DESIGN AND ECONOMICAL EVALUATION OF SUCKER ROD AND ELECTRICAL SUBMERSIBLE PUMPS: OIL WELLS IN A FIELD, TURKEY

A THESIS SUBMITTED TO THE GRADUATE SCHOOL OF
NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

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IN PARTIAL FULFILLMENT OF THE REQUIREMENTS FOR THE DEGREE
OF MASTER OF SCIENCE OF PHILOSOPHY
IN
PETROLEUM AND NATURAL GAS ENGINEERING

SEPTEMBER 2004

Approval of the Graduate School of Natural and Applied Sciences

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This is to certify that we have read this thesis and that in our opinion it is fully adequate, in scope and quality, as a thesis for the degree of Master of Science of Philosophy.

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ABSTRACT

DESIGN AND ECONOMICAL EVALUATION OF SUCKER ROD AND ELECTRICAL SUBMERSIBLE PUMPS: OIL WELLS IN A FIELD, TURKEY

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September 2004, 165 pages

There are some alternatives of artificial lift methods to increase the production of oil well or to keep it producing. Sucker rod pumping (SRP) and electrical submersible pumping (ESP) systems are selected for the design and economical evaluation of thirteen oil wells of R field. Although selected wells are already producing artificially, they are redesigned for SRP and ESP. LoadCalC software developed by Lufkin and SubPUMP developed by DSSC are used for SRP and ESP designs respectively. For economic evaluation, the rate of return (ROR) of each design is calculated for ten year period. In technical comparison, advantage of higher production ability with lower power consumption was observed in ESP applications. In wells which have lower production than 100 bpd, SRP takes the advantage as it has the ability of low volume lifting. In economical comparison it was observed that using both methods together was given better result. By increasing the number of wells that were applied ESP, 3.61% of increment in ROR was obtained relative to the present status.

Key Words: sucker rod pump, electrical submersible pump, economic evaluation, design.

ÖZ

AT BAŞI VE ELEKTRİKLİ DALGIÇ POMPALARIN TASARIMI VE EKONOMİK DEĞERLENDİRİLMESİ: BİR SAHADAN PETROL KUYULARI, TÜRKİYE

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Eylül 2004, 165 sayfa

Bir petrol kuyusunun üretimini arttırmak ya da üretmeye devam etmesini sağlamak için yapay üretim yöntemleri vardır. Bu çalışmada, teknik tasarım ve ekonomik değerlendirme amacıyla at başı pompa (SRP) ve elektrikli dalgıç pompa (ESP) sistemleri seçildi. Yapay çekme uygulamaları için R sahasından 13 petrol kuyusu kullanıldı. Seçilen kuyuların halen yapay olarak üretim yapmasına reğmen, bu kuyulara yeniden SRP ve ESP tasarımı yapıldı. SRP için Lufkin tarafından geliştirilen LoadCalC ve DSSC tarafından geliştirilen SubPUMP yazılımı da ESP tasarımında kullanıldı. Ekonomik değerlendirmede her uygulama projesinin geri dönüş oranları ham petrol fiyatının varil başına 21 $ değeri tahmin edilerek (ROR) hesaplandı. R sahasından seçilen kuyulara uygulanan ESP sisteminin, düşük güç ile yüksek üretim üstünlüğü gözlemlendi. Günlük 100 varilin altındaki üretimlerde düşük hacim çekme yeteneği nedeni ile üstünlüğü SRP sistemi aldı. ESP uygulanan kuyu sayısı arttırıldığında, ROR şimdiki duruma göre % 3.61artış elde edildi.

Anahtar Kelimeler: atbaşı pompa, elektrikli dalgıç pompa, ekonomik değerlendirme, tasarım

ACKNOWLEDGEMENTS

I wish to express my indebtedness to my supervisor, Prof. Dr. Fevzi Gümrah, for his guidance, advice and encouragement throughout this study.

I would also like to thank to Haldun Sucuka first for his patience and for his valuable contribution.

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CHAPTER 1

INTRODUCTION

The driving force which displaces oil from a reservoir comes from the natural energy of the compressed fluids stored in the reservoir. The energy that actually causes the well to produce is a result of reduction in pressure between the reservoir and the wellbore. If the pressure reduction between the reservoir and the surface producing facilities is great enough, the well will flow naturally to the surface using only the natural energy supplied by the reservoir [1].

When the natural energy associated with oil will not produce a pressure differential between reservoir and wellbore sufficient to lift reservoir fluids to the surface and into surface facilities, or will not drive it into the surface in sufficient volume, the reservoir energy must be supplemented by some form of artificial lift.

Artificial lift methods fall into two groups, those that use pumps and those that use gas. Common artificial lift methods used in the world are, sucker rod pumps (SRP), electrical submersible pumps (ESP), gas lift (GL), plunger lift (PLNG), hydraulic pumps (HP), and progressive cavity pumps (PCP).

Sucker rods are solid high grade steel rods that are run inside of the producing tubing string to connect a subsurface pump to the pumping unit. They are the most used artificial methods in the world [2]. In ESP system the entire unit is lowered to the bottom of the well with an insulated cable from the surface. Basic elements are a centrifugal pump, the shaft and an electric motor. Main parts of the hydraulic pumping systems' are; a hydraulic engine and a pump connected to the engine. High pressure water or oil (power fluid) is the main element. The idea is produce fluid from oil well by injecting clean power fluid downward. Gas lift is a method of producing oil in which gas under pressure is used to lift the well fluid. System depends on the principle of lightening the gradient by injected gas. Progressive

Cavity Pumps are operating by rotating a steel helically shaped rotor inside an elastomer stator. Surface unit is generally being a rotating rod, but some manufacturers can offer down-hole ESP type motors as the prime mover.

Each method needs special considerations for specific a well. Their technical properties may not be suitable for the well that needs to produce artificially. Limitations of artificial lift installations are depend on the reservoir properties and whole lift system.

In this study, technical properties and economical advantages of two most commonly used artificial lift methods, sucker rod pumps and electrical submersible pumps, were compared in the selected thirteen oil wells of R-field in Turkey. Two softwares were used for designing the lift systems; for SRP design calculations LoadCalc software, developed by Lufkin, and SubPUMP software developed by DSSC for ESP system design. The results of designs were used to select the proper equipment combination of the artificial lift method. After finishing the design of systems they were economically analyzed. After calculating the cost and income parameters, rate of return of each method was calculated. Economical analysis was based on comparing the rate of returns.

CHAPTER 2

ARTIFICIAL LIFT METHODS

In the following paragraphs, the brief descriptions of the pumps are introduced. In this study ESP and SRP pumps were examined.

2.1 SUCKER ROD PUMPS

Sucker Rod Pump (SRP) is the simplest artificial method known and most widely used choice of artificial methods. In United States 80 % - 85 % of wells operated with sucker rod pump while this percentage 50 % in the world (Figure 2.1).

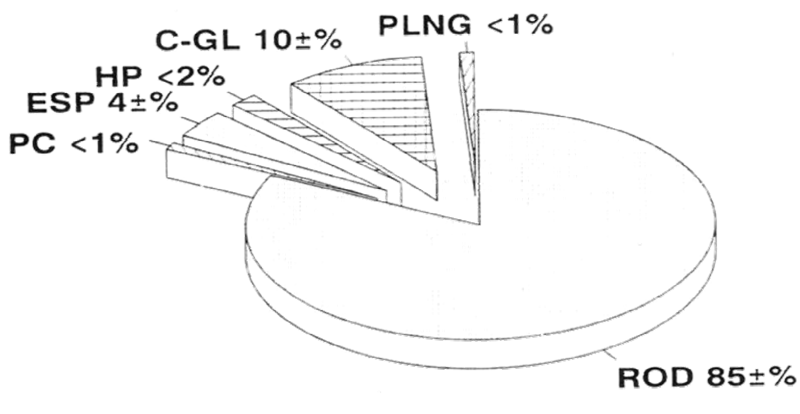

Figure 2.1 Percentages of artificial lift methods in U.S (1993ESP: electrical submersible pumps; ROD: sucker rod pumps [2].

Basically a SRP system consists of a tube divided into chambers by plunger and a simple surface unit including power plant (Figure 2.2). Operating principle is depending on the two valves work with plunger, transferring fluid from bottom chamber to top. Although sucker rod pumping considered as a simple system, installation has to be properly designed by the engineer.

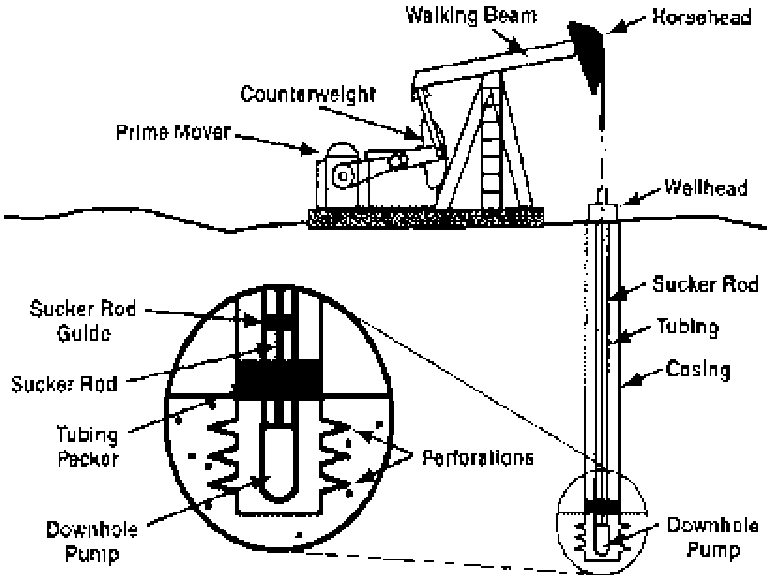

Figure 2.2 Basic scheme of Sucker Rod Pump System [6]

Limitations of the system should be considered while choosing the equipments. Strength of the rods determines the maximum performing depth which is up to 12000 ft [2,3]. Metallurgy of the component should be in compliance with the well environment. Corrosives, contaminants and salinity play important role in equipment life. The amount of fluid past through the interval between barrel and plunger called plunger slippage. Overall pump efficiency can decrease dramatically if plunger slippage increases because of improper design of barrel inner diameter (ID) and plunger outer diameter (OD) [2].

2.2 ELECTRICAL SUBMERSIBLE PUMPS

High production rates from deeper depths considered to be accomplished by using ESP. Improving technology increases the usage of ESP making it flexible for different rates. This system reported as not forgiving errors, so it requires excellent operating practices. Thus, operating personnel have to be well trained and qualified.

Besides operating practices design of the entire system should be done carefully. Otherwise serious failures result high repair and pulling costs [1, 5].

Centrifugal pump, shaft, electric motor, cable and control box are main parts of the ESP system (Figure 2.3). During operation motor gives revolving movement to the pump, than impellers within the pump impart it to the fluid. Resulting pressure forces the fluid through the tubing to the surface. Centrifugal pump stages in ESP systems become efficient as they become larger or at rates over 100 BFPD [3]. The lower limit of ESP's is 100 BFPD but below 200 BFPD operational problems may occur [3, 5]. As all other artificial methods, ESP system is sensitive to well environment especially temperature. Motor and cable selections should be done considering well temperature as they are the most temperature sensitive parts.

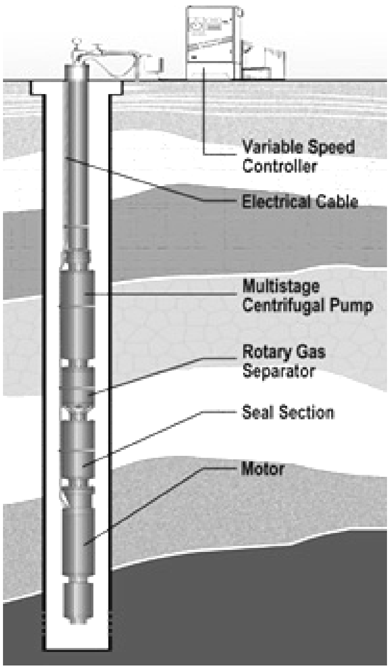

Figure 2.3 Basic scheme of Electrical Submersible Pump System [6]

2.3 GAS LIFT

After SRP gas lift is the second most widely used artificial method in world, generally offshore [2]. Gas lift system depends on the principle of lightening the gradient of fluid by injecting high pressure gas down the annulus. Specially designed gas lift valves installed on the tubing string. Gas under pressure is injected down through the space between casing and the tubing. Gas enters from valves and the fluid standing above the gas inlet point displaced.

In wells with gas problems this artificial method can be the best alternative depending on other well and location conditions. It can be used for either high volume of production or low volume wells [5].

Depending on the production capacity gas injection can be continuous or intermittent. If gas injected into the well by intervals because of the need for the build up in the tubing it is the intermittent gas lift. A well which is able to maintain a column of fluid above gas injection point called under continuous flow gas lift.

Without a central system surface compression will be expensive and in extreme cold climates hydrate problems are reported in surface lines.

2.4 PLUNGER LIFT

Plunger lift can be an alternative to gas lift method in wells, which have high formation gas/liquid ratio. In such cases natural gas supply is sufficient, and high gas/liquid ratio reduces the gas lift system efficiency [5].

The plunger placed in the tubing contains a valve, which controls the fluid flow. A cushion seat, containing an opening, at the bottom and a rubber or spring bumper at the upper end of the tubing helps the plunger valve to open and close. Gravitational force pulls the plunger down, and rise of bottomhole pressure with production from formation lifts it up [4].

As decreasing depth and increasing productivity the efficiency of plunger lift decreases. In suitable wells plunger lift is an efficient method which is trouble free and cheep.

2.5 HYDRAULIC PUMPS

In deviated wells hydraulic pumps takes the advantage against sucker rod system. During installation does not requiring a rod string or pumping unit makes it relatively cheaper. Offering the choice of between central power system and individual power system can influence the decision on artificial method.
Two main parts of the system are; a hydraulic engine and a pump connected to the engine. High pressure water or oil (power fluid) is the main element. Surface pump can be a hydraulic piston or jet pump. This choice should depend on the well type; jet pumps are able to pump abrasive sand or scale. Hydraulic pumps are considered as more efficient then jet pumps as jet pumps need a power fluid supply and at 2000 psi flowing bottomhole pressure jet pumps can not operate [5].
The idea is produce fluid from oil well by injecting clean power fluid downward. Two strings of fluid, alongside or inside the other are used. Fluid from well and power fluid return to the surface through those tubing, than power fluid separated or sometimes the mixture itself used as power fluid. Surface units require big triplex pumps and a separate line to the well for the power oil [3, 4, 5].

2.6 PROGRESSIVE CAVITY PUMPS

Progressive Cavity Pump (PCP) is a production application of equipment used originally in drilling as a mud motor for rotating the drill bit. In viscous fluid or solid problem wells this method can be preferred [5]. They operate by rotating a steel helically shaped rotor inside an elastomer stator. They can operate up to 3000 – 4000 ft depth [3]. In wells with H_2S or high temperature its elastic compound is subjected to deformation, so continual pump submergence can be required.

2.7 SCREENING CRITERIA FOR SRP AND ESP PUMPS

In this study ESP and SRP system will be considered for determining the thirteen wells of R-field in Turkey. To compare the artificial lift methods in a simple way Table 2.1 can be used. It includes the primary factors that are used to evaluate the lift methods under consideration. The technology and equipments of those pumping systems are presented in chapters 3 and 4 respectively.

Table 2.1 Comparison of Sucker Rod Pumping and Electrical Submersible Pumping System [2]

	SRP	ESP
Depth	Rods limit the depth 500 B/D at 7500 ft, 150 B/D at 15000 ft.	Operate up to 10000 ft Limited by motor horsepower and temperature
Casing Size	Small casing size, 4.5-5.5 in, may limit free-gas separation; high-rate wells need large plunger pumps.	Limits motor size and pump. Performance reduce in casings smaller than 5.5 in.
Temperature	Can operate up to 550 ^oF	Standard up to 250 ^oF, up to 350 ^oF special cable and motor required
Lift Capability	High-volume capacity is fair and limited by depth (4000 BFPD at 1000 ft and 1000 BFPD at 5000 ft) Low-volume capacity is excellent (below 100BFPD)	High-volume capacity is excellent but limited by horsepower need (4000 BFPD at 4000 ft) Low-volume capacity is poor, high operating cost for rates below 400 BFPD
Efficiency	Excellent total system efficiency. 50 % - 60 % pump efficiency	Above 1000 BFPD total system efficiency is about 50 %, below typically decreases by 10 %
Operation Cost	For depths less than 7500 ft and productions smaller than 400 BFPD very low	Repair costs are high and short run life results high pulling cost. Energy costs can be high.

CHAPTER 3

ELECTRICAL SUBMERSIBLE PUMPS (ESP)

Electrical Submersible Pumps are multistage centrifugal pumps driven by an electric motor. In petroleum industry they are generally used for production of oil from reservoir, increase production limited by inflow performance or tubing pressure loss and provide wellbore pressure during injection [1]. The pumping system is comprised of several major components. These are: three-phase electric motor, seal section, rotary gas separator, multi-stage centrifugal pump, electric power cable, motor controller and transformers. Additional components will normally include wellhead, cable bands, check and drain valves. A downhole pressure and temperature sensor may optionally include monitoring wellbore conditions.

3.1 COMPONENTS OF AN ESP SYSTEM

3.1.1 Impeller

Submersible pumps are multi-staged centrifugal pumps; each stage consists of a rotating impeller and stationary diffuser.
Pressure – energy change is achieved as the liquid being pumped surrounds the impeller, and as the impeller rotates it gives a rotating motion to the liquid.
Smaller flow pumps are generally centrifugal flow design as flow rates increased design changes to mixed flow(radial and axial). The energy imparted to the fluid determined by the configuration and diameter of the pump impeller. Impeller outside diameter is limited by the internal diameter of the pump housing while well casing inside diameter effects pump housing diameter. Another limitation for the impeller

internal diameter is the outside diameter of the shaft, must be strong enough to transmit power to all stages [1, 7].

3.1.2 Rotary Gas Separator

A rotary gas separator used generally in high gas-oil ratio wells to separate free gas using the centrifugal force from well fluid before entering the pump.

3.1.3 Equalizer (Seal Assembly)

Placed between motor shafts and pump or gas separator shaft. It allows the expansion of the dielectric oil contained in the rotor gap of the motor. Temperature rise resulting from the environment and motor will result expanding of dielectric oil. Seal assembly takes this expansion.

There is a difference in between casing annulus pressure and dielectric motor fluid which can cause a leakage of well fluid to the motor. By equalizing this pressure difference seal section keeps well fluid from leaking past the sealed joints of the motor.

Result of pump pressure acting across the cross sectional area of pump shaft is called down thrust of the pump. Seal assembly absorbs the down thrust.

3.1.4 Seal Section Thrust Bearing

The drive shaft of the motor is connected to the pump shaft which is splinted on both ends. The upper end of the seal shaft fits on the pump shaft in such a manner that the weight of the pump shaft and any unbalanced impeller loads are transmitted from the pump to seal assembly shaft. These loads are in turn transferred to the trust bearing [1].

3.1.5 Electrical Submersible Motor

Submersible motors are two pole, three-phase, squirrel cage and induction type. They filled with highly refined mineral oil. The motor is made up of rotors mounted on a shaft and located in the electrical filed within the housing.

A group of electro-magnets come together to forma hollow cylinder with one pole of each electro-magnet facing toward the center. This group of electro-magnets is called stator. Their magnetic filed rotates without a physical movement of electro-magnets. Electrical movement obtained by progressively changed the polarity of the poles. This magnetic field created in the stator induces the rotor. The rotor is composed of a group of electro-magnets in a cylinder with the poles facing the stator poles. The electrical field generated by the stator makes the rotor's poles to follow. This attempt result the rotor to rotate by magnetic attraction and repulsion [1, 7].

3.1.6 Motor Controllers

Three types of motor controllers are switchboards, soft starter, and variable speed controller (VSD) and all used for protection and control of an ESP system. There are many types of them and offering options to make design for various conditions.

3.1.6.1 Switchboards

Main parts are; motor starter, solid state circuitry for overload and under load protection, a manual disconnect switch, time delay circuit and recording ammeter. When stating an ESP system with a switch board, the frequency and voltage are same at the input and output terminals result a fixed speed operation.

3.1.6.2 Soft Starter

During the start up because of the high starting current a high mechanical and electrical stress occurs on the ESP equipment. Soft starters used to reduce this stress by dropping the voltage to the motor terminals during start-up.

3.1.6.3 Variable Speed Controller (VSC)

Having a fixed speed makes the ESP system operates at a limited production and fixed head output at operating speed. VSC varies the pump speed without any modification of downhole unit. VSC is basically converts the incoming 3-phase AC power to a single DC power, then invert DC to three AC output phases. This way gives the advantage of controllable frequency and voltage. Beside overcome the restrictions of fixed speed this application also extend the equipments life.

3.1.7 Downhole Pressure and Temperature Monitor

The need of changing pump size, injection rate or well work over can be determined when valuable data present to correlate reservoir pressure. A common used downhole pressure and temperature monitor has the capability of continuously observation of the pressure and temperature at the bottomhole, detecting the electric failures, and regulate speed working with the VSC.

3.1.8 Transformer

The distribution of electrical power to the oil fields is usually achieved at an intermediate voltage. Since ESP equipment can operate within 250 and 4000 volts a transformer must be used to transform the distribution voltage [1].

3.1.9 Junction Box

Has three functions, first is providing a point to connect the power cable from the controller to power cable from the well, second is being a gas vent to the atmosphere in case of gas migration up to the power cable, and providing a test point for checking downhole units.

3.1.10 Wellhead

Mainly it supports the weight of the subsurface equipment and used to maintain surface annular control of the well

3.1.11 Check Valve

A check valve is used to prevent the reverse rotation of the subsurface unit when motor is shut off. If this unit is not installed a leakage of fluid down the tubing through the pump occurs which can be results cable burn or broken shaft.

3.1.12 Drain Valve

This device is generally used with check valve placing above it. As check valve holds a column of fluid above the pump, the risk of pulling a wet tubing string occurs. Drain valve prevent the fluid to come up while pulling the downhole units.

3.1.13 Centralizer

Especially in deviated wells to eliminate damage and obtain the proper cooling of the equipment centralizers are used to place the equipment in the center of the wellbore. They also prevent cable damage due to rubbing.

3.1.14 Cable

Three phase electric cables are used to transmit power from surface to submersible motor. They must be small in size and well protected from aggressive well environment. As a limited space available between casing and equipment flat types can be used.

3.2 ESP APPLICATIONS

3.2.1 Shrouded Configuration

If motor is set below the perforation zone, to achieve the motor cooling shroud used. Completely cover the pump intake, seal section and motor with a metal jacket. Produced fluid directed from perforations to the pump intake through the motor.
It can be used for increase fluid velocity past through motor for cooling or as a gas separator by placing below the perforations [1, 7].

3.2.2 Booster Pump

An electric pump used as a boaster pump to increase the incoming pressure when too long pipelines are in consideration. Unit set in a shallow set vertical section of casing. An incoming line is connected to the casing feeds fluid into the casing and pump. If pumps connected in series flow rate will be constant while pressure increases. If pumps connected in parallel pressure will be the same while production rate increases.

3.2.3 Direct Production-Injection System

This application allows the produced water from a water supply well injected into an injection well or wells by installing the ESP in a water supply well.
In early stages of water flood, the reservoir requires large flow rate at low injection pressures. As the reservoir fills, the flow rate declines and injection pressure increases. In such a case the equipment can be economically modified to meet the varying reservoir conditions [1].

3.2.4 ESP Installation with Deep Set Packer

In case of dual production zone or cable damage problem because of gas saturation in high pressure well ESP installation with packers can be used. In this application an electrical feed placed in the packer using prefabricated connections.

3.2.5 ESP Installation with "Y" Tool

Y tool application is designed for testing downhole without pulling the pump out of the well. The tool would be run in conjunction with the pump and provides information about changes of pressure or temperature, monitoring water movements. Some other usages are placing acid, perforating and dual ESP completions.

3.2.6 High Temperature Wells

Standard submersible pumps are designed as applicable to well temperatures of 220 ^oF (105 ^oC) to 240 ^oF (115 ^oC) but the upper limit can be as high as 300 ^oF (150 ^oC) [1]. With some changes in motor design and use materials for harsh conditions adequate equipment life can be achieved. Motor selection plays an important role in handling high temperature wells. The combination of well temperature and motor temperature rise is expected not exceed the insulation thermal rating of the motor. Insulation system's life is reduced by one-half of each 10 ^oC above the insulation rated thermal life [1]. Motor temperature rise is related with horsepower load, motor voltage, and voltage waveform and heat dissipation characteristics of the well. If the chosen motor horsepower is larger than the required one, the horsepower load of the rotor will be smaller. By this way temperature rise in the motor reduced.

Another important element in motor temperature rise is the fluid properties. Cooling characteristics of the well fluid, a function of flow rate of the produced fluid, may be the most effective one. Tendency of the well fluid to cool the motor with scale, precipitants or other deposits should be considered.

While determining temperature rise specific heat of produced fluid is the element need to be examined. Water cut, fluid gravity, amount of free gas flowing by the motor and tendency of producing emulsions are factors which have significant effect on composite specific gravity of produced fluid.

3.2.7 Abrasive Well Fluids

Many deep, hot and hostile well environments contain abrasive fluids. This condition is mostly seen in unconsolidated sand stone formations where sand particles tend to ingested into the pump. Abrasive grinding wear and cutting wear due to erosion are failures of pumps because of sand particles.

Wear types generally occurs at pump are; radial wearing in head and base bushings and stages, up thrust or down thrust wear on the stage's surface and corrosive wear in the flow path of the stages. Because of impeller design primary wear first occurs on the thrust surfaces of the impeller and diffuser. Metal to metal contact destroys the stages and locks up the pump. Insulation breakdown can be seen because of fluid leakage result of radial wear.

When designing abrasion resistant options for ESP quantity of sand, acid solubility, particle size distribution, quantity of quartz and sand geometry must be examined.

3.2.8 Corrosive Well Fluids

Corrosion problems generally appear in deeper wells and in use of CO_2 injection. One of the solutions is the application of a coating to the surface of the equipment with a polyester resin. Another is the metal coating application to the surface of the equipment by using flame spray. In the unprotected areas where the coating was lost due to metal rubbing during installation accelerated corrosion took place. A more effective method of high chromium content materials usage solves corrosion problem in wells.

Cooper based parts, especially conductors, of the downhole components are faced with another type of corrosion. Cooper parts are under attack by low to medium concentrations of H_2S, at intermediate to high pressure and temperature [1]. Shielding the cooper parts with lead sheath can be effective as long as the sheath does not crack. Aluminum, not attacked by H_2S, can be used as a conductor instead of cooper. In case H_2SO_4 present in the well it will damage aluminum also, so it must be kept isolated from the conductor.

3.2.9 Gaseous Production Fluids

Presence of free gas in a well can cause serious problems like deterioration of the discharge head of the pump. If free gas to liquid ratio is 8 % to 10 % the need of gas separator appears, if not pump can operate without problem [1].
Besides the usage of a gas separator increasing the pump intake pressure by lowering the pump can be a solution. Lowering the pump below the casing perforations can cause the gas separate from liquid naturally and solve the problem. If last solution preferred a motor shroud should be used to maintain the cooling of the motor temperature.

3.3 ESP PROBLEMS

In this section possible causes of system failures and appropriate solutions will be examined. Cause of a failure can be improper design, harsh conditions, bad installation, faulty equipment, bad electrical system or sometimes manufacture. High prices of ESP equipments force an engineer to make failure analysis of each component of the system.

3.3.1 Pump Failures

Due to producing below peak efficiency of installed pump down thrust wear can occur, above the peak efficiency up thrust wear failure observed. Abrasive environments are also the reason of another wear, grinding wear. If scale build-up is not prevented stages within the pump are locked. Some times absence of Variable Speed Controller (VSC) can be a reason for pump failure such as twisted shaft, locked pump or starting during back spin can be other reasons.

3.3.2 Motor Failures

Excessive Motor Overload Failure: High specific gravity of the well fluid, undersized motor from poor data, worn out pump, unbalanced voltage can be the cause of a motor failure.

Seal Section Leak: Result of this failure is mixing of well fluid with motor fluid. If the pump is worn out it can cause seal damaging vibrations or rough handling can cause broken mechanical seals.

In Sufficient Fluid Movement: Generally 1 ft/sec fluid velocity by the motor recommended for cooling [1, 7], below velocities can cause increasing internal temperature which can result serious motor failures. If fluid is not directed through the motor same excessive motor heat observed.

3.3.3 Cable Failures

During the running or pulling processes mechanical damage can occur as a result of crushing, stretching or cutting. High temperature, high pressure gas or corrosion can deteriorate the cable. Excessive current results in breaking down the insulation.

3.3.4 Ammeter

To insure the investments against failures a combination of oilfield test procedures should be used. Premature failures will result serious and costly downhole problems. Thus each unit is properly and rigorously monitored in order that these malfunctions are corrected. Ammeter is the common device used for recording the input amperage of the monitor. It is located on the motor controller visibly. That recording device can work either one day or seven days period. Detecting minor operational problems provided with analysis of amp charts. Besides timely and exact analysis of those charts production plots for a well also prevent failures.

An ammeter chart looks like a record of heart beat electronically on a circular paper, which has date and time record on it. It records the input amperage of the motor. The recording paper divided in to 96 sections each represents 15 minutes and there are also lines have different amperage values on them. As every well has different operation characteristics, ammeter charts will not be the same.

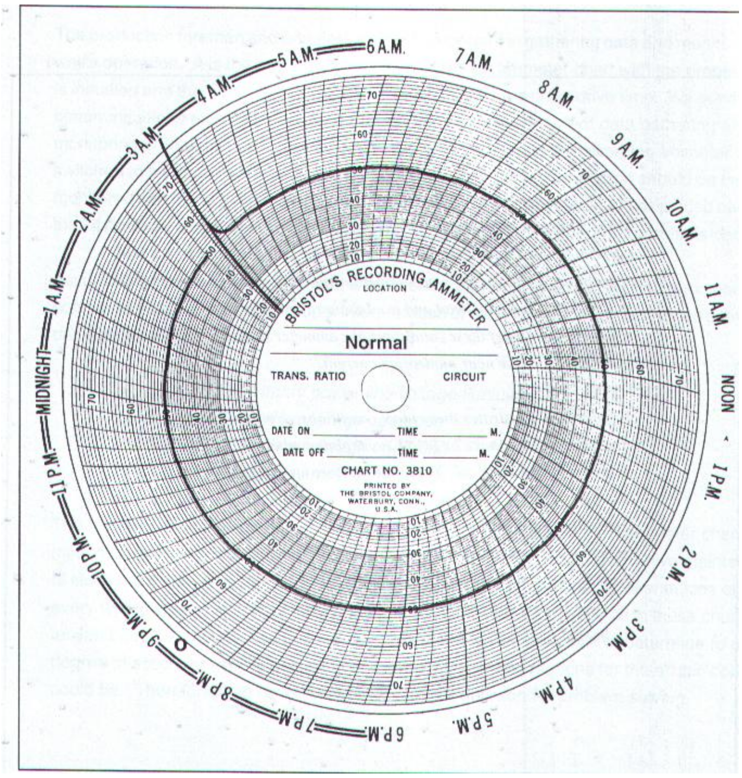

Figure 3.1 Normal Operation Ammeter Chart [1]

Figure 3.1 is an example of ammeter chart represents an ideal operation condition. During a normal operation recording on the ammeter chart will be a smooth and symmetric line. In this Figure a spike was recorded at 3 A.M. which is the result of the starting inrush current.

As previously mentioned in this study gas can cause serial mechanical failures which can have high prices. Thus, monitoring any gas problem before damaging the system seriously has critical importance. There may be different Figures on the ammeter chart due to well operation characteristics; in Figure 3.2 an example of gas locking problem was represented.

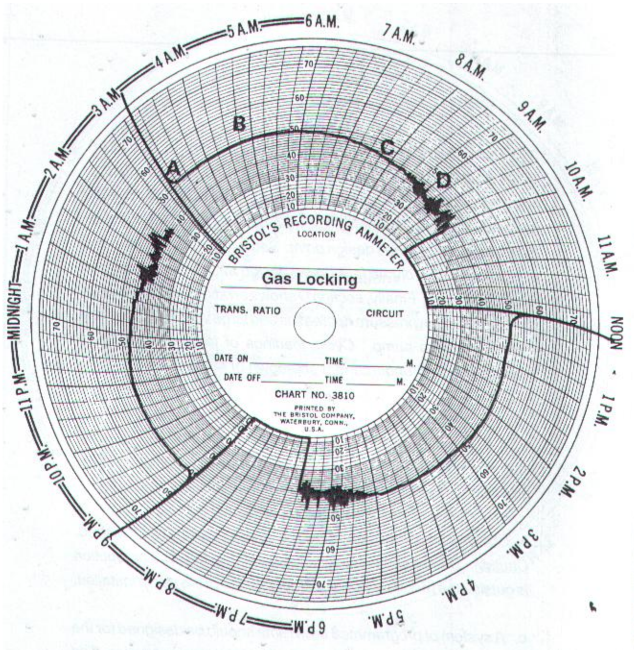

Figure 3.2 Gas Locking Ammeter Chart [1]

In section A, the start up, because of excessive gas annular fluid level is high and required total dynamic head reduced so production rate and current is above the designed value. When the volume decreases to the designed value section B occurs. Continual decrease in the volume result a reduction in current as seen in section C and fluctuations occurs because of gas change. What happen in section D is the result of reduced pressure in the pump and increasing gas volume. Loading of gas and fluid finally cause undercurrent shutdown.

