MONTAN UNIVERSITAT LEOBEN

Department of Mineral Resources and Petroleum Engineering

Amal field artificial lift optimization

partial fulfillment of the requirements for the degree of MASTER OF SCIENCE

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Affidavit

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

Ahmed Elwefati

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Abstract

Amal field Concession 12 is one of the oldest fields Libya was relying on in the past 50 years, The production of the field has been fallen dramatically in the past 20 years to be less than 30,000 bbl/days instead of nearly 100,000 bbl/day in the late 80's , this reduction is not only because of the exploitation of the reservoir, where some of the wells has been re-designed in the last decade, most of the wells however are still operated with artificial lift designs made in the early 90's.

less than the half of the operated wells in the field have been re-designed in the last decade, the rest however are still operated with an artificial lift designs made in the early 90's, thus 10 wells (8 gas lift wells, and 2 ESP wells) has been chosen to be re-modeled in this study considering the current production conditions ie. Water cut, gas liquid ratio, productivity index, reservoir pressure, ..etc. PROSPER (the well modeling, design and optimization software) is used for this purpose which provided by Montan universitat computer labs

The gas lifting method is the most preferable artificial lift method in the field since the gas needed for the operation and the necessary surface facility (compressors and gas loops) are already available, however some wells specially with the higher water cut percentage need a tremendous amount of injected gas to produce a small amount of oil. this brings the electrical submersible pumps to the competition, as it has the capability to work more efficiently than the gas lift method in the presence of high water cut percentage, , however the cost of purchasing, installing and the production interruption due to ESP's maintenance is a good reason to think twice before deciding which artificial lift method should be used. Therefore, an economic study is conducted for these wells in order to figure out which artificial method is more likely to be chosen.

Kurzfassung

Amal field Concession 12 ist eines der ältesten Felder auf das Libyen die letzten 50 Jahre angewiesen war. Die Fördermenge dieses Feldes fiel die letzten 20 Jahre dramatisch auf weniger als 30,000 bbl/days anstatt fast 100.000 bbl/day in den späten 80ern. Diese Verringerung gibt es nicht nur wegen der Ausbeutung des Reservoirs, in dem einige der Bohrlöcher die letzten 10 Jahre überholt wurden, viele der Bohrlöcher werden vielmehr nach wie vor mit artificial lift designs betrieben die aus den frühen 90ern stammen.

Weniger als die Hälfte der betriebenen Bohrlöcher im Feld wurden in den letzten 10 Jahren umgebaut, der Rest allerdings wird nach wie vor mit einem artificial lift design betrieben das nicht den derzeitigen Bedingungen der Bohrlöcher entspricht. Daher wurden 10 Bohrlöcher (8 gas lift , und 2 ESP Bohrlöcher) unter Berücksichtigung der aktuellen Produktionsbedingungen z.B. Water cut, gas liquid ratio, productivity index, reservoir pressure, etc. zum Umbau ausgewählt. PROSPER (Bohrlochmodellierungs, -design und -optimierungssoftware) wird für diesen Zweck verwendet und wurde von den Computerlabors der Montanuniversität zur Verfügung gestellt.

Die gas lifting Methode ist die meist bevorzugte artificial lift Methode im Feld weil das benötigte Gas für das Verfahren und die notwendige surface facility (Kompressor und gas loops) bereits verfügbar sind. Andererseits brauchen manche Bohrlöcher, im speziellen solche mit hohem water cut Anteil eine enorme Menge an injiziertem Gas um nur eine kleine Menge an Öl zu fördern. Dies bringt die elektrischen Tauchpumpen ins Spiel da sie das Potential haben in Anwesenheit von hohem water cut Anteil effizienter als die gas lift Methode zu arbeiten. Jedoch sind die Kosten für Anschaffung, Installation und Förderunterbrechungen aufgrund von Wartungen ein guter Grund es sich zweimal zu überlegen welche artificial lift Methode verwendet werden sollte. Daher wird eine Wirtschaftlichkeitsstudie für diese Bohrlöcher durchgeführt um herauszufinden welche artificial lift Methode wahrscheinlicher ist gewählt zu werden.

Dedication

This work is dedicated with love to

the merciful God

My parents for their support, love and prayers

My two brothers and sister

Acknowledgments

First of all, I would like to express the embrace and thanks to Allah. Then all the thanks to my brother waleed and my friend Ameer Glia who played a great rule in order to accommodate the field Data , also my gratitude to those who have offered me the technical advice, also to Alhrooj Oil Company which provided me with the field data I used in the study.

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Introduction

Amal field is one of the giant fields in Libya, was discovered in November 1959. It has a productive area of some 500 km2, and it possesses more than five (5) billion barrels as a reserve. Production peaked to 210,000 from about 100 wells in 1970. There was a 32-well infill-drilling program over the 1980s to 1990s. At the end of year 2007 the field was producing about 37,000 bopd from 70 wells with a water cut of 52%. Cumulative oil production was 980 million barrels over the 40-year production history to date giving a recovery factor of 20%. Most of the wells are on gas-lift, with a few on ESP.

Amal Field's production is grouped into 10 substations (stations 1 to 10). Stations 8, 9, and 10 are not connected to the rest of the stations via the gas distribution system and are thus not included in this gas optimization study.

The oil production of the Amal field, predominantly assisted by gas lift, is currently around 37,000 bopd, with associated gas production of 36 MMSCFD. Gas Lift system utilizes 117 MMSCFD of injection gas that is constantly re-circulated through the Separation system and the Gas Compression units via the ring main system. Making best use of lift gas and optimization is a high priority for Amal, as its production relies heavily on the gas lift system which is of high maintenance.

Amal gas lift system is designed to re-circulate the lift gas in a closed rotative system. Excess gas production is flared to the atmosphere. Continuous flow gas lift operations are preferable because of the constant gas injection requirement and constant return of gas to the low production facility.

Chapter1 Amal Field Overview

1 System Description

1.1 Gas lift loops

The field possesses seven compression stations, the compressors discharge units of the seven acting stations are linked to a high pressure loop, where gas can be supplied to any well either from the hp loop or directly from operating station. The pressure control of the production system is designed to relieve the pressure at the suction of the gas lift compressors – this means that when the pressure exceeds a preset value (around 40 psig) the pressure control valve (PCV) will open and relieve the excess gas to the flare. The pipeline dimensions of the HP gas loop are available.

1.2 Low Pressure Gas Loop

The LP gas loop is available only between stations 1, 2 and 4. Currently they are using this facility to send low pressure gas from station 4 to station 2 when required. Mostly the gas will go by its own pressure differential, but there is also a small transfer compressor that can be used to transfer gas if required. The pipeline dimensions of the LP gas loop are available.

1.3 The compression stations

The stations house the separation and compression facilities. The separated fluid is also processed further and pumped out by transfer pumps. The stations from 1 to 7 are connected to gas lifted and ESP wells, station 9 has ESP and naturally flowing (NF) wells. Station 10 provided only by NF wells. The associated gas produced in the last two stations is flared. Station 8 is not producing.

1.4 The compression system

It's a 3-stage, reciprocating (piston type) compressors, driven by gas engines with the exception of two units which are motor driven. The gas after every stage is cooled using finned air coolers and passed through a scrubber to knock off the liquid. This liquid is returned to the production system via a liquid recovery unit (LRU).

Most of these units have been installed under different periods of time in the 70's and 80's. The maintenance of these units and availability of spare parts are major challenges. Amal field operation is significantly influenced by the compressor availability and performance.

Even though the field has a capacity of 148.8 MMscf/D, many compressors are shut-down or under maintenance. Table(1.1) shows the compression status as of 18 Feb 2010 in the Amal Field where the compressed volume is captured as 72.3 MMscf/D. Part of the reason for this is that the field is under a production quota now, and due to the compressor related issues the field would prefer to keep the ESP wells on production and shut-in some of the GL wells.

