlation, which gave unreal results for all wells.

For B9 the critical flow correlations of Gilbert, Ros, Baxendall, Achong and Pilehvari were used, where the equation is the same with different exponents. Nind[14] stated that a generalized expression with some simplifying assumptions can describe the flow through a choke under critical conditions. This equation was the base for several modifications by the authors listed in Table 20.

$$q = a\,P_1(GOR)^{-b}d^c$$

Where

q- liquid flow rate at standard conditions (STB/D)

P_1 - upstream pressure (psia)

d - choke diameter (64ths in.)

a,b,c - empirical coefficient

Correlation	a	b	c	q [stb/d]	D [1/64 inch]
Gilbert[13]	0.1	0.546	1.89	339.04	34.28
Ros[29]	0.05747	0,5	2.00	359.30	32.65
Baxendall[30]	0.1046	0.546	1.93	402.71	31.12
Achong[31]	0.26178	0.65	1.88	475.08	28.70
Pilehvari[5]	0.021427	0.313	2.11	552.11	26.21
real				665	24

Table 20: Critical Flow Correlations and Results

The correlation was solved with the listed exponents first for the actual choke size and then for actual production. Compared to observed test results, the correlation of Pilehvari is the most accurate for well B9 and can be recommended.

6.4 Re-calculation of the ESP

Based on the derived IPR curves, existing designs can either be validated or new pumps installed. This is done by means of the ESP design program Subpump provided by IHS. With the Schlumberger Oilfield Manager (OFM), the production forecast and therefore the increased water cut within 4 years is calculated.

The ESP completion is designed for the entire run life, but the reservoir depletes in the course of time, so a change in the static bottom-hole pressure is expected. So far, a run life of 3 years could be achieved, but with several changes it is possible to increase the run life to 4 years. As the reservoir depletes, static bottom hole pressure p_{ws} declines. Figure 17 and 18 indicate this pressure drop of about 50 [psia] for 4 years and a constant pressure difference (Δp) is assumed, so the p_{wf} drops by 50 [psia] as well. The future IPR is used to check, if the proposed pump design still meets the desired production and if it is still within the recommended operation range. This simplified procedure is valid, because the program takes into account the different PVT data at the new pressure.

If a new pump is installed, it should be able to produce the expected amount of liquid throughout its run life. This leads to the common belief that a pump with an FSD at the beginning of its run life, would deliver more than desired to ensure sufficient outflow at the end of its run life is sufficient. The pump has to be choked back to ensure the outflow does not exceed the desired flow-line pressure of 5 [bar], so the corresponding p_{wh} is higher at the beginning. As stated above, no correlation recommends the correct choke size for the desired pressure drop, so the solution is expected to meet solely p_{wh}, which can be adjusted by a choke and completed by experienced field staff.

Especially when designing an FSD it should be taken into account that API specifications for ESP state, that the variation compared with catalogue performance of the vendor can differ by ±5 [%] in regard to total dynamic head, power requirement by ±5 [%] and efficiency by -10 [%]. To ensure the design produces the desired rates, every pump design is rerated by 5 [%] for head, power and rate, which is included in the solution guide.

A pump equipped with a VSD may be more beneficial, as in the course of time the speed of the pump can be increased to ensure the pump can deliver the desired production rate at the end of its run life, despite declining reservoir pressure. Additionally, the tornado chart directly provides the change of production, if the pump speed is varied. If the design of the pump is done properly, no choke should be necessary.[32] Using a choke would create unnecessary backpressure and the motor of the pump would produce more heat and thus diminish the pump's run life. For designs with a VSD, it is recommended not to take a choke into consideration.

The setting depth of the pump, in regard to dogleg severity and distance to the top of perforation, was checked and found to be already optimal.

The use of two protectors is advisable to ensure a high amount of clean motor oil for the high number of restarts. The labyrinth section of the second protector can be skipped in every completion except B1 because, as stated in 3.1.3, this protector design does not work in deviated well sections. The High Load design is necessary due to the compression design of the pump.

According to the field engineers, the motors of the GN series are more reliable than the DN series and so GN should be used. The voltage and amperage rating of the motors are checked and validated. The small range of available motors, namely 83, 104 and 125 [HP], is unsatisfying. Smaller motors are recommended, because the load on the motor should be about 80- 85 [%]. Smaller pumps would even have a rating of less than 60 [%], so smaller motors should be requested from Schlumberger Egypt or bought in Dubai. To ensure a maximum load of 85 [%] nameplate rating of the motor the required pump horsepower should not exceed 71 [HP] for the motor with 83 [HP], for the motor with 104 [HP] this limit would be 88 [HP] required horsepower by the pump.

In addition to the required horsepower of the designed pump the AGH uses 30 [HP].

B1 - VSD

Design	Type	Stages	BEP [stb/d]	Range at 50 [Hz] [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 3200	54	2870	1831 to 3416	2800	2068	59.50
Proposed	GN 2500	57	1998	1500 to 2583	2800	2068	61.49

Table 21: Comparison of actual and proposed pump type, B1

While the first design would be optimal for the reported production figures, the second does not need to be considered. But with allocated production, the actual pump GN 3200 is still in the operating range, but definitely in its lower limits and therefore efficiency will decrease dramatically with decreasing production. In contrast, a smaller pump would produce at its point of best efficiency (BEP) and is more flexible in regard to production rates and will meet the production decline more easily in this case. The impact of the allocation factor can be seen quite well here.

Additionally to the horsepower of 44 [HP] required by the pump, the AGH G 20-40 uses approximately 30 [HP], resulting in a total required horsepower of 74 [HP]. The motor with 83 [HP] would lead to a motor load of 89%. This is a little more than the recommended load of 85 [%], but the motor with 104 [HP] would have only a load of 71 [%].

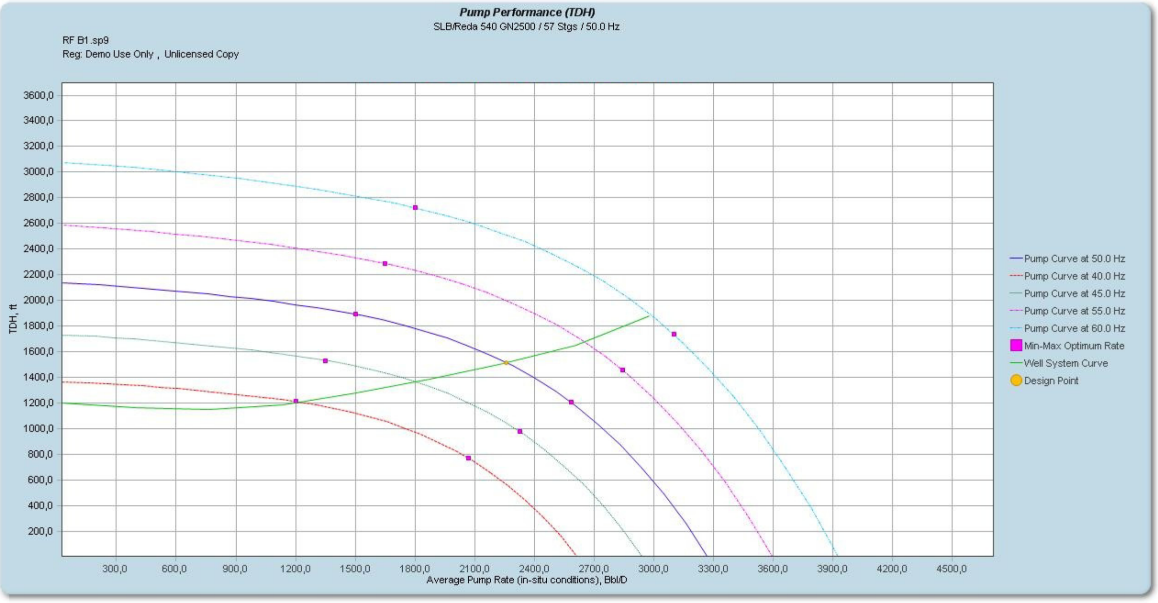

Figure 33: Tornado chart for the present IPR

This difference is more important with declining reservoir pressure and future IPR. Comparing A.Figure 1 and A.Figure 2 in the Appendix, which show tornado charts for the future IPR, it becomes obvious that the actual design is restricted as far as future production rates are concerned.