To overcome such a problem pump can be lowered to increase the pump intake pressure and preventing gas from leave the solution.

Figure 3.3 is an ammeter chart of a unit which has shutdown due to under current and pumped off. It is automatically restarted but shutdown again periodically. Section A through C it looks like gas locking problem but no fluctuations due to gas break out present. The fluid level comes to pump intake depth and fluid production is decreased in section D. As under current point is reached the unit shuts down. This kind of problems may be the result of designing a too large unit for the well capacity or due to the change in reservoir condition like, decreasing reservoir pressure or change in fluid property.

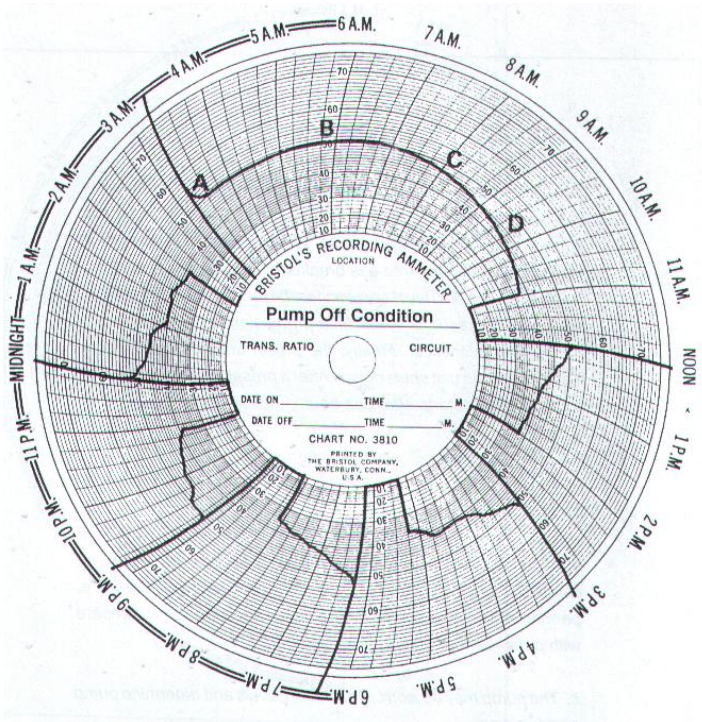

Figure 3.3 Pump Off Condition Ammeter Chart [1]

3.4 DESIGNING AN ESP SYSTEM

3.4.1 Limitations

Well conditions, such as well depth, pressure, temperature, flow rate, gas occurrence, generally impose the design. Pressure increase with depth is also limiting the design. Manufacturers are providing a range from 2000 ft for a large diameter pump to 13000 ft for a small diameter pump. Bottomhole temperature determines the operating temperature of the motor and cable [1, 7]. Maximum temperature of motor and cable will be higher than the formation temperature due to frictional and electrical heat. Wellbore pressure and temperature at the pump in take will determine the volume of gas present. As a rule of thumb when 10 % volume of gas was exceed a gas separation system will require [1].

3.4.2 General Factors Effecting ESP Selection

3.4.2.1 Casing Size: Internal diameter of the casing must be known to guarantee the pumping unit will fit inside the casing.

3.4.2.2 Perforated Intervals or Open Hole Depth: The fluid produced from the production zone is also used for the cooling purpose of the submersible pumps' motors. If the motor placed below the fluid entry point some instruments are need to direct the flow through the motor.

3.4.2.3 Tubing Size and Thread: Size of the tubing is used in total head design by determining the friction loss and also used to evaluate the volume to be pumped.

3.4.2.4 Bottomhole Temperature: Effective in the selection of the temperature sensitive bottomhole equipments like cables and motor.

3.4.2.5 Datum Point, Sand, Scale, Corrosion or Paraffin Problem: If any of those contaminants are present in well then bottom-hole equipments made up from specific materials to resist the corrosive affects of harsh conditions [1, 7] should be used. Measurements of a well made at a specific depth. That value must be known for appropriate correlations and calculations for new setting depth.

3.4.2.6 Desired Production Rate: Pump and motor capacities are various, surface production rate is the main factor effecting the selection of those equipments.

3.4.2.7 Specific Gravity of Liquids, Water cut, and Gas to be produced: Well fluid conditions are considered in every steps of the design procedure. For example, depending on the fluid condition engineer decide whether to use gas separator.

3.4.2.8 PI, IPR, Present Production Rate or Pwf: As the primary goal of any artificial lift method is increasing the production first thing to know is the ability of the well to produce. Well capability calculations need at least one of these.

3.4.2.9 Produced Gas SCF/B or Gas Fluid Ratio GFR: To determine how much fluid can be obtained in the surface and what will be the gas percentage in the pump intake those ratios are necessary.

3.4.2.10 Bubble Point Pressure: Flow regime in the tubing will affect the working conditions and special equipments may be need if there is excessive gas amount in the pump intake. Flow regime is limited by bubble point pressure so it is also another important data that should be considered.

CHAPTER 4

SUCKER ROD PUMPS (SRP)

Sucker rod pumping is so common and mechanically so simple. Chambers and traveling piston is characteristic components of a SRP system. The strength limit of the rods makes SRP effective for shallow or medium depths. Comparing with ESP system SRP requires relatively little training people for the operation and maintaining [5].

4.1 PUMPING CYCLE

Basic structure of the pump consists of a working barrel or liner suspended on the tubing, the sucker rod string moved up and down with plunger inside this barrel. Sucker rod string takes the oscillating motion from the surface units. At the bottom of the working barrel there is a stationary ball-and-seat ball (standing valve) and another ball-and-seat valve (traveling valve) in the plunger [9].

4.1.1 Plunger moving down; near the bottom of the stroke:

As the rods moving down the weight of the fluid column in the tubing supports the standing valve to be closed, while the fluid moving up through the traveling valve.
While the fluid moving up through the traveling valve the bottomhole flowing pressure exceeds the pressure of the fluid column and standing valve is now open. The load due to the fluid column has been transferred to from the tubing to the rod string.

4.1.2 Plunger moving up; near the top of the stroke:

Standing valve is still open, permitting the formation to produce into the tubing, while traveling valve is closed, until pressure difference changed.

The pressure result of the fluid column between standing and traveling valve now comes to a point that force the standing valve to close and traveling valve to open. But that point of down stroke depends on the percentage of free gas in the trapped fluid (Figure 4.1).

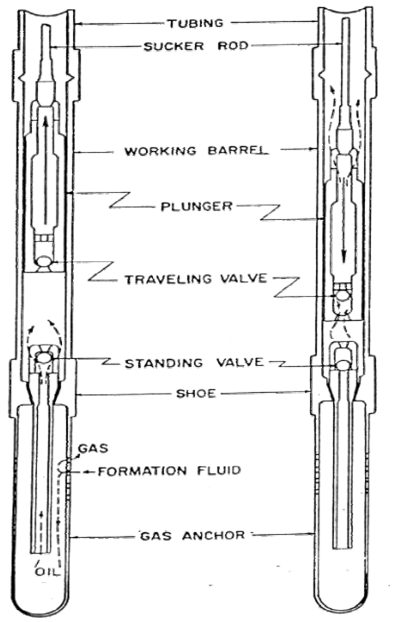

Figure 4.1 Locations of standing and traveling valve on upstroke (left) and down stroke (right) [8]

4.2 COMPONENTS OF A SRP SYSTEM

4.2.1 The Subsurface Pump

Tubing pump and rod pump are two main types of the subsurface pumps. Liner and standing valve, in a rod pump type, run on the rod string and plunger diameter must be smaller while in a tubing pump type, those assemblies run in the tubing [9].

4.2.3 The Sucker Rod String

Sucker rods are solid high grade steel rods which are subjected to transmit energy from the surface to the pump by running inside the tubing string. Sucker rods have to overcome the tremendous stresses resulting from forces of pull, compression and vibration. In addition to those forces harsh well environment makes the design process complex. There are standard diameters for a rod, when choosing the rod string suitable for a given well it is desired to use the lightest, more economic, string while keeping the rod stress below 30000psi [8].

If the well depth exceeds 3500 feet tapered rod string preferred [8]. Tapered rod string consists of rods of different sizes. Aim of this arrangement is to get the smaller load on the surface equipment. Basic principle is using the smaller diameter rod where the rod load is smaller (above plunger) and larger diameter rods where the rod loads bigger.

4.2.4 The Surface Pumping Equipments

4.2.4.1 Prime Mover: Functioning as an energy supply which is transmitted to the pump for lifting the fluid. A prime mover can be a gas engine, oil engine or electric motor. Choosing of which type of engine is used depends on the relative costs and availability of fuel. An electric motor has lower initial and maintenance cost, dependable all-weather-service and an automatic system. On the other hand gas engines have more flexible control, operation over a wider range of load conditions.

4.2.4.2 Crank Arm and Walking Beam: They are responsible of changing the rotary motion of the prime mover to reciprocating motion for the sucker rods.

4.2.4.3 Pitman Arm: The stroke length for any unit is variable within limits, about six possible lengths being possible. These are achieved by changing the position of the pitman connection in the crank arm.

4.2.4.4 Horse's Head and Hanger Cable: They are used to pull on the sucker rod string vertical, by this way no bending movement is applied to the string above the stuffing box.

4.2.4.5 Counter Weight: The counterbalance weights store energy during down stroke when power demand is low, and release energy during op stroke when power demand is high due to lifting the fluid and also rods. Counterbalance is accomplished by placing weights directly on the beam in the smaller units, or by attaching weights to the rotating crank arm or by a combination of two. Recently, shifting the position the weight on the crank arm by a jack screw use for obtain counterbalance. On larger units air pressure is used to obtain counterbalance.

4.2.4.6 Polished Rod: it is the direct linkage between sucker rod string and surface equipment. Diameter of the sucker rod and size of the tubing limit the size of the polished rod.

4.2.4.7 Wellhead: A well head is maintaining the surface control of the well. Pumping wells need some pressure controlling devices to prevent leakage of the fluid and gas wellhead contains stuffing box for that purpose, consists of packing. This flexible material is housed in a box providing packing or sealing of pressure inside the tubing.

4.3 SRP APPLICATIONS

Conditions of the well will describe which material is used for the pump. Some corrosive environments need pumps with anti-corrosive materials. A designation system is helpful for identifying the materials used in pump build-up and application.

4.3.1 Pump Designations:

A classification system was adopted by the American Petroleum Institute [8]. First letter of abbreviated designation includes;

T: indicating tubing type

R: indicating rod type

Second letter of abbreviated designation includes;

W: indicating full barrel

L: indicating liner barrel

H: using a heavy barrel or metal plunger

P: indicating tubing pump using heavy barrel and soft pack plunger

S: indicating tubing wall barrel and a soft pack plunger

Third letter of abbreviated designation includes;

E: indicating use of an extension shoe and nipple

B: indicating stationary barrel with bottom hold-down

T: traveling barrel

Fourth letter of abbreviated designation includes;

C: indicating cup-type hold-down

M: indicating mechanical hold-down

4.3.2 Tubing Pumps

This application includes tubing type pumps using a heavy barrel or metal plunger and tubing type pumps using heavy barrel and soft pack plunger (TH, TP). Tubing pumps have greater production capacity than API insert pumps for the same tubing size and they are considered as heavy duty workhorse [8]. Because of their design tubing pumps have large fluid flow areas and they are adaptable for viscous fluids. Large capacity of fluid makes a tubing pump not suitable for deep wells as the weight of fluid column will be too much for the strength of the sucker rod. Design of tubing pumps results difficult install conditions and expensive repair cost as tubing must be pulled (Figure 4.2).

4.3.3 Traveling Barrel with Bottom Hold-Down Insert Pumps

In this application the plunger settled on the seating nipple on the tubing string and the barrel travels over it. The barrel movement causes an agitation around hold-down seal and prevents the sand settlement. Its design makes the traveling valve close while the pump not in motion and sand can not settle between barrel and plunger [8]. These properties make traveling barrel pumps a favorable choice for sandy wells. If the well is deviated there could be excessive wear between tubing and traveling barrel. Flow design of these pumps is not suitable for gassy wells (Figure 4.3).

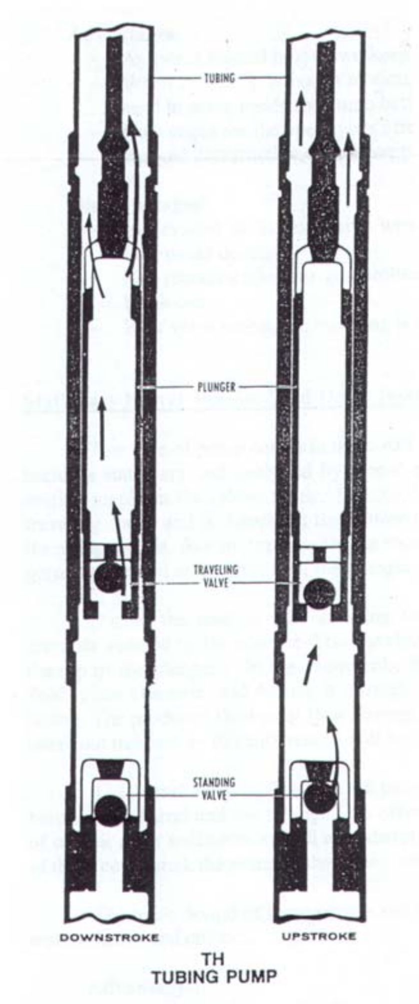

Figure 4.2 Tubing Pump (TH) [8]

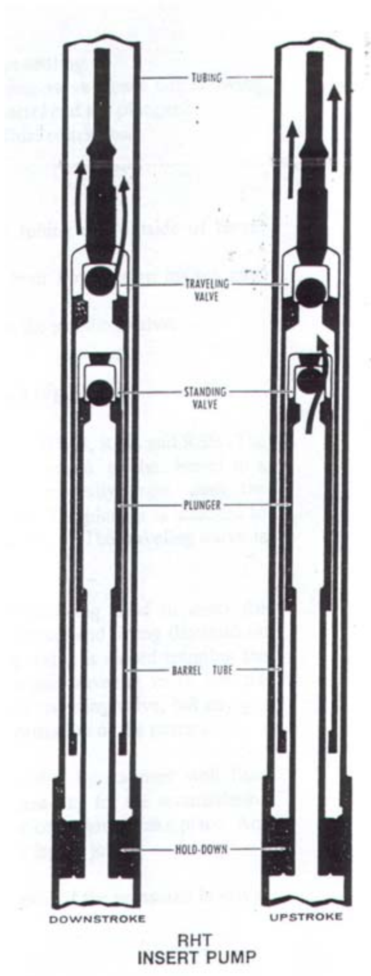

Figure 4.3 Insert pump (RHT) [8]

4.3.4 Stationary Barrel with Bottom Hold-Down Insert Pumps

Three pump configurations are in this type: rod type pumps with full barrel using stationary barrel with bottom hold-down (RWB), rod type pumps using a heavy plunger or metal plunger with stationary barrel with bottom hold down (RHB) and rod type pumps with thin wall barrel and a soft pack plunger using stationary barrel. Unlike the traveling barrel type standing valve is the larger valve of this design and the barrel located at the bottom of the well. The produced fluid must flow through the smaller traveling valve this difference can cause a gas break out but will not affect the operation. The space between barrel and the tubing is a suitable place for inactive well fluid which causes sand deposition and corrosion [8]. Compared with traveling barrel type stationary barrel types have more parts and becoming more expensive.

Stationary barrel with bottom hold-down unit pumps have less tendency to have pressure ruptured tubes and they can be used in deep wells. The change of gas foaming is reduced by detained the fluid friction (Figure 4.4).

4.3.5 Stationary Barrel with Top Hold-Down Insert Pumps

Rod type with full barrel using stationary barrel with top hold-down (RWA), rod type with a heavy barrel or metal plunger using stationary barrel with top hold-down (RHA) and rod type with thin wall barrel and a soft pack plunger using stationary barrel with top hold-down (RSA) are included in these type of pumps. In this type of pump application the barrel hangs from the hold-down unit. Suitable for wells with sand problems because its flow design do not let the sand to settle and sanding up the pump as the fluid is discharged immediately above the hold-down. On the down stroke, as the hold-down unit is placed at the top of the barrel the entire fluid load is supported by the standing valve. This load also affects the barrel tube and brings some strength limitations so this type of pump is not applicable for deep wells. In low fluid level conditions pump reported as stay longer below the liquid level as the standing valve positioned below the hold-down (Fig 4.5).

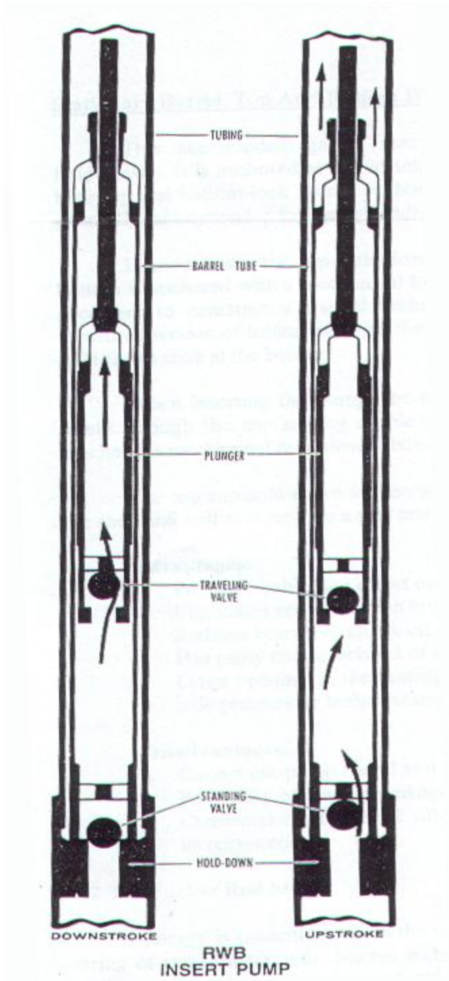

Figure 4.4 Insert Pumps (RWB)[8]

4.3.6 Stationary Barrel with Top and Bottom Hold-Down Insert Pumps

Rod type with full barrel using stationary barrel with top and bottom hold-down (RWAB) and rod type with a heavy barrel or metal plunger using stationary barrel with top hold-down (RHAB) are two applications of this type. In this combination the advantages of using bottom and top hold-down used without effected by their disadvantages.

In these pumps there is a need of constructing special tubing which consists of a tubing section between the cup seating nipple on top and mechanical hold-down shoe at the bottom (Figure 4.6).

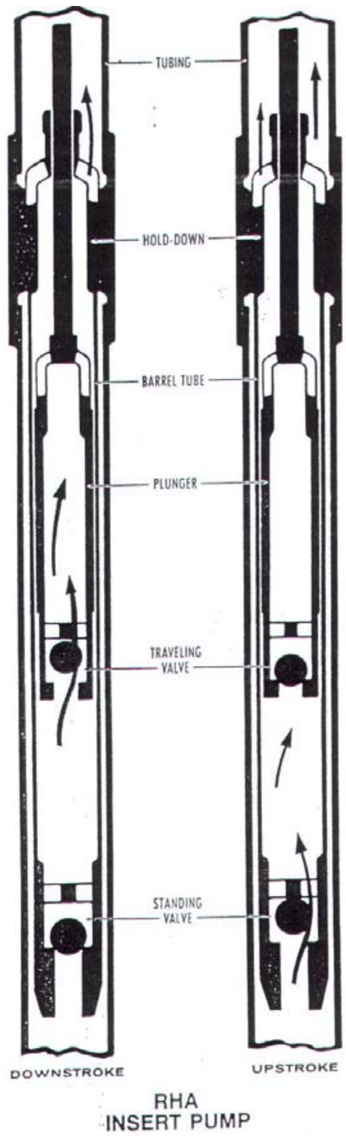

Figure 4.5 Insert Pumps (RHA) [8]

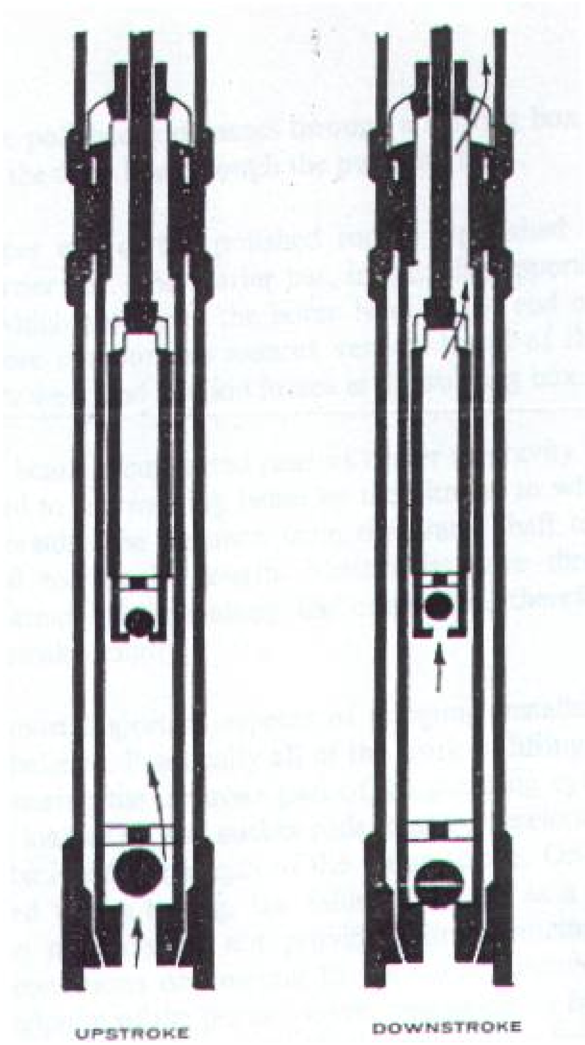

Figure 4.6 Insert Pump (RHAB) [8]

4.4 SRP PROBLEMS

Monitoring the equipments of a sucker rod system in the well is important as much as for an electrical submersible pump system. Sucker rod systems are classified as tubing pumps and the insert type pumps (rod pumps) as mentioned previously. Recording instruments are also two types to meet the requirements of systems. The pump dynagraph is used for insert type and the surface dynamometer is used for tubing pumps [8].

4.4.1 The Pump Dynagraph

As the recording unit if the dynagraph is set the rod string inside the well it is suitable for insert type pumps (Figure 4.7). The load carried by plunger and plunger stroke is recorded by the dynagraph during the cycle. Relative motion between the tubingand sucker rod string, is recorded on a card within the recording tube.

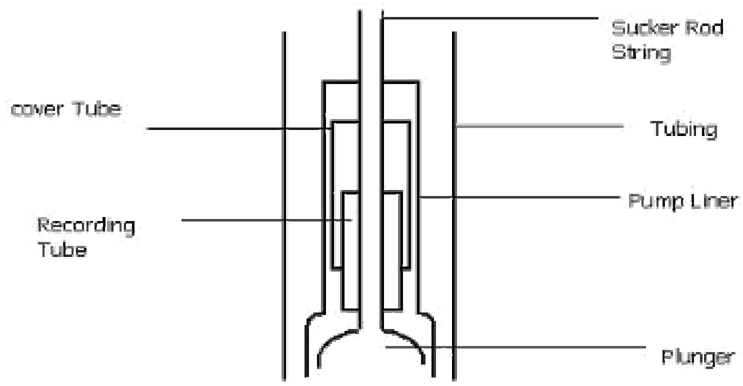

Figure 4.7 Diagrammatic Sketch of the Pump Dynagraph

Examples of typical pump dynagraph cards and some common problems are explained in the fallowing.

Figure 4.8 Ideal Pump Dynagraph Card [8]

Figure 4.8 represents the ideal pump dynagraph. The arrow in the Figure shows the upstroke direction. During the upstroke load on the plunger is increasing because of the static fluid load in the tubing. The increase in the load seen in the card during the upstroke is a result of this fluid column. The opposite condition is expected to be seen during the downstroke in an ideal situation.

During the upstroke free gas enters into the pump and it creates a resistance against the pump on the downstroke. In Figure 4.9 a gradual decrease in the load on the downstroke can be seen.

Figure 4.9 Pump Dynagraph Card in Case Presence of Free Gas [8]

Figure 4.10 Pump Dynagraph Card in Case of Fluid Pound [8]

Figure 4.10 is a record example of fluid pound case. Serious mechanical system failures may occur if there is a fluid pound problem in a well. That is a result of higher plunger displacement than the well capacity. As the plunger volume is not full of enough fluid a volume of low-pressure gas occurs. Like in the free gas condition free gas is compressed during the downstroke but this time pressure built up in the below of traveling valve is not sufficient to over come the load of the fluid in the fluid column. Stress in the rod string can be quickly dropped and forced shock occurs.

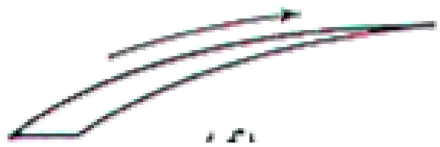

Figure 4.11 Pump Dynagraph Card in Case of Gas-Lock [8]

This is the condition which can occurs if no liquid can be pumped. Figure 4.11 is the dynagraph record of such situation. In the Figure no pump stroke can be seen. Reason for that can be very low volumetric efficiency which results no pumped liquid no valve action.

4.4.2 The Surface Dynamometer

Installation of a pump dynagraph and taking the recoveries needs pulling the rods and pump out of the well. If the well to be monitored is operating with tubing type pump it is not practical to use a dynagraph because of the design of the tubing pumps. For pulling the rod and pump it is compulsory to pull the tubing also. To monitor tubing pumps a device which placed in the surface not in well is more suitable, the surface dynamometer. In Figure 4.12 the location of a typical surface dynamometer can be seen.

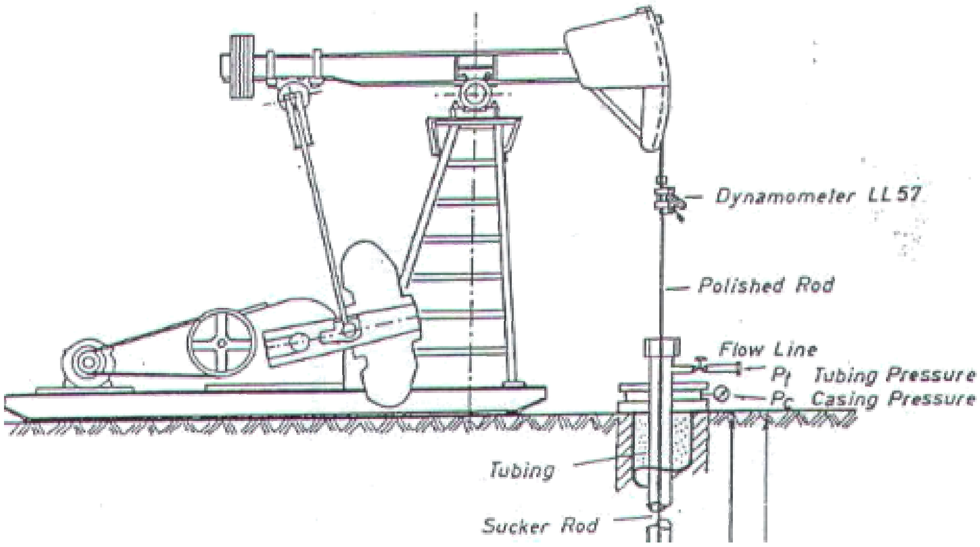

Figure 4.12 Location of Atypical Surface Dynamometer [8]

Place of the device enables it to be exposed to the total polished rod load. Any change in this load is recorded on a dynamometer card. In the Figure4.13 an ideal dynamometer card is illustrated. Between points A and B rods are in upstroke, between B and C load is transferring to standing valve. Downstroke period is from C to D and than load is transferred to the traveling valve.

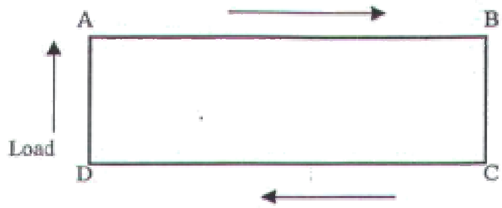

Figure 4.13 Ideal Surface Dynamometer Card [8]

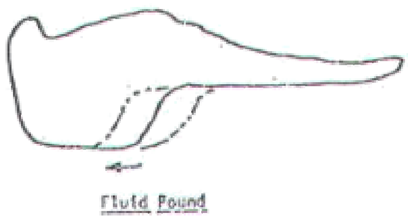

Figure 4.14 Surface Dynamometer Card in Case of Fluid Pound [8]

4.5 DESIGNING A SRP SYSTEM

4.5.1 Limitations

Location of the well is the main limitation factor for a SRP system especially in offshore. Depending on the rod size a sucker rod system can work at 7500 – 15000 ft. interval Intake capability is limited at 50 to 100 psi and gas occurrence above 50 % needs a proper designed pump [3, 5]. Wells with corrosion scale or paraffin will need special materials or chemicals which can be cost affective. Casing string, tubing diameter determine the rod size end even type of pump.

4.5.2 General Factors Effecting SRP Selection

4.5.2.1 Total Depth of Well: Effective depth range of sucker rod system is from 7500 ft to 15000 ft [3]. In deeper wells peak stress at the top of the rod string can be above the maximum permissible working stress of the rods being used. In a situation like this severe damages can occur in rod string.

4.5.2.2 Fluid Level from Surface: Fluid level has a linear relationship with rate if average specific gravity of fluid constant. In wells with high free gas percentage fluid level surveys will show the gas volume which can reduce the volumetric efficiency. Fluid level is an effective parameter in intake pressure calculations.

4.5.2.3 Fluid Gravity, API: In every steps of design procedure fluid gravity is effective as fluid characteristic determines the decisions. Manufacturers have pumping units for different API ^{o}.

4.5.2.4 Water Cut: As water cut effects the cumulative production, gross productivity index (PI) is also affected.

4.5.2.5 H2S, CO2 Percentages: Those corrosive molecules are important characteristics of a well for every pump systems. As they need special material usage, corrosives are cost effective properties. Operational difficulties may occur because of mechanical failures due to corrosion.

4.5.2.6 Sand and Gas Presence: Like corrosive molecules contaminants are cause both mechanic difficulties and economical burden. They need to be concerned while choosing the rods.

4.5.2.7 Volumetric Efficiency and Production Rate: Pump displacement calculations need these two parameters.

4.5.2.8 Pump Depth: Pump depth is very important for overall efficiency of the system as depth increment increase the stress at the top of the rod string.

4.5.2.9 Tubing Size and Anchored Tubing: Net lift of the fluid, plunger selection, rod size

4.5.2.10 Stroke Length: It is the distance that the plunger travels relative to the working barrel. That parameter effects the pump displacement.

4.5.2.11 Pumping Speed: As pump displacement and production is a time dependent value pumping speed adjustment will effect the production per day.

4.5.2.12 Pump Plunger Diameter: As the volume of the plunger depends on the cross sectional area of the pump plunger it is an affective factor in design procedure.

CHAPTER 5

STATEMENT OF PROBLEM

Although there are many alternatives of artificial lift method only sucker rod pump (SRP) and electrical submersible pumps (ESP) will be used in this study. Thirteen oil wells of R-field in Turkey will be used as case study. Nine of wells are still producing with SRP and the rests are producing with ESP. In this study, those wells will be redesigned for SRP and ESP systems to obtain enough data for comparison of both artificial lift methods. Design of each well will be performed by using LoadCalC software by Lufkin, and SubPUMP software by DSSC. After the design step economical evaluation of applications will be examined.

CHAPTER 6

METHODOLOGY

In this chapter the procedure which was used for the design of the ESP and SRP systems are represented. The data of R-field was taken from T.P.A.O. Recently the well number in this field is over two hundred and 47% of the wells are producing with a production of 52 bpd per well. Detailed information about the field and wells used in this study are given in chapter 8. One well, R-3 as an example, was chosen for describing the design steps of both systems.

6.1 ELECTRICAL SUBMERSIBLE SYTEM DESIGN

ESP system design is usually not so complicated if well data are reliable. While starting the design procedure it has to be known that enough well data was available. Abrasive well environment and power source information also affect the final decision of selecting equipments.

In the following, design procedure of an ESP system on R-3 well is given in detail.

Table 6.1 Casing and Tubing data for R-3 well

	OD, in.	ID, in.	Weight, lb/ft	Depth, ft.
Casing	5	4.494	13	4790
Tubing	2.875	2.441	6.5	4100

Table 6.2 Reservoir and production data for R-3 well

Reservoir Pressure (P_R), psi	1200
Well Flowing Pressure (P_{wf}), psi	1046
Bubble Point Pressure (P_{bp}), psi	325
Bottom Hole Temperature (T_b), ^oF	140
Well Head Temperature (T_{wh}), ^oF	100
Gas Oil Ratio (GOR), scf/stb	57
Water Cut (f_w), %	77
Oil API, ^{o}API	18
Oil Specific Gravity (γ_o)	0.946
Water Specific Gravity (γ_w)	1.02
Gas Specific Gravity (γ_g)	0.75
Oil Viscosity (μ_{oil}), cp	30
Present Production Rate (Q), bpd	346
Perforation Depth, ft	4790
Pump Setting Depth, ft	4100
Desired Production Rate (q), bpd	400

Step1: Pump Intake Pressure Calculations

Well's capacity is the primary element and starting point of the procedure [1]. Depending on the flow type in the well, related with the bubble point pressure (P_{bp}, psi) and well flowing pressure (P_{wf}, psi) relation, which method will be used to determine the production capacity was chosen. If the P_{wf} has a greater value than P_{bp} than fluid flow is similar to a single phase flow as gas will stay in its liquid form in the mixture. Smaller P_{wf} than P_{bp} is not capable of handling gas remain in the solution which means multi phase flow type. For both case there are different relations between pressure and production. To observe those relations inflow performance relation (IPR) curve, production rate versus pressure, are used. In this study, F.A.S.T VirtueWell software F.E.K.E.T.E was used to obtain the IPR curves of the selected wells. In this section R-3 well was used for describing the design steps, so only that well's IPR curve was represented, rest of them are given in appendix A.