	Rated Capacity MMscf/D	Actuals for the day MMscf/D
Station 1	8.8	6.4
Station 2	29.5	19.8
Station 3	22.6	15
Station 4	37.3	17
Station 5	12.3	6.5
Station 6	30.5	0
Station 7	7.5	7.64
	148.5	**72.34**

Table 1 compression status as of 18 Feb 2010

1.5 Production Separation System

The productions separators are in parallel operation also test separator operating in parallel with the production separator. Currently only one production separator is in service in Stations 7, 1 and 5. One of the two production separators available in each of Station 3 and 4 are currently under maintenance. The production and test separators are 3-phase. The oil and water outlet lines of the test separator measured bya turbine meter,the gas is measured via orifice meters installed on the separator outlet.

Water from the separators is run into skimmer tanks and disposed through water pits or further processed and injected back into the reservoir. Water treatment is done in stations 3, 5 and 6 for reservoir injection (wells N-4, 11 and 15).

De-emulsifiers are injected into the separators to enhance the quality of separation. Corrosion inhibitor is also used.

The oil outlet of production separator is directed to gas boot where the gas is stripped off. The oil is then run through wash tank and run tank (to remove traces of water) before being pumped by transfer pump. The pumped oil is heated and then goes through metering before leaving the station.

1.6 Operation Data

There are very little operation data available from the production operations,table (2) lists some of the operation parameters in station 2.

LOCATION	PRESSURE, PSIG
Production manifold	37
Production Separator	35
Compressor skid arrival pressure	30
Compressor stage pressures	26 / 124 / 370 / 1140

Table 2 operation data

1.7 Well Site Arrangement

In the well site drawings (process flow, piping and instrumentation and isometric) provided by the office there is no drawing showing a typical gas lifted well site arrangement. Based on the well site audit, two such sketches (one for tubing flow gas lifted well, B-35 and the other for casing flow gas lifted well, B-67),The approximate length of the gas lift line or production line seen at the well pad above ground is 50 ft.

At the well location there is no power supply or service air supply available. No lighting is available either. The gas pressure required to run any chemical injection pump is taken from the available lift gas supply pressure. The gas lift choke is manually adjustable. There is no choke on the production side of the well.

Two flowlines depart from some of these wells carrying production from well site to the Station. On the other hand, in case of some wells one single flowline shares the production flowing from more than one well. These are summarized in table (3) below.

STATION NO.	WELLS WITH TWO FLOWLINES	WELLS WITH SHARING FLOWLINE
Station 2	B-27 B-29	B-92, 98, 101
Station 3		N-55, N-60
Station 4	B-65, 67	B-85, 99
Station 5		B-70, 94, 45 (3 wells)
Station 6	N-36	N-18, R-1
Station 7	B-84	

Table 3 well site arrangement

2 Artificial lift systems

Various artificial systems are available for increasing oil rates or to bring the dead wells to life. This chapter will discuss only the two artificial lift methods used in Amal field which are gas lift method and the Electrical submersible pump lifting method.

2.1 Well inflow and out flow performance

Artificial lift installation design is basically based on production rate prediction of the reservoir fluid under a certain pressure drawdown. In order to design an artificial lift installation, it is necessary to determine the well productivity and then apply a nodal analysis in order to determine the capability of the entire system of delivering the fluid to the surface facilities.

2.1.1 Node analysis

It's done by choosing a solution node where all the components upstream the node considered in flow section, whereas the downstream components represent the out flow section. It's important in order to be able to calculate the pressure drop that will occur in all system components due to the production process which will help to determine the following applications[1]

- Selecting tubing size
- Selecting flow line size
- Gravel pack design
- Artificial lift design
- Selecting the SSSV sizing
- Surface chock sizing

The fluid flows from the reservoir to the separators on the surface due to the pressure difference, this pressure difference is a sum of the pressure drop through different 4 segments , as can be seen in figure(1).

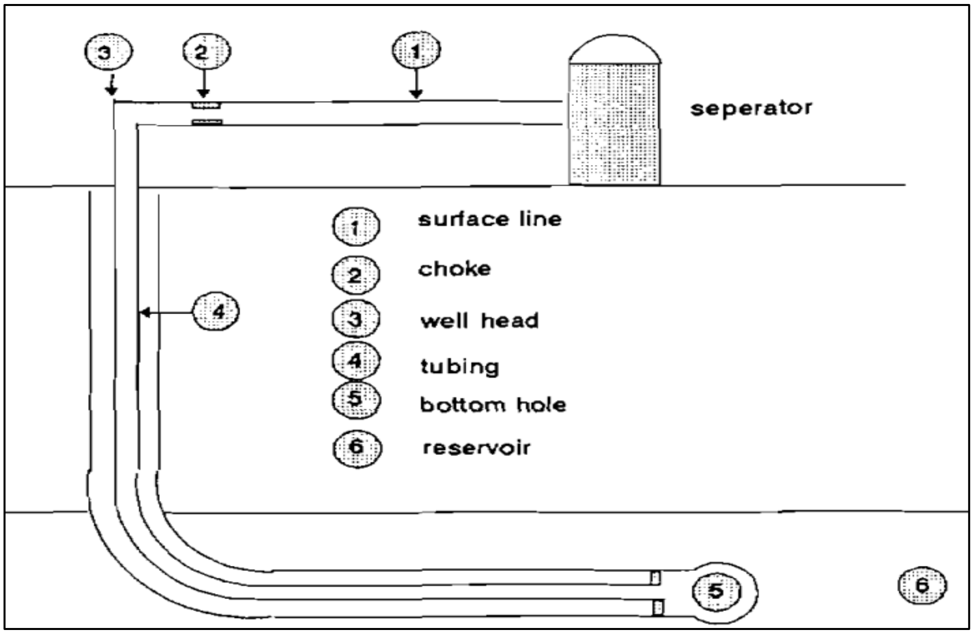

Figure 1 pressure losses in well system

2.1.2 Productivity index

The relation between the well inflow rate and the pressure draw down which often expressed in terms of J or PI

$$J = \frac{Ko * h}{\mu o * \beta o * \ln\left(\frac{re}{rw}\right)}$$

By substitution in Darcy's law the inflow equation of oil can be written as

$$qo = J(Pr - Pwf)$$

By plotting different flow rates on the x axis and its corresponding bottom hole flowing pressure on the y axis the IPR curve is established as can be seen in figure (2). For reservoirs produce at pressures above the bubble point pressure the IPR curve is simply a straight line, however if the pressure is less than the bubble point pressure (saturated reservoir) the relation is no longer straight line and vogle equation takes place where the linear equation is not applicable any more.

$$\frac{qo}{qo(\max)} = 1 - 0.2\frac{Pwf}{PR} - 0.8(\frac{Pwf}{Pr})^2$$

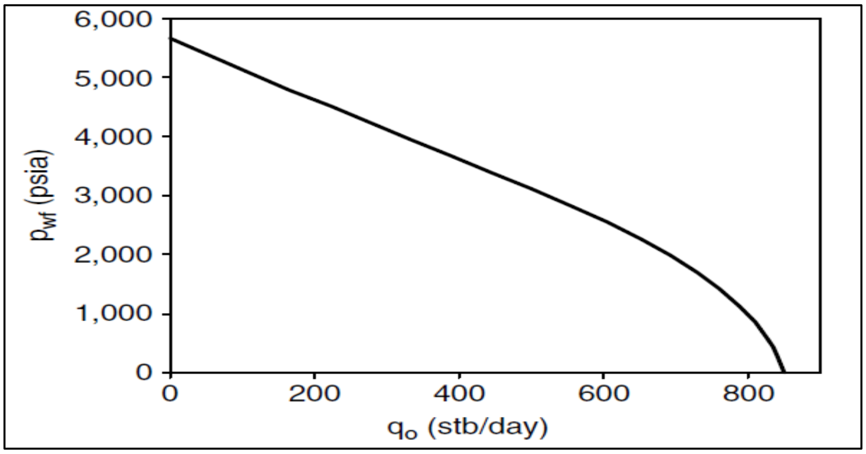

Figure 2 IPR curve

2.2 Multiphase vertical flow correlations

Although the exact final equations and correlating parameters vary from one correlation to another, the basic typical pressure gradient equation for vertical multiphase flow consists of the following terms:

$$pressure\ gradient\ term = density\ term + friction\ term + accelration\ term$$

The acceleration term is normally ignored in most correlations exepet in case of high velocities flow such as in annular mist flow regime.