B2 – FSD

Design	Type	Stages	BEP [stb/d]	Range [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 4000	45	3300	2666 to 4000	3350	2475	63.6
Proposed	GN 3200	-	2870	1831 to 3416	3350	2475	64.7

Table 22: Comparison of actual and proposed pump type, B2

Without an allocation factor, the actual design (built in June 2009) is optimal. A gross production of 3350 [bbl/d] means an efficiency of 67.89 [%] and accordingly BEP. But taking the allocation factor into account, the pump is outside its operating range and is suffering from excessive downthrust; pump wear is a possible consequence.

The smaller pump GN 3200 is recommended in this case with a variation in its stages for a design rate of 2500 [stb/d]. If the pump works in its catalogue specifications, 54 stages would be enough, leading to a wellhead pressure of 7 [bar] in year 4 (see table Table 23). As stated before, it is possible the pump does not meet catalogue performance and the rerated version would not meet the desired production rates at a flow-line pressure of 5 [bar] any more. Nevertheless, 54 stages are recommended since it is not clear if the pump will work for 4 years, the difference being 100 barrel gross production. This would lead to an oil production loss of only 7 [stb/d] with an expected water cut of 93 [%] at the end of the pump's run life. The version with 67 stages would have to produce against a p_{wh} of 20 [bar] in the best case scenario, which would cause an increase of motor heat and reduce pump run life as well.

Depending on the number of stages 38 to 47 [HP] are required by the pump. Taking the AGH G 20-40 into account the required horsepower is 68 to 77 [HP]. The one with fewer stages has a motor load of 82 [%] using the 83 [HP] motor, the other compasses a load of 75 [%] equipped with the motor with 104 [HP].

GN 3200 Stages	Pwh [bar] year 0	Pwh [bar] year 4	Production year 0 [stb/d]	Production year 4 [stb/d]
54	12	7	2498	2501
54 derated	9.5	5 to 5.5	2499	2377 to 2431
67	20	16.5	2527	2518
67 derated	16.5	12.5	2513	2508

Table 23: Proposed designs for B2

B3 – FSD

Design	Type	Stages	BEP [stb/d]	Range [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 4000	32	3300	2666 to 4000	2600	1925	63.6
Proposed	GN 2500	-	1998	1500 to 2583	2600	1925	61.4

Table 24: Comparison of actual and proposed pump type, B3

The pump was installed in the well in March 2000 and a redesign is necessary if a pump failure occurs. Again two variations in the pump stages are visualized in Table 25 for a production of 2000 [stb/d]. If the smaller version with 45 stages is chosen, gross production could possibly be 240 [stb/d] below the desired 2000 [bbl/d], leading to a drop of oil production by 16.8 [stb/d] only in its worst case with an expected water cut of 93 [%].

In addition to the horsepower of 35 [HP] required by the pump with 57 stages the AGH G 20-40 uses approximately 30 [HP], resulting in a total required horsepower of 65 [HP]. The motor with 83 [HP] would lead to a motor load of 78 [%]. For the pump with fewer stages, a smaller motor is recommended.

GN 2500 Stages	Pwh [bar] year 0	Pwh [bar] year 4	Production year 0 [stb/d]	Production year 4 [stb/d]
57	17.5	13	2009	2012
57 derated*	14	10	2004	1973
45	9.5	5.5	1998	1930
45 derated*	7	5.5	2008	1760

Table 25: Proposed designs for B3

B7 – FSD

Design	Type	Stages	BEP [stb/d]	Range [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 3200	54	2870	1831 to 3416	3500	2585	64.7

Table 26: Actual design is in operation range, B7

Without considering the allocation factor the pump would be above its upper operating limit and a GN 4000 would be more efficient. But with allocated production this pump design is already optimal. For the future the GN 3200 with 66 stages may be more suitable to ensure the production rate stays constant. Keeping the actual design would lead to a possible gross production loss of 230 [stb/d], resulting in an oil production decrease of only 10 [stb/d] with an expected water cut of 95 [%].

Depending on the number of stages the pump needs, energy of 47 to 56 [HP] is necessary. The AGH G 20-40 uses approximately 30 [HP]. The minimum required horsepower is 77 [HP], the maximum 86 [HP]. In this range only the motor with 104 [HP] is applicable with a motor load between 74 and 82 [%].

GN 3200 Stages	Pwh [bar] year 0	Pwh [bar] year 4	Production year 0 [stb/d]	Production year 4 [stb/d]
54	10	5.5	2617	2543
54 derated	7	5.5	2611	2268
66	17	14.5	2612	2618
66 derated	12.5	10	2608	2617

Table 27: Proposed designs for B7

B8a – FSD

Design	Type	Stages	BEP [stb/d]	Range [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 1600	32	1374	831 to 1793	2000	1475	57.64

Table 28: Actual design is in operation range, B8a

The design in Table 28 was installed in May 2009 and unlike B2 it was exactly designed for the allocated gross production. If the pump does not work according to catalogue performance, it should produce 100 [stb/d] less than the desired 1500 [stb/d] after 4 years. This would lead to a loss of only 7 [stb/d] produced oil with an expected water cut of 93 [%]. The version with more stages would produce a much higher p_{wh} and should not be considered, because this would considerably reduce the pump's run life.

The pump with fewer stages uses 40 [HP], the pump with more 50. Furthermore the AGH G 20-40 uses approximately 30 [HP], resulting in a total required horsepower of 70 to 80 [HP]. For the pump with fewer stages the motor with 83 [HP] would be applicable with a load of 84% and the one with more stages requires the 104 [HP] motor with a load of 77 [%].

GN 1600 Stages	Pwh [bar] year 0	Pwh [bar] year 4	Production year 0 [stb/d]	Production year 4 [stb/d]
58	10	6	1508	1510
58 derated	6.5	5 to 5.5	1503	1418 to 1400
73	20	17	1510	1508
73 derated	14.5	11	1500	1502

Table 29: Proposed designs for B8a

B9 – VSD

Design	Type	Stages	BEP [stb/d]	Range at 45 [Hz] [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 1600	73	1374	750 to 1610	900	665	49

Table 30: Actual design is not in operation range, B9

A production increase is planned for B9, so the actual pump will produce within its operating range again. The p_{wh} of 30 [bar] can be reduced slightly, but nevertheless, has to be high enough to avoid slug flow. This will transfer the outflow curve (green "Well System Curve" in Figure 34) downwards, because the resistance of the flow will decrease and enhance flexibility in respect to production rates. The procedure behind this will be explained later. Smaller pumps of the DN series would require more than 100 stages to generate the required p_{wh} and would be too excessive in relation to dogleg severity.

With an AGH G 20-40 the required horsepower is only 56 [HP]. So the motor load of the smallest available motor with 83 [HP] is only 67 [%].