P_{wf} = 1046 psi > P_{bp} = 325 psi, single phase flow expected, Productivity index (PI) method will be used [1];

$$PI = Q/(P_R - P_{wf}) \tag{6.1}$$

$$PI = 346/(1200 - 1046) = 2.25 bpd/psi$$

That relation between pressure and production was used to determine the new well flowing pressure (P_{wfd}, psi) at desired production.

New well flowing pressure at desired production rate (P_{wfd}) [1];

$$PI = q/(P_R - P_{wfd}) \tag{6.2}$$

$$2.25 = 400/(1200 - P_{wfd})$$

P_{wfd} = 1022 psi, still higher than P_{bp}

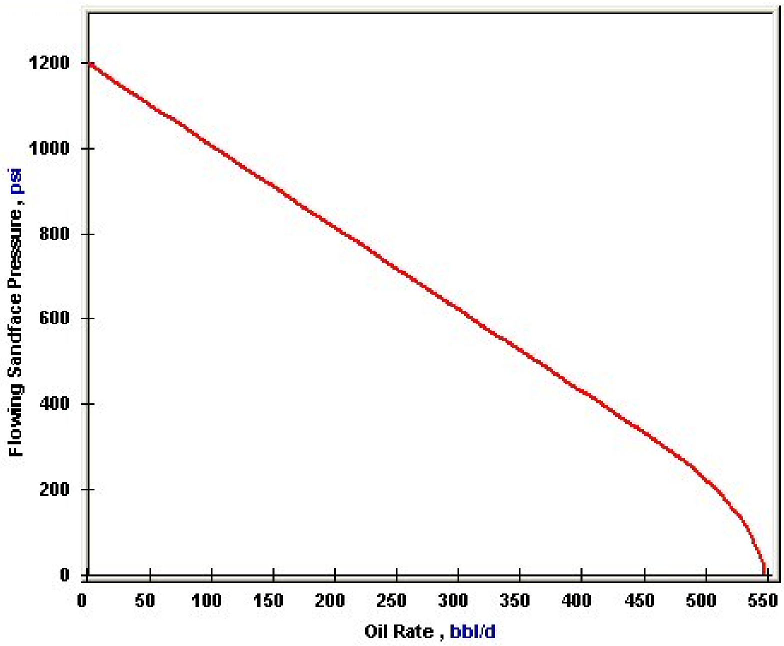

Figure 6.1 Inflow performance relation curve of well R-3 F.E.K.E.T.E

For well R-3 the chart represented in Figure 6.1 was used to check the calculated P_{wfd} and desired oil production. According to that chart oil rate was expected to be 95 bpd at 1022 psi.

As the fluid in the pump intake can be a mixture of oil, water and gas it was necessary to determine the composite specific gravity of the fluid entering to the pump. It is simply the sum of the weighted percentages of the produced fluids.

Composite Specific Gravity (γ_{comp}) [1];

$$\gamma_{\text{water in composition}} = f_w * \gamma_w = 0.77 * 1.02 = 0.79 \tag{6.3}$$

$$\gamma_{\text{oil in composition}} = (1 - f_w) * \gamma_o = (1 - 0.77) * 0.946 = 0.22 \tag{6.4}$$

$$\gamma_{comp} = \gamma_{\text{water in composition}} + \gamma_{\text{oil in composition}} = 0.79 + 0.22 = 1.01 \tag{6.5}$$

New well flowing pressure was correlated for the difference in pump setting depth and the datum point considering friction loss in the casing annulus. Correlated pressure was the pump in take pressure (PIP, psi) which is an important factor in selecting the pump unit [1].

$$\text{PIP} = P_{wfd} - \left[(\text{Datum Depth} - \text{Pump Depth}) * \gamma_{comp} / 2.31\right] \tag{6.6}$$

$$\text{PIP} = 1022 - \left[(4790 - 4100) * 1.01 / 2.31\right]$$

PIP = 721 psi still above the bubble point pressure.

Step 2: Gas Calculations

Equipment selection and design can be much more complicated in the case of presence of excessive amount of gas. From intake to discharge, volume, density and pressure values are changing in the liquid and gas mixture. Presence of gas at the discharge of the tubing can result a reduction in the required discharge pressure. Separation of the liquid and gas phase in the pump stages and slippage between phases can cause lower pump head than the required value. A submergence pressure below the bubble point to keep the gas all in liquid phase is the ideal case, in the reverse condition free gas volume must be separated from the other fluids by the help of gas separators. Depending on the amount of gas and well conditions combinations of equipments are available. Some equipments use the natural buoyancy of the fluids for separation while some can use the fluid velocity to produce a rotational flow for inducing radial separation of gas.

To decide which kind should be used it is necessary to determine the gas effect on fluid. If solution gas/oil ratio (R_S, scf/stb), the gas volume factor (B_g, bbl/Mcf) and the formation volume factor (B_o, rbbl/stb) are not available from the well data they should be calculated. Those ratios were used for calculating the amount of water oil and free gas in the solution, and their effect on the fluid characteristics.

Determining R_S with Standing's Equation [1];

$$R_S = \gamma_g * \left[(P_b/18) * \left(10^{0.0125 \ *API} / 10^{0.00091 \ *T} \right) \right]^{1.2048} \tag{6.7}$$

$$R_S = 0.75 * \left[(325/18) * \left(10^{0.0125 \ *18} / 10^{0.00091 \ *140} \right) \right]^{1.2048}$$

R_S = 32 scf/stb

Determining B_o with Standing's Equation [1];

$$B_o = 0.972 + 0.000147 * F^{1.175} \tag{6.8}$$

$$F = R_S * \left[\gamma_g / \gamma_o \right]^{0.5} + 1.25 * T \tag{6.9}$$

$$F = 32 * [0.75/0.946]^{0.5} + 1.25 * 140$$

F = 204

$B_o = 0.972 + 0.000147 * 204^{1.175}$

B_o = 1.05 rbbl/stb

Determining B_g;

$$B_g = 5.04 * z * T / PIP \tag{6.10}$$

Where; z = Gas compressibility factor (0.81 to 0.91) [1]

$$B_g = 5.04 * 0.85 * (460 + 140) / 721$$

B_g = 3.57 bbl/mcf

Total volume of fluids entering to the pump and percentage of free gas at the pump intake can be calculated by the help of Rs, B_o and B_g [1].

$$\text{Total Volume of Gas} = T_G = \text{BOPD} * \text{GOR} / 1000 \quad (6.11)$$

$$\text{BOPD} = 400 * f_o = 400 * (1 - 0.77) = 92 \text{ bpd}$$

$$T_G = 400 * (1 - 0.77) * 57 / 1000 = 5.2 \text{ Mcf}$$

$$T_G = 92 * 57 / 1000 = 5.2 \text{ Mcf}$$

$$\text{Solution Gas} = S_G = \text{BOPD} * R_S / 1000 \quad (6.12)$$

$$S_G = 92 * 32 / 1000 = 2.94 \text{ Mcf}$$

$$\text{Free Gas} = F_G = T_G - S_G \quad (6.13)$$

$$F_G = 5.24 - 2.94 = 2.30 \text{ Mcf}$$

$$\text{Volume of Oil at Pump Intake} = V_O = \text{BOPD} * B_O \quad (6.14)$$

$$V_O = 92 * 1.05 = 96.6 \text{ bpd}$$

From Figure 6.1 oil rate was estimated as 95 bpd and the calculated value was 96.6 bpd. That difference may be the result of non-sensitive chart reading.

$$\text{Volume of Free Gas at Pump Intake} = V_g = F_G * B_g \quad (6.15)$$

$$V_g = 2.30 * 3.57 = 8.21 \text{ bpd}$$

$$\text{Volume of Water at Pump Intake} = V_w = q * f_w \quad (6.16)$$

$$V_w = 400 * 0.77 = 308 \text{ bpd}$$

The total volume of fluid at pump intake:

$$V_T = V_o + V_g + V_w \qquad (6.17)$$

$$V_T = 96.6 + 8.21 + 308 = 413 \text{ bpd}$$

If the ratio of free gas volume to the volume of fluid is below 10 % than it would have little effect on pump performance means no need for gas separator, but it has an effect on density anyway.

$$\text{Free Gas Percentage} = V_g / V_T * 100 \qquad (6.18)$$

$$\text{Free Gas Percentage} = 8.21 / 413 * 100 = 2 \text{ \%}$$

As the percentage of gas at pump intake smaller than 10% by volume it is expected that pump performance will not be affected by gas, so no need for gas separator.

Step 3: Total Fluid Entering the Pump

Total Mass of Produced Fluid= TMPF [1]

$$\text{TMPF} = \begin{Bmatrix} \left[\text{BOPD} * \gamma_o + (q * f_w) * \gamma_w\right] * 62.4 * 5.6146 + \\ \left[\text{GOR} * \text{BOPD} * \gamma_g * 0.0752\right] \end{Bmatrix} \qquad (6.19)$$

$$\text{TMPF} = \begin{Bmatrix} \left[92 * 0.946 + (400 * 0.77) * 1.02\right] * 62.4 * 5.6146 + \\ \left[57 * 92 * 0.75 * 0.0752\right] \end{Bmatrix}$$

$$\text{TMPF} = 140854 \text{ lb/d}$$

Specific Gravity of Mixture= γ_{mix}

$$\gamma_{mix} = \text{TMPF} / (\text{BFPD} * 5.6146 * 62.44) \qquad (6.20)$$

$$\gamma_{mix} = 140854 / (413 * 5.6146 * 62.44) = 0.97$$

Step 4: Total Dynamic Head Calculations

In the design procedure another important step is the calculation of total dynamic head (TDH, ft). Total dynamic head is the feet of liquid being pumped. It is the sum of net well lift, well tubing friction loss, and well head discharge pressure (Figure 6.2) [1].

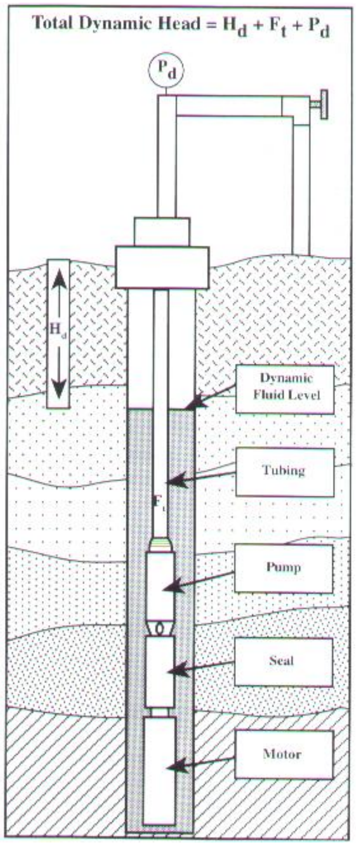

Figure 6.2 Total Dynamic Head [1]

$$TDH = H_d + F_t + P_d \tag{6.21}$$

H_d = The vertical distance between the estimated producing fluid level and surface, ft

F_t = Tubing friction loss (neglected)

P_d = Desired wellhead pressure, ft

$$H_d = \text{Pump Depth} - [PIP * 2.31/\gamma_{mix}] \tag{6.22}$$

$$H_d = 4100 - [721 * 2.31/0.97] = 2383 \text{ ft}$$

$$P_d = (100 \text{ psi} * 2.31 \text{ ft/psi})/\gamma_{mix} \tag{6.23}$$

P_d = 238 ft

TDH = 2383 + 238 = 2621 ft

Step 5: Equipment Selection

Pump performance charts are depending on the TDH, production and operating frequency. Selection of the pump unit was performed by using those charts prepared by the manufacturers. Rate of pumps at peak efficiencies were compared to find the closest one to the desired production rate. From manufacturer catalog [10] a pump unit was chosen which can handle that production for R-3 well and AN 550 REDA pump from 338 series was selected. Figure 6.2 is the pump performance chart at 50 Hz frequency for well R-3.

Once the type of the pump determined seal section and motor parts are generally from the same series with pump. Seal sections' horse power requirement depends on the TDH produced by the pump. Figure 6.3 represents a pump graph prepared for a one stage pump. From Figure 6.3, 12 ft head, 0.07 HP motor load and 45% pump only efficiency was obtained at 400 bpd production. Those values were for one stage pump so they need to be correlated. As calculated head value was 2621 ft the stage number of the selected pump unit should be 218, motor load for that number of stage should be 15 HP.

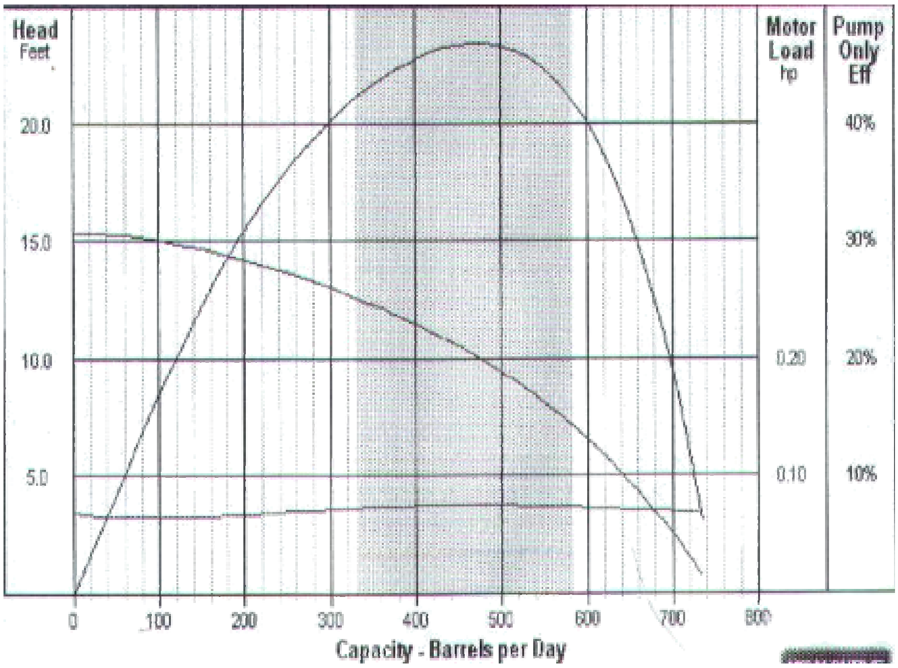

Figure 6.3 Pump Performance Graph for R-3 well [9]

The high voltage, low current, motors are reported as having lower cable losses and require small conductor size cable. High voltage motors can cause problems if excessive voltage losses are expected during starting [1]. Manufacturer recommend for the motor section was 375 series 87-Single type motor. As it has a horsepower range of 6-21 it can operate the pump of R-3 well. Seal section selection was done according to manufacturers' recommendations, series of 325-375 seal. Current carrying capacity of a cable is the selection criteria while selecting the cable. The cable with the voltage drop less than 30 volts per 1000 ft should be selected if its diameter is within the casing limits [1, 7]. In R-3 well polyethylene type cable was preferred. The cable can operate up to 180 ^{o}F which is suitable for R-3 well temperature of 140 ^{o}F [10]. Cables with higher operating temperatures are available but as the temperature limit increase cost of the item is also increase.

6.2 CONVENTIONAL SUCKER ROD PUMPING SYTEM DESIGN WITH API RP 11L RECOMMENDED PRACTICE [11]

Design procedure of a conventional sucker rod pump system should start with a preliminary selection of the components. By the help of the formulas, Tables and Figures operating characteristics of the selected units are determined for the specified well conditions. Preliminary selected components have some limitations like, stress, load ratings, and volumes. Calculated operating characteristics should be within those limits, if not the procedure must be restart by changing the preliminary selected components. To reach the optimum selection more than one calculation of operating characteristics is necessary.

For a design calculation of conventional sucker rod system following data must be known or at least assumed; fluid Level (H), ft, pump depth (L), ft, pumping speed (N), spm, length of surface stroke (S), in, pump plunger diameter (D), in, specific gravity of the fluid (G), nominal tubing diameter, in, hanging condition of tubing, anchored or not, sucker rod size, in.

Table 6.3 Tubing data for R-3 well

OD in	ID in	Nominal Size in	Cross Sectional Area (A_t) in^2	Weight (W_t) lb/ft	Anchored	Depth ft
2.875	2.441	2 1/2	1.812	6.5	No	4100

Table 6.4 Production data for R-3 well

Fluid Level (H), ft	2240
Pump Depth (L), ft	4100
Specific Gravity of Fluid (γ)	0.946
Desired Production Rate (q), bpd	400

Step 1: Determining Rod and Plunger Sizes:

While selecting the initial components some simplified Tables and Figures are used. Those Tables are developed from the conventional pumping equations with the assumptions; lifted fluid has a specific gravity of 1 and pump setting depth is equal to the working fluid level. In the example design of R-3 well Table 6.5 was used for determining rod sizes, pumping speed and plunger size. Depending on the nominal tubing size and pump setting depth (2 ½ in and 4100 ft);

Plunger Diameter (D), in = 1.75

Rod Sizes, in = 3/4, 7/8

Stroke Length (S), in = 64

Pumping Speed (N), spm = 18

Table 6.5 Design data for API size 160 units with 64-in stroke [8]

Pump Depth ft	Plunger Size in	Tubing Size in	Rod Sizes in	Pumping Speed spm
2000-2200	$2^{3/4}$	3	7/8	24-19
2200-2400	$2^{1/2}$	3	7/8	23-19
2400-3000	$2^{1/4}$	$2^{1/2}$	3/4-7/8	23-19
3000-3600	2	$2^{1/2}$	3/4-7/8	23-18
3600-4200	$1^{3/4}$	$2^{1/2}$	3/4-7/8	22-17
4200-5400	$1^{1/2}$	2	5/8-3/4-7/8	21-17
5400-6700	$1^{1/4}$	2	5/8-3/4-7/8	19-15
6700-7750	1	2	5/8-3/4-7/8	17-15

Using tubing size and pump depth data, plunger size, rod sizes, pumping speed is obtained beside stroke length and API size of the unit. Rod weight (W_r, lb/ft), rod elastic constant (E_r, in/lb-ft), tubing elastic constant (E_t, in/lb-ft), frequency factor (F_c) and percentages of the rods are obtained from Table 6.6 and Table 6.7. If tubing is anchored E_t is not necessary.

Table 6.6 Rod and pump data used in example design of well R-3 [11]

Rod No.	Plunger Diameter D in	Rod Weight W_r lb/ft	Elastic Constant E_r in/lb-ft	Freq. Factor F_c	Rod String, % of each size				
					1 in	7/8 in	3/4 in	5/8 in	1/2 in
76	1.75	1.855	$7.95*10^{-7}$	1.088	-	37.5	62.5	-	-

Rod No. in this Table refers to the largest and smallest rod size in eights of an inch. For example, Rod No 76 is a two way taper of 7/8 and 6/8.

Table 6.7 Tubing data of example well R-3 [8]

Tubing Size in	Outside Diameter OD in	Inside Diameter ID in	Metal Area At in2	Elastic Constant Et in/lb-ft
11/2	1.900	1.610	0.800	0.500*10-6
2	2.375	1.995	1.304	0.307*10-6
21/2	2.875	2.441	1.812	0.221*10-6
3	3.500	2.992	2.590	0.154*10-6
31/2	4.000	3.476	3.077	0.130*10-6
4	4.500	3.958	3.601	0.111*10-6

Step 2: Calculation of Non-Dimensional Parameters:

Next step in API RP 11L recommended practice is the calculation of non-dimensional variables. Those variables are rod stretch (F_o), rod stroke (Sk_r), spring constant for rod ($1/k_r$), spring constant for tubing ($1/k_t$) and dimensionless pumping speed (N/N_o').

$$\text{Rod Stretch} = F_o = 0.340 * \gamma * D^2 * H \tag{6.24}$$

$$F_o = 0.340 * 0.946 * 1.75^2 * 2240 = 2206 \text{ lb}$$

$$\text{Rod Spring Constant} = 1/k_r = E_r * L \tag{6.25}$$

$$1/k_r = 7.95*10^{-7}*4100 = 0.0033 \text{ in/lb}$$

$$\text{Rod Stroke} = Sk_r = S/(1/k_r) \tag{6.26}$$

$$Sk_r = 64/0.0033 = 19394 \text{ lb}$$

$$F_o / Sk_r = 2206/19394 = 0.11 \tag{6.27}$$

$$N/N_o = N*L/245000 \tag{6.28}$$

$$N/N_o = 18*4100/245000 = 0.301$$

$$\text{Pumping Speed} = N/N_o^{'} = (N/N_o)/F_c \tag{6.29}$$

$F_c = 1.088$ from Table 6.6

$$N/N_o^{'} = 0.301/1.088 = 0.277$$

$$\text{Tubing Spring Constant} = 1/k_t = E_t * L \tag{6.30}$$

$E_t = 0.221*10^{-6}$ from Table 6.7

$$1/k_t = 0.221*10^{-6}*4100 = 0.0009 \text{ in/lb}$$

Step 3: Calculation of Plunger Stroke and Pump Displacement:

Figure 6.4 was used by the help of F_o/Sk_r and N/N_o' calculated values to obtain plunger stroke factor (S_p/S) to calculate the plunger stroke which is an effective parameter in pump displacement (PD, bpd) equation.

$S_p/S = 1.05$ is obtained from Figure 6.4

$$\text{Plunger Stroke} = S_p = [(S_p/S)*S] - [F_o*1/k_t] \tag{6.31}$$

$$S_p = [1.05*64] - [2206*0.0009] = 65 \text{ in}$$

Pump displacement is a check point to evaluate the known or assumed requirements if the calculated value fails to satisfy the desired value than assumed data must be modified.

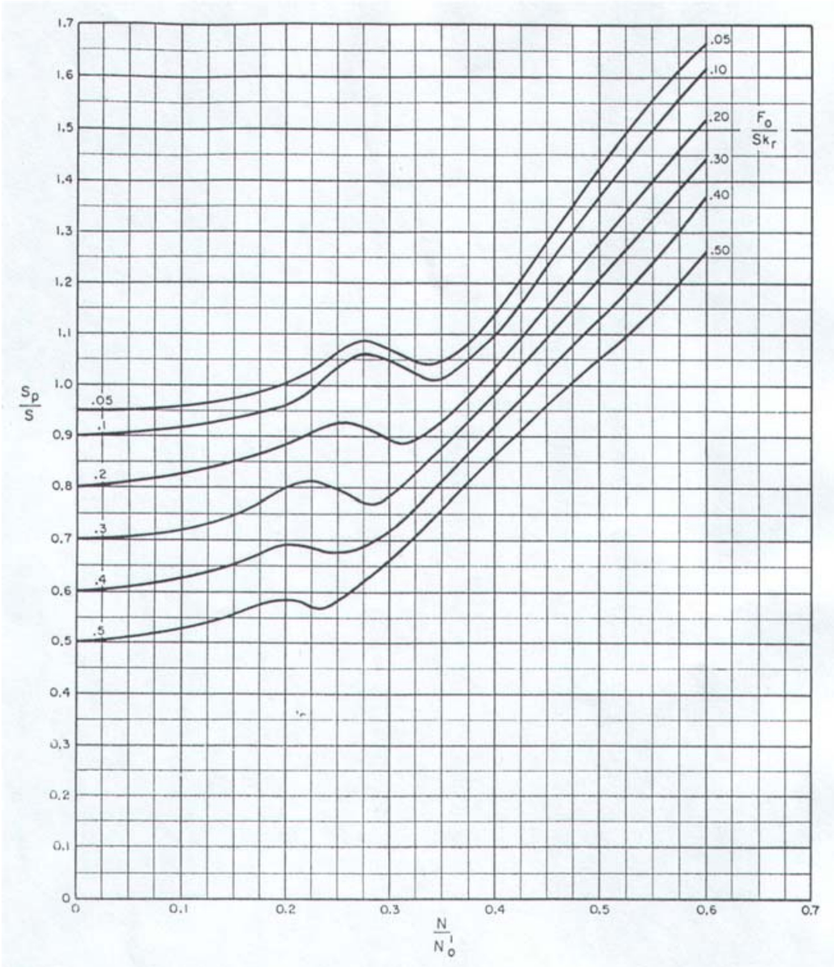

Figure 6.4 Plunger stroke factor [11]

$$\text{Pump Displacement} = PD = 0.1166 * S_p * N * D^2 P \tag{6.32}$$

$$PD = 0.1166 * 65 * 18 * 1.75^2 = 418 \text{ bpd}$$

$$\text{Weight of Rod} = W = W_r * L \tag{6.33}$$

$$W = 1.855 * 4100 = 7606 \text{ lb}$$

$$\text{Weight of Rod in Fluid} = W_{rf} = W * [1 - (0.128 * \gamma)] \tag{6.34}$$

$$W_{rf} = 7606 * [1 - (0.128 * 0.946)] = 6685 \text{ lb}$$

Step 4: Determining Non-Dimensional Parameters:

Other non-dimensional parameters are peak polished rod load (F_1/Sk_r), minimum polished rod load (F_2/Sk_r), peak torque ($2T/S^2k_r$), polished rod horse power (F_3/Sk_r) and adjustment for peak load (Ta). Those factors obtained from Figure 6.5 through 6.9 and they were used to calculate the operating characteristics.

Peak Polished Rod Load Factor: $F_1/Sk_r = 0.3$ is obtained from Figure 6.5

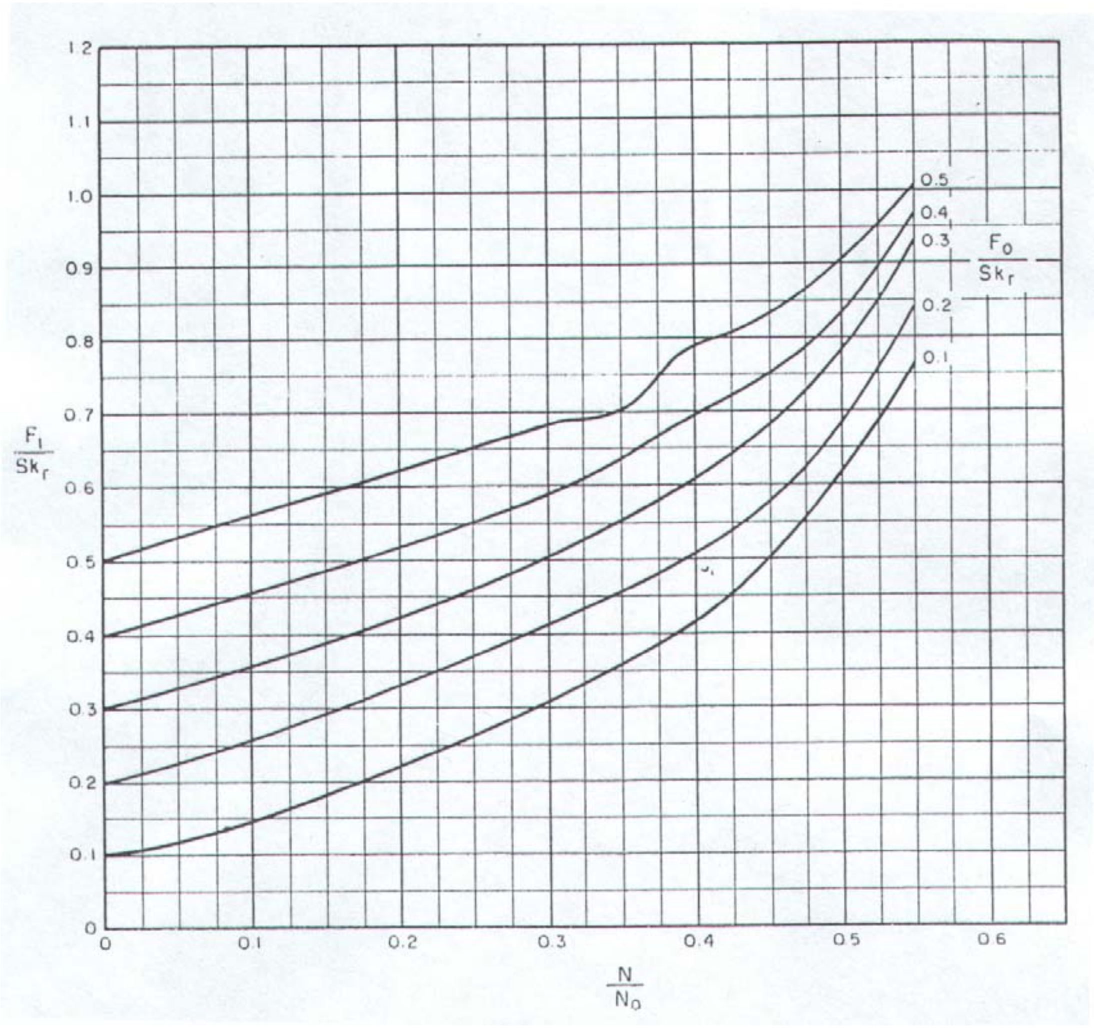

Figure 6.5 Peak polished rod load factor [11]

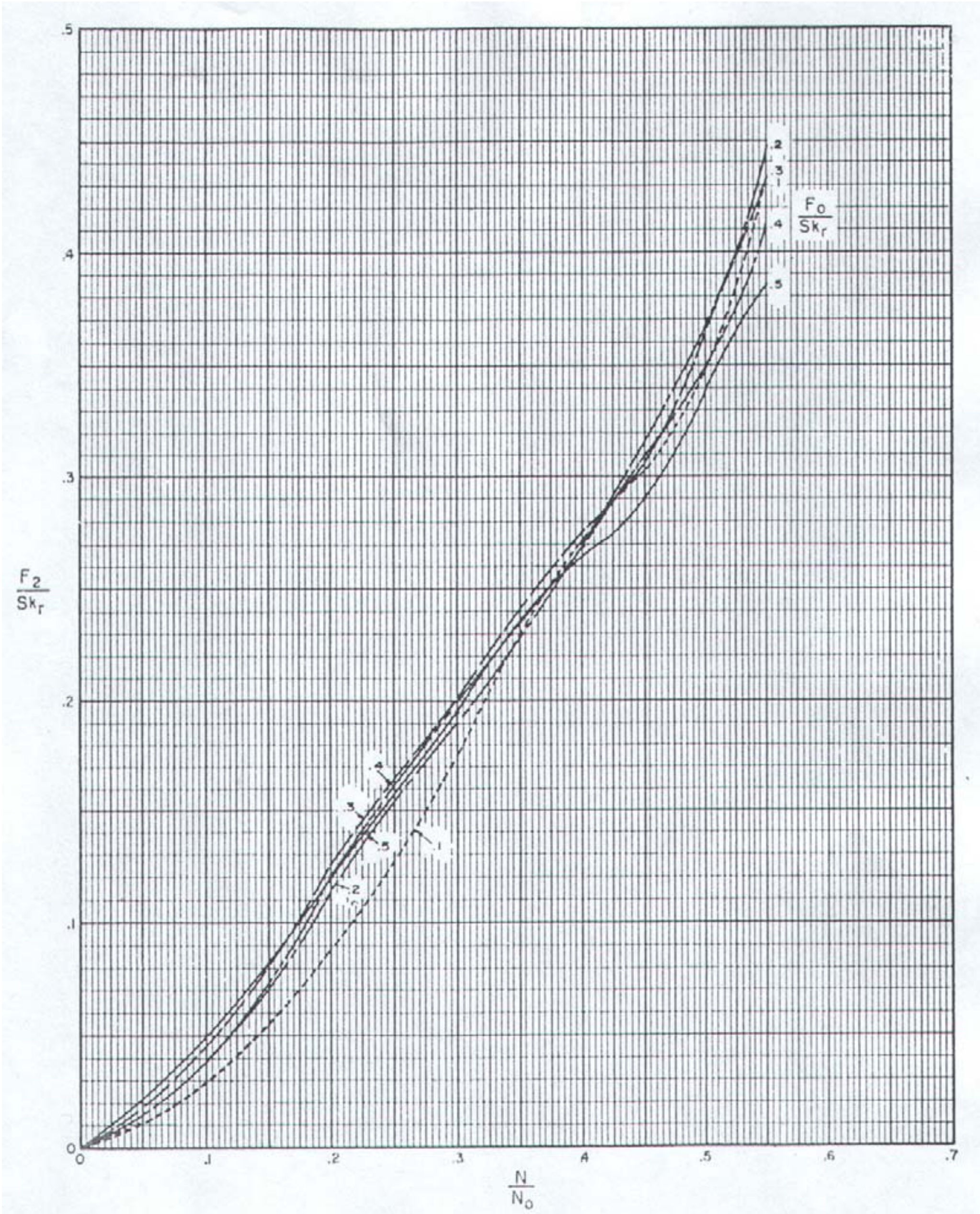

Figure 6.6 Minimum polished rod load factor [11]

Minimum Polished Rod Load Factor: $F_2/Sk_r = 0.175$ is obtained from Figure 6.6

Peak Torque Factor: $2T/S^2k_r = 0.26$ from Figure 6.7

Peak torque for values of $W_{rf} / Sk_r = 3$, torque adjustment is not necessary, for other values of W_{rf} / Sk_r different than 3 need torque adjustment.