Published correlations

The multiphase correlations developed by Ros, Orkiszewski, Aziz, et. al, are considered general. The original paper by Hagedorn and Brown' stated that it was unnecessary to separate two-phase flow into the various flow patterns and develop correlations for each pattern. Many computer programs based on the Hagedorn and Brown correlation include separate sets of equations for the different flow regimes and use the Hagedorn and Brown correlations for only the slug flow pattern, which is Region II on the Ros flow regime. Orkiszewski packed this approach up as he has noted that slug flow occurred in 95 percent of the cases he had studied. however Hagedorn did not encounter the bubble flow regime during his experimental work because his tests were conducted in a shallow 1500 foot wells. The accepted categories or flow regimes for two-phase flow are ideally depicted by Orkiszewski.

2.3 Completion Components

The completion components will differ depending upon whether the well is eruptive or non-eruptive. Non-eruptive wells require "artificial lift" methods to give the extra energy required to drive the formation fluids to the surface. These methods include sucker-rod pumping usually associated with on-land low producing wells, gas lift or electrical submersible pumps for the higher rate wells.

2.4 Gas lift method

Amongst the other artificial lift methods available these days gas lift technique is the only method that does not require any additional mechanical or electrical machineries in the well bore. where it's based on re injecting the produced gas through gas lift valves which installed on the tubing in the well bore in order assist the reservoir lifting mechanism so the fluid will find its way out from the well to the production separators, the injected gas will affect the fluid by one or by all of the followings

1. Reduction in the fluid gradient.
2. Expansion of the injected gas.
3. Displacement of the fluid by the injected gas.[2]

There are two injecting methods

2.4.1 Continuous flow gas lift

This method is applied to wells that have high fluid level though have not the sufficient energy to deliver the fluid to the surface. The gas is injected in relatively small volume and high pressure. [2]

2.4.2 Intermittent flow gas lift

This is applied to low bottom hole pressure wells which translated to low production flow rate, where the gas is injected in short periods in order to give the time to the fluid to build up between each cycle.[2]

2.4.3 Advantages of gas lift

1. The initial cost of the equipment is much less than the other artificial methods.
2. Since there is no any moving parts sand production has no negative effect on the down hole installation.
3. Applicable in the very high GOR wells where other methods are unfeasible.[2]

2.4.4 Disadvantages of gas lift

1. Gas must be available.
2. The presence of highly corrosive components can compromise the operation unless it properly treated before use.
3. Supplying wide distanced well with the compressed gas from the central compressing unit.[2]

2.4.5 Types of installations

The down hole installation in the gas lift system comes in different combinations of gas lift mandrels, gas lift valves, packers, nibbles, etc. mainly the type of the installation used is governed by the reservoir properties .

The two main types of installations

2.4.6 Tubing flow installation

In this method the reservoir fluid is produced through the tubing where the gas is injected in the casing passing to the tubing through the gas lift valves, there are three types of tubing installation.

1. The open installation: this method is no longer used where the tubing is just hanged in the well bore no packer is used where the gas is supposed to be injected down into the tubing shoe this requires enormous amount of gas to be injected which considered not economically worthy.
2. The semi closed installation: it's the most common method, packer is used in order to isolate the tubing from the casing and isolates the formation from the pressure applied to the casing during gas injection.
3. The closed installation: in this type of installation used to overcome the flow back while gas injecting in very low reservoir pressure wells (intermittent injection) where a standing valve is installed at the tubing shoe to fulfill this purpose.

4. The multiple installation: in wells that produce from different layers especially if the properties of the produces fluids are not the same in this case dual installation takes place in order to separate the zones of interest, straddled packer is used to isolate each layer to be produced by different tubing.

2.4.7 Casing flow installation

This method is used for high production rates wells where the gas is injected into the tubing and the formation fluid is produced through he casing, the tubing shoe is plugged to make sure that the gas will injected into the casing only the gas lift valves, also to avoid filling the tubing with the formation fluid while shutting down the well.

2.4.8 Gas Lift System

A complete gas lift system consists of a gas compression station, a gas injection manifold with injection chokes and time cycle surface controllers, a tubing string with installations of unloading valves and operating valve Figure (3) depicts a configuration of a gas-lifted well with installations of unloading valves and operating valve.[3]

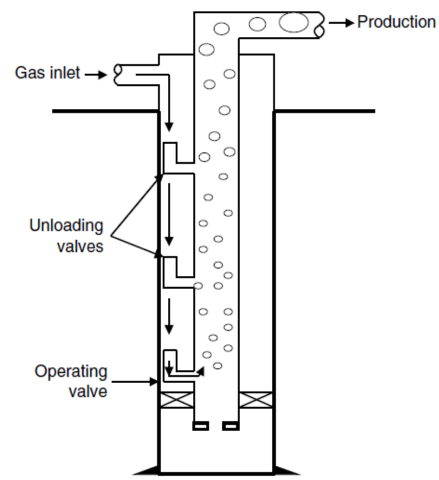

Figure 3 downhole gas lift system

2.4.9 Selection of Gas Lift Valves

Kickoff of a dead well requires a much higher gas pressure than the ultimate operating pressure. Because of the kickoff problem, gas lift valves have been developed and are run as part of the overall tubing string. These valves permit the introduction of gas (which is usually injected down the annulus) into the fluid column in tubing at intermediate depths to unload the well and initiate well flow. Proper design of these valve depths to unsure unloading requires a thorough understanding of the unloading process and valve characteristics. [3]

2.4.10 Gas lift process

Usually all valves are open at the initial condition due to high tubing pressures. When the gas enters the first (top) valve a slug of liquid–gas mixture of less density is formed in the tubing above the valve depth. the expansion of the slug and the lightning of the fluid column as its density is reduced push the liquid column above to flow to the surface. as the length of the light slug grows due to gas injection, the bottom-hole pressure will eventually decrease to below reservoir pressure, which causes inflow of reservoir fluid. Eventually the tubing pressure at the depth of the first valve is reduced to reach the closing valve pressure, the first valve should begin to close and the gas should be forced to the second. The same process is continued from valve to valve until the gas enters the orifice valve the main valve which never closes to be the only valve open in the operation figure(4) shows the complete process.[3]

2.4.11Gas lift valves

Gas lift valves are the heart of the system where it work as down hole pressure regulators, where it can be set to operate under any desired pressure, the valves installed on side pocket mandrels and run in the hole in the open position where it supposed to be shut when the designed pressure is reached. The valves are categorized into three types according to the way the valve is triggered.