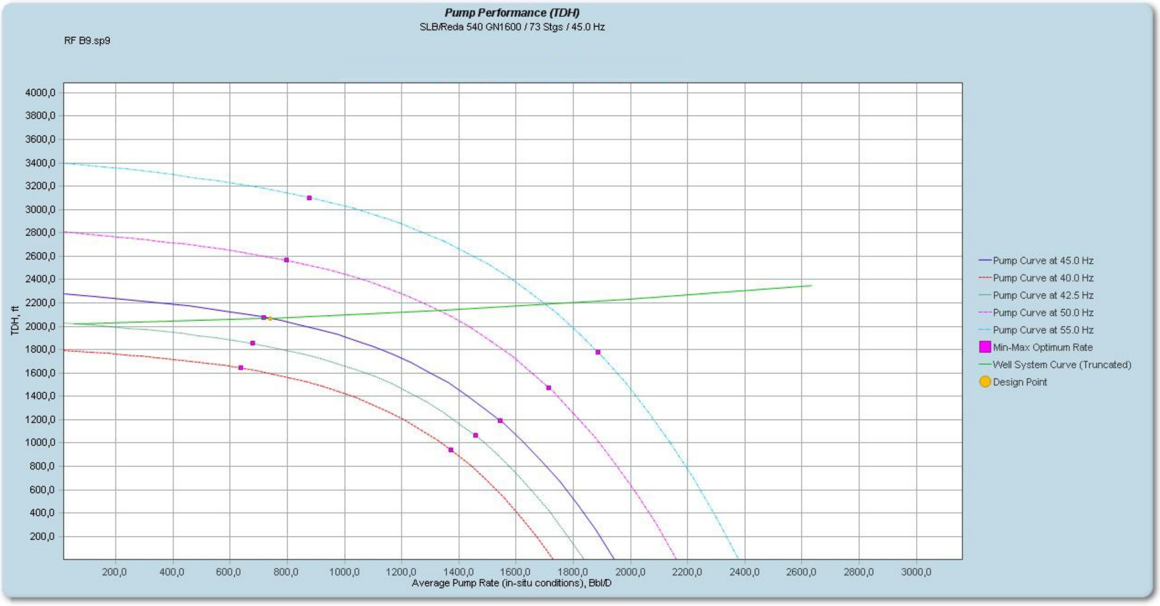

Figure 34: Tornado chart for the present IPR, actual pump and 30 bar p_{wh}

B10 – VSD

Design	Type	Stages	BEP [stb/d]	Range at 43 [Hz] [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 1600	73	1374	750-1610	1550	1150	59.7

Table 31: Actual design is in operation range, B10

The upper green line in figure 35 represents the actual design including a choke. The green line below shows the well curve without using this choke. Now it can easily be seen why a choke in combination with a VSD is not best practice, because the pump at a lower speed would have the same production rate as with a choke, but the motor is not heated so much and the pump run life increases. The actual design is optimal, the usage of a choke in combination with a VSD only suboptimal.

Adding the consumed horsepower of an AGH G 20-40 to the simulation result the required horsepower is only 55 [HP]. So the motor load of the smallest available motor with 83 [HP] is only 66 [%].

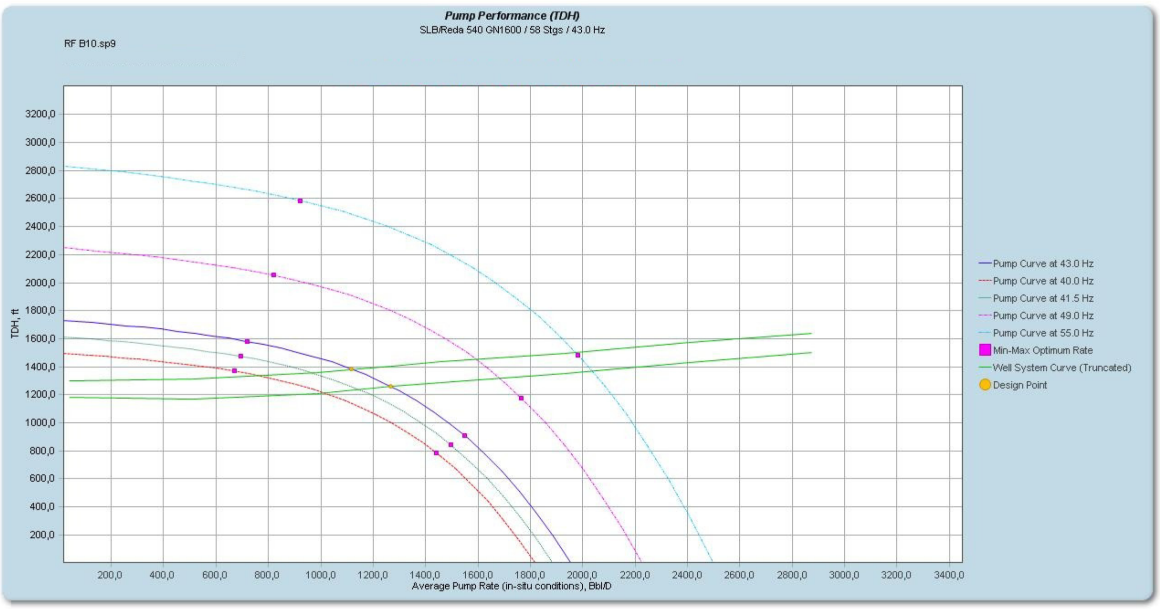

Figure 35: Tornado chart of B10

B11c – VSD

Design	Type	Stages	BEP [stb/d]	Range at 43 [Hz] [stb/d]	Gross production [stb/d]	Allocated production [stb/d]	Efficiency [%]
Actual	GN 3200	43	2870	1580 to 2950	1150	850	33
Proposed	DN 1100	89	911	500 to 1125	1150	850	57.9

Table 32: Proposed design, B11

As mentioned in 6.3.5 it was not possible to create a matching IPR. With available data a new IPR was created to propose a new pump, which is absolutely necessary, because the old pump is far outside its production range and suffers from excessive downthrust wear. The new pump offers flexibility in regard to production rates and is designed without a choke in the flowline.

Taking into account the AGH G 20-40 the required horsepower is only 50 [HP]. So the motor load of the smallest available motor with 83 [HP] is only 60 [%].

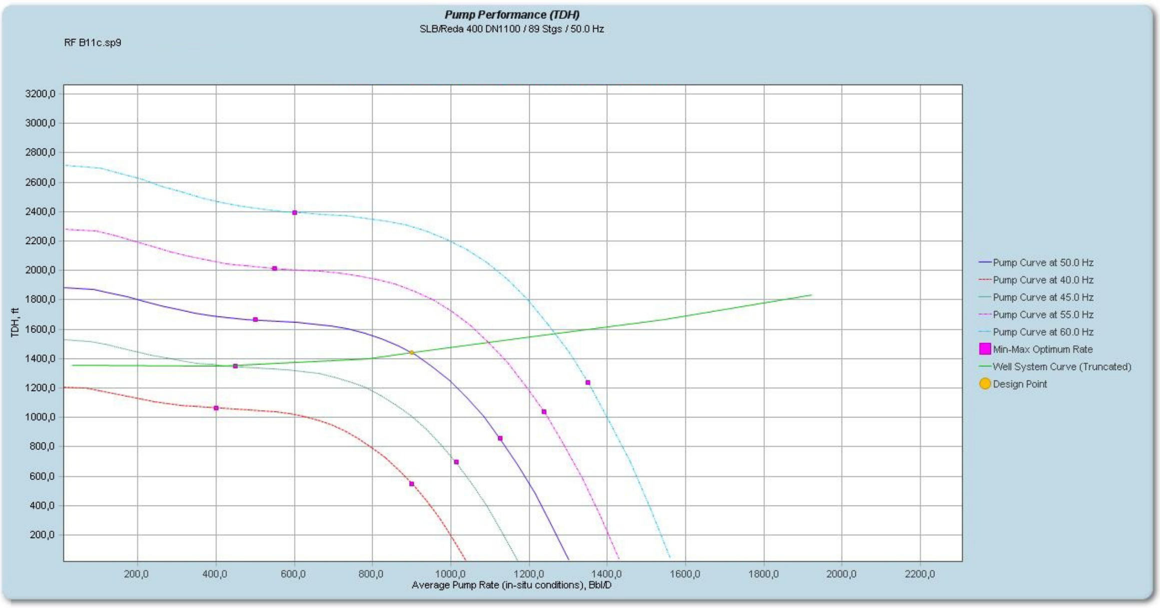

Figure 36: Tornado chart of B11

6.5 Chemical treatment

When production decreases, the tubing and the casing are filled with diesel to disintegrate paraffin more or less regularly every three months. This procedure is questionable, because the reservoir temperature is 120 °[F] (48.9° [C]), the wellhead temperature in wells equipped with an ESP system is between 110-120° [F] (43°-48.9° [C]), the flow-line temperature is only slightly lower and the chemical analysis states that the paraffin has a pour point of 9°C at standard conditions. It is not clear how paraffin can condense in the system with these conditions, but the Chemical Department insists on this procedure.