$W_{rf} / Sk_r = 6685 / 19394 = 0.35$, in well R-3so torque adjustment is needed.

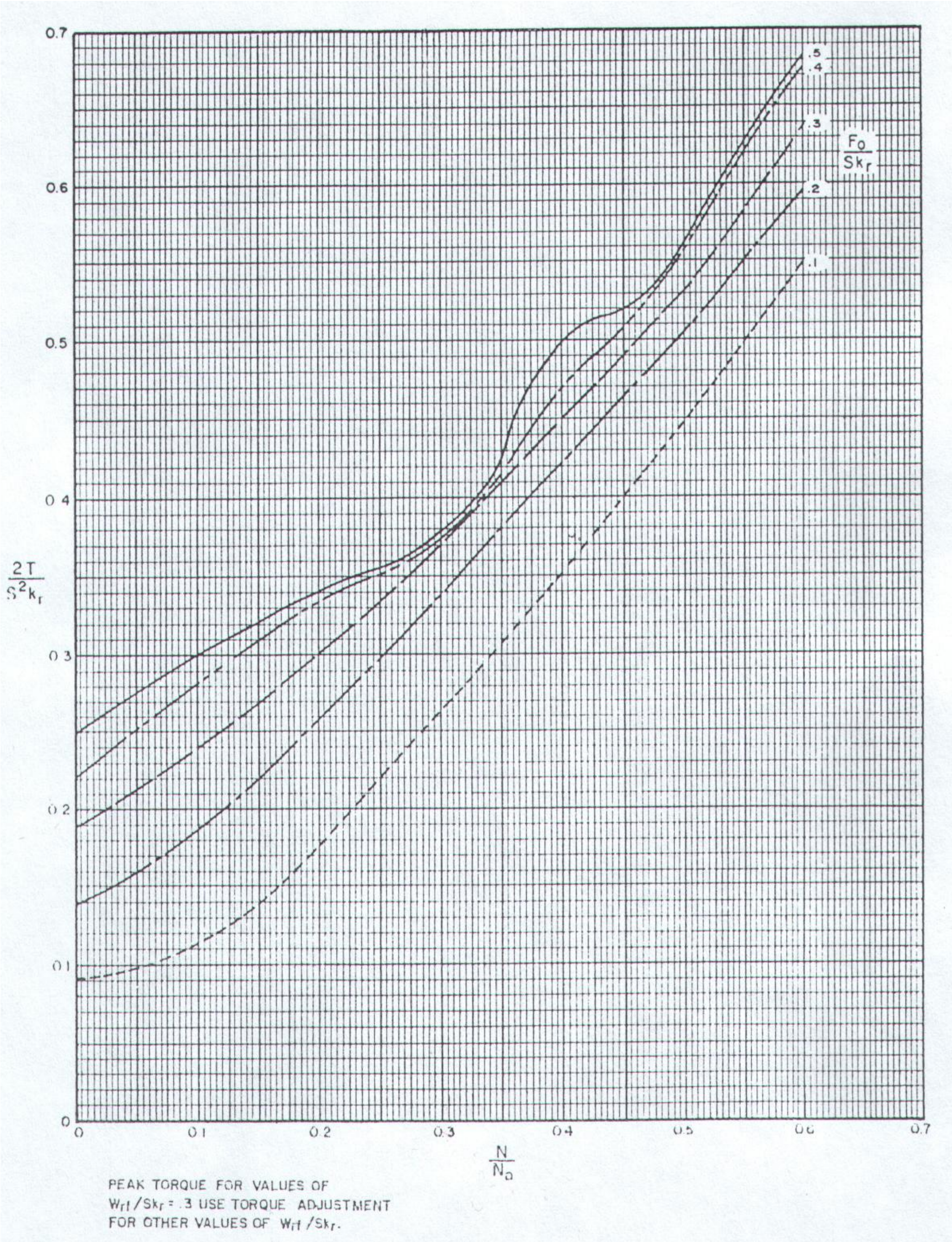

Figure 6. 7 Peak torque factor [11]

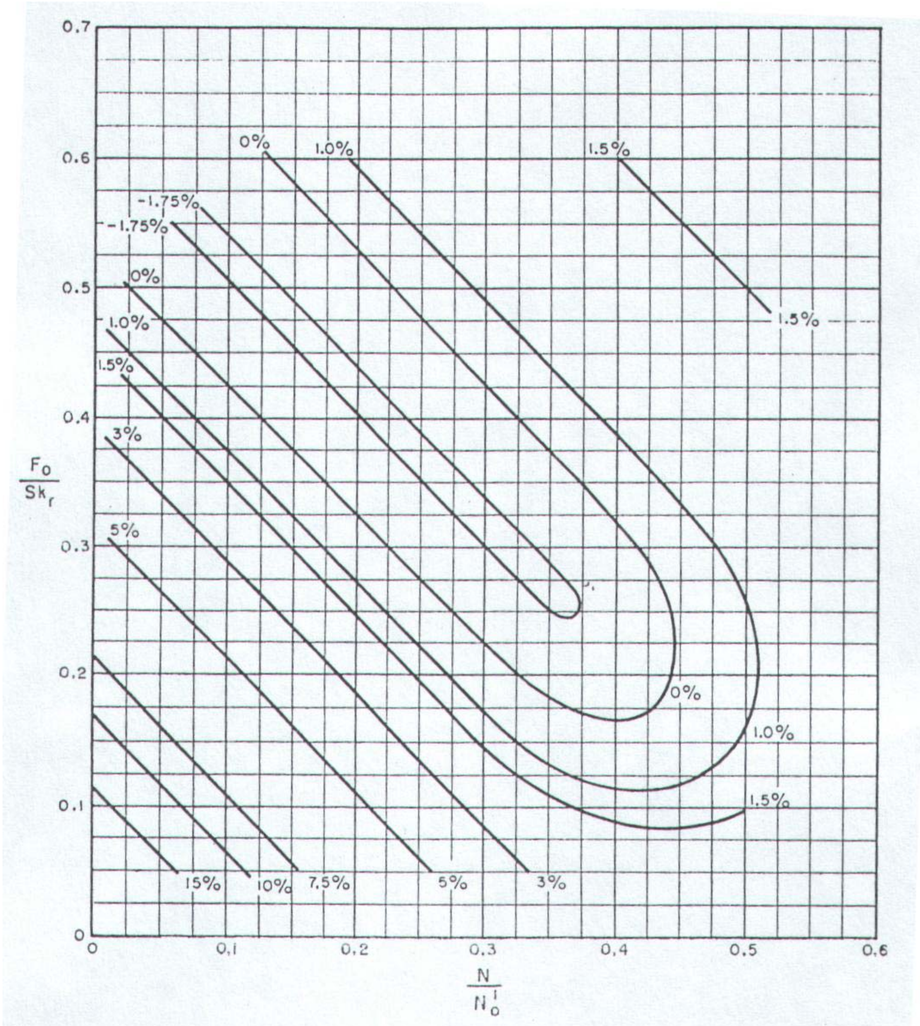

Figure 6.8 Peak load adjustment [11]

Using N/N_o' and F_o/Sk_r which were calculated before, the percentage indicated on Figure 6.8 was found as 3%.

The percentage obtained from Figure 6.8 will be multiplied by:

$$\text{Multiplication Factor} = (W_{rf} / Sk_r - 0.3)/0.1 \qquad (6.35)$$

$$\text{Multiplication Factor} = (0.35 - 0.3) / 0.1 = 0.5$$

$$\text{Total Adjustment} = (\% \text{ from figure } 6.5) * \text{Multiplication Factor} \qquad (6.36)$$

$$\text{Total Adjustment} = 0.03 * 0.5 = 0.015$$

$$\text{Peak Load Adjustment}: T_a = 1 + \text{Total Adjustment} \qquad (6.37)$$

$$T_a = 1 + 0.015 = 1.015$$

If W_{rf} / Sk_r is smaller value than 0.3 than total adjustment will be negative.

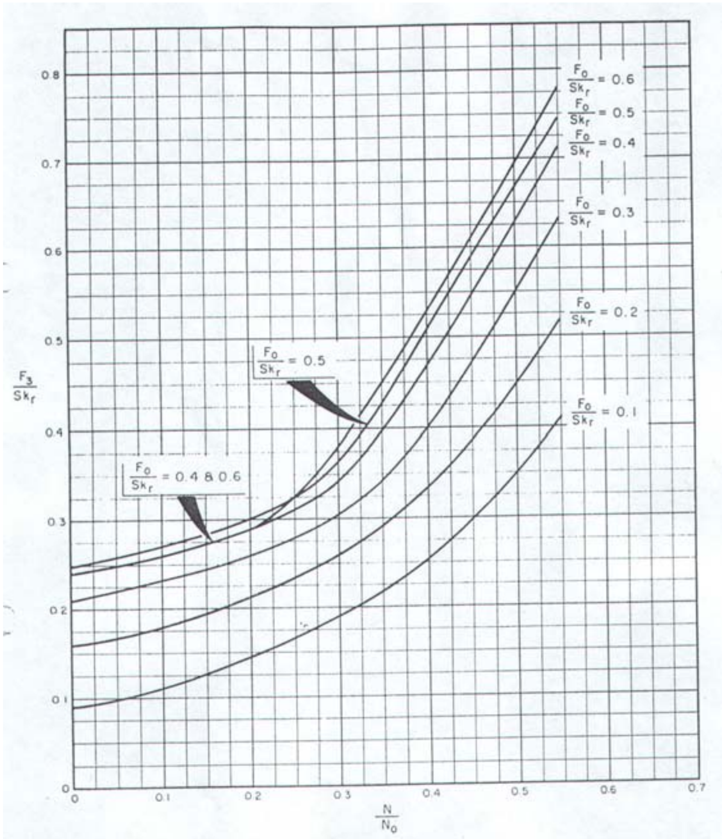

Figure 6.9 Polished rod horse power factor [11]

Polished Rod Horse Power Factor: $F_3/Sk_r = 0.19$ is obtained from Figure 6.9

Step 5: Calculation of Operating Characteristics

Peak polished rod load (PPRL, lb), minimum polished rod load (MPRL, lb), peak torque (PT, lb-in), polished rod horse power (PRHP, hp) and counterbalance effect (CBE, lb) are the final values that were obtained at the end of the procedure. Components of a conventional sucker rod pump system should meet those load values.

$$PPRL = W_{rf} + \left[\left(F_1 / Sk_r \right) * Sk_r \right] \tag{6.38}$$

$$PPRL = 6685 + [0.3 * 19394] = 12503 \text{ lb}$$

$$MPRL = W_{rf} + [(F_2 / Sk_r) * Sk_r] \qquad (6.39)$$

$$MPRL = 6685 + [0.175 * 19394] = 7025 \text{ lb}$$

$$PT = (2T / Sk_r) * Sk_r * S / 2 * T_a \qquad (6.40)$$

$$PT = 0.26 * 19394 * 64/2 * 1.015 = 163778 \text{ lb}$$

$$PRHP = (F_3 / Sk_r) * Sk_r * S * N * 2.53 * 10^{-6} \qquad (6.41)$$

$$PRHP = 0.19 * 19394 * 64 * 18 * 2.53 * 10 - 6 = 11 \text{ hp}$$

Counter Balance Effect:

$$CBE = 1.06 * (W_{rf} + 1/2 * F_o) \qquad (6.42)$$

$$CBE = 1.06 * (6685 + 1/2 * 2206) = 8255 \text{ lb}$$

Step 6: Equipment Selection

Pump selection is depending on load factors. Manufacturers are preparing their pump notifications as the pump can be easily notified according to the load standards. For the R-3 well C-320D-213-86 pump unit was selected from the LUFKIN catalog [12]. In this notification first two numbers are representing load limits of the unit, while the last number is the maximum stroke length of the unit. So, C-320D-213-86 is a unit having a maximum polished rod limit of 21300 lb which can operate up to 320 000 lb torques and its maximum stroke length is 86 inches [12]. Comparing those limits with the calculated ones shows the selected pump is an appropriate alternative for R-3 well. Counterbalance or counterweight selection depends on the selected pump unit. Counterbalance can have different counterweight effect at different stroke length so it was necessary to calculate the effect of a weight in preliminary determined stroke length. For R-3 well as ideal counterbalance effect calculated as

8255 lb it is desired for the selected one provide at least that much of load. From manufacturers catalog [12] 4 No. 2RO Counterbalance was selected with a counterbalance effect of 10154 lb which is above the calculated value.

4 No. 2RO Counterweight has a structural unbalance of +450 lb and a maximum of 13490 lb counterbalance weight (W_c) at 86 in strokes. To obtain the effect at 64 in stroke:

$$4 \text{ No. 2RO Counterweight effect} = [13490-450] * 64/86 + 450 = 10154 \text{ lb}$$

Rod percentages represent the length percentages of the rods in the well. 7/8 inches rod is 37.5 % of 4100 ft and 3/4 inches rod is 62.5% of pump setting depth. A single rod length is generally 25 ft, so rod lengths of R-3 well were adjusted for the 25 ft increment. 1550 ft was decided as the 7/8 inches rod length while 2550 ft was the 3/4 inches rod length.

CHAPTER 7

ECONOMICAL EVALUATION

Thirteen wells of R-field of T.P.A.O. in Turkey were used for the ESP and SRP design applications, and their designs were performed by already developed softwares. In the previous sections details of the design steps are given. In this chapter economic analysis part of the study is represented. All information, including costs of the personnel, maintenance and equipment costs were gathered from Production Group of Turkish Petroleum Corporation (T.P.A.O.) [13].

Economic evaluation was based on two cases. In case 1 only 9 wells were assumed to be produced with SRP and ESP systems. While in case 2, those four wells that were not produced in the first case, were assumed to be producing only with SRP. Table 7.1 briefly explains the artificial lift applications on 13 wells. Wells 2, 4, 7 and 8 were not producing in case 1 as their production capacities are not enough for ESP application.

Table 7.1 Artificial Lift Applications of R- field wells

Well No:	CASE 1		CASE 2		Present Status
	Case 1-A	Case 1-B	Case 2-A	Case 2-B	
R-1	SRP	ESP	SRP	ESP	SRP
R-2	not operating	not operating	SRP	SRP	SRP
R-3	SRP	ESP	SRP	ESP	SRP
R-4	not operating	not operating	SRP	SRP	SRP
R-5	SRP	ESP	SRP	ESP	ESP
R-6	SRP	ESP	SRP	ESP	ESP
R-7	not operating	not operating	SRP	SRP	SRP
R-8	not operating	not operating	SRP	SRP	SRP
R-9	SRP	ESP	SRP	ESP	SRP
R-10	SRP	ESP	SRP	ESP	ESP
R-11	SRP	ESP	SRP	ESP	SRP
R-12	SRP	ESP	SRP	ESP	ESP
R-13	SRP	ESP	SRP	ESP	SRP

To accomplish the economic evaluation, income and cost items of the production operation should be established.

Step-1: Determining income parameters

Petroleum industry includes an inter-connected system which starts with petroleum research than production and continuing with refinery, delivery, distribution and storage. In this relation crude oil price is the concern of the study. Petroleum consumption and exploration of new wells are the primary factors affecting the oil prices. But political events are also important in oil price as they can result in shortage or oversupply. Figure 7.1 represents the change in oil price with events occurred in the world. Beginning from 2004, ten years period of evaluation was made in this study. According to the International Energy Agency's (IEA) by 2010 word demand for crude oil could increase by 40 percent and crude oil prices will rise gradually to 28 $ per barrel in 2005 and remain flat for the rest of ten years [14].

However, today's prices are not match this forecast as the crude oil prices rises up to 45 $/barrel, an average of 21 $ per barrel of oil was used in this study as it is a world average of past 56 years. If the crude oil price will be higher than this assumption, higher rate of returns will be its effect on the result of this study.

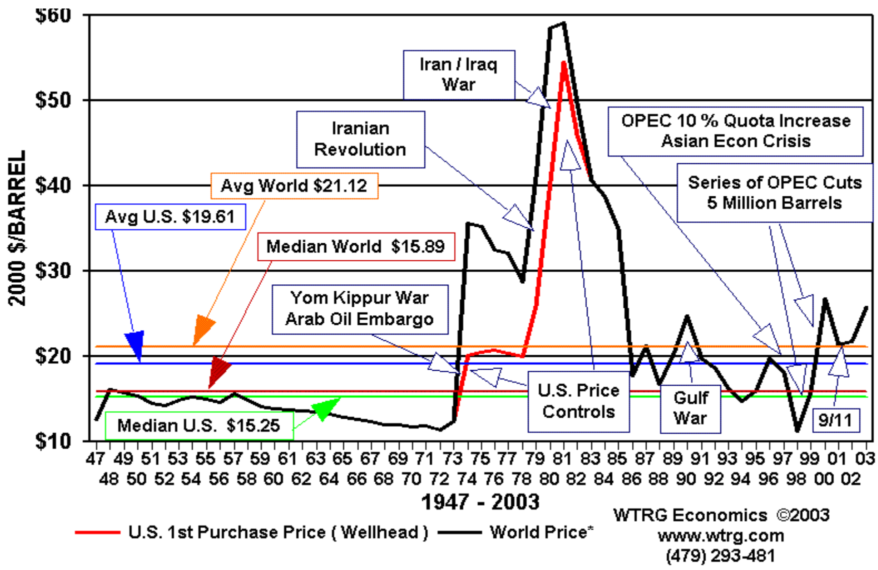

Figure 7. 1 Change in oil price in the world 1947-2003 periods [16].

Step-2: Cost items

Disbursements include personnel payments, maintenance expense, energy costs, tax, insurance, royalty. Initial investments are also included in disbursements and they are the sum of the prices of the units that are used in two artificial lift systems. SRP unit prices are given in appendix C.1 through C.3 and ESP unit prices are given in appendix C.4 through C.7. Personnel payment was 3 $ per barrel of oil, and maintenance expense was 5 $ per barrel of oil produced plus equipment replacement cost. In SRP systems replacement of the pump unit in every year was recommended by T.P.A.O [13]. But for ESP systems this period is three years. Besides the equipment cost, replacement expense also includes the daily cost of the work over rig, used for replacing the equipments, as 4000 $ and the operation assumed completed within one day. 38 percent of the income was paid to the government as tax and 12.5 of the yearly production oil were given as royalty. Besides, 5 percent of the income was used as insurance. The difference between income and disbursements is net cash flow. Economic comparisons of cases were performed based on recognizing the time value of the money. Rate of returns (ROR), the interest rate makes the present value of net receipts equal to the present value of investments, of each project were calculated aiming an economic evaluation.

The relation between present worth and future worth of a net cash flow expressed as [16]:

$$F = P \times (i+1)^n \tag{7.1}$$

Where

i: Ratio between interest payable at the end of a year and money owned at the beginning, %

n: number of interest periods, (10 years in this study)

P: Present sum of money (Present Worth), $

F: Sum of money at the end of n equal to P with i (Future Worth), $

$$P/F = \frac{1}{(i+1)^n} \tag{7.2}$$

Where

P/F: The single payment present worth factor

Multiplication of the net cash flow of each year with the single payment present worth factor will give the present worth of that money at chosen interest rate (i, %). As the definition implies the interest rate makes the present value of net receipts equal to the present value of investments is rate of return. Thus, sum of present worth versus different interest rates, 5 %, 10 % and 20 %, was plotted. Trend lines of those charts were expected to be intersecting with interest rate axis (x-axis), which means the present value of the net receipts equal to the present value of investment at that point. Tabulation of those calculations is given in the appendix D.

CHAPTER 8

RESULTS AND DISCUSSION

8.1. FIELD AND WELL DATA

Field and well data used in this study are obtained from Production Group of T.P.A.O [13]. Some of the reservoir properties and production data are represented in table 8.1. In table 8.2 well data used in this study are given. Although the well number is over two hundred, only 47% of the wells are producing nowadays with a production of 52 bpd per well. According to reports the cumulative petroleum production is about 72 MMstb

Table 8.1 Field Data of R-field [13]

Producing Since	15-07-1948
Production Mechanism	Water Drive
Original Reservoir Pressure, psi	1300
Reservoir Temperature, ^oF	140
Average Porosity, %	14
Average Permeability, md	50
Water Salinity, ppm	27972
API Gravity, ^oAPI	18
Oil Specific Gravity	0.9460
Oil Viscosity, cp	30
Bubble Point Pressure, psi	325
Gas/Oil Ratio, scf/stb	57
Original Oil in Place, MMstb	600
Total Number of Wells	232
Producing Wells	109
Daily Oil Production, stb/d	5 680

Table 8.2 Production and Reservoir Data of R Wells

Well	Total Fluid Rate bpd	Water %	Oil bpd	Wellhead Pressure psi	Reservoir Pressure psi	Bottomhole Flowing Pressure psi	Productivity Index bpd/psi
R-1	124	64,0	45	250	1200	244	0.13
R-2	36	44,0	20	150	1200	167	0.03
R-3	346	77,0	80	60	1200	1046	2.25
R-4	20	40,0	12	120	1200	473	0.03
R-5	936	85,0	140	180	1200	391	1.16
R-6	1182	85,0	177	200	1200	991	5.65
R-7	28	75,0	7	200	1200	696	0.06
R-8	45	51,0	22	240	1200	85	0.04
R-9	438	81,0	83	250	1200	1094	4.13
R-10	1050	75,0	263	270	1200	616	1.80
R-11	100	70,0	30	200	1200	551	0.15
R-12	954	83,0	162	100	1200	689	1.87
R-13	240	94,0	14	100	1300	1143	1.53

Table 8.3 Well Completion Data of R Wells

Well	Casing Outer Diameter in	Casing Depth ft (m)	Casing Weight lb/ft	Perforation Interval ft (m)	Datum Depth ft (m)
R-1	7	4246 (1294)	26	Open	4456 (1358)
R-2	7	4600 (1402)	26	Open	4682 (1427)
R-3	5	4232 (1290)	13	Open	4790 (1460)
R-4	5	4492 (1369)	18	Open	4757 (1450)
R-5	6 5/8	4505 (1373)	24	4305-4331 (1312-1320)	4567 (1392)
R-6	6 5/8	4898 (1493)	24	4646-4665 (1416-1422)	4580 (1396)
R-7	6 5/8	4774 (1455)	20	4570-4590 (1393-1399)	4633 (1412)
R-8	6 5/8	4705 (1434)	20	4577-4636 (1394-1413)	4567 (1392)
R-9	6 5/8	4144 (1263)	20	4029-4052 (1228-1235)	4524 (1379)
R-10	6 5/8	4688 (1429)	24	4623-4639 (1409-1414)	4633 (1412)
R-11	6 5/8	4708 (1435)	20	4643-4656 (1415-1419)	4744 (1446)
R-12	7	4646 (1416)	23	4721-5519 (1430-1682)	4718 (1438)
R-13	7	4528 (1380)	23	Open	4760 (1451)

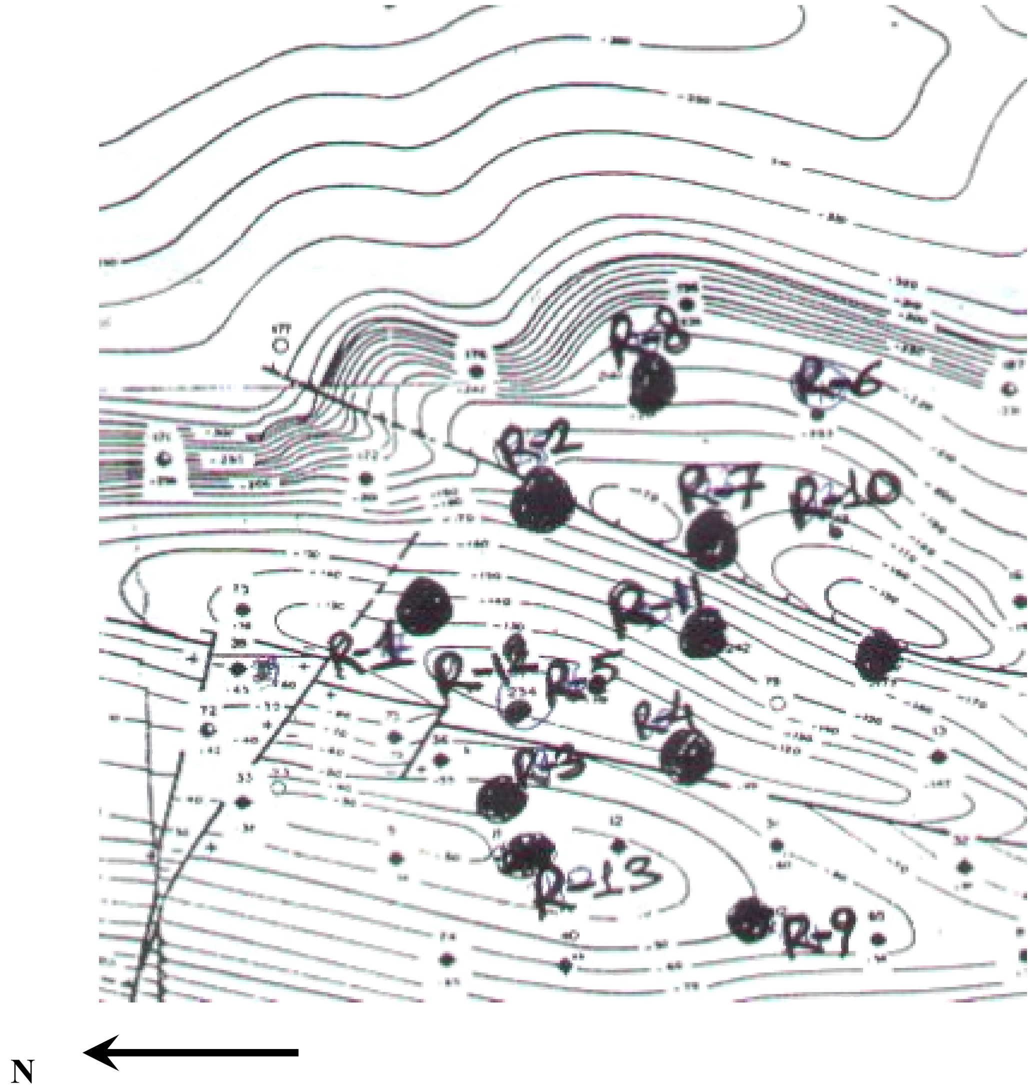

Figure 8.1 13-R wells locations, scale 1/20000 [13]

8.2. WELL ANALYSIS

Before starting the design calculations, each well were examined to decide which artificial lift method should be applied. In this study, first property of the well that was considered as a limiting factor was casing diameter. Casings used in all wells are within the range of 5-7 inches as seen in table 8.3. Neither ESP nor SRP system has difficulties with respect to casing diameter. Casing depths of the chosen wells vary in 4144-4898 ft. This range is within working depths limits of both lift method. There is no report about excessive amount of gas production from wells but during the study, gas amount was calculated incase of a need of gas separator. None of the contaminants, like sand, scale or paraffin are present in the wells which makes the design relatively easier. Next new production rates were determined. Inflow performance relations of the wells were used for that purpose as it was described in chapter 6. After those first observations of the wells it was decided to apply SRP system then ESP system to the all wells but some of the wells have too low productivity index that causes problems in ESP systems because of very low production rate. When low-volume lifting abilities were compared, SRP has an advantage. For that reason only SRP system was applied for the wells with low productivity.

8.3. ESP DESIGN

SubPUMP software developed by DSSC is a licensed program used by T.P.A.O for electrical submersible pump applications [23]. During this study by the permission of the production group of T.P.A.O design of 13 wells of R-field in Turkey was performed with this software [13]. SubPUMP is a graphical tool to design an electrical submersible pump application for current well conditions with optimum performance. For proper design it is desired to describe the well to the program. In table 8.4 input tubing and casing data that SubPUMP needs are presented. To describe the well fluid, the specific gravities of well fluids were entered with water cut, GOR and bubble point pressure. Table 8.5 includes the input and the calculated fluid properties.

Table 8.4 Tubing and casing data of well R-3 used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth , ft	4100
Casing OD, in	5
Casing ID, in	4.494
Casing Weight, lb/ft	13
Casing Bottom Depth, ft	4246
Pump Intake Depth, ft	4100
Top of Perforations, ft	4790
Bottom Hole Temperature, ^{o}F	140
Wellhead Temperature, ^{o}F	100

Table 8.5 Fluid data of well R-3 used and calculated in SubPUMP software

Input Data	
Oil Gravity, ^{o}API	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	77
Producing Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	13.5
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	6.163
Mixture Gradient @ Pump Intake, psi/ft	0.436

Any change in the depth changes pressure and temperature values which also affect the viscosity. Program needs at least one reference point for oil viscosity calibration which includes the depth, pressure and temperature data of that point. Table 8.6 represents the described calibration point and calibration factor calculated by SubPUMP for R-3 well.

Table 8.6 Viscosity Calibrations for well R-3 by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil Viscosity cp	Calibration Factor
1	1200	140	30	49.257	0.609

Inflow method can be selected manually and total test rate should be entered for calculation of productivity index. In table 8.7 total test rate and manually selected inflow method for well R-3 can be seen. Same table also includes the calculated inflow data for R-3 well.

Table 8.7 Inflow data for well R-3 by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	346
Productivity Index, bpd/psi	2.2468
Bubble Point Rate, bpd	450
Max. Oil Flow Rate, bpd	103.5
Max. Total Flow Rate, bpd	550

After completely describing the well the program needs at least two of total fluid rate, pump intake pressure or pump setting depth. Those two inputs are used by SubPUMP to calculate other missing parameters. Those are free gas percentage, total dynamic head, and total liquid entering into the pump and fluid over pump. Total fluid rate and pump setting depth were used as input data. Besides those two required data the flow line pressure was also entered. In table 8.8 input and output design criteria for R-3 well are represented.

Table 8.8 Design criteria for well R-3 by SubPUMP software

Input Data	
Total Fluid Rate, bpd	400
Flow Line Pressure, psi	80
Casing Pressure, psi	0
Pump Depth, ft	4100
Output Data	
Fluid Over Pump, ft	1706
Fluid Level, ft	2395
Pump Intake Pressure, psi	728.92
Total Dynamic Head, ft	2492
Bottom Hole Pressure, psi	1021.97
Gas Through Pump	Gas compressed
Packer Installed	No
Percentage Free Gas Available at Pump, %	1
Percentage Free Gas into Pump, %	0.3

SubPUMP calculated free gas percentage at pump as 1 % for R-3 well, so a gas separator was not installed to the well. The program provides data to create a well system curve (Figure 8.1). Table 8.9 is the well system curve detail for well R-3, it can be seen from that table if the design conditions were appropriate or not. The last row of the table includes the design condition which was the 400 bpd total oil and water production rate. Design conditions desired to be below pump off limit. Pump off is the condition in which the fluid level comes to the pump intake depth and fluid production decrease. At that point fluid velocity is not enough to cool the motor and the ESP unit shut itself automatically. In Figure 8.1 the total dynamic head and pumping fluid level can be obtained by using desired surface rate for R-3 well.

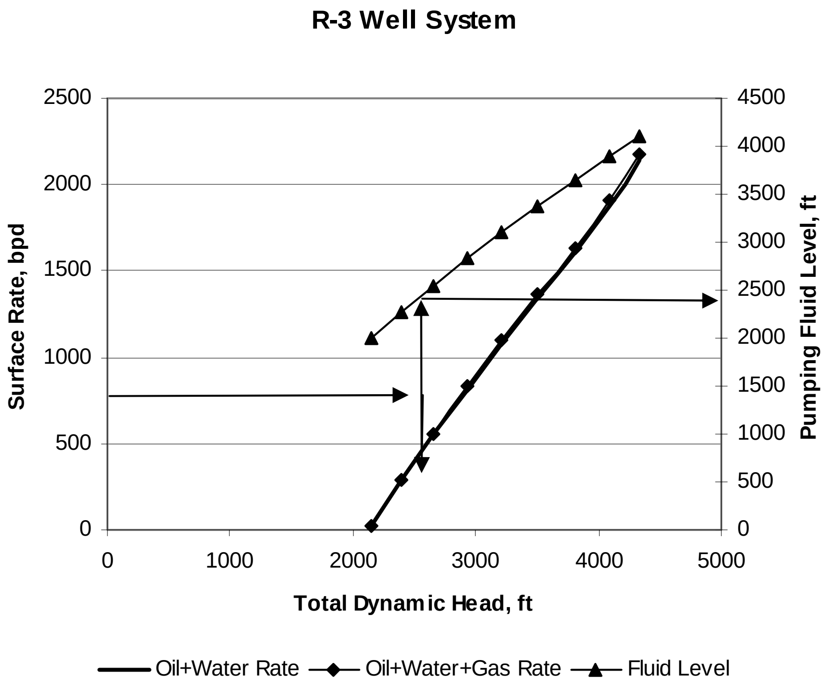

Figure Figure
8.2 Well system curve of well R-3

Table 8.9 Well system curve detail for well R-3 by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2142	21	22	2004.08
2	2386	286	291	2276.32
3	2648	550	560	2551.84
4	2928	815	828	2824.08
5	3215	1076	1097	3096.32
6	3506	1343	1366	3371.84
7	3810	1608	1635	3640.8
8	4094	1872	1904	3896.64
Pump Off	4333	2136	2173	4100
DESIGN	2492	400	407	2394.4

Table 8.10 shows the theoretical pump data and using the total rate at surface represented in this table pump unit was selected. Selections of equipments start with pump section, a list of pumps matching the design criteria is used for choosing the

most suitable pump and number of stages is calculated for a given frequency. Pump list includes the maximum and minimum recommended rates of the pumps. While selecting the pump unit it was desired to find the closest rate at peak efficiency to the theoretical rate. An equipment data base is available in the programs' features. Once the design of the production system completed appropriate equipments can be chosen from that data base.