1. Production fluid valves: this type is sensitive to the produced fluid pressure, this type of valve is more often applicable in the dual system installations. [3]
2. Injection pressure operated valves: they have one or two ports where the injected gas can enter the valve chamber either from the tubing (injecting through the tubing) or from the casing .[3]

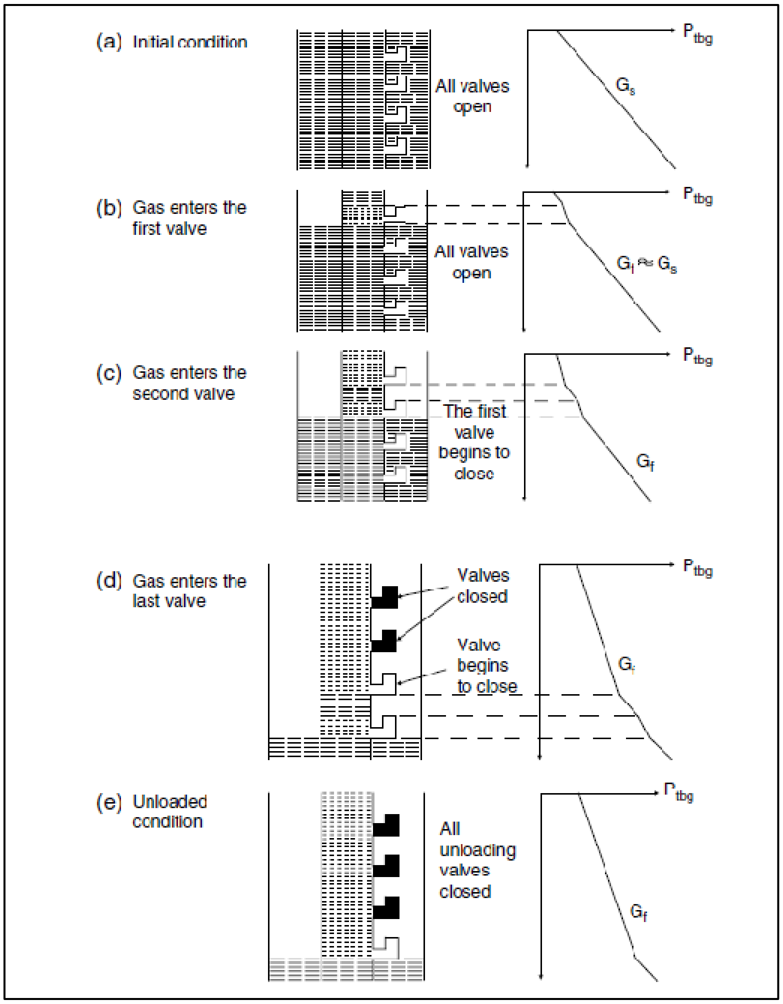

Figure 4 Gas lift process

2.5 The electrical submersible pump (ESP)

Electrical submersible pumps add more energy to the fluids to lift them to the surface without lowering the hydrostatic pressure as in gas lifting.

2.5.1 Pros and Cons

Pros:

- Wide application in oil and water wells, pumping at rates from200-60,000 BPD to depths of 15,000 ft.
- Crooked or deviated wells cause few problems.
- Applicable offshore and at urban sites.
- Simple to operate.

- Lifting cost for high volumes is generally low.

Cons:

- Not applicable to multiple completion.
- Only applicable where electric power and high voltages are available.
- Expensive to change equipment to match declining well productivity.
- Handling tubular is difficult with cable.
- Gas and solids production are troublesome.

2.5.2 ESP components

2.5.3 Subsurface equipment

2.5.3 .1 Downhole motor

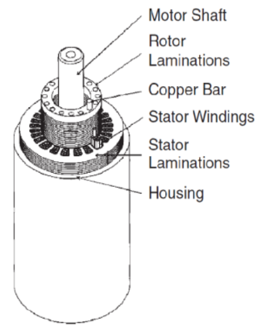

Figure 5 ESP motor diagram

The motor provides the rotary power force which responsible on operating the pump which consists of two poles and three phase induction squirrel which operates in a similar to the induction motor used in the surface operations figure (5), the motor is sealed in order prevent the formation fluids from entering and the dielectric oil used to cool and lubricate the motor from leaking outside the motor. The size of the down hole motor is limited by the inside casing diameter in case of the need of extra horse powers multiple motors can be installed, ESP motor has the longest operating life if it's designed correctly.[4]

Types of motor failures

- Overheating due to overloading or bearing failure.
- Overheating due to inadequate fluid velocity.
- Bearing failure due to insufficient dielectric oil filling.[4]

2.5.3 .2 Seal (equalizer)

Seal assemblies consist of the sealing and the trust bearings, which required to support the motor shaft and to prevent transmitting the rotary movement from the motor the pump, and to prevent the formation fluid from entering the motor, and to equalize the pressure between the motor housing and the well bore. [4]

Sealing types

- Mechanical seal: which responsible of preventing the fluid from flowing between the rotating shaft and the housing.[4]
- Labyrinth seal: by implying the effect of gravity to prevent the motor fluid and the formation fluid from mixing.[4]
- Elastomer seal: flexible membrane to prevent the formation fluid entered the pump from mixing with motor filled oil. [4]

2.5.3.3 Pump

The ESP is a multistage centrifugal type pump operating in vertical position. The number of stages determines the total design head generated and the motor horsepower required. [4]Each stage consists of a rotating impeller and a stationary diffuser figure (6). Sand is the most common enemy of SP pumps as the sand moves with very high velocity it erodes the impellers and the diffusers leading the pump to be failed, the pump manufacturing material can be changed to resist the sand aggressive behavior, or use a rubber bearing which can be used to take all the sand attack. [5]

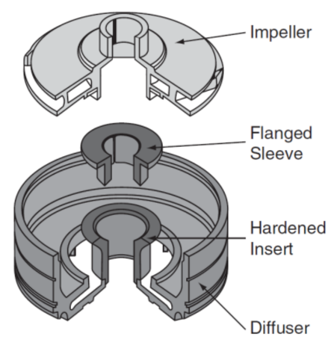

Figure 6 ESP pump components

2.5.3.4 The gas separator

Free gas has undesirable effect on the performance of the pump. If the gas exceeded the maximum amount that the pump can operate with, gas lock will occur which leads the pump production to drop to zero to eliminate this problem a downhole gas separator should be installed in order to prevent the excessive amount of gas from entering the pump.[5]

2.5.3.5 The ESP cable

The electrical power is transferred from the transformers at the surface down to the motor via three phase electric cable which exposed directly to the harsh conditions in the well bore so it must possess the following specifications.[5]

- Its diameter has to be small in order to fit in the space between the pumping assembly and the casing.
- they must maintain their dielectric properties and integrity under harsh well conditions such as:

1. High temperatures.
2. Aggressive fluid environments.
3. The presence of hydrocarbon and/or other gases.

- Must be protected against the mechanical damage occurring the running pulling operations. [5]

The ESP cable is made of

- Conductor: it's either made from copper or aluminum, aluminum is cheaper but has less conductivity than copper, copper in the other hand has more sensitivity to H2S.
- Insulator: it's used to insulate the conductor and the jacket and it must withstand the high operating temperatures, prevent the migration of gas through the cable.
- Jacket: to protect the insulation from the mechanical damage while running and pulling out of the well, usually made from nitrile rubber.
- Covering: Metal armor is the outer covering providing mechanical protection to the ESP cable during handling. In addition to this function the armor also constrains the swelling or expansion of the insulating materials when they are exposed to well fluids.[5]

Cable construction

Cable construction is available in two forms, flat and rounded figure(7), round cable is used between the tubing and the casing where the clearance space is not critical, the flat cable however is run along the ESP unit because of its small diameter it can fit in the

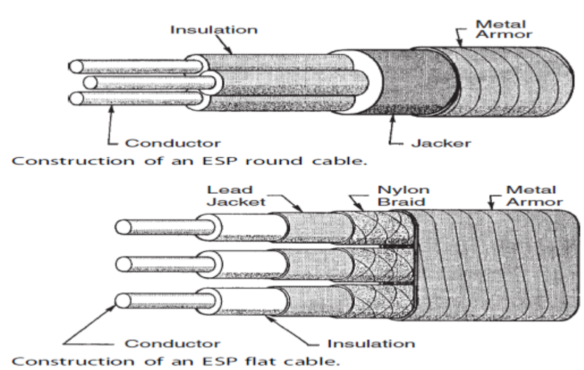

Figure 7 cable types

narrow space between the unit and the casing.