A corrosion inhibitor based on sulphite-carbonate is added continuously downhole based on the production average measured in the pipeline, which is 10-15 [%] H_2S. Moreover, the production pipeline is checked for iron content onshore to ensure the corrosion treatment is adequate.

During the first completion designs in the Main Field in 1996, demulsifiers were added downhole, but this practice was stopped after a few months since no relevant changes were observed. Since then, a demulsifier has been added to the 12 [in] production pipeline and on the way from the platform to the onshore process facilities emulsion separates.

7 Recommendations

7.1 Chemical treatment

7.1.1 Downhole injection of Corrosion Inhibitor

The amount of downhole injected corrosion inhibitor is determined by the production pipeline average of 10-15 [%] H_2S. Gas sample analysis data is available for each well (see Table 8) and it is recommended to optimize the amount of corrosion inhibitor for every well on its own available parameters, because the amount of H_2S differs from 5.7 [%] in B1 to 14.8 [%] in B8. The decrease in costs by this action must be further evaluated by the Chemical Department.

7.1.2 Sampling Procedure

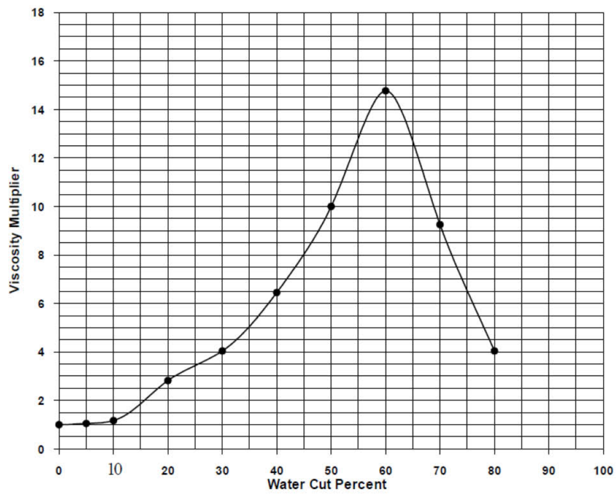

Figure 37: Emulsion viscosity multiplier for medium light crude oil[33]

In 1996, the wells were checked for emulsions and it was decided to stop adding demulsifiers downhole. It was not checked for 13 years if emulsions had gained influence on the production in the meantime, nor was the increment revised for newly developed wells in the West field. Crude oils with lower API gravity like the oil in the West Field will form a more stable and higher percentage volume of emulsion than lighter oils, common in the Main Field. Likewise, asphaltic oils have the tendency to emulsify more easily than paraffin based oils. Those two parameters were the main variation from the old Main field, where the oil was tested for emulsion, and the new West Field, where this possibility was not taken into account. The effects of increasing viscosity are summed up in 3.2.2 and the possible increment is shown in Figure 36, which is only one example (in other curves the multiplier goes up to 14). Additionally, the effect of gas separating equipment is reduced, because gas tends to migrate more slowly through more viscous oils, so more gas passes the fluid. It is strongly recommended to test especially newly developed wells in the West Field with low water cut.

On the one hand the parameters of the West Field favour the development of emulsions and on the other hand the example curve figure 36 shows that the critical percentage of water cut begins at 20% and drops sharply after 60%. The Main field wells already exceeded this water cut.

The Chemical Department stated that the measurement of the API and for emulsions would cost too much and would not be representative enough, because of the complicated sampling procedure. Now a test sample is taken out of a bleeder valve at the bottom of the flow-line, where the flow can be separated into the gathering line or the line for the test separator, into a random plastic bottle. This sample is tested for the water cut of the well only. The Petroleum Engineering Handbook recommends two methods to obtain a representative sample for emulsions. One is to use a small diameter tubing approximately 10 feet long, attached to a bleeder valve on the line at one end and to a sample container at the other. The bleeder valve is opened fully and the sample flows into the container. Although the pressure drop of the line into the container is absorbed by the tubing, additional emulsification is possible. The second possibility is the use of a sample container initially filled with water. The sample container has three valves. The upper one is connected with the line and opened. The container is pressured by the line and the lower part is opened and the water extrudes. All valves can be closed and the third can be opened to bleed off the pressure, which has no significant effect on the sample.[10] An improvement of the sample procedure would enlarge the capability for testing of water cut, API gravity and emulsions.

7.2 Electricity

7.2.1 Improvement of power quality

Figure 38: Pseudo-Sine Wave[34]

In general, the VSD uses high voltage solid-state circuitry to convert the three phase AC into a set of square waves, which are added up to form a pseudo sine wave. The VSD can only approximate the perfect sine wave that the motor is designed for. The more steps the VSD is capable of producing, the closer the degree of approximation and the more expensive it is. Each point on the cycle, where the voltage is higher or lower than the perfect sine wave, is energy that the motor cannot use, which lowers the overall efficiency and generates excess heat, reducing run life of the motor.[34]

The common six-pulse converter can reduce input current total distortion (TDH) to 25 to 35 [%], the twelve-pulse converter can reduce the TDH to 8[%]. Higher pulse number converters will further reduce the input current distortion levels, the eighteen-pulse converter – for example- will operate at less than 3 [%] TDH and a twenty-four converter can be matched with high horsepower systems. The constant development of those systems made them cheaper over the past years and it is recommended to check if improved systems are economically applicable in Ras Fanar. As to the poor power quality, the FSD drives should be exchanged with VSD to enhance the power quality of the downhole pumps.

The design conditions are evaluated using the VSD equipment by the vendor Schlumberger and protection equipment is installed based on this. But high voltage spikes can be so short, that they occur between the measured intervals, which may be the case in poor power systems like the one in Ras Fanar. Voltage spikes cause insulation failures in the motor and in the cable, consequently a short circuit will follow. Therefore it is recommended to perform a complete electric system analysis by a specialized company over a few weeks to improve protection equipment. The costs cannot be estimated for Egypt and must be evaluated.

7.2.2 Minimum Motor Current

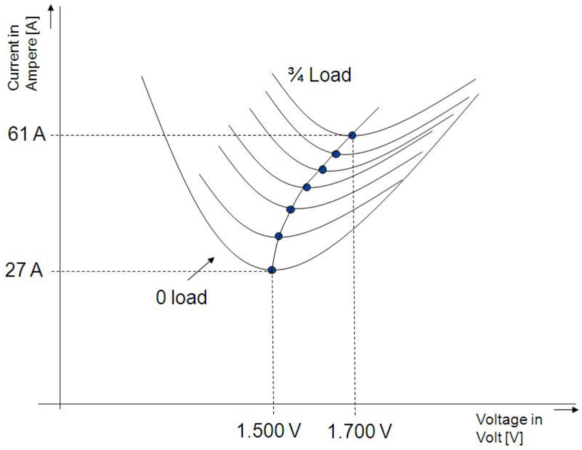

Figure 39: Effect of changing load on the motor[35]

Different load curves are illustrated for a motor and the blue point represents the BEP. While the pump is running at the desired frequency and therefore at resulting motor load, the Volts per Hertz parameter has to be adjusted to produce the minimum value of load current. This can be done by increasing or decreasing the Volts/Hertz parameter a few volts at a time and checking the value of motor current. If a decrease of the motor current can be observed, the value variation has to be repeated until motor current starts to increase. The Volts/Hertz can be reset to the previous setting, which produced the lowest load current. If the motor load changes due to gas slugs, or if viscosity changes happen due to emulsions, the motor uses less/more current. If the motor uses less current, the voltage drop in the downhole cable is lower than calculated and the voltage at the motor becomes too high and vice versa. This produces excess heat and thus reduces the run life of the motor. In gassy wells like Ras Fanar, where this change of loads exists rather frequently, a special transformer is recommended to be used, which provide the required optimization automatically. In Germany, this function is currently available in transformers provided by Siemens and costs approximately 2500 Dollars, possibly less in Egypt (difference in currency).