Table 8.10 Theoretical pump performance for well R-3 by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	94.3	94	91.8
Gas Through Pump, bpd	1.3	0.4	N/A
Gas Rate From Casing, bpd	2.9	1.0	N/A
Free Gas Percentage, %	0.3	0.1	N/A
Water Rate, bpd	311.6	310.7	307.4
Total Rate, bpd	407.2	405.1	399.2
Pumping Pressure, psi	729.3	1815.2	60
Specific Gravity of Liquid, wtr = 1	0.99	0.99	N/A
Specific Gravity of Mixture, wtr = 1	0.98	0.99	N/A
Solution GOR, scf/STB	32.6	32.6	N/A

REDA 338 series AN 550 pump was selected from program database as it has a rate of 467.5 bpd at peak efficiency which was the closest rate to the theoretical one. In table 8.11 and 8.12 rate, power and stage data for the selected pump unit are tabulated. Figure 8.1 is the performance graph of the selected pumping unit. As it was described previously in chapter 5 every pump has performance curves like that one at different frequencies. Program data base includes those performance curves. In figure 8.1 is showing the design conditions, TDH of 2492 ft and production rate of 400 bpd, are within the optimum range of the selected unit. For motor selection power need of the selected unit was used.

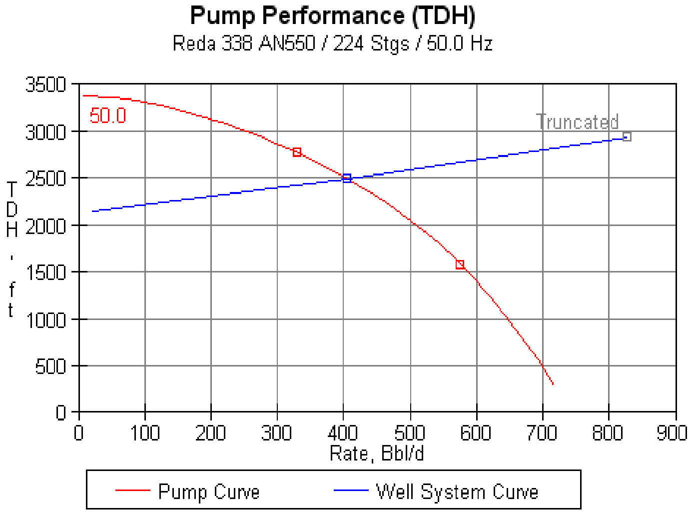

Figure 8.3 Pump performance curve for R-3 well by SubPUMP software

Table 8.11 Pump data for well R-3 by SubPUMP software

Manufacturer	REDA
Series	338
Model	AN 550
Minimum Recommended Rate, bpd	329.7 * *
Maximum Recommended Rate, bpd	577.0 * *
Design Frequency, Hz	50
Total Stages	224

* *: Corrected for frequency and viscosity

Table 8.12 Stage data of pump unit for well R-3 by SubPUMP software

	Design	224 Stages
Total Dynamic Head, ft	2491.9	2505.1
Surface Rate O+W, bpd	400	413
Average Pump Rate O+W+G, bpd	N/A	420.1
Pump Intake Pressure, psi	728.9	723.2
Operating Power, HP	N/A	16.6
Efficiency, %	N/A	45.6

A list of motors that will operate the chosen pump helps for finding the motor of the system. Horsepower, voltage and temperature around the motor were calculated in this step. Table 8.13 includes the motor information which was selected for the R-3 well. Proper seals were listed after the selection of the motor and table 8.14 represents the selected unit's properties.

Table 8.13 Motor data for well R-3 by SubPUMP software

Manufacturer	REDA
Series	375
Type	87-Single
Name Plate Power, HP	25.5
Name Plate Voltage, Volts	760
Name Plate Current, Amps	25
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ design frequency	16.3
Fluid Velocity, ft/sec	0.66
Well Fluid Temperature, ^oF	134.2

Table 8.14 Seal section data of well R-3 by SubPUMP software

Manufacturer	REDA
Series	325-375
Bearing Type	325 STD
Chamber Selection	P SB HTM
Bering Trust Capacity, lb	740.8
Power Consumption, HP	0.3

Last part of the system to be designed is cable. Program offers a list of cables that meet the voltage requirements of the motor section while revisiting the well conditions. In every step of the program warning messages can be seen if the design conditions are not match with the well conditions or equipment properties. Tabulations of the program output of other R wells are given in appendix B.

Table 8.15 Cable data for well R-3 by SubPUMP software

Manufacturer	REDA
Type	Polyethylene
Size	6 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^oF	180
Solve for	Surface voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^oF	162.6
Monthly Operating Cost, $/month	87

8.4. SRP DESIGN

LoadCalC software was used for SRP system application to 13 wells [24]. LoadCalC is based upon the LOADCALB program provided by Lufkin Industries, Inc. Program offers three alternatives of design procedure. First alternative predicts pumping unit loading for standard API rod strings (APIROD), second predicts pumping unit loading with non-standard rod strings (SBAR). The third one determines production and pumping unit loadings for a given maximum torque with a standard API rod string assumption (TMAX).

Table 8.16 LoadCalC software input data for R-3 well

Well ID	R-3
Pump Depth, ft	4100
Fluid Level, ft	2240
Pump Size, in	1.75
Stroke Length, in	64
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	1046
Total Production, bpd	500

After selection of the procedure LoadCalC provides design calculations for Conventional, Mark II, RM, and Air Balanced SRP units. In this study APIROD procedure was used for conventional SRP design. Minimum required input data are pump depth (ft), fluid level (ft), pump size (in), stroke length (in), rod size, specific gravity, tubing O.D (in), flowline pressure (psi), pumping speed (spm) or production rate (bpd). Production rate used in R-3 well was 500 bpd at 100 % pump efficiency. But program estimates 80 % pump efficiency which is a general approach than the total production is 400 bpd at that pump efficiency. An example of input data can be seen in table 8.16 LoadCalC uses API RP 11L recommended practice for design calculations for conventional sucker rod pumping systems [11]. An example calculation with this method was given in chapter 5. Table 8.17 represents the output of R-3 well.

Table 8.17 LoadCalC software output for R-3 well

Torque (in-lbs)	267,603
PPRL (lbs)	16,691
MPRL (lbs)	699
CBE (lbs)	9,690
Pumping Speed (spm)	23.76
PRHP (hp)	26.2
BPD @ 100% Pump Efficiency	500
BPD @ 80% Pump Efficiency	400
M.C. Eng./Nema 'C' Mtr, HP	51.7
Max. Rod Stress (psi)	27,757
Min. Rod Stress (psi)	1,162
7/8 in. Rod Section (ft)	1,550
3/4 in. Rod Section (ft)	2,550
1/kt (in/lb)	0.292
1/kr (in/lb)	3.258
Sp (in)	58.9
Wr (lbs/ft)	1.857
Wrf (lbs)	6,780
Fo (lbs)	4,722
Skr (lbs)	19,642
Wrf/Skr	0.345
Fo/Skr	0.24
N/No	0.398
N/No'	0.365
Ta	0.986
Sp/S	1.001
F1/Skr	0.505
F2/Skr	0.31
F3/Skr	0.347
2T/S2kr	0.432

Rests of the program output are given in appendix B. Torque (in-lbs), peak polished rod load (PPRL, lbs) and stroke length were used to select the proper pumping unit. Those values were limits of a unit to work properly in the well under consideration. To obtain the counterbalance effect calculated by the program, recommended counterweights for the selected pumping unit are compared.

8.5. TECHNICAL ANALYSIS

During the design step of this study, it was desired to observe the changes in the rate at same pump depth of SRP and ESP or vice versa. Table 8.17 is including the design conditions used in the applications and the resulting power need of the system to accomplish those conditions. It was observed that ESP systems can not operate properly under the rate of 100 bpd. But SRP systems have no difficulties at rates even below 30 bpd. In wells R-1 and R-3 same rate was desired from both lift method. In that case ESP system was needed to be set at a deeper point than SRP. When the power necessity of the systems in R-1 and R-3, four times higher production results 4.33 times horse power in SRP while in ESP it is only 1.42 times higher.

Table 8.18 Technical comparison of SRP and ESP on R-wells systems by means of rate, depth and power

Well	Present Total Rate bpd	SRP Design			ESP Design		
		Total Rate bpd	Depth ft	Power HP	Total Rate bpd	Depth ft	Power HP
R-1	124	100	3500	12	100	4100	12
R-2	36	29	4600	3.7	-	-	-
R-3	346	400	3000	52	400	4100	17
R-4	20	24	4200	3	-	-	-
R-5	936	900	4000	113	950	4500	47
R-6	1182	1000	4000	122	2000	4300	86
R-7	28	50	4200	6	-	-	-
R-8	45	90	4500	11	-	-	-
R-9	438	900	4000	108	900	4000	30
R-10	1050	1100	4500	138	1100	4500	49
R-11	100	200	4500	26	130	4500	15
R-12	954	1000	4400	129	1000	4400	45
R-13	240	500	4500	65	500	4500	20

In R-9, R-10, R-12 and R-13 wells same rate at same pump setting depth for both method were applied to see the effect on horse power need of the systems. Generally ESP systems need less horse power than SRP systems. Because in those wells desired productions increased the fluid load, means a horse power increase in SRP systems. Knowing as a high-volume producer ESP system has a power need advantage in those four wells. Operating characteristics are varied in each well, so the results are needed to be examined according to them. But in our study wells were chosen from same field and all have similar characteristics. Absence of any contaminants or excessive amount of gas makes the comparison easier. While comparing the SRP and ESP systems, it was observed that ESP has the advantages of higher production ability with lower power consumption in 13 R wells but, SRP must be used to operate some of the wells with lower than 100 bpd production.

8.6. ECONOMIC ANALYSIS

As it was mentioned in previous sections of this study the wells used in this study are already producing with SRP and ESP lift methods. Current statuses of the wells were also compared with the ones performed in the study. Figure 8.3 is the rate of return (ROR) graph of the present status (see Table 7.1) wells of R-field. In chapter 6 calculation steps of the ROR were mentioned, and tabulation of those calculations are given in appendix D. For each case there are two tables including income and cost parameters. In income tables the cure oil amount after royalty was given besides the yearly cure oil productions of the cases. In chapter 7 it was mentioned that the crude oil price was assumed as 21 \$/bbl. According to that assumption, yearly net incomes of the cases were tabulated by considering the insurance (%5 of the income) and tax (%35 of the income). Cost tables are representing the personnel expenditures (3 \$/bbl/d) and maintenance (5 \$/bbl/d and replacement costs). Besides those two parameters energy costs of the applied units were also included. Summation of the cost items are given in the disbursements column which also includes the initial investment in year 2004. The difference between net incomes and disbursements gives the yearly net cash flow of the cases. In ROR calculations, summation of the net cash flows was used to obtain future worth at different interest rates.

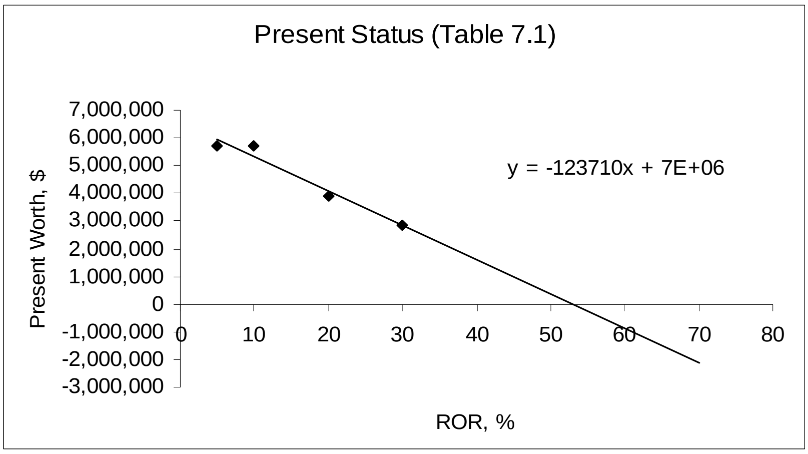

Figure 8.4 ROR versus present worth of net cash flow of present design

In this study there were mainly two alternatives of lift systems to be compared. But wells with low productivity were not suitable for ESP application. For that reason 4 wells were considered as not operating in case 1 (see table 7.1). Figures 8.4 and 8.7 are their graphical presentations.

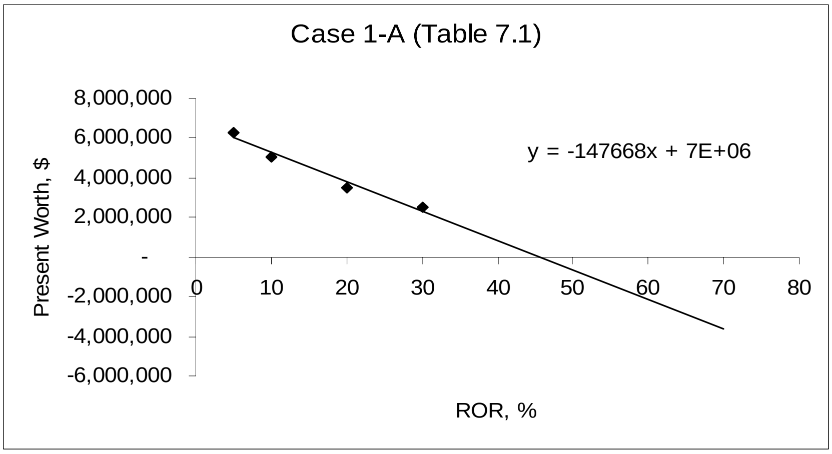

Figure8.5 ROR versus present worth of net cash flow for case 1-A

From the definition of ROR it is the interest rate at which the present worth of net cash flow is zero. Below figures were prepared by calculating present worth of the project's net cash flow at different interest rates. The intersections of the trend lines are representing the ROR of the projects. According to those graphs present status has a ROR of 56.58%, case 1-A has a ROR of 47.40 % while case 1-B has 45.93 %.

35.21 % and 60.19 % are the ROR's of cases 2-A and 2-B respectively. Table 8.19 includes some of the items used in economical comparison.

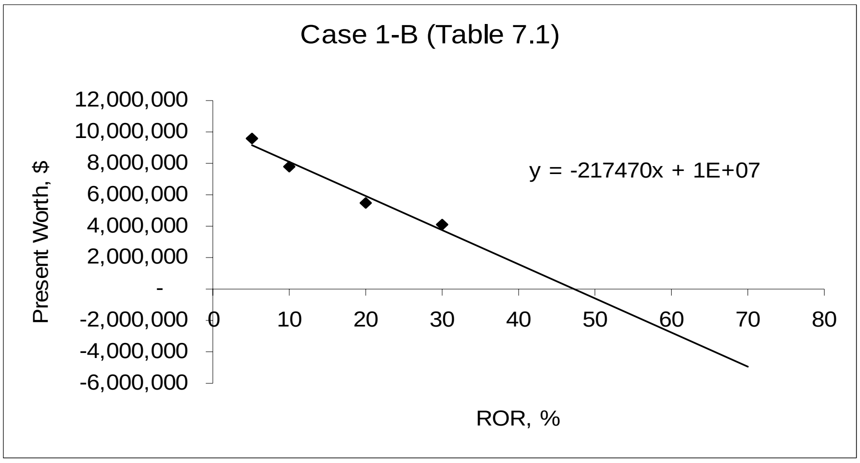

Figure 8.6 ROR versus present worth of net cash flow for case 1-B

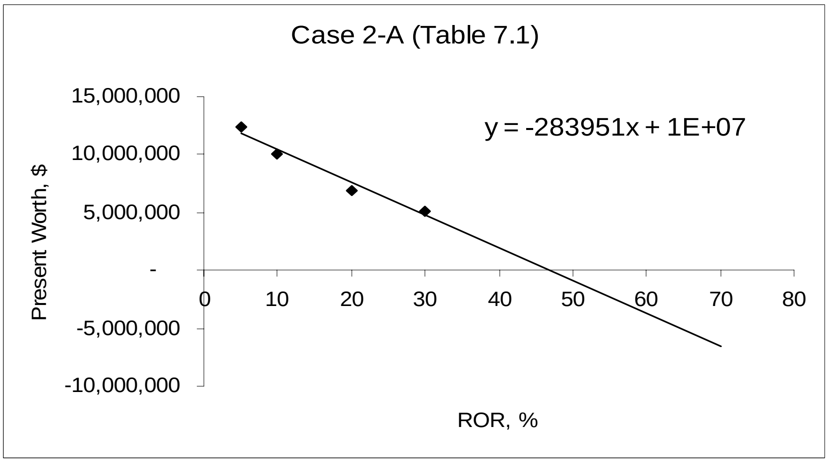

Figure 8.7 ROR versus present worth of net cash flow for case 2-A

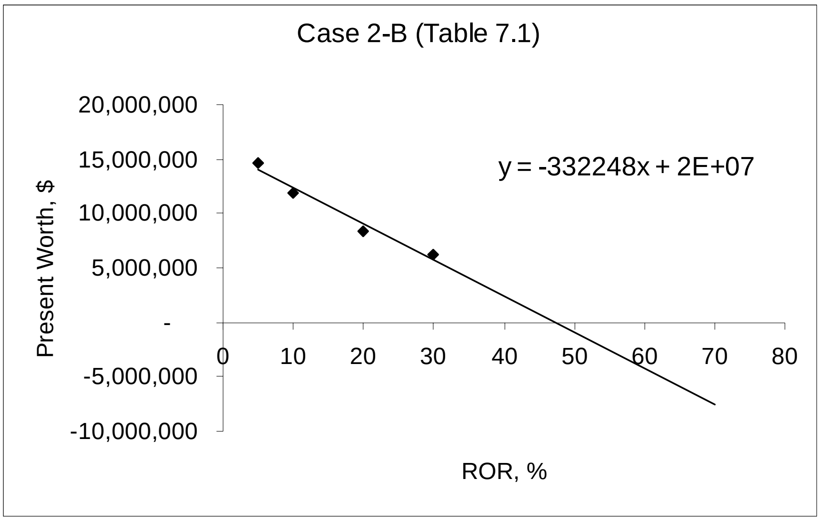

Figure 8.8 ROR versus present worth of net cash flow for case 2-B

Comparing the ROR of each alternative case, present status and case 2-B have the higher rates. It was expected that there will be a difference in between case 1 and 2 because of not operating wells. Within case 1, SRP and ESP applications have nearly same ROR. But there is a considerable increase in between case 1-B and 2-B, ESP applications of each case. The increment in the ROR is a result of 4 wells operating in the case 2. However, that increment can not be seen between case1-A and 2-A which are both SRP applications.

Table 8.19 Parameters used in economical comparison of ESP and SRP applications

	PRESENT STATUS	CASE 1-A	CASE 1-B	CASE 2-A	CASE 2-B
ROR %	56.58	47.40	45.93	35.21	60.19
Initial Investment $	638 468	537 055	447 495	698 647	609 087
Sum of 10 Years Net Cash Flow $	9 027 642	8 030 703	12 161 041	15 730 438	18 626 281

It was observed that incremental effect of 4 wells on production is not enough to overcome the increasing disbursements when they operate with other nine SRP systems. Besides, both can have equal economic advantages when they applied on the chosen wells separately. But ESP system has an advantage when it was used with SRP system. As it can be seen in the present status those lift methods are applied together to 13 wells. The difference between the present status and case 2-B is the higher percentage of the ESP system application, 30.77 % in the present status and 69.23 % in case 2-B.

CHAPTER 9

CONCLUSION

This study was performed by using 13 artificially producing wells from R field in Turkey. Applications of two artificial lift methods, sucker rod pump (SRP) and electrical submersible pumps (ESP), on those wells were compared technically and economically.

The followings can be drawn from the results of this study.

1. ESPs need less horse power than SRPs at the same pump depth to produce the same amount of fluid.
2. ESP systems should be set to the depths lower than SRP pump setting depth to obtain the same amount of daily production from a well.
3. In SRP applications it was observed that horse power requirement of the unit was increased with increasing depth and production.
4. Four wells among 13 R wells observed as producing only with SRP system because of their low productivity. For economical comparison, four wells with low productivity were assumed as not operating for both ESP and SRP systems (case-1, see Table 7.1). Then they assumed as operating with SRP in case-2. It was observed that incremental effect of four wells on production is not enough to overcome the increasing disbursements when they operate with other nine SRP systems.
5. The incremental effect of four SRP wells and nine ESP wells on production, case-2, has positive reflection on the rate of return.
6. Application of both methods together for 13 R wells gives better results than that of the application of each method separately when the rate of returns are compared.

7. It was observed that increasing the number of wells producing with ESP systems will increase the rate of return of the project.

CHAPTER 10

RECOMMENDATIONS

In this study ESP and SRP systems were compared technically and economically by applying the both methods on 13 wells of R-field in Turkey. During the design procedure variable speed drive (VSD) technology was not used for ESP applications, the study can be improved by the addition of that option in ESP systems. For SRP systems only conventional pumping unit design was performed, but air balance unit and Mark-II unit types are also available. Another study on SRP design may include those alternatives.

Future studies on this subject may include progressive cavity pumps since an application of that artificial lift method is available in that field.