Cable temperature is a function of the well's ambient temperature and the heating effect of the AC current flowing through it, the ampacity charts (ampere capacity) figure(8) for available cables which specify the maximum allowed cable current as a function of maximum well temperature.[5]

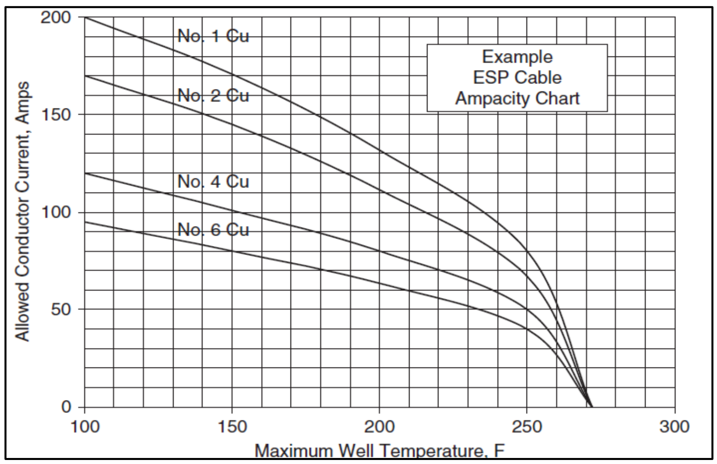

Figure 8 ampacity chart

2.5.4 Miscellanies parts

The check valve is usually installed 2 joint above the pump in order to prevent the back flow to protect the pump from reverse spinning while shutting down.

The bleeder valve it is used one joint above the check valve to bleed out the formation fluid down into the wellbore before ROOH to minimize pollution on the surface.

The Y-tool is a special crossover assembly of an inverted Y shape installed at the bottom of the tubing string with one side being in line with the tubing and the other side being offset. The straight section provides a straight run down the hole; while the ESP unit is connected to the offset section. This will allow the following:

- formation treatment: acidizing, fracturing, ..etc.
- Well completion: perforation of new pays.

- Pressure and temperature gauge running.

Motor shrouds is a short sections of pipe around the length of the ESP unit have been successfully used to:

As simple reverse flow gas separators which, by changing the direction of flow, allow the buoyancy effect to decrease the amount of free gas that enters the pump, and as the shroud reduces the free space between the motor and the casing it helps to achieve the necessary fluid velocity required for cooling the motor down.

2.5.5 Surface installations

2.5.5.1 Well head

Special ESP well head is used in order to support the downhole equipment weight, in addition to adding a positive seal not only around the tubing but around the cable as well.

2.5.5.2 The junction box

It's known also as the venting box, it's a connecting point between the cable coming from well bore and the one coming from switch board figure(9) and it's used to ventilate the gas which might have traveled up through the cable, and gives the opportunity to change the direction of pump rotation by switching the poles.[5]

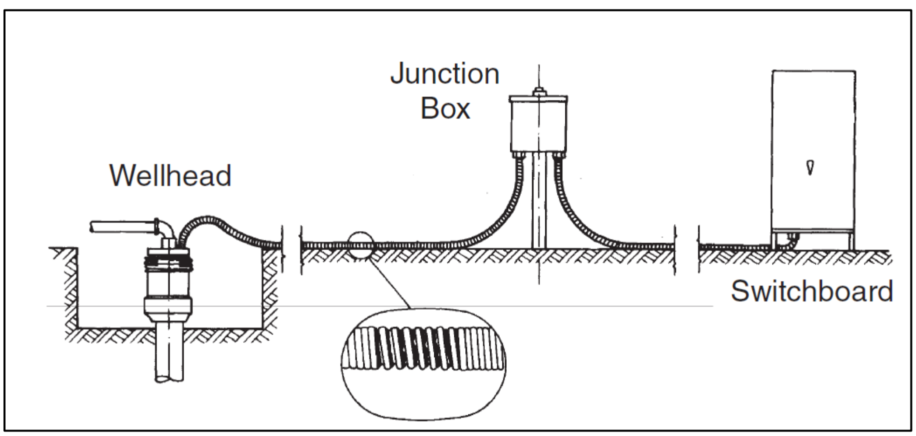

Figure 9 ESP surface installation diagram

2.5.5.3 Switch board (FSD)

It's the control point of ESP unit where it has the following functions

- Switching on/off the unit.
- Monitoring and recording most of the operating parameters i.e., current, voltage, and so on.
- Protect the surface and the downhole equipment from wide variety of problems such: inadequate voltage supply, wrong phase rotation, motor over load, excessive of starts. [5]

Current models can store operational parameters in memory for later retrieval and can communicate by radio or wireline to central stations or the field's SCADA system.[5]

2.5.5.4 Variable speed drives (VSD)

VSDs provide more flexibility than the switchboards, instead operating the ESP with one frequency 50 or 60 Hz, the pump can operate with different frequencies which will provide more controllability of the pump speed which necessary to optimize the pumping unit performance and the well productivity during the long years of production.

2.5.5.5 Transformers

Surface Voltage has to be adapted in order to meet the specifications of ESP equipment, Step down transformers are used to reduce the voltage coming from the high lines to be compatible with what is needed in the switch board, in case the voltage supplied was not enough step up transformers take a place to make up the necessary shortage.[5]

2.5.6 ESP lifting mechanism

- Works by transferring the energy provided by motor shaft to the formation fluid to be moved
- Rotating impeller creates a centrifugal force which increases the fluid velocity (kinetic energy).
- Stationary diffuser diffuses, or reduces velocity of fluid and pressurizing the fluid (converting kinetic energy into potential energy).In addition to that diffusers
- direct the fluid to the next pumping stage.

2.5.7 pump performance curve

The characteristics of the pump performance is typically presented in the form of a "pump curve" a single graph that contains curves for the dynamic head, shaft horse power required, and efficiency.

The total pump performance is performance of one stage multiplied by the number of stages for a specified fluid rate.

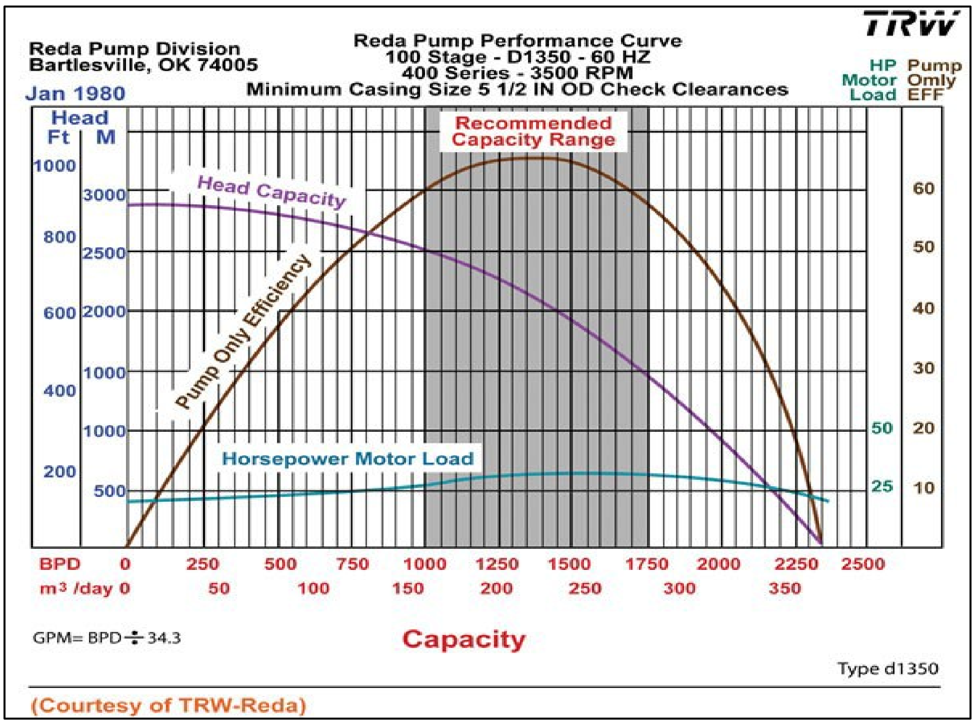

Figure 10 pump performance curve

Chapter 3 health safety and Environment

The exploitation of gas and oil comes usually with severe side effects on the environment of the exploited area such as oil spills air and water pollution, and fire incidents.