7.2.3 VSD Setting for Gassy Wells

Some VSD modules provide a very useful option, when operating in wells where significant amounts of gas are produced. They are able to compensate the impact of changing gas rates. One limit is set to the maximum allowed operation frequency and one to the desired optimal value. When gas is present in the pump, the motor load will decrease and the output frequency will rise until the upper frequency limit is reached. The slight increase in frequency will further compress the gas and help to move it out of the pump, a highly desirable effect when producing wells with variable gas rates.

7.3 Data

7.3.1 Static Pressure Surveys

Static pressure surveys in the West Field were only performed in the initial phase of a well, which was in early 2000. Only one survey was carried out a few years later and a regression analysis based on one data point is not the best practice and very inaccurate. With the installed multisensors in B11 and B12, build up tests can be carried out without any special equipment, only a possible production loss has to be taken into account. More static pressure surveys are recommended for the Main Field and West Field. The reservoir department could enhance the reserve estimation and the production department can design more accurate pumps and improve the run life of the completion.

7.3.2 Multisensor

With multisensors, the communication between the wells can be evaluated. Additionally, the wear of the pump can be identified to improve the IPR. When the pump has to produce against a closed choke the discharge pressure should reach the pressure rate of zero production in a tornado chart. If this is not the case at the beginning of a pump run life, the IPR can be corrected. However, some pump stages may be damaged, which diminishes pump run life significantly. In addition to vibration, monitoring troubleshooting becomes more precise with multisensors. E.g. the frequency and the current drawn by the motor are stable, but vibration occurrence indicates that a water slug is being produced. Without vibration asphaltene or paraffin may be the cause and proper actions can be enforced. The greatest benefit of multisensors is the recording of the well pressure at the pump intake and the bottom hole flowing pressure, which is recorded very accurately, enhancing the accuracy of IPR curves and therefore improving equipment design and run life.

7.3.3 Echometer Survey

As it is the only way in Ras Fanar to evaluate and monitor the bottom hole flowing pressure, monthly tests are a MUST to ensure the accuracy of generated IPRs. The procedure of the Echometer was validated and the processing program was corrected for Platform B. The process programme files for the wells of Platform A have to be corrected by field staff and validated by the production department.

7.3.4 Production Data

The problem of the allocation factor of the test separator in Ras Fanar was discussed extensively in Chapter 6. It is recommended to allocate gross production with the monthly evaluated allocation factor and report both the allocated production and the used factor separately.

So far, the actual amount of gas produced in Ras Fanar has not been of interest, because it did not represent any economic value. Investigations in 6.3.3 revealed two important facts: it is not a good practice to allocate the produced gas with the allocation factor and calculation procedures have to be changed, which leads to an increased GOR. Furthermore, EGPC reported that it received 29% more gas than measured by the offshore test separator. The exact measurement conditions of EGPC are not known, so this issue has to be investigated further find a more accurate gas allocation factor than the introduced factor of 1.29. This significantly higher amount of gas explains observed gas locks in A1, A5, A6, A8, B1, B9, and B12, because the installed gas handling equipment is designed for a lower amount of gas. Comparison of all wells in Ras Fanar revealed that the limit for the installed equipment is between a recalculated GOR of 600 and 700 scf/stb. Further investigation of this issue is strongly recommended to design proper gas handling equipment, which will increase the pump's run life more than any other proposal presented in this report.

7.3.5 Availability of Data

It is recommended to build up a detailed databank for ESP failures and Troubleshooting to solve future problems with ESP equipment and procedures in order to prevent failures due to lack of knowledge in case of staff changes. Simultaneously, a database with available production related data is highly recommended. E.g. gas analysis data of 2003 is stored in a file in the field, but the optimization potential of chapter 7.3.1 would have been revealed earlier by the Chemistry Department, if gas analysis data had been available to them. It is the task of the production department to verify and validate collected data at least once a month and establish a database.

7.4 ESP Design

7.4.1 ESP Set-Up

The design of gas handling equipment like the Advanced Gas Handler has to be adapted to the corrected amount of gas produced in Ras Fanar, so gas locks can be avoided in future designs.

The labyrinth section in the upper protector can be skipped in all wells except B1, because it does not work in deviated wells. This will decrease the cost per completion by 1500 US-Dollars.

7.4.2 Simulation

The optimization of the IPR design can be completed by using the data set summarized in Table 12. The change of input data to allocated gross production to ensure the pump operates within its design limit to improve run life and decrease wear due to downthrust is of uttermost interest and will have a great impact on overall well performance. Another important change concerns GOR, which is nearly twice then expected, and has to be evaluated further (see 7.3.4). The multiphase flow correlations of Hagedorn & Brown original (Tulsa code) and in case of an inclination of more than 45° - Beggs & Brill (Tulsa code) - were found to be most accurate for the wells in Ras Fanar.

It is recommended to use the measured PVT data and the correlation derived by Kartoadmodjo and Schmidt, because it's based on a wide range of data covering Southeast Asia, Middle East and North and South America.[36] The correlation of Al-Marhoun would be more accurate as it is designed for Middle East crude oils, especially Egypt, but unfortunately it is not available in the current simulation programs.[37] If neither are available, the correlation of Standing may be accurate enough, although it is based on Californian crude oils solely.[38]

Only one single license for Schlumberger Pipesim 2007 is available to model three operating fields, which restricts the time during wich the production engineers can evaluate and refine models. Nodal Analysis and Gas Lift design capabilities of this program are satisfying, the option to design an ESP completion, however, is not recommended. Additionally, no software is available to design an ESP completion so neither the production department is able to design an ESP completion, nor can it revaluate the proposal of the vendor Schlumberger. At least one license of Schlumberger Pipesim is recommended per field, and in additional an ESP design program must be available to ensure correct design of the vendor and scenario planning. The operation would highly benefit from an ESP design program, if the artificial lift method were changed from gas lift to ESP. A small benchmark A.Table 3 of the programs IHS Subpump 9.11, Schlumberger Pipesim 2007 and Centrilift Autograph PC is added in the Appendix.

7.5 Production

7.5.1 High p_{wh} of B9

The p_{wh} and henceforth, the discharge pressure of the pump has to be kept high not in order to prevent water coning, as assumed by the production department, but in order to stabilize the outflow of the well. The high pressure regime is necessary to prevent the saturated gas to desaturate, due to the natural pressure drop in the tubing to the surface. It must be noted that a p_{wh} higher than the p_{wf} would only produce excess motor heat, because the amount of gas already desaturated at p_{wf} cannot be re-satiated. For this procedure, twice the bubble point pressure would be necessary, which cannot be applied.

It is recommended to lower wellhead pressure and evaluate the pressure when the flow becomes unstable and remains slightly above equilibrium. This reduces flow resistance and the pump run life improves. This operation mode is applicable for B12 to stabilize the flow and increase production time and volume significantly. Additionally, the frequencey of gas locks will decrease.