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APPENDIX A

INFLOW PERFORMANCE RELATION CHARTS

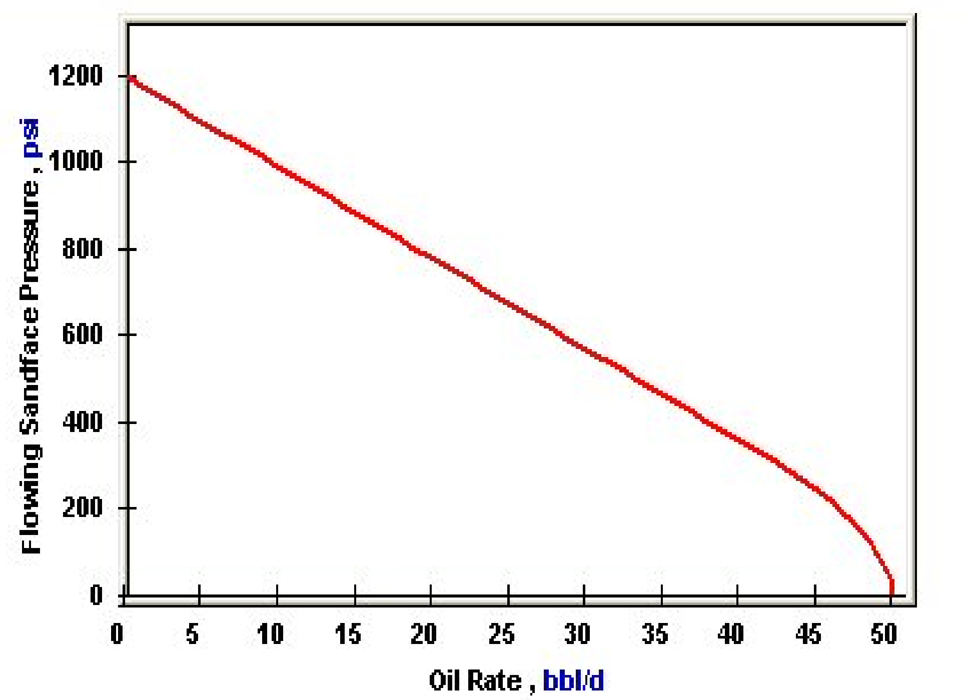

Figure A.1 Inflow performance relation of R-1 well F.E.K.E.T.E

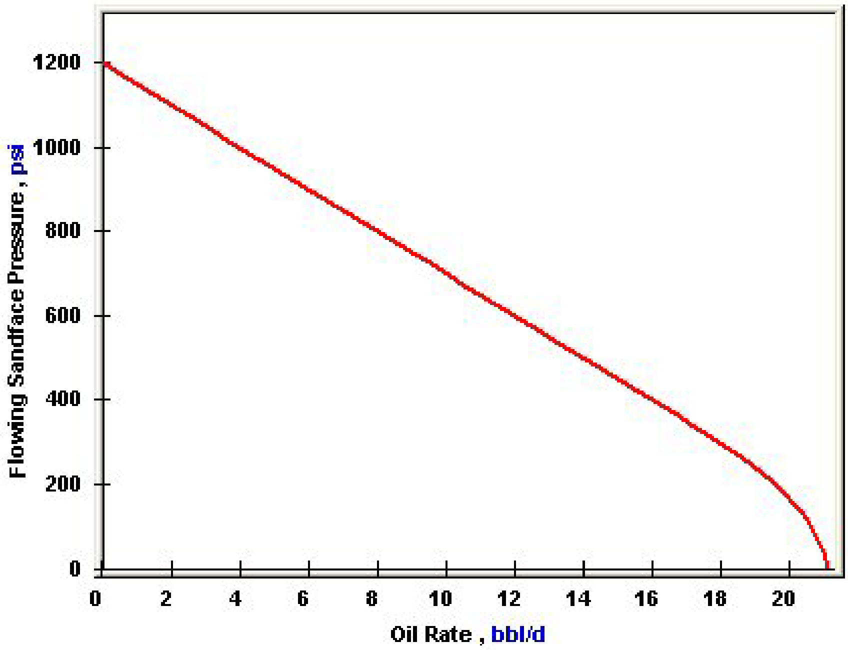

Figure A.2 Inflow performance relation of R-2 well F.E.K.E.T.E

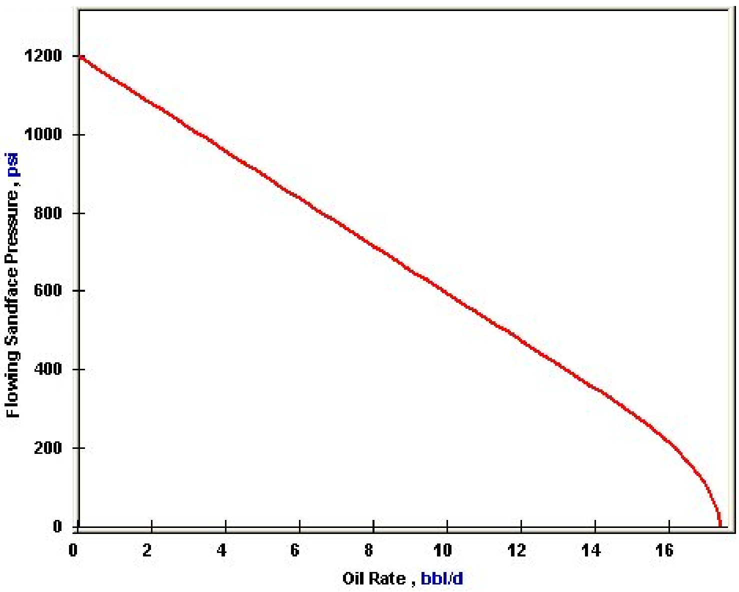

Figure A.3 Inflow performance relation of R-4 well F.E.K.E.T.E

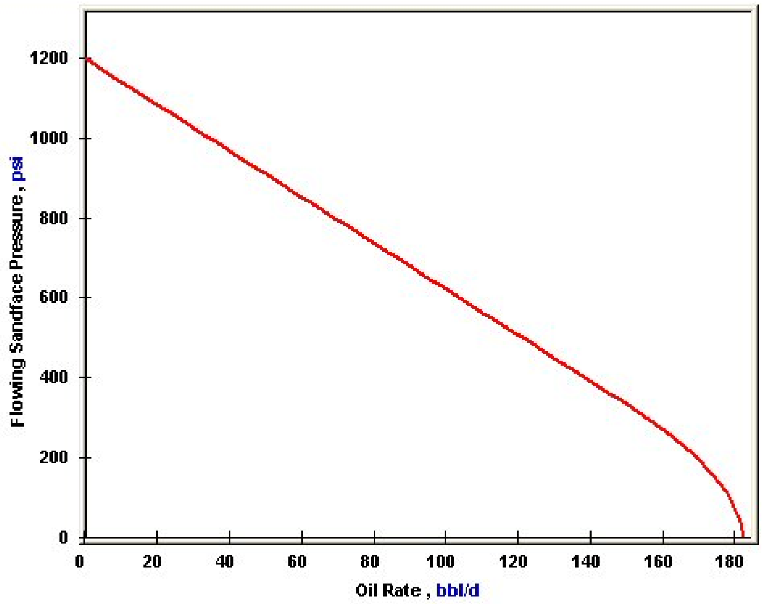

Figure A.4 Inflow performance relation of R-5 well F.E.K.E.T.E

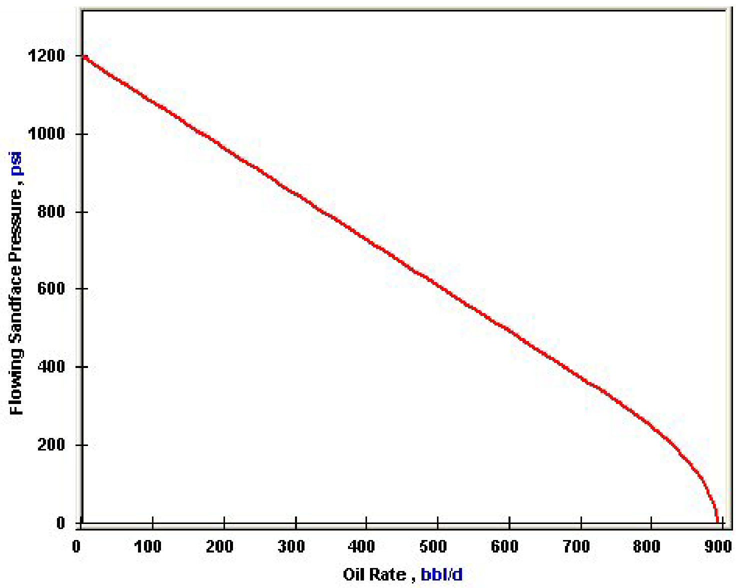

Figure A.5 Inflow performance relation of R-6 well F.E.K.E.T.E

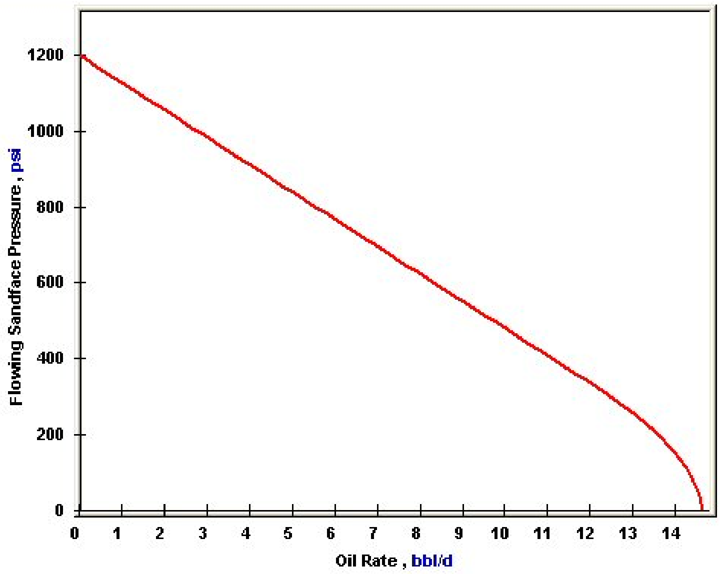

Figure A.6 Inflow performance relation of R-7 well F.E.K.E.T.E

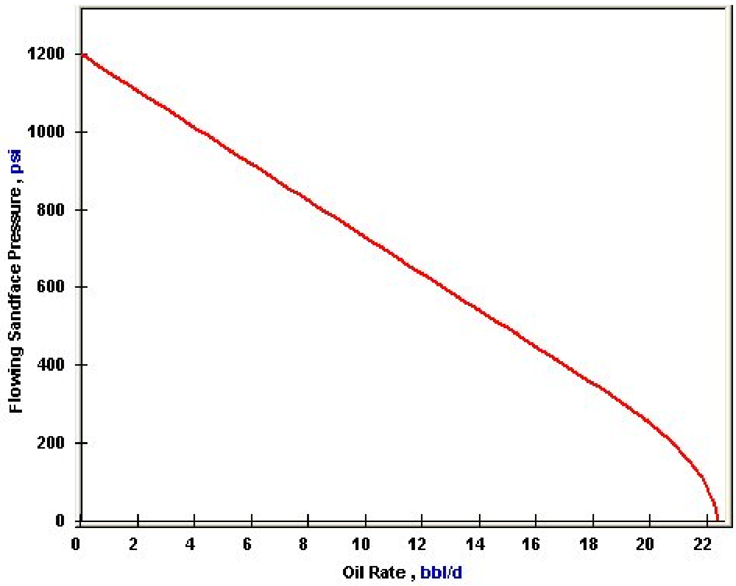

Figure A.7 Inflow performance relation of R-8 well F.E.K.E.T.E

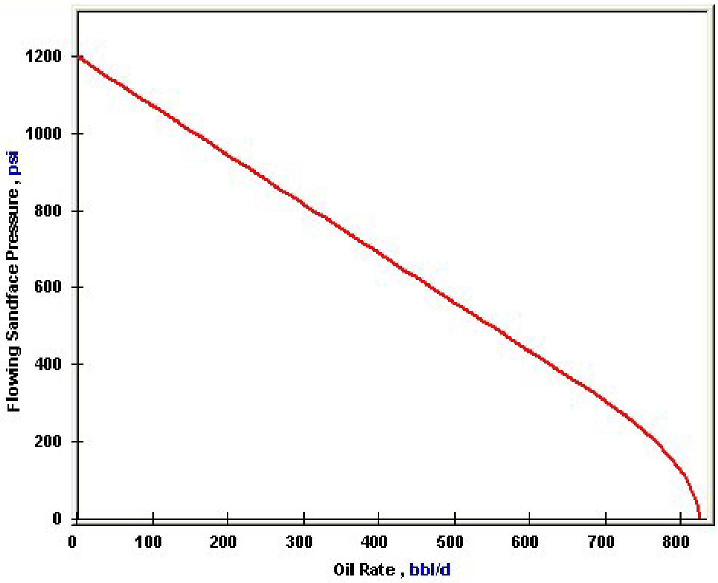

Figure A. 8 Inflow performance relation of R-9 well F.E.K.E.T.E

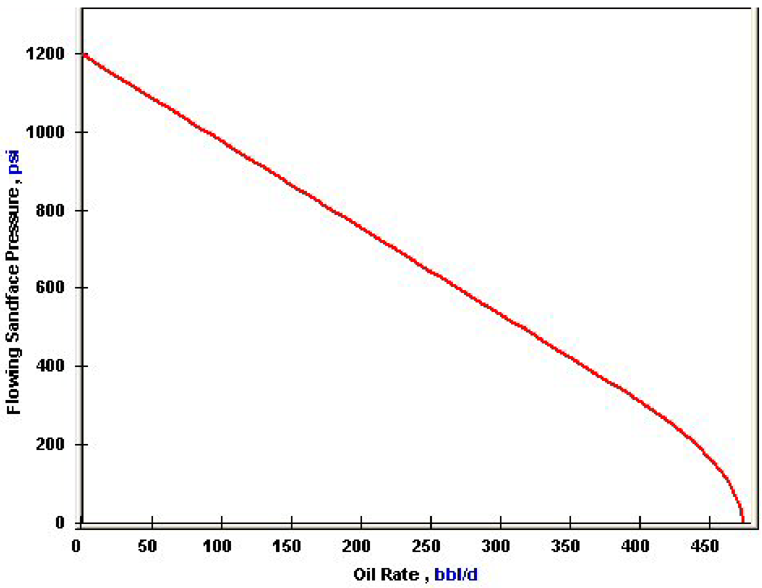

Figure A.9 Inflow performance relation of R-10 well F.E.K.E.T.E

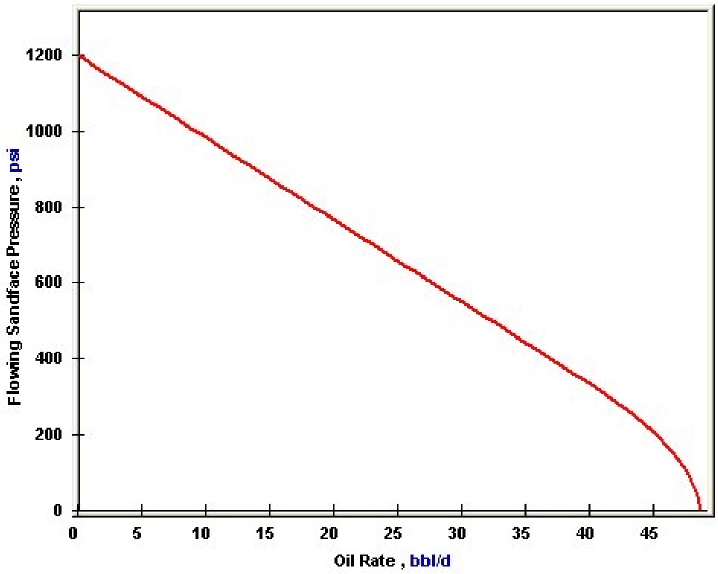

Figure A.10 Inflow performance relation of R-11 well F.E.K.E.T.E

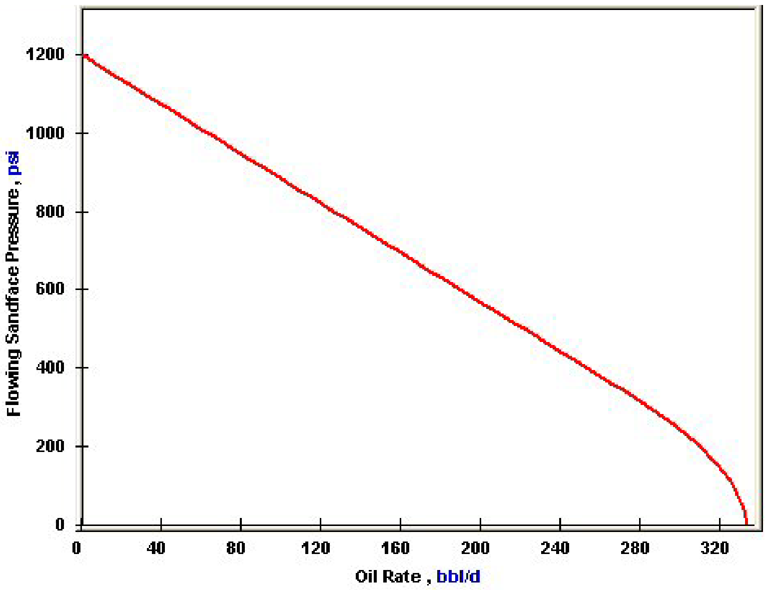

Figure A.11 Inflow performance relation of R-12 well F.E.K.E.T.E

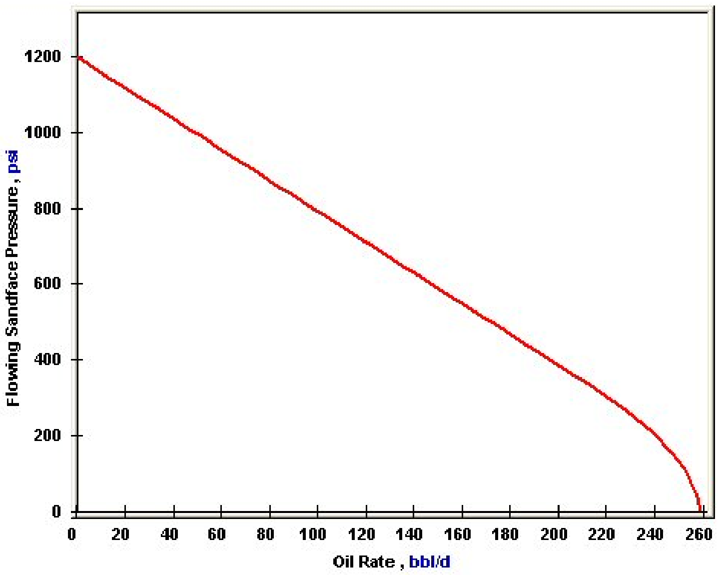

Figure A.12 Inflow performance relation of R-13 well by F.E.K.E.T.E

APPENDIX B

DESIGN SOFTWARE'S INPUT AND OUTPUT DATA

In this study wells R-1, R-3, R-5, R-6, R-9, R-10, R-11, R-12, R-13 were applied both ESP and SRP systems while well R-2, R-4, R-7, R-8 were applied only SRP system. In section B.1 ESP design results obtained by SubPUMP software are represented. Section B.2 includes the SRP design result obtained by LoadCalC software.

B.1 SubPUMP SOFTWARE OUTPUT AND INPUT DATA

B.1.1 SubPUMP Software Input and Output Data for R-1 Well

Table B.1 Tubing and casing data for R-1 well used in SubPUMP Software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom, ft	4100
Casing OD, in	7.000
Casing ID, in	6.276
Casing Weight, lb/ft	26
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4600
Pump Intake Depth, ft	4100
Bottom Hole Temperature, ^{o}F	140.0
Wellhead Temperature, ^{o}F	100.0

Table B.2 Fluid data for R-1 well used in SubPUMP Software

Input Data	
Oil Gravity, °API	18
Specific Gravity of Gas (air = 1)	0.750
Specific Gravity of Water (wtr=1)	1.020
Salinity, ppm	27972
Water Cut, %	64
Producing Gas-Oil Ratio scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio scf/stb	20.5
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	9.262
Mixture Gradient @ Pump Intake, psi/ft	0.432

Table B.3 Viscosity Calibrations for R-1 well generated by SubPUMP Software

Point Num	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil Viscosity cp	Calibration Factor
1	1200	140	30	49.257	0.609

Table B.4 Inflow data for R-1 well generated by SubPUMP Software

IPR Calculation Method	PI
Total Test Rate, bpd	124
Productivity Index, bfpd/psi	0.14
Bubble Point Rate, bpd	119
Max. Oil Flow Rate, bpd	50
Max. Total Flow Rate, bpd	138

Table B.5 Design criteria for R-1 well in SubPUMP Software

Input Data	
Total Fluid Rate, bpd	100
Flow Line Pressure, psi	100
Casing Pressure, psi	0
Pump Depth, m	4100
Output Data	
Fluid Over Pump, m	798.56
Fluid Level, ft	3304
Pump Intake Pressure, psi	337.16
Total Dynamic Head,ft	3460.37
Bottom Hole Pressure, psi	485.71
Gas Through Pump	Gas compressed
Packer Installed	No
Percentage Free Gas Available at Pump, %	4.9
Percentage Free Gas into Pump, %	1.5

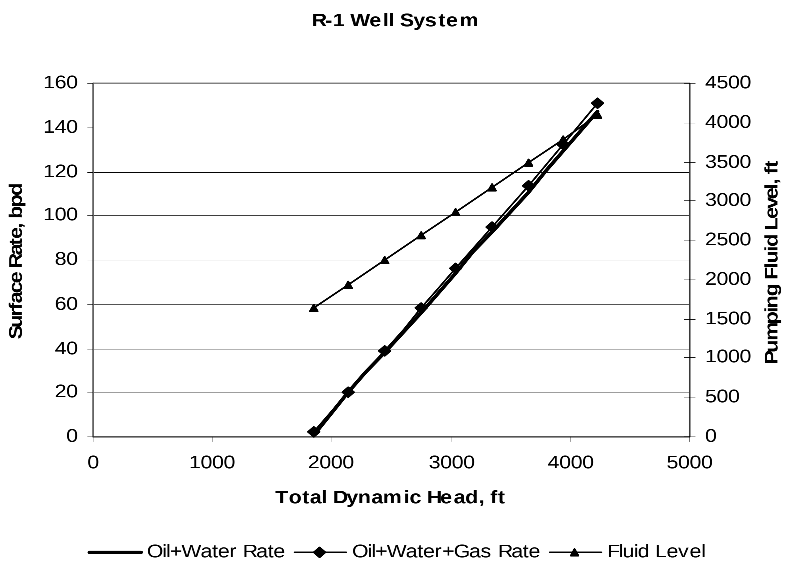

Figure B.1 Well system curve for R-1 well

Table B.6 Well system curve detail for data for R-1 well generated by SubPUMP Software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	1847	1	2	1640
2	2145	20	20	1945.04
3	2444	38	39	2253.36
4	2743	56	58	2561.68
5	3042	74	76	2870
6	3341	93	95	3178.32
7	3642	111	114	3486.64
8	3940	129	132	3794.96
Pump Off	4230	147	151	4100
DESIGN	3460	100	102	3302.96

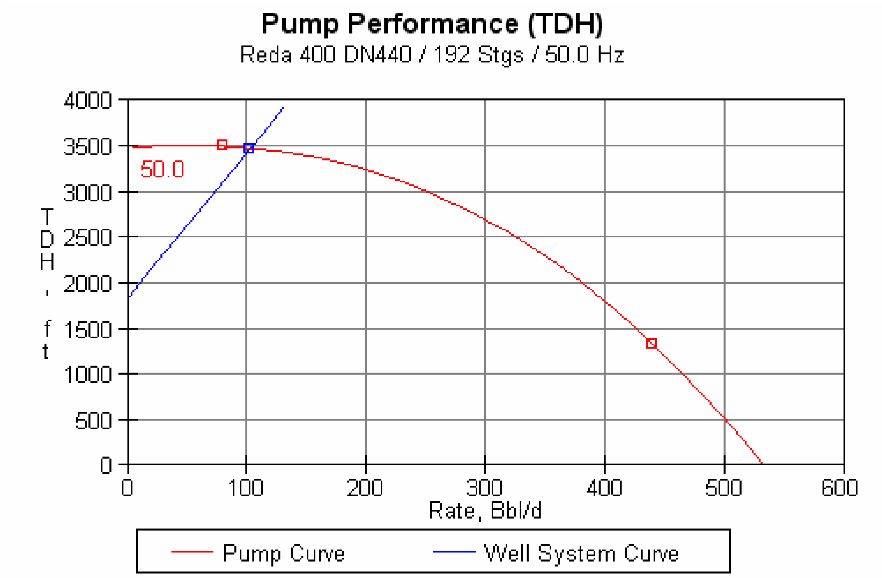

Figure B.2 Pump performance graph of R-1 well drawn by SubPUMP software

Table B.7 Theoretical pump performance for R-1 estimated by SubPUMP

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	37.4	37.1	36.3
Gas Through Pump, bpd	1.6	0.2	N/A
Gas Rate From Casing, bpd	3.7	0.6	N/A
Free Gas Percentage, %	1.6	0.2	N/A
Water Rate, bpd	65.5	65.2	64.5
Total Rate, bpd	104.5	102.6	100.7
Pumping Pressure, psi	332.1	1803.4	100
Specific Gravity of Liquid, wtr = 1	0.97	0.98	N/A
Specific Gravity of Mixture, wtr = 1	0.96	0.97	N/A
Gas Deviation Factor	0.945	0.769	N/A

Table B.8 Pump data for R-1 well proposed by SubPUMP Software

Manufacturer	REDA
Series	400
Model	DN 440
Minimum Recommended Rate, bpd	79.9 **
Maximum Recommended Rate, bpd	439.7 **
Design Frequency, Hz	50
Total Stages	176

**: Corrected for frequency and viscosity

Table B.9 Stage data for R-1 well generated by SubPUMP Software

	Design	176 Stages
Total Dynamic Head, ft	3460.4	3462.5
Surface Rate O+W, bpd	100.0	100.1
Average Pump Rate O+W+G, bpd	N/A	102.6
Pump Intake Pressure, psi	337.2	336.1
Operating Power, HP	N/A	12.0
Efficiency, %	N/A	21.0

Table B.10 Motor data for data R-1 well generated by SubPUMP Software

Manufacturer	REDA
Series	456
Type	90-O-Single
Name Plate Power, HP	12.5
Name Plate Voltage, Volts	450
Name Plate Current, Amps	17.5
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	11.8
Fluid Velocity, ft/sec	0.33
Well Fluid Temperature, ^{o}F	136.8

Table B.11 Seal section data for R-1 well generated by SubPUMP Software

Manufacturer	REDA
Series	400-456
Bearing Type	400 HL
Chamber Selection	LSLSB-HL
Bearing Trust Capacity, lb	7083.3
Power Consumption, HP	0.1

Table B.12 Cable data for R-1 well generated by SubPUMP Software

Manufacturer	REDA
Type	Redablack
Size	4 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface Voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^{o}F	204.5
Monthly Operating Cost, $/month	62

B.1.2 SubPUMP Software Input and Output Data for R-5 Well

Table B.13 Tubing and casing data of R-5 well used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4500
Casing OD, in	6.625
Casing ID, in	5.921
Casing Weight, lb/ft	24
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4505
Pump Intake Depth, ft	4500
Bottom Hole Temperature, ^oF	140
Wellhead Temperature, ^oF	100

Table B.14 Fluid data of R-5 well used in SubPUMP software

Input Data	
Oil Gravity, ^oAPI	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	85
Producing Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	8.6
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	4.274
Mixture Gradient @ Pump Intake, psi/ft	0.438

Table B.15 Viscosity Calibrations of R-5 well generated by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil Viscosity, cp	Calibration Factor
1	1200	140	30	49.257	0.609

Table B.16 Inflow data of R-5 well generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	936
Productivity Index, bfpd/psi	1.157
Bubble Point Rate, bpd	1033
Max. Oil Flow Rate, bpd	183
Max. Total Flow Rate, bpd	1220

Table B.17 Design criteria of R-5 well in SubPUMP software

Input Data	
Total Fluid Rate, bpd	950
Flow Line Pressure, psi	180
Casing Pressure, psi	0
Pump Depth, ft	4500
Output Data	
Fluid Over Pump, ft	770.34
Fluid Level, ft	3658.79
Pump Intake Pressure, psi	331.82
Total Dynamic Head, ft	4838
Bottom Hole Pressure, psi	378.9
Gas Through Pump	Gas compressed
Packer Installed	No
Percentage Free Gas Available at Pump, %	0.7
Percentage Free Gas into Pump, %	0.2

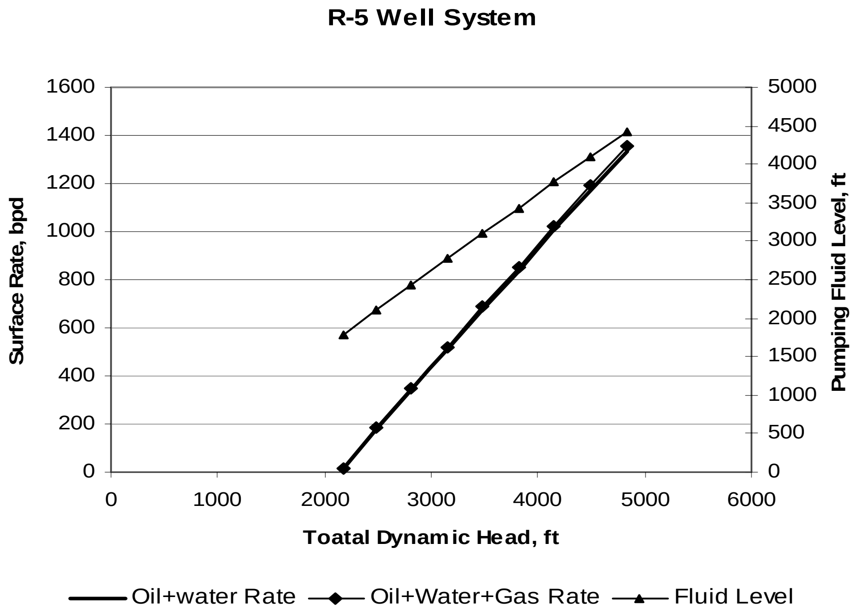

Figure B.3 Well system curve of R-5 well

Table B.18 Well system curve detail of R-5 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2176	13	14	1781.04
2	2493	179	182	2109.04
3	2818	344	350	2440.32
4	3148	509	518	2771.6
5	3481	675	686	3102.88
6	3816	840	854	3437.44
7	4155	1005	1022	3768.72
8	4495	1171	1190	4100
Pump Off	4838	1336	1358	4428
DESIGN	4041	950	966	3657.2

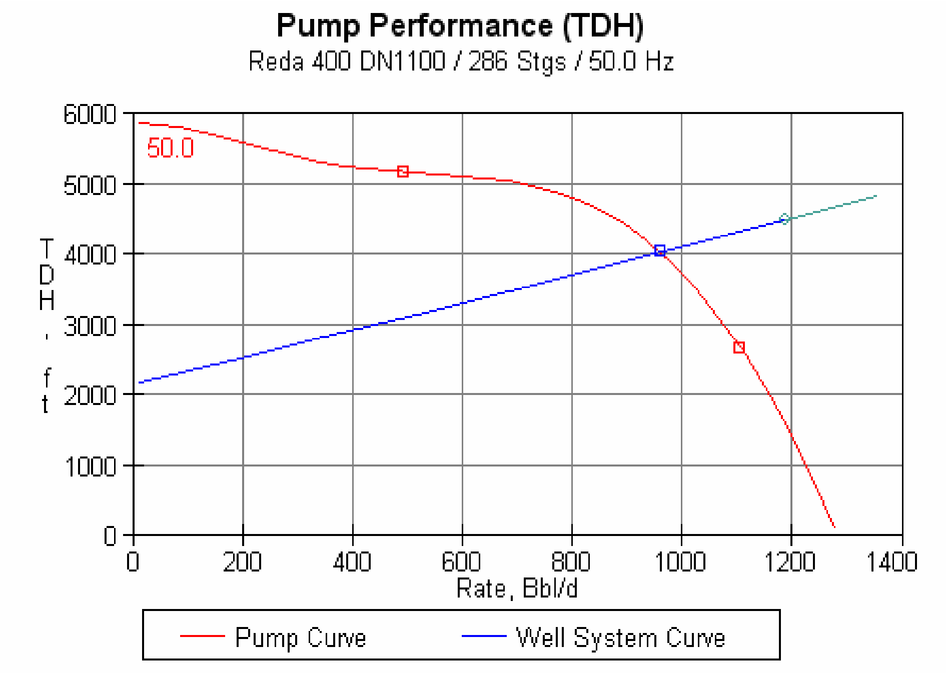

Figure B.4 Pump performance graph of R-5 well drawn by SubPUMP software

Table B.19 Theoretical pump performance of R-5 well proposed by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	146.2	144.9	141.7
Gas Through Pump, bpd	1.9	0.3	N/A
Gas Rate From Casing, bpd	4.5	0.6	N/A
Free Gas Percentage, %	0.2	0.0	N/A
Water Rate, bpd	816	811.9	802.7
Total Rate, bpd	946.1	957.1	944.4
Pumping Pressure, psi	336.7	2131	180
Specific Gravity of Liquid, wtr = 1	0.99	1	N/A
Specific Gravity of Mixture, wtr = 1	0.99	0.99	N/A
Gas Deviation Factor	0.945	0.760	N/A

Table B.20 Pump data of R-5 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 1100
Minimum Recommended Rate, bpd	492 * *
Maximum Recommended Rate, bpd	1107 * *
Design Frequency, Hz	50
Total Stages	273

* *: Corrected for frequency and viscosity

Table B.21 Stage data of R-5 well generated by SubPUMP software

	Design	273 Stages
Total Dynamic Head, ft	4040.8	4039.5
Surface Rate O+W, bpd	950	949.8
Average Pump Rate O+W+G, bpd	N/A	965.8
Pump Intake Pressure, psi	331.8	332
Operating Power, HP	N/A	46.5
Efficiency, %	N/A	61.3

Table B.22 Motor data of R-5 well proposed by SubPUMP software

Manufacturer	REDA
Series	540-I
Type	91-Single
Name Plate Power, HP	70
Name Plate Voltage, Volts	1320
Name Plate Current, Amps	35
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	46.5
Fluid Velocity, ft/sec	1.97
Well Fluid Temperature, ^oF	140

Table B.23 Seal section data of R-5 well proposed by SubPUMP software

Manufacturer	REDA
Series	400-456
Bearing Type	400 HL
Chamber Selection	LSL-HL
Bering Trust Capacity, lb	7083.3
Power Consumption, HP	0.1

Table B.24 Cable data of R-5 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	4 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^{o}F	160.5
Monthly Operating Cost, $/month	240

B.1.3 SubPUMP Software Input and Output Data for R-6 Well

Table B.25 Tubing and casing data of R-6 well used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4300
Casing OD, in	6.625
Casing ID, in	5.921
Casing Weight, lb/ft	24
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4898
Pump Intake Depth, ft	4300
Bottom Hole Temperature, ^{o}F	140
Wellhead Temperature, ^{o}F	100

Table B.26 Fluid data of R-6 well used in SubPUMP software

Input Data	
Oil Gravity, °API	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	85
Producing Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	8.6
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	6.104
Mixture Gradient @ Pump Intake, psi/ft	0.438

Table B.27 Viscosity Calibrations of R-6 well by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil viscosity cp	Calibration Factor
1	1200	140	30	38.761	0.774

Table B.28 Inflow data of R-6 well generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	1182
Productivity Index, bfpd/psi	5.6555
Bubble Point Rate, bpd	5000
Max. Oil Flow Rate, bpd	900
Max. Total Flow Rate, bpd	6000

Table B.29 Design Criteria for R-6 well in SubPUMP software

Input Data	
Total Fluid Rate, bpd	2000
Flow Line Pressure, psi	210
Casing Pressure, psi	0
Pump Depth, ft	4300
Output Data	
Fluid Over Pump, ft	1668.18
Fluid Level, ft	2596.92
Pump Intake Pressure, psi	2355.87
Total Dynamic Head, ft	3183.23
Bottom Hole Pressure, psi	846.36
Gas Through Pump	Gas compressed
Packer Installed	No
Percentage Free Gas Available at Pump, %	0.3
Percentage Free Gas into Pump, %	0.1

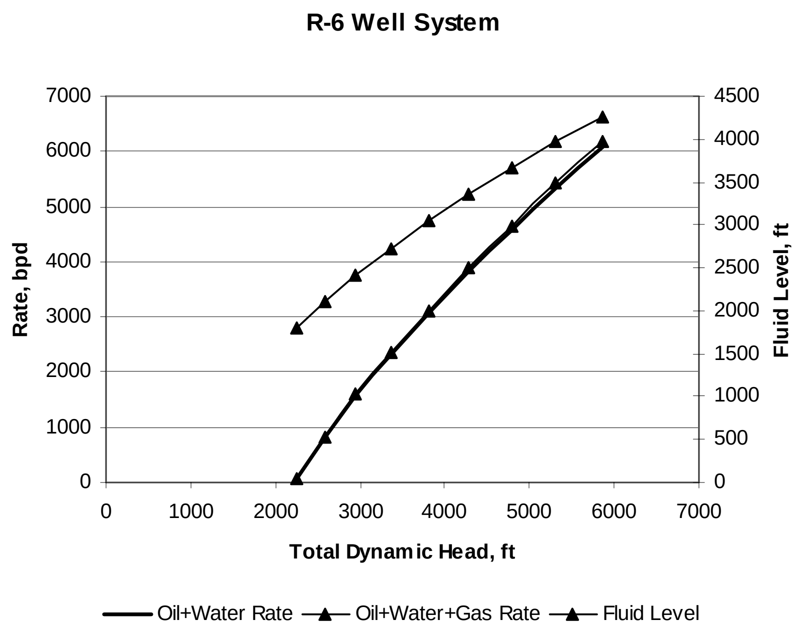

Figure B.5 Well system curve of R-6 well

Table B.30 Well System curve detail of R-6 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2260	61	62	1800.72
2	2577	814	826	2109.04
3	2951	1567	1591	2417.36
4	3362	2320	2355	2728.96
5	3805	3073	3119	3040.56
6	4278	3826	3884	3352.16
7	4782	4579	4648	3667.04
8	5312	5332	5413	3978.64
Pump Off	5852	6085	6177	4264
DESIGN	3183	2000	2030	2597.76

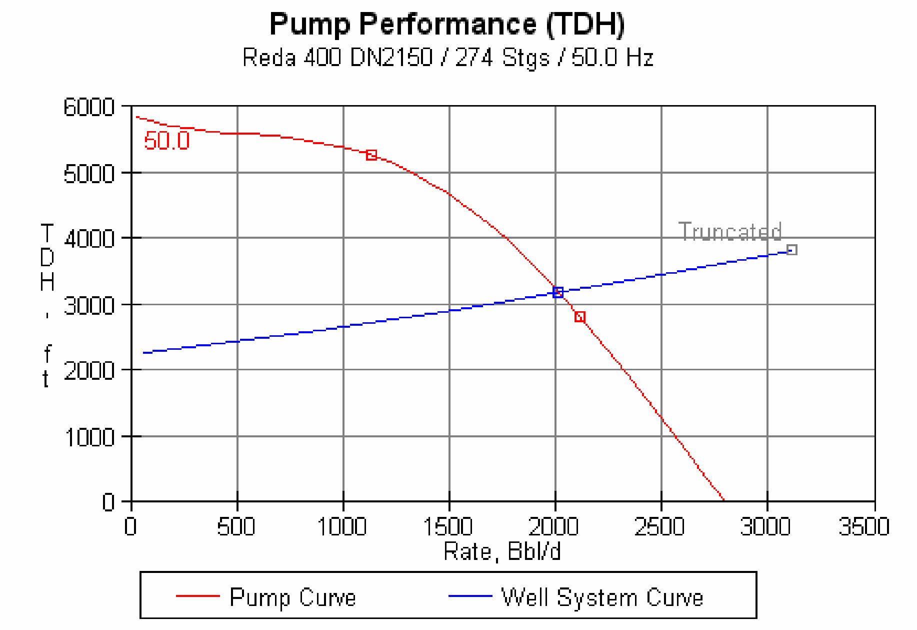

Figure B.6 Pump performance graph of R-6 well drawn by SubPUMP

Table B.31 Theoretical pump performance of R-6 well proposed by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	306.4	304.9	298.0
Gas Through Pump, bpd	1.7	0.5	N/A
Gas Rate From Casing, bpd	4.1	1.2	N/A
Free Gas Percentage, %	0.1	0.0	N/A
Water Rate, bpd	1713.8	1707.1	1688.7
Total Rate, bpd	2021.9	2012.6	1986.7
Pumping Pressure, psi	720.4	2118.3	200
Specific Gravity of Liquid, wtr = 1	0.99	1	N/A
Specific Gravity of Mixture, wtr = 1	0.99	1	N/A
Gas Deviation Factor	0.887	0.757	N/A

Table B.32 Pump data of R-6 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 2150
Minimum Recommended Rate, bpd	1142.7 **
Maximum Recommended Rate, bpd	2122.1 **
Design Frequency, Hz	50
Total Stages	256

**: Corrected for frequency and viscosity

Table B.33 Stage data of R-6 well proposed by SubPUMP software

	Design	256 Stages
Total Dynamic Head, ft	3183.2	3184.4
Surface Rate O+W, bpd	2000	2002
Average Pump Rate O+W+G, bpd	N/A	2032.4
Pump Intake Pressure, psi	718.1	717.7
Operating Power, HP	N/A	86.4
Efficiency, %	N/A	54.9

Table B.34 Motor data of R-6 well proposed by SubPUMP software

Manufacturer	REDA
Series	540
Type	90-O-Single
Name Plate Power, HP	125
Name Plate Voltage, Volts	2425
Name Plate Current, Amps	32
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	86.7
Fluid Velocity, ft/sec	3.94
Well Fluid Temperature, ^{o}F	137.4

Table B.35 Seal section data of R-6 well proposed by SubPUMP software

Manufacturer	REDA
Series	400-456
Bearing Type	400 STD
Chamber Selection	66L
Bering Trust Capacity, lb	1333.3
Power Consumption, HP	0.1

Table B.36 Cable data of R-6 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	4 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface Voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^{o}F	157.6
Monthly Operating Cost, $/month	414

B.1.4 SubPUMP Software Input and Output Data for R-9 Well

Table B.37 Tubing and casing data of R-9 well used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4000
Casing OD, in	6.625
Casing ID, in	6.049
Casing Weight, lb/ft	20
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4144
Pump Intake Depth, ft	4000
Bottom Hole Temperature, ^oF	140
Wellhead Temperature, ^oF	100

Table B.38 Fluid data of R-9 well used in SubPUMP software

Input Data	
Oil Gravity, ^oAPI	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	81
Producing Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	10.8
Solution Gas-Oil Ratio, scf/stb	32.6
Fluid Viscosity, cp	7.607
Fluid Gradient @ Pump Intake, psi/ft	0.437

Table B.39 Viscosity Calibrations of R-9 well generated by SubPUMP software

Point Num.	Pressure, psi	Temperature, °F	User Viscosity, cp	Calculated viscosity, cp	Calibration Factor
1	1200	140	30	38.761	0.774

Table B.40 Inflow data of R-9 well generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	438
Productivity Index, bfpd/psi	4.1321
Bubble Point Rate, bpd	3978.95
Max. Oil Flow Rate, bpd	825
Max. Total Flow Rate, bpd	4342.11

Table B.41 Design criteria for R-9 well used in SubPUMP software

Input Data	
Total Fluid Rate, bpd	900
Flow Line Pressure, psi	210
Casing Pressure, psi	0
Pump Depth, ft	4000
Output Data	
Fluid Over Pump, ft	1835.30
Fluid Level, ft	2232.94
Pump Intake Pressure, psi	787.46
Total Dynamic Head, ft	2702.76
Bottom Hole Pressure, psi	982.19
Gas Through Pump	Gas Compressed
Gas Separator Performance	
Packer Installed	No
Percentage Free Gas Available at Pump, %	0.6
Percentage Free Gas into Pump, %	0.2

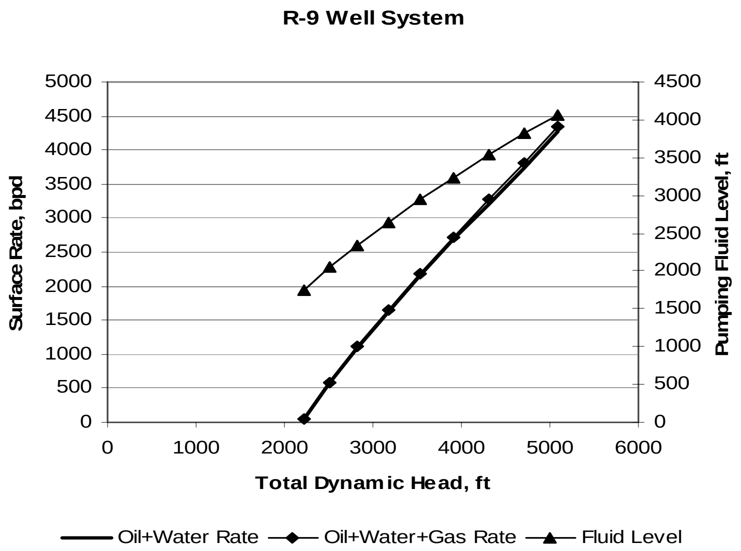

Figure B.8 Well system curve of R-9 well

Table B.42 Well system curve detail of R-9 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2212	43	43	1751.52
2	2503	572	581	2046.72
3	2829	1101	1118	2345.2
4	3176	1629	1656	2643.68
5	3541	2158	2193	2938.88
6	3921	2687	2730	3237.36
7	4314	3216	3268	3532.56
8	4711	3745	3805	3821.2
Pump Off	5084	4274	4342	4067.2
DESIGN	2703	900	914	2233.68