3 Potential environmental impact

Oil and gas exploration and production operations impact is controlled by the following:

- The size and the complexity of the project.
- The nature and the sensitivity of the surrounding environment.
- Mitigation and controlling techniques.[7]

3.1Atmospheric impact

The most challenging task in oil and gas production is to minimize the emission to the atmosphere which has a long term impact on climate changes and increasing the temperature of planet earth. The main source of these emissions comes from.

- Flaring and venting.
- Fuel combustion needed for compressors, diesel engines and turbines.
- Well testing

The emission gases manly contain carbon dioxide carbon monoxide methane and nitrogen oxides, and if the crude contains sulphur the emission will contain sulphur dioxides and hydrogen sulphide.

Amongst the above flaring is the most significant source of these emissions, where the operators tend to flare the produces associated gas where the nessacary infrastructure to process the gas and sell it.[7]

3.2Aquatic impact

The disposed fluids generated from the exploration and production operations have a catastrophic impact on the environment of the exploited area, the disposed fluids are usually come from:

- Produced brine.
- Drilling fluids and cuttings.
- Sewerage and domestic use.
- Spills and leakages.
- Cooling water.

The produced water which pumped to water disposal bits have in deserted areas could penetrate down to pollute the shallow fresh water reserve, in addition to that it might endanger the life of the inhabitant creatures.

The best solution to get rid of these undesired enormous amount of water is to be re injected back into the aquifer where it came from, this process has the following advantages.

- Protect the shallow fresh water reserves.
- Preserve the eco system by sparing the life of the creatures inhabit the area.
- Increasing the recovery factor by maintaining the reservoir pressure.
- Reduce the possibility of ground subsidence due to production.[7]

3.3Terrestrial impact

Three basic sources lead to damage the soil of the exploited area

- Physical distribution as result of construction.
- Contamination resulted from spillage, leakage and solid waste disposal.
- Disposal bits

Exposing the soil to eroding environment.

Where in order to prepare the site all the obstacles have to be removed tress and pushes are included which will lead the soil to be eroded by wind or water, as a result of that more lands will be turned into deserts, decreasing the green areas on the planet which needed to absorb the CO2 emissions. [7]

3.4 Potential emergencies

No matter how good are the monitoring and inspection system on the site there is always a probability of accidents to be happened such as

- Spillages of fuel, gas, oil, chemicals and hazardous materials;
- Blowouts;
- Explosions;
- Fire;
- Natural disasters ;
- Wars and sabotage;

3.5 Gas flare

Associated gas flaring is one of the most challenging energy and environmental problems facing the world today. Approximately 150 billion cubic meters of natural gas are flared in the world each year, representing an enormous waste of natural resources and contributing 400 million metric tons of CO_2 equivalent global greenhouse gas emissions,[8] where its known as a combustion process of the unwanted flammable gases produced along with oil. Which converts the flammable, toxic or corrosive vapors to less hazardous components.

Two types of flares in the oil industry:

- Ground flares are primarily designed for low release rates and are not effective for emergency releases.
- Elevated flares, the stack heights can exceed 400ft with diameters over 40 inches. The high elevation reduces potential flaring hazards because ground level radiation is lower and better dispersion of gases.[7]

3.5.1Gas flare measurement methods

Three methods have proved to measure the amount of the flared gas.

- Insertion turbine
- Thermal mass meter
- Annubar
- The ultrasonic time

3.5.2The turbine method

The gas is led through the meter rotor. The rotor is designed with a specific number of blades positioned at a certain angle. The gas hits blades leading them to rotate, the angular velocity of the rotor has a direct proportional relationship with the gas velocity.[8]

3.5.3.Thermal mass meters

are typically based on two Thermo well-protected Resistance Temperature Detectors (RTDs). When placed in the process stream, one RTD is heated and the other is sensing the process temperature. The temperature difference between the two elements is

Figure 11 Thermal mass detector

related to the process flow as higher flow rates cause increased cooling of the heated RTD. Thus, the temperature difference between the two RTDs is reduced. In addition, it has no mechanical parts, high temperature range and requires little installation space. Typical flow range for the thermal mass meters is 0.3 to 30 m/s.[7,8]

3.5.4 Annubars

The annubar is a differential pressure device with the signal increasing proportional to the square of the flow. Annubars are good for high flow rate applications, but are not good for low flow applications due to the small pressure difference these flows represent. It has potentially high maintenance costs. and several annubars are required in order to cover a large flow range.[7,8]

3.5.5 The ultrasonic time

The ultrasonic time-of-flight gas flow meter is based on measurement of time of the propagating of the ultrasonic pulses, in which the transit time of the sonic signal is measured along one or more diagonal paths in both the upstream and downstream directions figure (12). Where the gas flowing through the pipes shorten the time for the pulse travelling in the downstream direction less than the travelling time in the upstream direction, the time difference between the gas travelling in the downstream and the upstream is used to measure for the gas flow rate.[7,8]

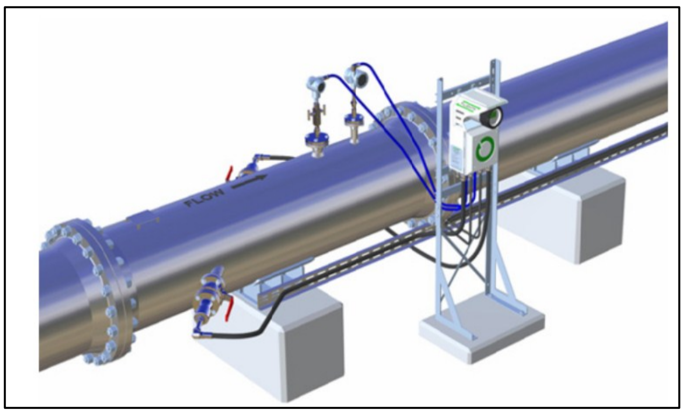

Figure 12 Ultra sonic gas measuring

3.5.6 Why measure the flared gas

- Detect if there is a leakage in the deferent processes.
- It's important for production optimization to know detailed information of what have been extracted.
- To control the CO_2 emissions.
- National legalizations as in some countries oil companies have to pay taxes for their CO_2 emissions. [7,8]

3.5.7 Solutions and alternatives

A lack of technology solutions is not the problem; gas flaring can be dealt with today through a variety of existing technologies at reasonable cost. Depending on the region, power generation, gas re-injection to enhance oil recovery, gathering and processing, pipeline development, liquefied natural gas (LNG) and a variety of distributed energy solutions can be deployed. However, often regional political complexities and lack of gas infrastructure systems drive the decision to flare gas.

4 Artifcial lift Optimization

10 wells has been chosen for this study according to their water cut , the current flow rate compared to the ultimate potential production rate, and how old is the artificial lift design installed in the well. The PVT data, the operational and the other The necessary data for these wells were given by Alhrooj Oil Company as listed in Appendix B And C.