7.5.2 Work over

To minimize junk in the well, all name tags on any ESP section should be peeled off. They might rip off while tripping and the ESP might suck in the name tags into the pump section, which would then be damaged. In general, all kinds of junk should be avoided. A track recorder on both run-in-hole and pulled-out-of-hole steel bands should be established and checked after retrieving completion, when the next work-over is performed. This record should be added in the completion design sheet.

Troubleshooting and failure analysis were implemented after a work-over, which is best practice. But their results are not available or were not filed properly.

Installation reports by Schlumberger are in poor condition and not completed carefully. The company's own supervisor should check if the Installation report is filled out completely and the production department has to establish a database of all installed equipment. A spreadsheet is available in the field department, but must be revised and optimized.

Tear down reports of Schlumberger are not available; only one sentence, as failure description is not best practice. A detailed failure analysis and optimizing proposals should be supplied by Schlumberger, as it is their responsibility as vendor. It is recommended to create a failure database with these reports administrated by the production department (see 7.3.5).

7.5.3 Production Increase

[stb/d]	actual oil production	scenario 1 production	scenario 2 production	Δproduction scenario 1	Δproduction scenario 2
RF-B1	412	453	340	37	-72
RF-B2	371	408	272	37	-99
RF-B3	288	317	211	29	-77
RF-B7	259	284	142	26	-116
RF-B8a	222	244	163	22	-59
RF-B9	266	293	256	27	-10
RF-B10	115	126	63	11	-52
RF-B11c	340	374	327	34	-13
RF-B12	382	420	374	38	-8

Table 33: Production scenarios

Two scenarios are summed up: First, gross production is increased by 10% without increasing water cut. Second, the production is increased by 10% including a rise of the water cut by 5%. No production increase can be recommended in wells with over 85% water cut, because the possible loss of production in case of scenario 2 is more than double or triple that of possible production increase in scenario 1. On the other hand, the loss of production in the wells B9, B11 and B12 is much lower than the possible increase, especially in B12. The reason for gas locks is either gas coming from the annulus due to low fluid levels, or gas being coned into the well. In both cases lowering production to increase the p_{wf} is recommended.[34]

This can be done for well B1 and B12, but would result in a loss of production. Choosing the right operating procedure for B9 is a dilemma. On the one hand the production should be increased, because the pump produces below its recommended operating range and suffers from wear due to excess downthrust; on the other hand production should be lowered to reduce the possibility of gas locking. As there are two installed protectors, the possible number of restarts is higher than normal. A production increase into the operating range can be risked, but must be evaluated by the production department.

An increase of production in B9 and B12 can only be achieved if new adequate gas handling equipment is installed, which will not be the case until the next work over.

7.5.4 Bottlenecks in the Flow Line

No forgotten, unnecessary gauges, valves and flow line bottlenecks could be identified. The only artificial restriction in the flow consists in the use of chokes in combination with VSD drives. The VSD serves to control the fluid flow by adjusting the frequency, an additional choke is only an excess load for the motor and the pump, resulting in additional heat and pump wear, which diminish the pump's run life. Chokes were implemented since they compensated the overdesigned pumps, when an ESP was designed with no allocated production potential, but it is recommended to decrease the frequency of the pump and open the choke for the desired flow rate. For future designs with a VSD, no chokes should be necessary in the flow line, the resulting improvement can be seen in Figure 35.

8 Economic Assessment

For the analysis of economic feasibility a budget for the proposals in chapter 7 has to be defined. The direct economic value of most of the proposed alternatives cannot be expressed in terms of a decrease of cost but of increased pump run life of equipment and therefore a postponed work over.

Alternative	Cost	Benefit
Adjust downhole corrosion inhibitor injection	-1500 [$/well/year] = 13500 [US $/year]	decrease of cost
Sampling procedure	2000 [US $]	run life
Electric System Analysis	10000 [US $]	run life
Transformer	2500 [US $/well]	run life
VSD setting	service contract	run life
Static pressure test with multisensor	4 days no production = -1200 bopd/well	run life and reserve estimation
Echometer	±0	Already implemented
Change reporting procedure	±0	run life
Databank	5000 [US $] + 1000 [US $/year]	run life
License IHS Subpump	8000 [US $/year]	run life
ESP set up: protector	-1500 [US $/well completion] except RF B1	decrease of cost
ESP set up: gas handling	+1000 [US $/well completion]	run life
Improved Simulation	±0	run life
Operation: Choke + VSD	±0	run life
Production increase due to better gas handling and change of production procedure for B12	increase gross production in B1, B9, B11 and B12 by 10%	Production increase
Work over	±0	run life

Table 34: Budget for several proposals

Economic Parameter	
Completion Equipment	300000 [US $/well]
Fuel	30000 [US $/well]
Intangibles (Services, Equipment Rental & Engineering)	244000 [US $/well]
Administrative Cost	26000 [US $/well]
Other economic parameters	
Average price Brent 4th quarter 2009	72 [US $]
Difference Brent – Ras Fanar	-2 [US $] = 70 [US $]
Decline Main field (see OFM)	0.2 [-/year]
Decline West field (see OFM)	0,155 [-/year]
Revenue gas	0 [US $]
Discount factor	10 [%]
Production cost oil	8.21 [bbl]
Production Increase B1, B9, B11c and B12	10 [%]
Cost increase CAPEX	5 [%]

Table 35: Input parameters for economical assessment

As economic assessment factors Net Present Value, Pay-out Time and Cumulated Discounted Cash Flow after 5 years are used. The Net Present Value of an amount to be received at a future date equals the amount that would have to be put on compound interest (in this case 10%) at the reference date to give the given amount of a future date.[39] Based on the parameters given in Table 35, the proposals given in Table 34 are compared with the current operation mode, assuming those proposals can increase the pump run life from 3 to 4 years.

Scenarios

The first scenario represents the current operational methods as a reference case. None of the proposed investments or operational changes are implemented. The economic calculation is added in the Appendix, see A.Table 4, based on the data presented in Table 34. The allocated production rate in Table 9 is used, future production decline is considered.

The second scenario assumes that the proposals summarized in Table 35 are implemented and an increase in run life from 3 to 4 years is achieved. The production rate is kept on the actual level and a future decline is considered. For further information see the spreadsheet in the Appendix in A.Table 5.

The third scenario is an increase of production rate at B1, B9, B11c and B12 by 10% as described in 7.5.3 with the help of the proposed alternatives summarized in Table 34. Again, detailed calculations are added in the Appendix, see A.Table 6.

Results

	NPV after 5 years [US $]	Pay-out Time [d]
Scenario 1	146,571,237	43.4
Scenario 2	146,761,513	43.8
Scenario 3	155,212,893	41.4

Table 36: Economic Assessment Factors

Table 36 clearly outlines the possibility of a production increase, as the change of operation procedures and minor investments are highly recommended with regard to the presented, higher Net Present Value (NPV). The small Pay-Out Time represents the good profitability of the project. The introduction of the proposals without any production increase, which is scenario 2, creates a higher NPV than the actual operation procedure, which is scenario 1. The best opportunity is with regard of the NPV scenario 3, which recommends the implementation of the proposals and the production increase.

9 Conclusion

The ESP operation in Ras Fanar with an average pump run life of three years corresponds the global average, but there is still potential to considerable improvement.

A direct cost decrease can only be achieved by adjusting the downhole injection of corrosion inhibitor to the actual measured data per well, which is noticeably lower than the average of the production pipeline in most cases. Either the measurements of 2003 are outdated or the wells of platform A contain higher H_2S fractions than platform B. In any case, the injection of corrosion inhibitor has to be checked.