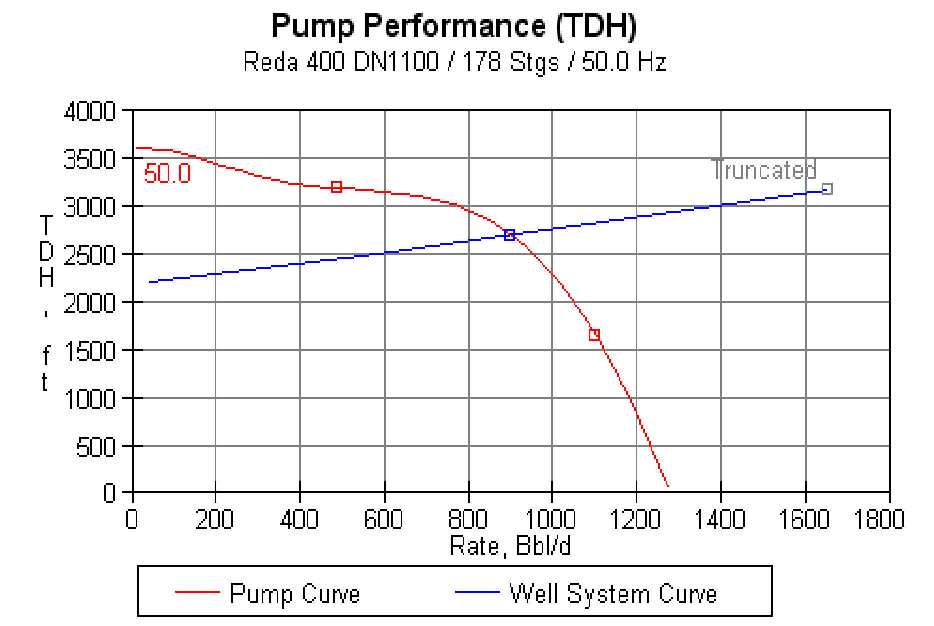

Figure B.9 Pump performance graph of R-9 well drawn by SubPUMP

Table B.43 Theoretical pump performance of R-9 well generated by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	173.3	172.6	168.6
Gas Through Pump, bpd	1.6	0.6	N/A
Gas Rate From Casing, bpd	3.8	1.3	N/A
Free Gas Percentage, %	0.2	0.1	N/A
Water Rate, bpd	729.2	726.8	719
Total Rate, bpd	904.1	900	887.6
Pumping Pressure, psi	790.5	1975	250
Specific Gravity of Liquid, wtr = 1	0.99	0.99	N/A
Specific Gravity of Mixture, wtr = 1	0.99	0.99	N/A
Gas Deviation Factor	0.876	0.759	N/A

Table B.44 Pump data of R-9 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 1100
Minimum Recommended Rate, bpd	489.9 **
Maximum Recommended Rate, bpd	1102.4 **
Design Frequency, Hz	50
Total Stages	171

Table B.45 Stage data of R-9 well proposed by SubPUMP software

	Design	171 Stages
Total Dynamic Head, ft	2702.8	2704.1
Surface Rate O+W, bpd	900	903.7
Average Pump Rate O+W+G, bpd	N/A	918.1
Pump Intake Pressure, psi	787.5	786.6
Operating Power, HP	N/A	29.2
Efficiency, %	N/A	62.1

Table B.46 Motor data of R-9 well proposed by SubPUMP software

Manufacturer	REDA
Series	540-I
Type	91-Single
Name Plate Power, HP	40
Name Plate Voltage, Volts	1325
Name Plate Current, Amps	20
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	28.7
Fluid Velocity, ft/sec	1.31
Well Fluid Temperature, ^oF	136

Table B.47 Seal section data of R-9 well proposed by SubPUMP software

Manufacturer	REDA
Series	375
Bearing Type	375 STD
Chamber Selection	66L
Bering Trust Capacity, lb	829.2
Power Consumption, HP	0.1

Table B.48 Cable data of R-9 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	4 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^{o}F	158.4
Monthly Operating Cost, $/month	146

B.1.5 SubPUMP Software Input and Output Data for R-10 Well

Table B.49 Tubing and casing data of R-10 well used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4500
Casing OD, in	6.625
Casing ID, in	5.921
Casing Weight, lb/ft	24
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4688
Pump Intake Depth, ft	4500
Bottom Hole Temperature, ^{o}F	140
Wellhead Temperature, ^{o}F	100

Table B.50 Fluid data of R-10 well used in SubPUMP software

Input Data	
Oil Gravity, ^{o}API	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	75
Producing Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	14.3
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	9.693
Mixture Gradient @ Pump Intake, psi/ft	0.435

Table B.51 Viscosity Calibrations of R-10 well generated by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil viscosity cp	Calibration Factor
1	1200	140	30	38.761	0.774

Table B.52 Inflow data of well R-10 generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	1050
Productivity Index, bfpd/psi	1.7979
Bubble Point Rate, bpd	1600
Max. Oil Flow Rate, bpd	480
Max. Total Flow Rate, bpd	1920

Table B.53 Design criteria for R-10 well in SubPUMP software

Input Data	
Total Fluid Rate, bpd	1100
Flow Line Pressure, psi	210
Casing Pressure, psi	0
Pump Depth, m	4500
Output Data	
Fluid Over Pump, ft	1177.79
Fluid Level, ft	3251.35
Pump Intake Pressure, psi	502.08
Total Dynamic Head, ft	3727
Bottom Hole Pressure, psi	588.19
Gas Through Pump	Gas compressed
Gas Separator Performance	
Packer Installed	No
Percentage Free Gas Available at Pump, %	1.8
Percentage Free Gas into Pump, %	0.6

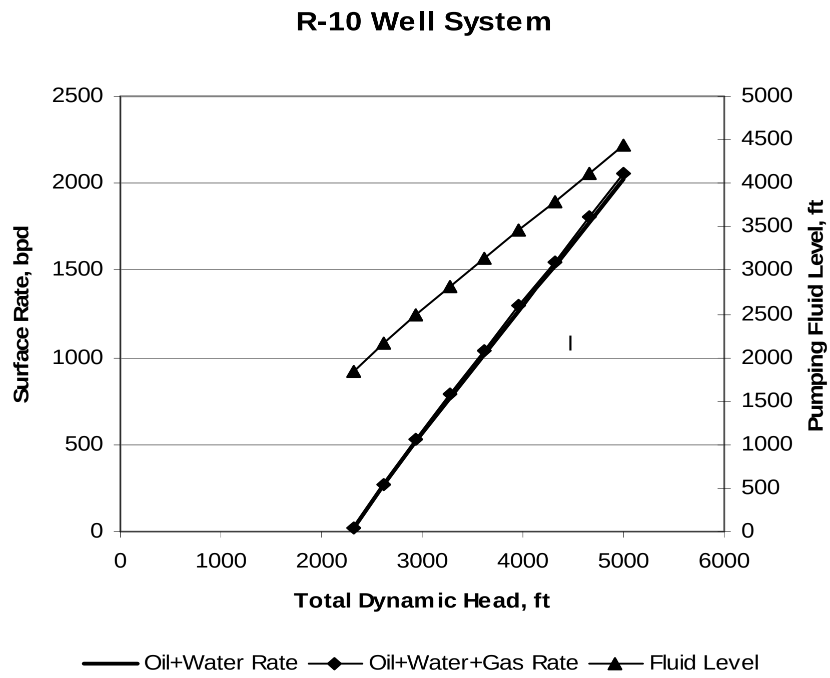

Figure B.10 Well system curve of R-10 well

Table B.54 Well System Curve detail of R-10 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2309	20	21	1846.64
2	2619	270	275	2171.36
3	2939	520	530	2496.08
4	3278	770	785	2820.8
5	3618	1021	1040	3145.52
6	3964	1271	1295	3473.52
7	4313	1521	1549	3798.24
8	4659	1771	1804	4122.96
Pump Off	4994	2021	2059	4428
DESIGN	3727	1100	1121	3250.48

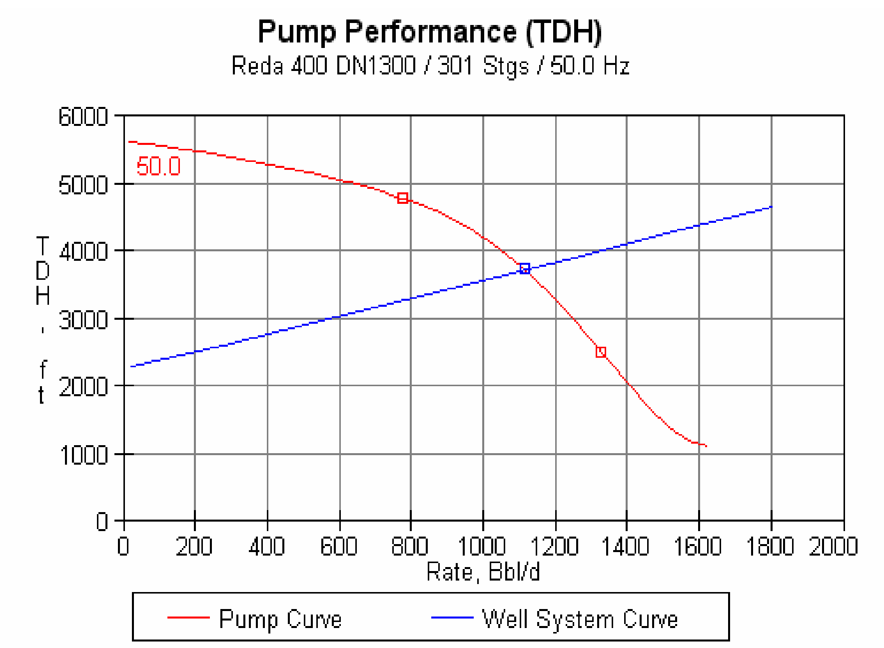

Figure B.11 Pump performance graph of R-10 well drawn by SubPUMP

Table B.55 Theoretical pump performance of R-10 well generated by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	282	280.2	273
Gas Through Pump, bpd	6.3	1.3	N/A
Gas Rate From Casing, bpd	14.7	2.9	N/A
Free Gas Percentage, %	0.6	0.1	N/A
Water Rate, bpd	834.5	830.6	821.5
Total Rate, bpd	1122.7	1112.1	1095.3
Pumping Pressure, psi	504.7	2133.7	270
Specific Gravity of Liquid, wtr = 1	0.98	0.99	N/A
Specific Gravity of Mixture, wtr = 1	0.98	0.99	N/A
Gas Deviation Factor	0.919	0.758	N/A

Table B.56 Pump data of R-10 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 1300
Minimum Recommended Rate, bpd	778 **
Maximum Recommended Rate, bpd	1329 **
Rate at Peak Efficiency, bpd	1069.2 **
Power at Peak Efficiency, HP	49.8 **
Design Frequency, Hz	50
Total Stages	277
Stages with Free Gas	277
Additional Stages Due to Gas	2

* *: Corrected for frequency and viscosity

Table B.57 Stage data of R- 10 well proposed by SubPUMP software

	Design	277 Stages
Total Dynamic Head, ft	3727	3729.8
Surface Rate O+W, bpd	1100	1101.9
Average Pump Rate O+W+G, bpd	N/A	1122.7
Pump Intake Pressure, psi	502.1	501
Operating Power, HP	N/A	48.7
Efficiency, %	N/A	62.2

Table B.58 Motor data of R-10 well proposed by SubPUMP software

Manufacturer	REDA
Series	540-I
Type	Old V&A-Single
Name Plate Power, HP	60
Name Plate Voltage, Volts	870
Name Plate Current, Amps	45
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	48.7
Fluid Velocity, ft/sec	2.30
Well Fluid Temperature, ^oF	138.2

Table B.59 Seal section data of R-10 well proposed by SubPUMP software

Manufacturer	REDA
Series	400-456
Bearing Type	400HL
Chamber Selection	LSB-HL
Bering Trust Capacity, lb	7083.3
Power Consumption, HP	0.1

Table B.60 Cable data of R-10 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	2 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^oF	300
Solve for	Surface Voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^oF	170.6
Monthly Operating Cost, $/month	262

B.1.6 SubPUMP Software Input and Output Data for R-11 Well

Table B.61 Tubing and casing data of R-11 used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4500
Casing OD, in	6.625
Casing ID, in	6.049
Casing Weight, lb/ft	20
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4708
Pump Intake Depth, ft	4500
Bottom Hole Temperature, ^{o}F	140
Wellhead Temperature, ^{o}F	100

Table B.62 Fluid data of R-11 well used in SubPUMP software

Input Data	
Oil Gravity, ^{o}API	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	70
Producing Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	17.1
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	11.49
Mixture Gradient @ Pump Intake, psi/ft	0.433

Table B.2 Viscosity Calibrations of R-11 well generated by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil Viscosity cp	Calibration Factor
1	1200	140	30	38.761	0.774

Table B.64 Inflow data of R-11 well generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	100
Productivity Index, bfpd/psi	0.1541
Bubble Point Rate, bpd	140
Max. Oil Flow Rate, bpd	49
Max. Total Flow Rate, bpd	163.33

Table B.65 Design Criteria for R-11 well in SubPUMP software

Input Data	
Total Fluid Rate, bpd	130
Flow Line Pressure, psi	210
Casing Pressure, psi	0
Pump Depth, m	4500
Output Data	
Fluid Over Pump, ft	770.73
Fluid Level, ft	3904.46
Pump Intake Pressure, psi	327.27
Total Dynamic Head, ft	4322
Bottom Hole Pressure, psi	356.3
Gas ThRoughness Pump	Gas Compressed
Gas Separator Performance	
Packer Installed	No
Percentage Free Gas Available at Pump, %	3.9
Percentage Free Gas into Pump, %	1.2

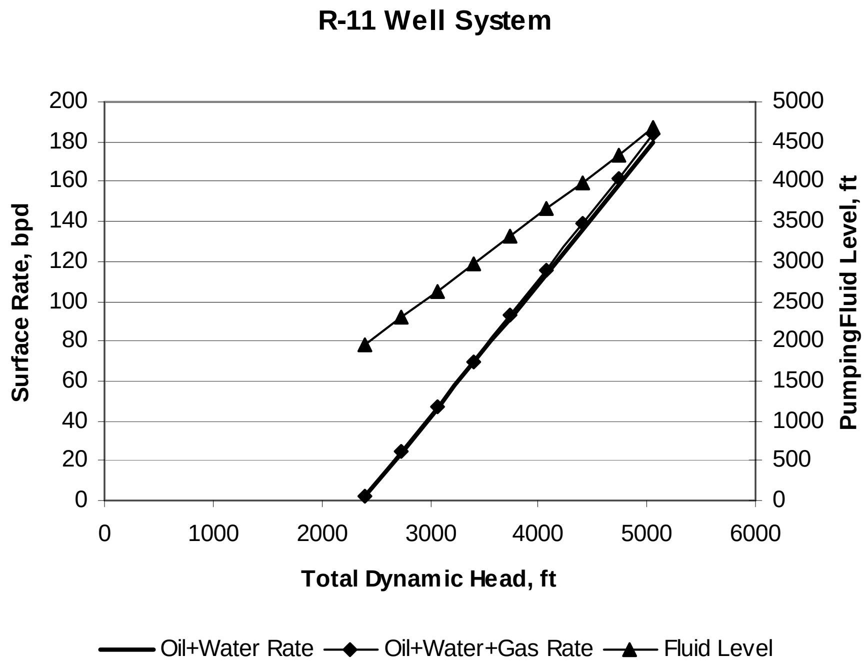

Figure B.12 Well system curve of R-11 well

Table B.66 Well system curve detail for R-11 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2409	2	2	1945.04
2	2742	24	25	2286.16
3	3075	46	47	2627.28
4	3408	69	70	2965.12
5	3741	91	93	3306.24
6	4074	113	116	3650.64
7	4408	136	139	3991.76
8	4739	158	162	4336.16
Pump Off	5065	180	184	4674
DESIGN	4322	130	133	3903.2

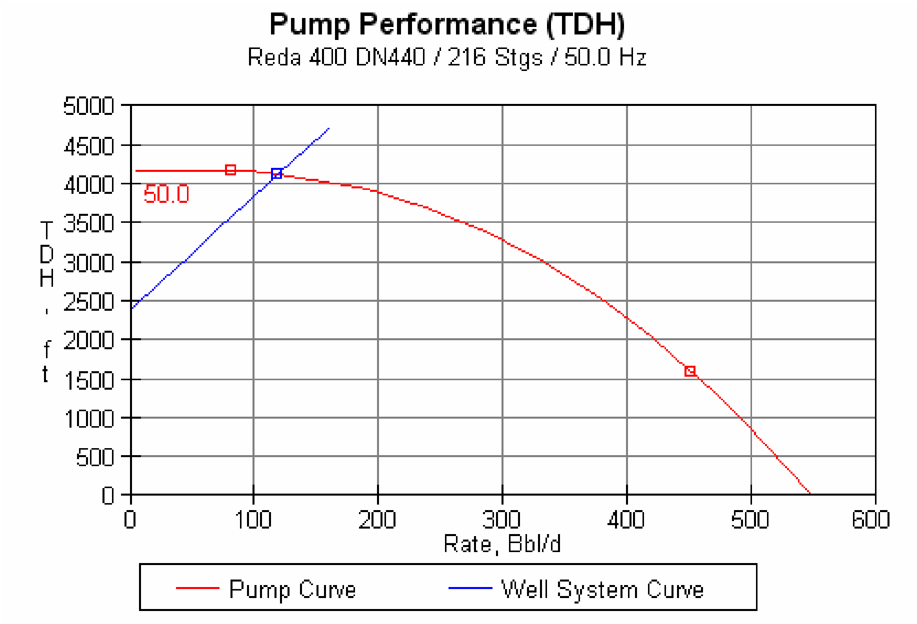

Figure B.13 Pump performance graph of well R-11 drawn by SubPUMP

Table B.67 Theoretical pump performance of R-11 well generated by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	36	35.7	34.9
Gas ThRoughness Pump, bpd	1.5	0.2	N/A
Gas Rate From Casing, bpd	3.4	0.4	N/A
Free Gas Percentage, %	0.9	0.2	N/A
Water Rate, bpd	82.8	82.4	81.4
Total Rate, bpd	120.3	118.3	116.4
Pumping Pressure, psi	415.8	2794.8	200
Specific Gravity of Liquid, wtr = 1	0.98	0.98	N/A
Specific Gravity of Mixture, wtr = 1	0.97	0.98	N/A
Gas Deviation Factor	0.933	0.759	N/A

Table B.68 Pump data of R-11 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 400
Minimum Recommended Rate, bpd	82.3 * *
Maximum Recommended Rate, bpd	452.6 * *
Design Frequency, Hz	50
Total Stages	216
Stages with Free Gas	216
Additional Stages Due to Gas	0

* *: Corrected for frequency and viscosity

Table B.69 Stage data of R-11 well proposed by SubPUMP software

	Design	216 Stages
Total Dynamic Head, ft	4321.5	4213.4
Surface Rate O+W, bpd	130	122.8
Average Pump Rate O+W+G, bpd	N/A	125.5
Pump Intake Pressure, psi	327.3	374
Operating Power, HP	N/A	15.2
Efficiency, %	N/A	26.3

Table B.70 Motor data of R-11 well proposed by SubPUMP software

Manufacturer	REDA
Series	540
Type	90-O-Single
Name Plate Power, HP	25
Name Plate Voltage, Volts	1175
Name Plate Current, Amps	13
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	14.5
Fluid Velocity, ft/sec	0.33
Well Fluid Temperature, ^{o}F	139.4

Table B.71 Seal section data of R-11 well proposed by SubPUMP software

Manufacturer	REDA
Series	400-456
Bearing Type	400HL
Chamber Selection	LSB-HL
Bering Trust Capacity, lb	7083.3
Power Consumption, HP	0.1

Table B.72 Cable data of R-11 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	4Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface Voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^{o}F	185.9
Monthly Operating Cost, $/month	68

B.1.7 SubPUMP Software Input and Output Data for R-12 Well

Table B.73 Tubing and casing data of R-12 well used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4400
Casing OD, in	7
Casing ID, in	6.366
Casing Weight, lb/ft	23
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4646
Pump Intake Depth, ft	4400
Bottom Hole Temperature, ^{o}F	140
Wellhead Temperature, ^{o}F	100

Table B.74 Fluid data of R-12 well use in SubPUMP software

Input Data	
Oil Gravity, ^{o}API	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	83
Prod. Gas-Oil Ratio, scf/stb	57
Bubble Point Pressure, psi	325
Output Data	
Prod. Gas-Liquid Ratio, scf/stb	9.7
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	6.806
Mixture Gradient @ Pump Intake, psi/ft	0.437

Table B.75 Viscosity Calibrations for R-12 well generated by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil Viscosity cp	Calibration Factor
1	1200	140	30	38.761	0.774

Table B.76 Inflow data of R-12 well generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	954
Productivity Index, bfpd/psi	1.8669
Bubble Point Rate, bpd	1647.05
Max. Oil Flow Rate, bpd	330
Max. Total Flow Rate, bpd	1941.18

Table B.77 Design criteria for R-12 well in SubPUMP software

Input Data	
Total Fluid Rate, bpd	1000
Flow Line Pressure, psi	210
Casing Pressure, psi	0
Pump Depth, ft	4400
Output Data	
Fluid Over Pump, ft	1423.20
Fluid Level, ft	3169.98
Pump Intake Pressure, psi	611.15
Total Dynamic Head, ft	3642
Bottom Hole Pressure, psi	664.36
Gas ThRoughness Pump	Gas Compressed
Gas Separator Performance	
Packer Installed	No
Percentage Free Gas Available at Pump, %	0.6
Percentage Free Gas into Pump, %	0.2

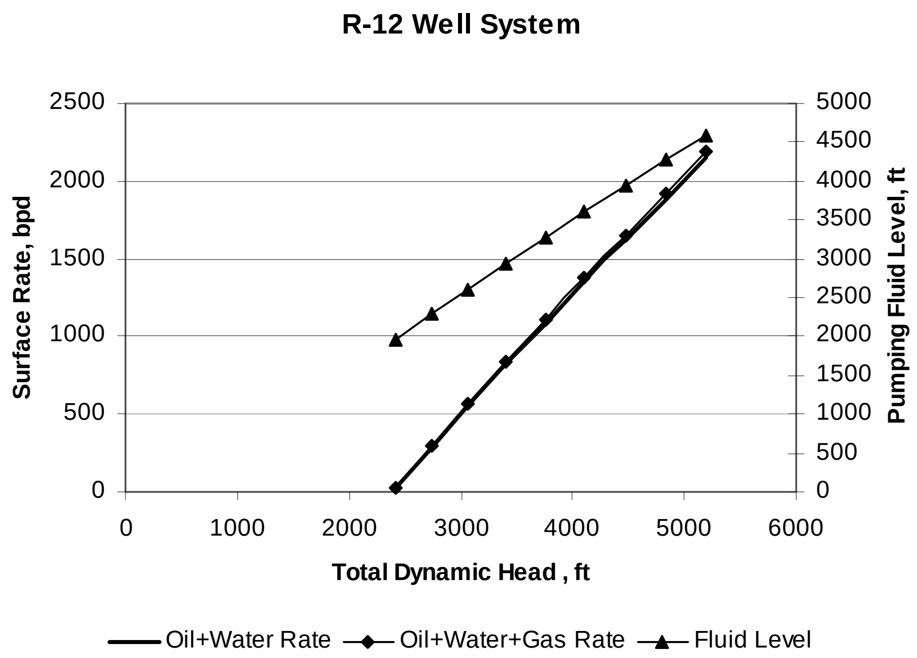

Figure B.14 Well system curve of R-12 well

Table B.78 Well System curve detail of R-12 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2416	22	22	1951.6
2	2732	288	292	2282.88
3	3067	554	563	2614.16
4	3408	820	834	2945.44
5	3756	1087	1104	3276.72
6	4110	1353	1375	3608
7	4469	1619	1645	3942.56
8	4829	1886	1916	4273.84
Pump Off	5187	2152	2187	4592
DESIGN	3642	1000	1016	3168.48

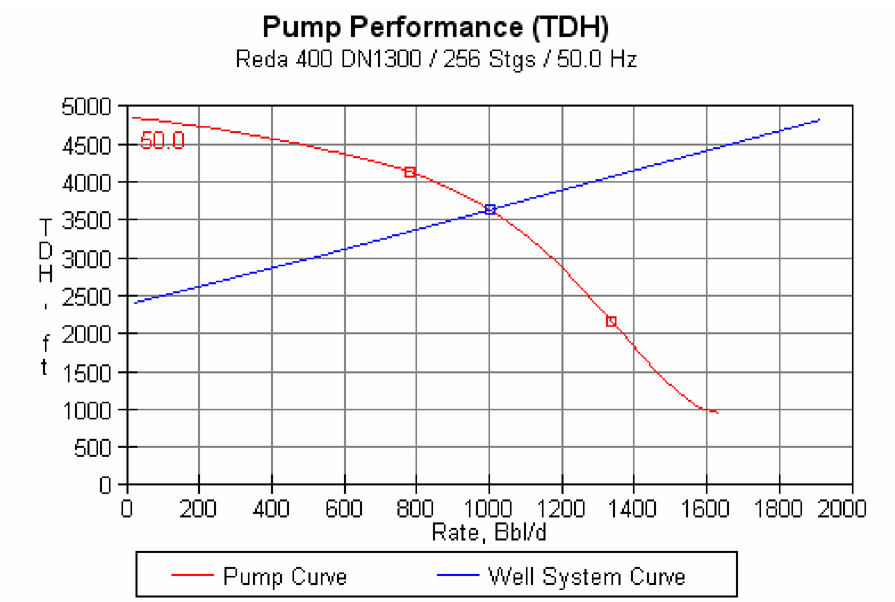

Figure B.15 Pump performance graph of R-12 well drawn by SuBPUMP

Table B.79 Theoretical pump performance for R-12 well generated by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	173.1	172.1	168.2
Gas ThRoughness Pump, bpd	1.8	0.4	N/A
Gas Rate From Casing, bpd	4.2	1.0	N/A
Free Gas Percentage, %	0.2	0.0	N/A
Water Rate, bpd	834.2	830.4	821.3
Total Rate, bpd	1009.1	1003	989.6
Pumping Pressure, psi	616.7	2223.3	100
Specific Gravity of Liquid, wtr = 1	0.99	0.99	N/A
Specific Gravity of Mixture, wtr = 1	0.99	0.99	N/A
Gas Deviation Factor	0.903	0.758	N/A

Table B.80 Pump data of R-12 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 1300
Minimum Recommended Rate, bpd	783.7 * *
Maximum Recommended Rate, bpd	1338.8 * *
Design Frequency, Hz	50
Total Stages	256
Stages with Free Gas	256
Additional Stages Due to Gas	0

* *: Corrected for frequency and viscosity

Table B.81 Stage data of R-12 well proposed by SubPUMP software

	Design	256 Stages
Total Dynamic Head, ft	3642.4	3692.6
Surface Rate O+W, bpd	1000	1038.5
Average Pump Rate O+W+G, bpd	N/A	1055.2
Pump Intake Pressure, psi	611.2	590.6
Operating Power, HP	N/A	45.5
Efficiency, %	N/A	62.2

Table B.82 Motor data of R-12 well proposed by SubPUMP software

Manufacturer	REDA
Series	540-I
Type	90-Single
Name Plate Power, HP	60
Name Plate Voltage, Volts	1180
Name Plate Current, Amps	29.5
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	43.2
Fluid Velocity, ft/sec	0.98
Well Fluid Temperature, ^oF	138.9

Table B.83 Seal section data of R-12 well proposed by SubPUMP software

Manufacturer	REDA
Series	400-456
Bearing Type	400 KMC
Chamber Selection	66L
Bering Trust Capacity, lb	3333.3
Power Consumption, HP	0.5

Table B.84 Cable data of R-12 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	4 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface Voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^oF	167.7
Monthly Operating Cost, $/month	199

B.1.8 SubPUMP Software Input and Output Data for R-13 Well

Table B.85 Tubing and casing data of R-13 well used in SubPUMP software

Tubing OD, in	2.875
Tubing ID, in	2.441
Tubing Weight, lb/ft	6.5
Tubing Roughness, in	0.00065
Tubing Bottom Depth, ft	4500
Casing OD, in	7
Casing ID, in	6.366
Casing Weight, lb/ft	23
Casing Roughness, in	0.00065
Casing Bottom Depth, ft	4528
Pump Intake Depth, ft	4500
Bottom Hole Temperature, ^{o}F	140
Wellhead Temperature, ^{o}F	100

Table B.86 Fluid data of R-13 well used in SubPUMP software

Input Data	
Oil Gravity, ^{o}API	18
Specific Gravity of Gas, (air = 1)	0.75
Specific Gravity of Water (wtr=1)	1.02
Salinity, ppm	27972
Water Cut, %	94
Producing Gas-Oil Ratio, scf/stb	84.6
Bubble Point Pressure, psi	325
Output Data	
Producing Gas-Liquid Ratio, scf/stb	5.1
Solution Gas-Oil Ratio, scf/stb	32.6
Mixture Viscosity, cp	2.778
Mixture Gradient @ Pump Intake, psi/ft	0.440

Table B.87 Viscosity Calibrations of R-13 well generated by SubPUMP software

Point Num.	Pressure psi	Temperature °F	User Oil Viscosity cp	Calculated Oil Viscosity cp	Calibration Factor
1	1200	140	30	38.761	0.774

Table B.88 Inflow data of R-13 well generated by SubPUMP software

IPR Calculation Method	PI
Total Test Rate, bpd	240
Productivity Index, bfpd/psi	1.5287
Bubble Point Rate, bpd	3666.66
Max. Oil Flow Rate, bpd	260
Max. Total Flow Rate, bpd	4333.33

Table B.89 Design criteria for R-13 well in SubPUMP software

Input Data	
Total Fluid Rate, bpd	500
Flow Line Pressure, psi	210
Casing Pressure, psi	0
Pump Depth, ft	4500
Output Data	
Fluid Over Pump, ft	1910.37
Fluid Level, ft	2518.77
Pump Intake Pressure, psi	829.52
Total Dynamic Head, ft	2973
Bottom Hole Pressure, psi	972.92
Gas ThRoughness Pump	Gas Compressed
Packer Installed	No
Percentage Free Gas Available at Pump, %	0
Percentage Free Gas into Pump, %	0

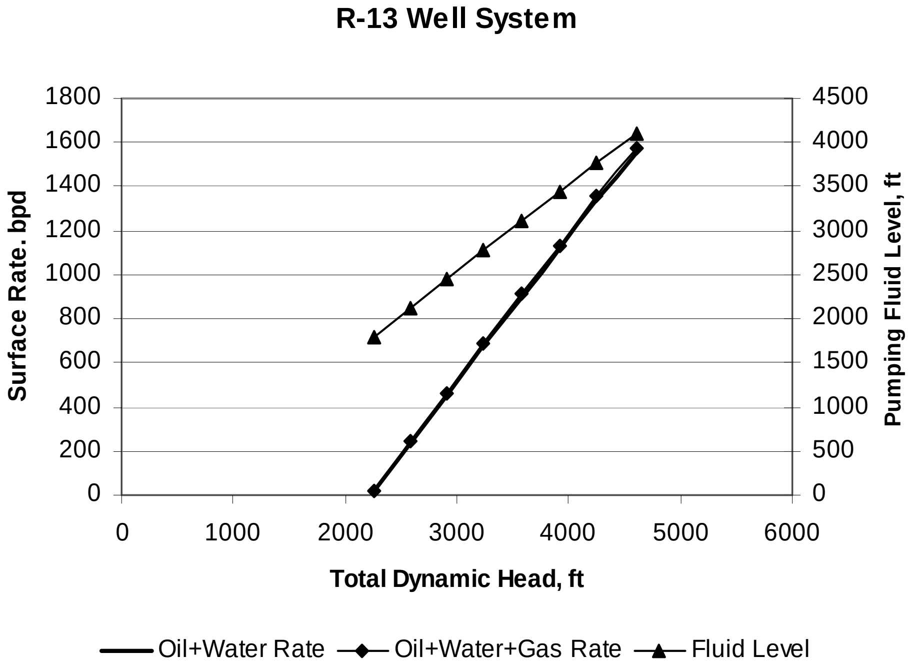

Figure B.16 Well system curve of R-13 well

Table B.90 Well system curve detail of R-13 well generated by SubPUMP software

Point Num.	Total Dynamic Head ft	Surface Rate O+W bpd	Avg. Pump Rate O+W+G bpd	Pumping Fluid Level ft
1	2255	18	18	1794.16
2	2578	238	241	2125.44
3	2909	457	464	2453.44
4	3242	677	687	2784.72
5	3577	897	910	3116
6	3915	1117	1132	3447.28
7	4256	1336	1355	3775.28
8	4604	1556	1578	4106.56
Pump Off	4955	1776	1801	4428
DESIGN	2973	500	507	768