4.1 Well B027

The well belongs to Station 2. table (4) shows the FGS date of Jan 09 2009 which clearly showing that this well matches with Duns Ros original.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.70947	0.64821	22.2536
Hagedorn Brown	0.77079	0.68389	25.3042
Fancher Brown	1.2231	0.77374	30.147
Mukerjee Brill	0.8766	0.64795	21.8215
Beggs and Brill	0.66057	0.26907	125.185
Petroleum Experts	0.74607	0.2	65.3394
Orkiszewski	1	0.99997	35.0858
Petroleum Experts 2	0.74185	0.2	57.4569
Duns and Ros Original	1.02873	1.04686	21.9976
Petroleum Experts 3	0.56346	0.94659	58.9546
GRE (modified by PE)	1.05743	0.46296	40.9732
Petroleum Experts 4	1.07342	1.16827	33.2248
Hydro-3P	0.78652	0.52589	26.7212

Table 4 B027 tubing correlation parameters

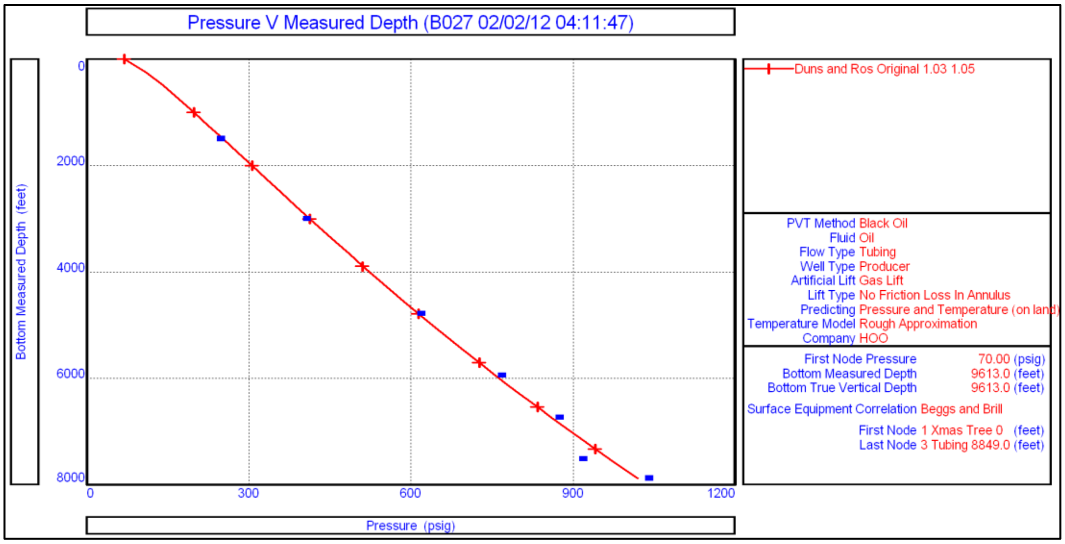

Figure 13 B027 Gradient match plot

The production history figure (14) shows that the increament of gas injection doesn't reflict corspponding increament in the liquid production.

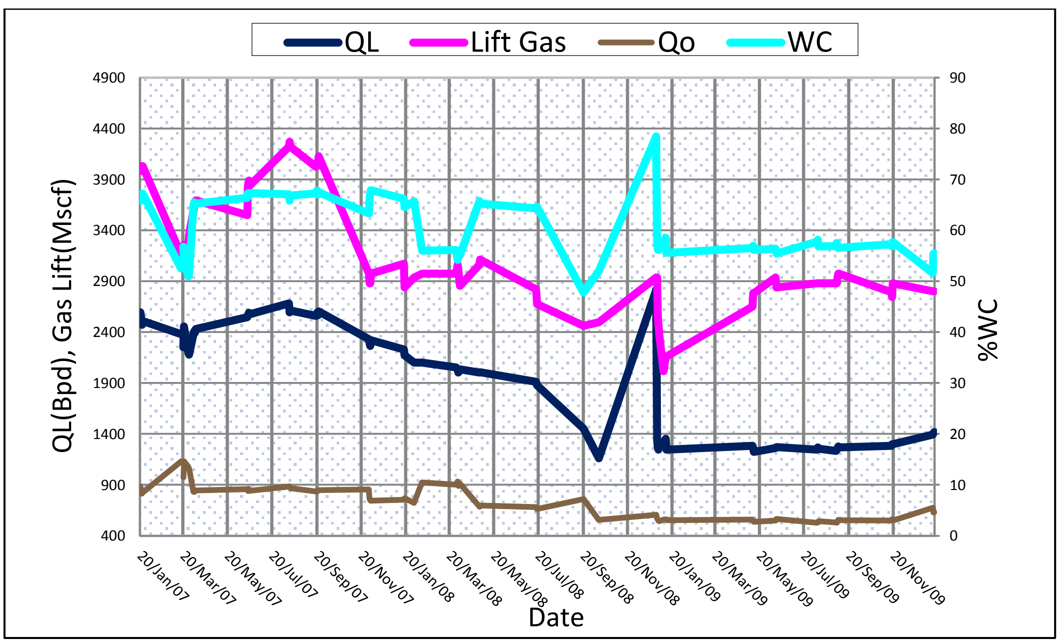

Figure 14 B027 production history

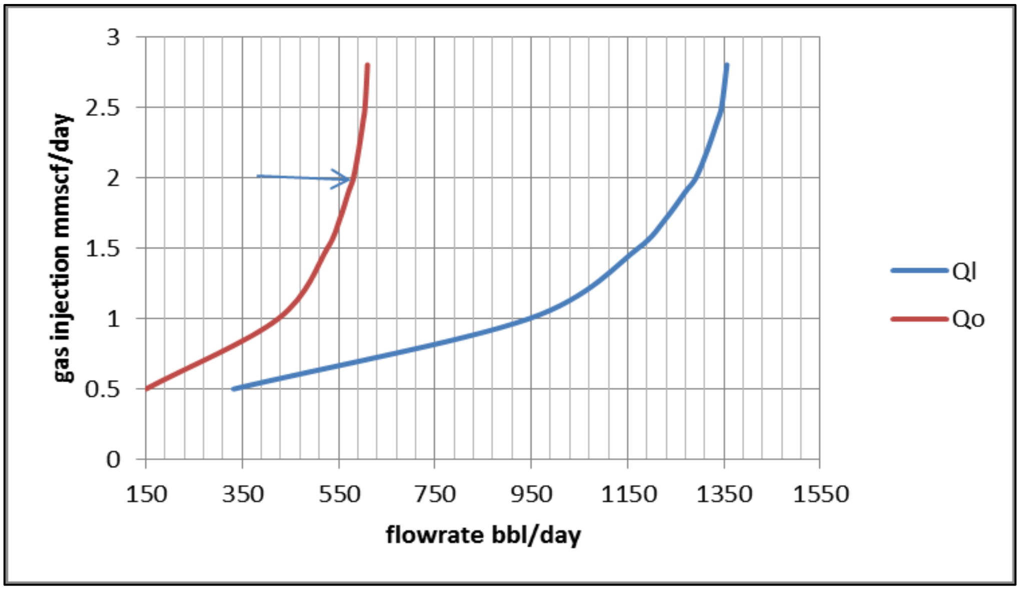

Figure 15 B027 Gas lift performance curve

The gas lift perfomance curve figure (15) shows the the production wont be effected if the injected rate is reduced from 2.8 to 2.0 mmscf.There is no need to redsign the well as The current valves distrobution is still aplicable figure (16).