A major problem was identified with the reported production of Ras Fanar. First, production was not allocated for design purposes, which led to pump designs below their operating ranges. This caused excessive wear and reduced run life of both pump and motor. Second, the accuracy of the gas measurement was not of interest, because the gas is delivered free of charge to the processing company in exchange for free electric power for the operation. Together with the failure to use the same allocation factor which is valid for liquid production and the inaccurate measurement led to an inadequate design of gas handling equipment by the vendor. The consequence was gas locking problems in 8 out of 17 wells in Ras Fanar Platforms A and B, which resulted in production losses and shorter pump run life. With adequate gas handling equipment it may be possible to increase production by 10% in up to 4 wells (on platform B), leading to a possible increase of the NPV by 8,641,657 [US $] after 5 years (including the cost of all proposals).

To sufficiently empower the staff to supervise the operation and design the equipment properly, it is indispensable to provide accurate production field data through e.g. static pressure surveys and computer programs to process this data. An ESP design program is recommended, if the ESP operation is intended to continue or to be enlarged. Additional licences of Pipesim, including GOAL software to supervise the production operation of the whole field (not only well per well) would definitely be highly efficient. With the help of both programs, more accurate models can be designed and actions can be taken more precisely, which will diminish future development cost.

One of the proposals concerns the familiar problem of the poor quality power supply, including disruptions in supply. Improvement of power quality by the use of specialized devices is highly adviseable, yet the worse the quality, the more expensive the devices. To evaluate the equipment actually required, a complete analysis of the power supply is of interest, since the evaluation, based on the VSD of the vendor, can be inaccurate. In addition to that, every stop of an ESP affects its run life, which is already taken into account in the actual design. If this problem can be solved, the main failure reason downhole cable could be avoided altogether, because this failure can occur due to old age as well.

10 References

1. **Samir**, M.: “Eclipse Reservoir Model, Ras Fanar”, SUCO Cairo, Egypt 2009
2. **Samir**, M.: “Integrated field study”, SUCO, Cairo, Egypt 2009
3. **Lea,** J. F. and **Winkler,** H.W.: “What’s New in Artificial Lift,” World Oil April 2009 pp 61-62
4. **Ghalambor**, A., **Guo**, B., Lyons, W.C.: “Petroleum Production Engineering,” Elsevier Science & Technology Books, February 2007
5. **Economides**, M.J., **Hill**, A.D., **Ehlig-Economides.**: “Petroleum Production Systems,” Prenticece Hall PTR, New Jersey 1993
6. **Baker Hughes Centrilift**: “Submersible Pump Handbook”, sixth edition, Baker Hughes, Oklahoma 1997
7. **Baker Hughes Centrilift**: “ESP System Technology Overview”, company presentation Centrilift, Baker Hughes, Mittelplate, Germany November 2004
8. **Schlumberger Reda:** “Electrical Submersible Pump Technology – Pump Catalog,” Portable Document Format, available at www.slb.com, 2007
9. **Baker Hughes Centrilift**: “Seal Theory of Operation”, ”, company presentation Centrilift, Baker Hughes, Mittelplate, Germany November 2004
10. **Bradley,** H.B.: “ Petroleum Engineering Handbook”, third printing, SPE, Richardson, Texas, U.S.A., 1992
11. **Baker Hughes Centrilift**: “ GCS Troubleshooting & Application,” Version 1.0 Release, March 2001
12. **Brown,** K. E.: “The Technology of Artificial Lift Methods, Vol. 2b,” Penn well Publ. Co., Tulsa, Oklahoma, 1978
13. **Gilbert,** W. E., :”Flowing and Gas-Lift Well Performance,” API Drilling and Production Practice,” 1954
14. **Nind,** T.E.W : „Principles of Oil Well Production,” McGraw-Hill Book Co. Inc., New York, 1981
15. **Brown,** K. E. and Beggs, H.D.: “The Technology of Artificial Lift Methods,” Volume 1. Penn well Publ. Co., Tulsa, Oklahoma, 1978
16. **Beggs**, H.D.: “Production Optimization using Nodal™ Analysis,” OGCI and Petroskills Publications, Tulsa Oklahoma, 2003
17. **Toni**, I.: “Well Design Ras Fanar”, PED SUCO Cairo, Egypt 2009

18. **Craig,** Bruce D.: " Sour Gas Design Considerations," SPE Monograph Volume 15, Richardson, Texas, 1993

19. **Standard MR-01-75** , **"**Sulphide Stress Cracking Resistant Metallic Materials for Oilfield Equipment," NACE, Houston, 1988

20. **Gray,** L.C. :" Electrical Submersible Pumps: How to Achieve Longer Run Lifes Through Simple Computer Data Monitoring," BP Exploring, 1993

21. **Brill**, P.J. and **Mukherjee**, H.:" Multiphase Flow in Wells," SPE Monograph Series, Volume 17, AIME, Richardson, Texas 1999

22. **Hagedorn**, A.R. and **Brown**, K.E.: "Experimental Study of Pressure Gradients Occurring During Continuous Two-Phase Flow in Small-Diameter Vertical Conduits," JPT, April 1965

23. **Users Manual for API 14B**: "SSCSV Sizing Computer Program" second edition,1978, Appendix B, p 38-41,

24. **Beggs**, H.D. and **Brill,** J.P.: " A study of two phase flow in inclined pipes," JPT, May, 1973

25. **Duns**, H. and **Ros**, N.C.J.: "Vertical Flow of Gas and Liquid Mixtures in Wells", Proceedings, 6th World Petroleum Congress, Frankfurt, Germany, 1963

26. **Orkiszewski,** J.: " Predicting Two-Phase Pressure Drops in Vertical Pipes," JPT, June 1967

27. **Aziz**, K., **Govier**, G.W. and **Forgarasi**, M.: " Pressure Drops in Wells Producing Oil and Gas," J.Cdn. Pet. Tech., July-Sep., 1972

28. **Govier**, G.W. et. Al: "The Upward Vertical Flow of Air-Water mixtures, Part I" Cdn. J. Chem. Eng (1957)

29. **Ros,** N. C. J.: " An Analysis of Critical Simultaneous Gas-Liquid Flow Through a Restriction and its Application to Flowmetering," Appl. Sci. Res. 1960

30. **Baxendell,** P. B.: "Bean Performance – Lake Maracaibo Wells," Internal Oil Company Report, Shell Oil Co., Houston (October 1967)

31. **Achong**, I.: "Revised Bean Performance Formula for Lake Maracaibo Wells," International Oil Company Report, Shell Oil Co., Houston (October 1961)

32. **Ghareeb,** M.: "A New Correlation for Calculating Production Considering Influences of Temperature, GOR and Water-Cut For Artificially Lifted Wells," IPTC Conference, Dubai 4-6 December 2007

33. **Baker Hughes Centrilift**: "Viscous Fluid Pumping Applicaton Guideline", Centrilift, Baker Hughes, November 2001

34. **Waring,** B.: "Electric Submersible Pump Basic," Shell International Exploration and Production B.V., May 2000

35. **Schierenbeck,** O.: "TKP Berechnung III" Internal Oil Company Presentation, RWE DEA, Friedrichskoog, October 2009

36. **Kartoadmodjo**, T. And **Schmidt**, Z.:" New Correlations for Crude Oil Physical Properties," paper SPE 23556 available from SPE, Richardson, Texas, U.S.A., June 1991

37. **Al-Marhoun**, M.A.: "PVT Correlation for Middle East Crude Oils," JPT May 1998, 650; Trans. AIME 285

38. **Standing**, M.B. "A Pressure-Volume-Temperature Correlation for Mixtures of California Oil and Gases," Drill. & Prod. Pract. (1957) 275

39. **Biedermann**, H.: "Investitionsrechnung" lecture notes for course "Allgemeine Wirtschafts- und Betriebswissenschaften I" Department of Wirtschafts- und Betriebswissenschaft of Montanuniversität Leoben, January 2001

Internet

1. http://www.slb.com/services/artificial_lift/submersible/gas_solutions/esp_gas_handling.aspx (call 3.05.2010)