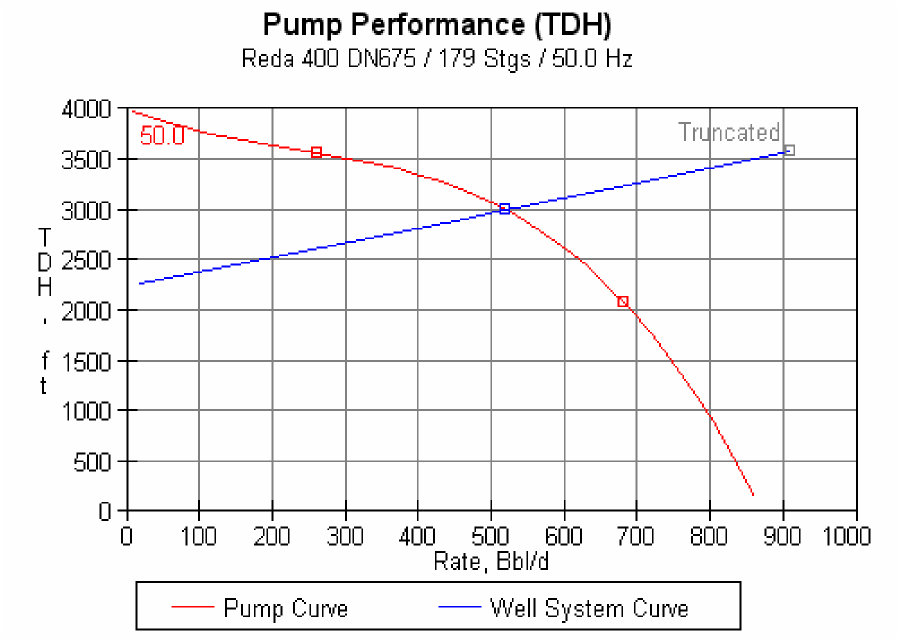

Figure B.17 Pump performance graph of R-13 well drawn by SubPUMP

Table B.91 Theoretical pump performance of R-13 well generated by SubPUMP software

	PUMP		SURFACE
	INTAKE	DISCHARGE	
Oil Rate, bpd	31.8	31.6	30.8
Gas Through Pump, bpd	0.0	0.0	N/A
Gas Rate From Casing, bpd	0.0	0.0	N/A
Free Gas Percentage, %	0.0	0.0	N/A
Water Rate, bpd	490	488.1	482.6
Total Rate, bpd	521.7	519.7	513.4
Pumping Pressure, psi	820.8	2155.6	100
Specific Gravity of Liquid, wtr = 1	1	1	N/A
Specific Gravity of Mixture, wtr = 1	1	1	N/A
Gas Deviation Factor	0.873	0.756	N/A

Table B.92 Pump data of R-13 well proposed by SubPUMP software

Manufacturer	REDA
Series	400
Model	DN 675
Minimum Recommended Rate, bpd	262.5 * *
Maximum Recommended Rate, bpd	681. * *
Design Frequency, Hz	50
Total Stages	179
Stages with Free Gas	0
Additional Stages Due to Gas	0

* *: Corrected for frequency and viscosity

Table B.93 Stage data of R-13 well proposed by SubPUMP software

	Design	256 Stages
Total Dynamic Head, ft	2973.1	3027.5
Surface Rate O+W, bpd	500	535.6
Average Pump Rate O+W+G, bpd	N/A	543.2
Pump Intake Pressure, psi	829.5	806.3
Operating Power, HP	N/A	20.1
Efficiency, %	N/A	59.1

Table B.94 Motor data of R-13 well proposed by SubPUMP software

Manufacturer	REDA
Series	540-I
Type	90-Single
Name Plate Power, HP	30
Name Plate Voltage, Volts	777
Name Plate Current, Amps	23
Name Plate Frequency, Hz	60
Adjust for Motor Slip	Yes
Design Frequency, Hz	50
Operating Motor Load, HP @ Design Frequency	19.7
Fluid Velocity, ft/sec	0.66
Well Fluid Temperature, ^{o}F	137.2

Table B.95 Seal section data of R-13 well proposed by SubPUMP software

Manufacturer	REDA
Series	400-456
Bearing Type	400 STD
Chamber Selection	66L
Bering Trust Capacity, lb	1333.3
Power Consumption, HP	0.4

Table B.96 Cable data of R-13 well proposed by SubPUMP software

Manufacturer	REDA
Type	Redablack
Size	4 Cu
Shape	Round
Conductor Type	Solid
Maximum Conductor Temperature, ^{o}F	300
Solve for	Surface Voltage
Cost, $/kwH	0.007
Frequency, Hz	50
Conductor Temperature, ^{o}F	154.5
Monthly Operating Cost, $/month	92

B.2 LoadCalC SOFTWARE INPUT AND OUTPUT DATA

Table B.97 Input and output data of R-1 well

Input	
Pump Depth, ft	3500
Fluid Level, ft	3864
Pump Size, in	2
Stroke Length, in	64
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	244
Total Production, bpd	122
Output	
Torque (in-lbs)	138,951
PPRL (lbs)	12,619
MPRL (lbs)	5,048
CBE (lbs)	9,272
Pumping Speed (spm)	5.71
PRHP (hp)	4.2
BPD @ 100%	122
BPD @ 80%	98
M.C. Eng./Nema 'C' Mtr	12
Max. Rod Stress (psi)	20,985
7/8 in. Rod Section (ft)	1,474
3/4 in. Rod Section (ft)	2,026
1/kt (in/lb)	0.221
1/kr (in/lb)	2.746
Sp (in)	45.8
Wr (lbs/ft)	1.882
Wrf (lbs)	5,879
Fo (lbs)	5,738
Skr (lbs)	23,305
Wrf/Skr	0.252
Fo/Skr	0.246
N/No	0.082
N/No'	0.075
Ta	0.936
Sp/S	0.773
F1/Skr	0.289
F2/Skr	0.036
F3/Skr	0.194
2T/S2kr	0.199

Table B.98 Input and output data of R-2 well

Input	
Pump Depth, ft	4600
Fluid Level, ft	4265
Pump Size, in	2
Stroke Length, in	64
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	167
Total Production, bpd	36
Output	
Torque (in-lbs)	122,863
PPRL (lbs)	14,012
MPRL (lbs)	7,465
CBE (lbs)	11,347
Pumping Speed (spm)	2.12
PRHP (hp)	1.4
BPD @ 100%	36
BPD @ 80%	29
M.C. Eng./Nema 'C' Mtr	3.7
Max. Rod Stress (psi)	23,302
Min. Rod Stress (psi)	12,414
7/8 in. Rod Section (ft)	1,937
3/4 in. Rod Section (ft)	2,663
1/kt (in/lb)	0.221
1/kr (in/lb)	3.609
Sp (in)	36.4
Wr (lbs/ft)	1.882
Wrf (lbs)	7,699
Fo (lbs)	6,012
Skr (lbs)	17,732
Wrf/Skr	0.434
Fo/Skr	0.339
N/No	0.04
N/No'	0.036
Ta	1.009
Sp/S	0.669
F1/Skr	0.356
F2/Skr	0.013
F3/Skr	0.223
2T/S2kr	0.215

Table B.99 Input and output data of R-4 well

Input	
Pump Depth, ft	4200
Fluid Level, ft	3608
Pump Size, in	1.75
Stroke Length, in	64
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	473
Total Production, bpd	30
Output	
Torque (in-lbs)	107,189
PPRL (lbs)	11,907
MPRL (lbs)	6,713
CBE (lbs)	9,846
Pumping Speed (spm)	1.87
PRHP (hp)	1.1
BPD @ 100%	30
BPD @ 80%	24
M.C. Eng./Nema 'C' Mtr	3.1
Max. Rod Stress (psi)	19,802
Min. Rod Stress (psi)	11,164
7/8 in. Rod Section (ft)	1,588
3/4 in. Rod Section (ft)	2,612
1/kt (in/lb)	0.221
1/kr (in/lb)	3.338
Sp (in)	44.7
Wr (lbs/ft)	1.857
Wrf (lbs)	6,943
Fo (lbs)	4,692
Skr (lbs)	19,174
Wrf/Skr	0.362
Fo/Skr	0.245
N/No	0.032
N/No'	0.03
Ta	0.975
Sp/S	0.762
F1/Skr	0.259
F2/Skr	0.012
F3/Skr	0.184
2T/S2kr	0.179

Table B.100 Input and output data of R-5 well

Input	
Pump Depth, ft	4000
Fluid Level, ft	3618
Pump Size, in	2
Stroke Length, in	144
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	391
Total Production, bpd	1125
Output	
Torque (in-lbs)	777,712
PPRL (lbs)	21,141
MPRL (lbs)	477
CBE (lbs)	10,226
Pumping Speed (spm)	17.89
PRHP (hp)	54.1
BPD @ 100%	1,125
BPD @ 80%	900
M.C. Eng./Nema 'C' Mtr	113
Max. Rod Stress (psi)	35,157
Min. Rod Stress (psi)	794
7/8 in. Rod Section (ft)	1,685
3/4 in. Rod Section (ft)	2,315
1/kt (in/lb)	0.221
1/kr (in/lb)	3.139
Sp (in)	134.8
Wr (lbs/ft)	1.882
Wrf (lbs)	6,706
Fo (lbs)	5,883
Skr (lbs)	45,881
Wrf/Skr	0.146
Fo/Skr	0.128
N/No	0.292
N/No'	0.267
Ta	0.891
Sp/S	0.97
F1/Skr	0.315
F2/Skr	0.136
F3/Skr	0.181
2T/S2kr	0.264

Table B.101 Input and output data of R-6

Input	
Pump Depth, ft	4000
Fluid Level, ft	2116
Pump Size, in	2
Stroke Length, in	144
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	991
Total Production, bpd	1250
Output	
Torque (in-lbs)	815,520
PPRL (lbs)	21,829
MPRL (lbs)	117
CBE (lbs)	10,201
Pumping Speed (spm)	19.62
PRHP (hp)	62.5
BPD @ 100%	1,250
BPD @ 80%	1,000
M.C. Eng./Nema 'C' Mtr	122.3
Max. Rod Stress (psi)	36,302
Min. Rod Stress (psi)	195
7/8 in. Rod Section (ft)	1,685
3/4 in. Rod Section (ft)	2,315
1/kt (in/lb)	0.221
1/kr (in/lb)	3.139
Sp (in)	136.6
Wr (lbs/ft)	1.882
Wrf (lbs)	6,706
Fo (lbs)	5,836
Skr (lbs)	45,881
Wrf/Skr	0.146
Fo/Skr	0.127
N/No	0.32
N/No'	0.293
Ta	0.902
Sp/S	0.982
F1/Skr	0.33
F2/Skr	0.144
F3/Skr	0.191
2T/S2kr	0.274

Table B.102 Input and output data of R-7 well

Input	
Pump Depth, ft	4200
Fluid Level, ft	2884
Pump Size, in	1.75
Stroke Length, in	64
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	696
Total Production, bpd	62
Output	
Torque (in-lbs)	112,659
PPRL (lbs)	12,068
MPRL (lbs)	6,435
CBE (lbs)	9,753
Pumping Speed (spm)	3.79
PRHP (hp)	2.2
BPD @ 100%	62
BPD @ 80%	50
M.C. Eng./Nema 'C' Mtr	6.2
Max. Rod Stress (psi)	20,069
Min. Rod Stress (psi)	10,702
7/8 in. Rod Section (ft)	1,588
3/4 in. Rod Section (ft)	2,612
1/kt (in/lb)	0.221
1/kr (in/lb)	3.338
Sp (in)	45.8
Wr (lbs/ft)	1.857
Wrf (lbs)	6,943
Fo (lbs)	4,515
Skr (lbs)	19,174
Wrf/Skr	0.362
Fo/Skr	0.235
N/No	0.065
N/No'	0.06
Ta	0.979
Sp/S	0.779
F1/Skr	0.267
F2/Skr	0.026
F3/Skr	0.184
2T/S2kr	0.188

Table B.103 Input and output data of R-8 well

Input	
Pump Depth, ft	4500
Fluid Level, ft	4357
Pump Size, in	2
Stroke Length, in	64
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	85
Total Production, bpd	113
Output	
Torque (in-lbs)	142,081
PPRL (lbs)	14,720
MPRL (lbs)	6,471
CBE (lbs)	11,098
Pumping Speed (spm)	6.17
PRHP (hp)	4.3
BPD @ 100%	113
BPD @ 80%	90
M.C. Eng./Nema 'C' Mtr	11.4
Max. Rod Stress (psi)	24,480
Min. Rod Stress (psi)	10,761
7/8 in. Rod Section (ft)	1,895
3/4 in. Rod Section (ft)	2,605
1/kt (in/lb)	0.221
1/kr (in/lb)	3.531
Sp (in)	39.2
Wr (lbs/ft)	1.882
Wrf (lbs)	7,533
Fo (lbs)	5,873
Skr (lbs)	18,126
Wrf/Skr	0.416
Fo/Skr	0.324
N/No	0.113
N/No'	0.104
Ta	1
Sp/S	0.708
F1/Skr	0.397
F2/Skr	0.059
F3/Skr	0.238
2T/S2kr	0.245

Table B.104 Input and output data of R-9 well

Input	
Pump Depth, ft	4000
Fluid Level, ft	1810
Pump Size, in	2
Stroke Length, in	144
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	1094
Total Production, bpd	1125
Output	
Torque (in-lbs)	768,062
PPRL (lbs)	20,954
MPRL (lbs)	549
CBE (lbs)	10,164
Pumping Speed (spm)	17.85
PRHP (hp)	53.2
BPD @ 100%	1,125
BPD @ 80%	900
M.C. Eng./Nema 'C' Mtr	108.4
Max. Rod Stress (psi)	34,846
Min. Rod Stress (psi)	913
7/8 in. Rod Section (ft)	1,685
3/4 in. Rod Section (ft)	2,315
1/kt (in/lb)	0.221
1/kr (in/lb)	3.139
Sp (in)	135.1
Wr (lbs/ft)	1.882
Wrf (lbs)	6,706
Fo (lbs)	5,766
Skr (lbs)	45,881
Wrf/Skr	0.146
Fo/Skr	0.126
N/No	0.291
N/No'	0.267
Ta	0.889
Sp/S	0.972
F1/Skr	0.311
F2/Skr	0.134
F3/Skr	0.178
2T/S2kr	0.262

Table B.105 Input and output data of R-10 well

Input	
Pump Depth, ft	4500
Fluid Level, ft	3097
Pump Size, in	2
Stroke Length, in	106
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	616
Total Production, bpd	1375
Output	
Torque (in-lbs)	680,561
PPRL (lbs)	26,522
MPRL (lbs)	-3,024
CBE (lbs)	11,123
Pumping Speed (spm)	25.57
PRHP (hp)	77.8
BPD @ 100%	1,375
BPD @ 80%	1,100
M.C. Eng./Nema 'C' Mtr	138.1
Max. Rod Stress (psi)	44,106
Min. Rod Stress (psi)	-5,029
7/8 in. Rod Section (ft)	1,895
3/4 in. Rod Section (ft)	2,605
1/kt (in/lb)	0.221
1/kr (in/lb)	3.531
Sp (in)	115.3
Wr (lbs/ft)	1.882
Wrf (lbs)	7,533
Fo (lbs)	5,920
Skr (lbs)	30,021
Wrf/Skr	0.251
Fo/Skr	0.197
N/No	0.47
N/No'	0.43
Ta	0.931
Sp/S	1.145
F1/Skr	0.633
F2/Skr	0.352
F3/Skr	0.378
2T/S2kr	0.459

Table B.106 Input and output data of R-11 well

Input	
Pump Depth, ft	4500
Fluid Level, ft	3376
Pump Size, in	2
Stroke Length, in	54
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	551
Total Production, bpd	250
Output	
Torque (in-lbs)	170,829
PPRL (lbs)	16,329
MPRL (lbs)	4,379
CBE (lbs)	11,205
Pumping Speed (spm)	15.98
PRHP (hp)	11.8
BPD @ 100%	250
BPD @ 80%	200
M.C. Eng./Nema 'C' Mtr	25.8
Max. Rod Stress (psi)	27,155
Min. Rod Stress (psi)	7,282
7/8 in. Rod Section (ft)	1,895
3/4 in. Rod Section (ft)	2,605
1/kt (in/lb)	0.221
1/kr (in/lb)	3.531
Sp (in)	33.5
Wr (lbs/ft)	1.882
Wrf (lbs)	7,533
Fo (lbs)	6,074
Skr (lbs)	15,294
Wrf/Skr	0.493
Fo/Skr	0.397
N/No	0.294
N/No'	0.269
Ta	1.005
Sp/S	0.734
F1/Skr	0.575
F2/Skr	0.206
F3/Skr	0.352
2T/S2kr	0.412

Table B.107 Input and output data of R-12 well

Input	
Pump Depth, ft	4400
Fluid Level, ft	3038
Pump Size, in	2
Stroke Length, in	144
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	689
Total Production, bpd	1250
Output	
Torque (in-lbs)	849,164
PPRL (lbs)	23,030
MPRL (lbs)	159
CBE (lbs)	11,029
Pumping Speed (spm)	19.7
PRHP (hp)	66.6
BPD @ 100%	1,250
BPD @ 80%	1,000
M.C. Eng./Nema 'C' Mtr	128.6
Max. Rod Stress (psi)	38,300
Min. Rod Stress (psi)	264
7/8 in. Rod Section (ft)	1,853
3/4 in. Rod Section (ft)	2,547
1/kt (in/lb)	0.221
1/kr (in/lb)	3.452
Sp (in)	136.1
Wr (lbs/ft)	1.882
Wrf (lbs)	7,368
Fo (lbs)	6,073
Skr (lbs)	41,710
Wrf/Skr	0.177
Fo/Skr	0.146
N/No	0.354
N/No'	0.324
Ta	0.93
Sp/S	0.985
F1/Skr	0.376
F2/Skr	0.173
F3/Skr	0.223
2T/S2kr	0.304

Table B.108 Input and output data of R-13 well

Input	
Pump Depth, ft	4500
Fluid Level, ft	2024
Pump Size, in	2
Stroke Length, in	84
Rod Size	76
Specific Gravity	0.946
Tubing OD, in	2.875
Flowline Pressure, psi	1143
Total Production, bpd	625
Output	
Torque (in-lbs)	381,165
PPRL (lbs)	20,389
MPRL (lbs)	3,401
CBE (lbs)	11,269
Pumping Speed (spm)	18.95
PRHP (hp)	30.4
BPD @ 100%	625
BPD @ 80%	500
M.C. Eng./Nema 'C' Mtr	64.8
Max. Rod Stress (psi)	33,907
Min. Rod Stress (psi)	5,655
7/8 in. Rod Section (ft)	1,895
3/4 in. Rod Section (ft)	2,605
1/kt (in/lb)	0.221
1/kr (in/lb)	3.531
Sp (in)	70.7
Wr (lbs/ft)	1.882
Wrf (lbs)	7,533
Fo (lbs)	6,195
Skr (lbs)	23,790
Wrf/Skr	0.317
Fo/Skr	0.26
N/No	0.348
N/No'	0.319
Ta	0.983
Sp/S	0.915
F1/Skr	0.54
F2/Skr	0.174
F3/Skr	0.318
2T/S2kr	0.388

APPENDIX C

SUCKER ROD PUMP AND ELECTRICAL SUBMERSIBLE PUMP SYSTEM'S UNITS AND PRICE

Table C.1 Sucker rod pump system's pumping unit price list [12]

Well	Manufacturer	Pumping Unit	Price $
R-1	Lufkin	C-160D-143-64	34000
R-2	Lufkin	C-160D-200-74	34000
R-3	Lufkin	C-320D-213-86	37000
R-4	Lufkin	C-114D-143-64	30000
R-5	Lufkin	C-912D-305-168	55000
R-6	Lufkin	C-912D-305-168	55000
R-7	Lufkin	C-114D-173-64	30000
R-8	Lufkin	C-160D-173-64	34000
R-9	Lufkin	C-912D-365-144	55000
R-10	Lufkin	C-640D-305-144	45000
R-11	Lufkin	C-228D-200-74	35000
R-12	Lufkin	C-912D-365-144	55000
R-13	Lufkin	C-456D-256-100	40000

Table C.2 Sucker rod pump system's prime mover price list [25]

Well	Manufacturer	Prime Mover HP	KWh	Price $
R-1	Baldor	15	11.2	2938
R-2	Baldor	5	3.7	1111
R-3	Baldor	50	37	6200
R-4	Baldor	5	3.7	1111
R-5	Baldor	125	93	11735
R-6	Baldor	125	93	11735
R-7	Baldor	7.5	6.5	1475
R-8	Baldor	15	11.2	2938
R-9	Baldor	125	93	11735
R-10	Baldor	125	93	11735
R-11	Baldor	30	22.4	4698
R-12	Baldor	128	93	11735
R-13	Baldor	60	44.8	8199

Table C.3 Sucker rod pump system's rods price list [13]

Well	Rod Type in	Length ft	Price $/ft	Price $
R-1	7/8 in -3/4 in	1475 - 2025	1.43 - 1.35	4843
R-2	7/8 in -3/4 in	1925- 2675	1.43 - 1.35	6364
R-3	7/8 in -3/4 in	1100 - 1900	1.43 - 1.35	4138
R-4	7/8 in -3/4 in	1575 - 2625	1.43 - 1.35	4632
R-5	7/8 in -3/4 in	1675 - 2325	1.43 - 1.35	5534
R-6	7/8 in -3/4 in	1675 - 2325	1.43 - 1.35	5534
R-7	7/8 in -3/4 in	1575 - 2625	1.43 - 1.35	4632
R-8	7/8 in -3/4 in	1900 - 2610	1.43 - 1.35	6240
R-9	7/8 in -3/4 in	1675 - 2325	1.43 - 1.35	5534
R-10	7/8 in -3/4 in	1900 - 2610	1.43 - 1.35	6240
R-11	7/8 in -3/4 in	1900 - 2610	1.43 - 1.35	6240
R-12	7/8 in -3/4 in	1850 - 2550	1.43 - 1.35	6088
R-13	7/8 in -3/4 in	2605 - 1895	1.43 - 1.35	6283

Table C.4 Electrical submersible pump system’s pumping units price list [10]

Well	Manufacturer	Pump			Price $
		Series	Model	Stage num.	
R-1	REDA	400	DN440	176	8705
R-3	REDA	338	AN400	224	11441
R-5	REDA	400	DN1100	273	16269
R-6	REDA	400	DN2150	256	15061
R-9	REDA	400	DN1100	171	9601
R-10	REDA	400	DN1300	277	11735
R-11	REDA	400	DN440	216	10358
R-12	REDA	400	DN1300	256	11016
R-13	REDA	400	DN675	179	7182

Table C.5 Electrical submersible pump system’s motors price list [10]

Well	Manufacturer	Motor			Price $
		Series	Type	HP	
R-1	REDA	456	90-0	12.5	6804
R-3	REDA	375	87	25.5	11300
R-5	REDA	540-I	91	70	14696.8
R-6	REDA	540	90-O	125	22861.6
R-9	REDA	540-I	91	40	8927.2
R-10	REDA	540-I	OLD V&A	60	14011.2
R-11	REDA	540	90-O	25	7316
R-12	REDA	540-I	91	60	14011.2
R-13	REDA	540-I	91	30	8273.6

Table C.6 Electrical submersible pump system's seals price list [10]

Well	Manufacturer	SEAL			Price $
		Series	Bearing	Chamber	
R-1	REDA	400-456	400HL	LSLSB-HL	9248
R-3	REDA	325-375	325STD	PF SB HTM	6386
R-5	REDA	400-456	400HL	LSL-HL	7358
R-6	REDA	400-456	400STD	66L	6124
R-9	REDA	375	375STD	66L	6930
R-10	REDA	400-456	400HL	LSB-HL	7862
R-11	REDA	400-456	400STD	66L	6124
R-12	REDA	400-456	400KMC	66L	6124
R-13	REDA	400-456	400STD	66L	6124

Table C.7 Electrical submersible pump system's cable price list [10]

Well	Manufacturer	CABLE				Price $
		Type	AWG	Length ft	Price, $/ft	
R-1	REDA	Redablack	4 Cu	4200	1.5	6450
R-3	REDA	Polyethlene	6 Cu	4200	0.75	3225
R-5	REDA	Redablack	4 Cu	4530	1.05	4861.5
R-6	REDA	Redablack	4 Cu	4370	1.05	4693.5
R-9	REDA	Redablack	4 Cu	4200	1.05	4515
R-10	REDA	Redablack	2 Cu	4530	1.35	6250.5
R-11	REDA	Redablack	4 Cu	4780	1.05	5124
R-12	REDA	Redablack	4 Cu	4690	1.05	5029.5
R-13	REDA	Redablack	4 Cu	4530	1.05	4861.5

Table C.8 Electrical submersible pump system's motor controller price list

Well	Manufacturer	Price, $
R-1	REDA	3000
R-3	REDA	2500
R-5	REDA	3250
R-6	REDA	2750
R-9	REDA	2000
R-10	REDA	3750
R-11	REDA	2200
R-12	REDA	3600
R-13	REDA	1950

APPENDIX D

INCOME AND COST TABLES OF THIRTEEN R WELLS

Table D.1 Income of present lift methods in R- field [13, 15]

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						
2005	857	750	21	6,569,040	6,240,588	4,056,382
2006	800	700	21	6,133,539	5,826,862	3,787,461
2007	747	654	21	5,726,911	5,440,565	3,536,367
2008	698	610	21	5,347,240	5,079,878	3,301,921
2009	651	570	21	4,992,740	4,743,103	3,083,017
2010	608	532	21	4,661,742	4,428,655	2,878,626
2011	568	497	21	4,352,688	4,135,053	2,687,785
2012	530	464	21	4,064,123	3,860,916	2,509,596
2013	495	433	21	3,794,688	3,604,954	2,343,220
2014	462	404	21	3,543,116	3,365,960	2,187,874

Table D.2 Cost of present lift methods in R-field [13]

Year	Personnel $/y	Maintenance $/y	Energy $/y	Disbursement $/y	NET CASH FLOW $/y
2004				638,468	-638,468
2005	938,434	1,690,057	30728	2,659,219	1,397,163
2006	876,220	1,586,367	30728	2,493,314	1,294,146
2007	818,130	1,623,350	30728	2,472,208	1,064,159
2008	763,891	1,399,152	30728	2,193,772	1,108,149
2009	713,249	1,314,748	30728	2,058,724	1,024,293
2010	665,963	1,369,739	30728	2,066,430	812,196
2011	621,813	1,162,354	30728	1,814,895	872,890
2012	580,589	1,093,648	30728	1,704,965	804,631
2013	542,098	1,163,297	30728	1,736,123	607,096
2014	506,159	969,599	30728	1,506,486	681,388

Table D.3 Income of Case 1-A (producing 9 wells with SRP) [13, 15]

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						
2005	1118	978	21	7,500,164	7,125,156	4,631,351
2006	1044	914	21	7,002,934	6,652,787	4,324,312
2007	975	853	21	6,538,668	6,211,735	4,037,628
2008	910	797	21	6,105,182	5,799,923	3,769,950
2009	850	744	21	5,700,433	5,415,412	3,520,018
2010	794	694	21	5,322,518	5,056,392	3,286,655
2011	741	648	21	4,969,657	4,721,174	3,068,763
2012	692	605	21	4,640,189	4,408,180	2,865,317
2013	646	565	21	4,332,564	4,115,935	2,675,358
2014	603	528	21	4,045,333	3,843,066	2,497,993

Table D.4 Cost of Case 1-A [13]

Year	Personnel $/y	Maintenance $/y	Energy $/y	Disbursements $/y	NET CASH FLOW $/y
2004				537,055	-537,055
2005	1,224,517	2,166,861	40,000	3,431,378	1,199,974
2006	1,143,336	2,031,560	40,000	3,214,897	1,109,415
2007	1,067,538	1,905,230	40,000	3,012,767	1,024,861
2008	996,764	1,787,274	40,000	2,824,038	945,911
2009	930,683	1,677,138	40,000	2,647,821	872,196
2010	868,983	1,574,304	40,000	2,483,287	803,368
2011	811,373	1,478,288	40,000	2,329,660	739,103
2012	757,582	1,388,636	40,000	2,186,218	679,098
2013	707,357	1,304,929	40,000	2,052,286	623,072
2014	660,462	1,226,771	40,000	1,927,233	570,760

Table D.5 Income of Case 1-B (producing 9 wells with ESP) [13, 15]

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						-
2005	1256	1099	21	8,420,482	7,999,457	5,473,313
2006	1172	1026	21	7,862,238	7,469,126	5,110,455
2007	1095	958	21	7,341,004	6,973,954	4,771,653
2008	1022	894	21	6,854,326	6,511,610	4,455,312
2009	954	835	21	6,399,912	6,079,917	4,159,943
2010	891	780	21	5,975,624	5,676,843	3,884,156
2011	832	728	21	5,579,465	5,300,492	3,626,652
2012	777	680	21	5,209,570	4,949,091	3,386,220
2013	725	635	21	4,864,197	4,620,987	3,161,728
2014	677	593	21	4,541,720	4,314,634	2,952,118

Table D.6 Cost of Case 1-B [13]

Year	Personnel $/y	Maintenance $/y	Energy $/y	Disbursements $/y	NET CASH FLOW $/y
2004				447,495	-447,495
2005	1,374,773	2,291,288	18,660	3,684,720	1,788,593
2006	1,283,631	2,139,385	18,660	3,441,675	1,668,780
2007	1,198,531	2,243,122	18,660	3,460,313	1,311,339
2008	1,119,074	1,865,123	18,660	3,002,856	1,452,456
2009	1,044,884	1,741,473	18,660	2,805,016	1,354,927
2010	975,612	1,871,590	18,660	2,865,862	1,018,293
2011	910,933	1,518,222	18,660	2,447,815	1,178,837
2012	850,542	1,417,570	18,660	2,286,772	1,099,448
2013	794,155	1,569,161	18,660	2,381,975	779,752
2014	741,505	1,235,842	18,660	1,996,008	956,111

Table D.7 Income of Case 2-A (producing 13 wells with SRP) [13, 15]

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						-
2005	1206	1055	21	9,240,311	8,778,295	6,006,202
2006	1126	985	21	8,627,716	8,196,330	5,608,016
2007	1051	920	21	8,055,734	7,652,947	5,236,227
2008	981	859	21	7,521,672	7,145,589	4,889,087
2009	916	802	21	7,023,016	6,671,865	4,564,961
2010	856	749	21	6,557,419	6,229,548	4,262,322
2011	799	699	21	6,122,689	5,816,555	3,979,748
2012	746	653	21	5,716,780	5,430,941	3,715,907
2013	696	609	21	5,337,781	5,070,892	3,469,558
2014	650	569	21	4,983,908	4,734,713	3,239,540

Table D.8 Cost of Case 2-A [13]

Year	Personnel $/y	Maintenance $/y	Energy $/y	Disbursements $/y	NET CASH FLOW $/y
2004				698,647	-698,647
2005	1,320,044	2,382,074	36,552	3,738,670	2,267,532
2006	1,232,531	2,236,218	36,552	3,505,301	2,102,715
2007	1,150,819	2,100,032	36,552	3,287,403	1,948,824
2008	1,074,525	1,972,874	36,552	3,083,951	1,805,136
2009	1,003,288	1,854,147	36,552	2,893,987	1,670,974
2010	936,774	1,743,290	36,552	2,716,616	1,545,706
2011	874,670	1,639,783	36,552	2,551,005	1,428,743
2012	816,683	1,543,138	36,552	2,396,373	1,319,534
2013	762,540	1,452,900	36,552	2,251,992	1,217,565
2014	711,987	1,368,645	36,552	2,117,184	1,122,357

Table D.9 Income of Case 2-B (producing 9 wells with ESP, 4 wells with SRP) [13, 15]

Year	Oil Production bpd	After Royalty bpd	Oil Price $/bbl	Income $/y	After Insurance $/y	After Tax Net Income $/y
2004						-
2005	1343	1175	21	10,292,102	9,777,497	6,689,866
2006	1254	1097	21	9,609,778	9,129,289	6,246,356
2007	1171	1024	21	8,972,689	8,524,055	5,832,248
2008	1093	956	21	8,377,837	7,958,945	5,445,594
2009	1021	893	21	7,822,421	7,431,300	5,084,574
2010	953	834	21	7,303,827	6,938,635	4,747,487
2011	890	778	21	6,819,613	6,478,632	4,432,748
2012	831	727	21	6,367,501	6,049,126	4,138,875
2013	776	679	21	5,945,362	5,648,093	3,864,485
2014	724	634	21	5,551,209	5,273,648	3,608,286

Table D.10 Cost of Case 2-B [13]

Year	Personnel $/y	Maintenance $/y	Energ y $/y	Disbursements $/y	NET CASH FLOW $/y
2004				609,087	-609,087
2005	1,470,300	2,506,501	20,136	3,996,937	2,692,930
2006	1,372,825	2,344,042	20,136	3,737,004	2,509,352
2007	1,281,813	2,437,925	20,136	3,739,873	2,092,375
2008	1,196,834	2,050,723	20,136	3,267,693	2,177,901
2009	1,117,489	1,918,481	20,136	3,056,106	2,028,468
2010	1,043,404	2,040,576	20,136	3,104,116	1,643,371
2011	974,230	1,679,717	20,136	2,674,084	1,758,665
2012	909,643	1,572,072	20,136	2,501,851	1,637,025
2013	849,337	1,717,132	20,136	2,586,606	1,277,879
2014	793,030	1,377,716	20,136	2,190,882	1,417,403