Appendix

PSAT	Rs [scf/stb]	BO [rb/stb]	VO [cp]
812	326,0	1,1756	1,85
715	306,9	1,1679	1,910
615	281,9	1,1580	2,000
515	258,0	1,1491	2,100
415	232,0	1,1394	2,230

A. Table 1: PVT Data Main Field

PSAT	Rs [scf/stb]	BO [rb/stb]	VO [cp]
832	207	1,1322	4,401
798	202	1,1303	4,483
653	183	1,1221	4,82
508	161	1,1126	5,279
832	207	1,1322	4,401

A. Table 2: PVT Data West Field

	AutographPC	Subpump 9.11	Pipesim 2007
Handling	Easy and intuitive; straightforward	Easy and intuitive; straightforward	Need to be familiar with the program
Deviation Data	Every single value by hand – time consuming	Copy Paste from Excel – misleading that only one pair MVD=TVD is allowed	Copy Paste from Excel
Housing	No Housing size	Housing size available	No Housing size
Gas Separator	Gas Handler can be chosen from list	Gas Handling only by value- SP 9.5 allows GH.	Gas Handling only by value
ESP	Only REDA/Centrilift	Many vendors	Many vendors
Nodal Analysis	No	Calculation based on Nodal Analysis	Yes
Flow Correlation	Few can be chosen, evaluation not possible	Average amount can be chosen, evaluation not possible –need Auto select option for the correlation	Broad Range of Correlations can be chosen and compared. Needs other program to evaluate right correlation
PVT	Calculated from few values	Can be entered or calculated by program	Can be entered or calculated by program
Different Scenarios	Yes	Yes	No
Manipulate Pump Values	Very easy to change Input and stages/Hz – converts immediate every change	Easy to change input Increment of change of stages/Hz is not visualized as good as in Autograph	Unnecessary complicated
Analyze options	Restricted	Option is available, but not useable Improvement in SP 9.5	Very good
Flow through choke	Not available	Available but didn't work in calculated cases	Restricted, didn't work
Compare Cases	Restricted	not suitable until now	Not possible
Select Motor	Should be checked by vendor, but ok	Since no Advanced Gas Handler can be added not possible.	Not suitable
Select Cable	Should be checked by vendor, but ok	Required Voltage and HP cannot be calculated because no gas handler can be added Available in SP 9.5	Not suitable
Help File	Suitable	Quite ok	Very good for background information but not usable for program
Tutorial	No	No - Video in SP 9.5	No

A. Table 3: Comparison of Autograph, Subpump and Pipesim

Year	0	1	2	3	4	5
oil production [stb]	0	903916	751277	624696	519682	432523
revenues [US $]	0	63274128	52589383	43728753	36377764	30276623
OPEX [US $]	0	-7421151	-6167983	-5128758	-4266592	-3551015
CAPEX (5%) [US $]						
Workover						
Tangible	-2700000			-3125588		
Intangible	-2160000			-2500470		
Consumables	-270000			-312559		
Administration	-270000			-312559		
Total	-5400000	0	0	-6251175	0	0
CAPEX	-5400000	0	0	-6251175	0	0
OPEX	0	-7421151	-6167983	-5128758	-4266592	-3551015
Cash Flow	-5400000	55852977	46421400	32348820	32111172	26725608
Cumulative Cash Flow	-5400000	50452977	96874377	129223197	161334369	188059977
Discount Factor	1.00	0.91	0.83	0.75	0.68	0.62
DCF	-5400000	50775433	38364793	24304147	21932363	16594500
Cumulative DCF	-5400000	45375433	83740227	108044374	129976737	146571237
			Net Present Value	146571237	[US $]	
			Pay Out Time	43.4	[d]	

A. Table 4: Economic calculation current procedure

Year	0	1	2	3	4	5
oil production [stb]	0	903916	751277	624696	519682	432523
Revenues [US $]	0	63274128	52589383	43728753	36377764	30276623
OPEX [US $]	0	-7421151	-6167983	-5128758	-4266592	-3551015
B1, B9, B11, B12						
Add. Oil Production [stb]	0	0	0	0	0	0
Revenues Add. Prod. [US $]	0	0	0	0	0	0
OPEX add. Prod. [US $]	0	0	0	0	0	0
Savings Injection	0	13500	13500	13500	13500	13500
Databank	-1000	-1000	-1000	-1000	-1000	-1000
License Subpump	-8000	-8000	-8000	-8000	-8000	-8000
CAPEX (5%) [US $]						
Transformer [US $]	-22500					
System Analysis [US $]	-10000					
Sampling Procedure [US $]	-2000					
Database [US $]	-5000					
Workover (5%) [US $]						
Tangible	-2700000				-3281867	
Intangible	-2160000				-2625494	
Consumables	-270000				-328187	
Administration	-270000				-328187	
ESP Design: GH [US $]	-9000				-10940	
ESP Design: Protector [US $]	13500				16409	
Total [US $]	-5435000	0	0	0	-6558264	0
Revenues	0	63274128	52589383	43728753	36377764	30276623
Add. Revenues	0	13500	13500	13500	13500	13500
CAPEX	-5435000	0	0	0	-6558264	0
OPEX	-9000	-7430151	-6176983	-5137758	-4275592	-3560015
Cash Flow	-5444000	55857477	46425900	38604495	25557408	26730108
Cumulative Cash Flow	-5444000	50413477	96839377	135443872	161001280	187731388
Discount Factor	1.00	0.91	0.83	0.75	0.68	0.62
DCF	-5444000	50779524	38368512	29004129	17456054	16597294
Cumulative DCF	-5444000	45335524	83704037	112708166	130164219	146761513
			Net Present Value	146761513	[US $]	
			Pay Out Time	43.8	[d]	

A. Table 5: Economic Calculation including proposals without production increase

Year	0	1	2	3	4	5
oil production [stb]	0	903916	751277	624696	519682	432523
Revenues [US $]	0	63274128	52589383	43728753	36377764	30276623
OPEX [US $]	0	-7421151	-6167983	-5128758	-4266592	-3551015
B1, B9, B11, B12						
Add. Oil Production [stb]	0	46720	43435	33215	27740	23360
Revenues Add. Prod. [US $]	0	3270400	3040450	2325050	1941800	1635200
OPEX add. Prod. [US $]	0	-383571	-356601	-272695	-227745	-191786
Savings Injection	0	13500	13500	13500	13500	13500
Databank	-1000	-1000	-1000	-1000	-1000	-1000
License Subpump	-8000	-8000	-8000	-8000	-8000	-8000
For all 9 wells:						
CAPEX (5%) [US $]						
Transformer [US $]	-22500					
System Analysis [US $]	-10000					
Sampling Procedure [US $]	-2000					
Databank [US $]	-5000					
Workover (5%) [US $]						
Tangible	-2700000				-3281867	
Intangible	-2160000				-2625494	
Consumables	-270000				-328187	
Administration	-270000				-328187	
					0	
ESP Design: GH [US $]	-9000				-10940	
ESP Design: Protector [US $]	13500				16409	
Total [US $]	-5435000	0	0	0	-6558264	0
Revenues	0	63274128	52589383	43728753	36377764	30276623
Add. Revenues	0	3283900	3053950	2338550	1955300	1648700
CAPEX	-5435000	0	0	0	-6558264	0
OPEX	-9000	-7813723	-6533585	-5410453	-4503337	-3751801
Cash Flow	-5444000	58744306	49109749	40656850	27271463	28173522
Cumulative Cash Flow	-5444000	53300306	102410054	143066904	170338367	198511889
Discount Factor	1.00	0.91	0.83	0.75	0.68	0.62
DCF	-5444000	53403914	40586569	30546093	18626776	17493541
Cumulative DCF	-5444000	47959914	88546483	119092577	137719353	155212893
			Net Present Value	155212893	[US $]	
			Pay Out Time	41.4	[d]	

A. Table 6: Economic calculation including proposals and production increase