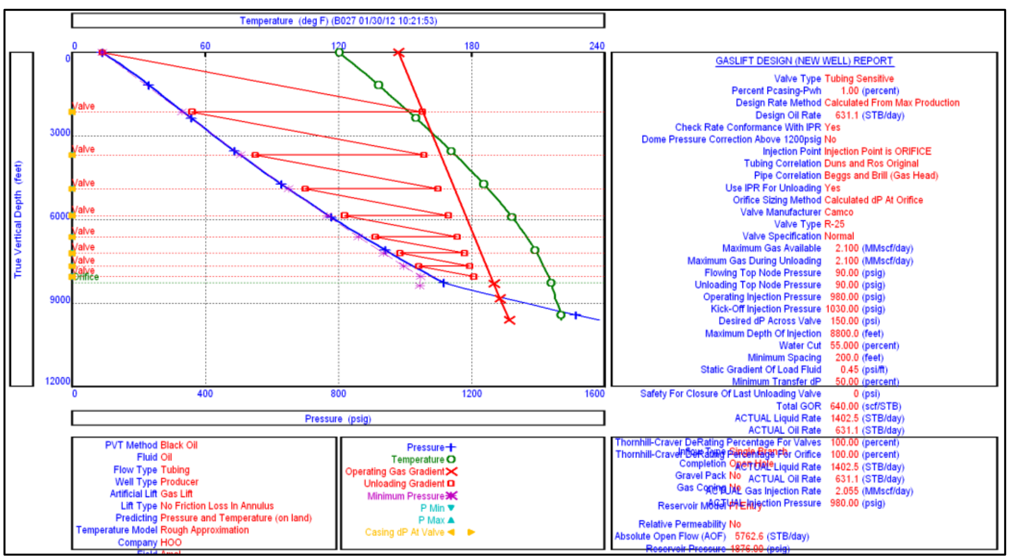

Figure 16 B027 current gas lift design

Water cut sensitivity

Figure (17) illustrates the potential oil production draw down as the water cut increases where it shows that the oil production rate will be around 60 bbl/day when the water cut reaches 95%

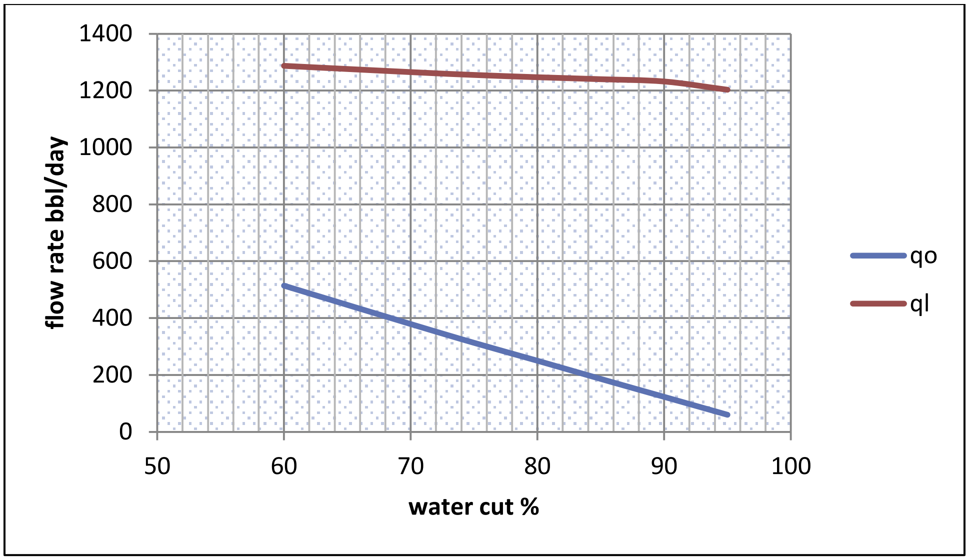

Figure 17 B027 water cut sensitivity

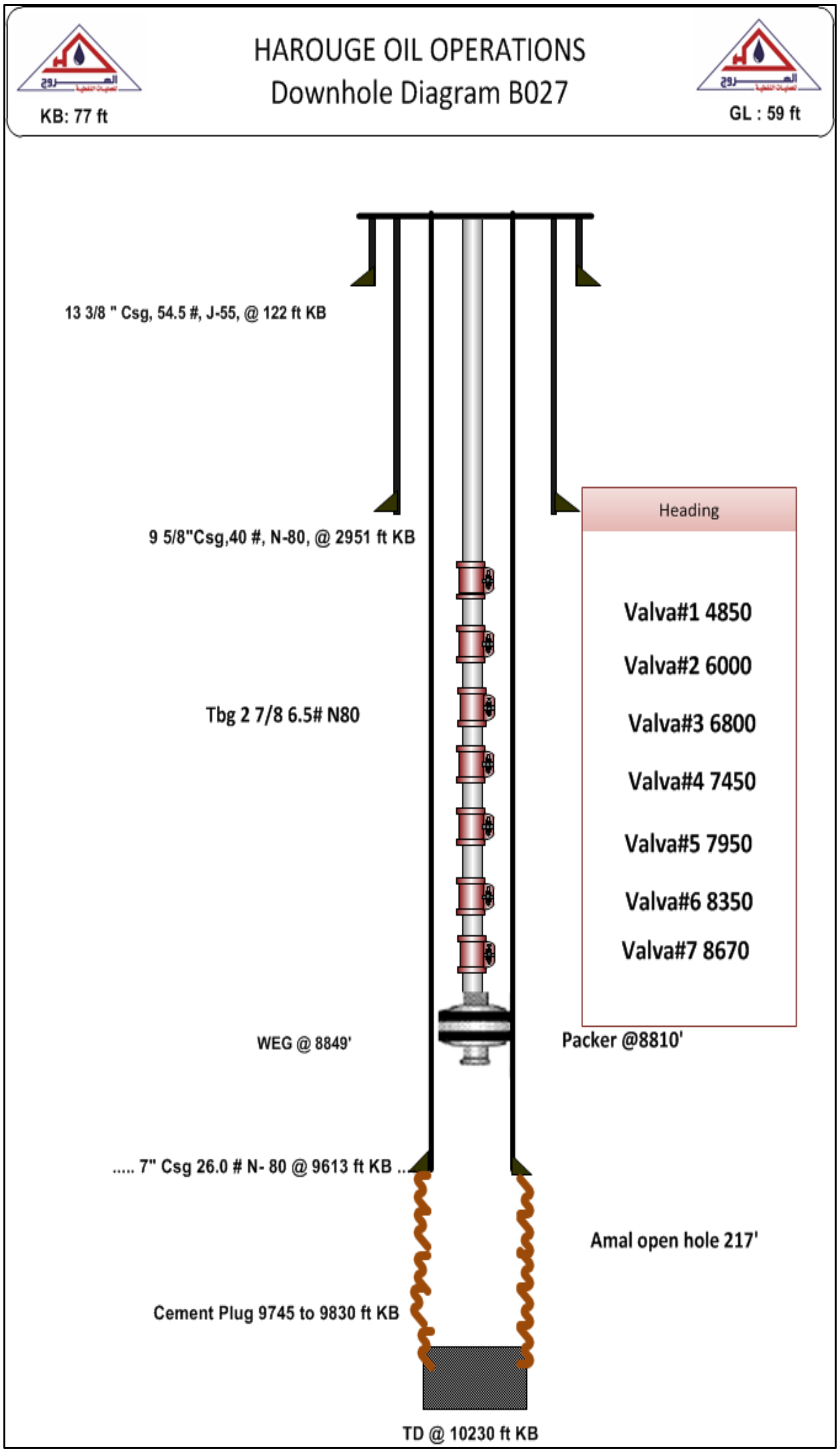

Figure 18 B027gas lift completion sketch

4.2 Well B029

The well is connected to station 2 and being injected from the deepest valve, which located on the depth of 8300ft figure (19), table(5) shows that the beggs and Brill correlation has the closest match amongst the others as it has the lowest standard deviation factor.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.2	0.2	63.5715
Hagedorn Brown	0.2	0.2	100.062
Fancher Brown	0.2	0.2	115.363
Mukerjee Brill	0.199	0.2	64.826
Beggs and Brill	0.2	0.2	63.5297
Petroleum Experts	0.2	0.2	93.9577
Orkiszewski	0.2	0.2	90.6761
Petroleum Experts 2	0.2	0.2	91.3359
Duns and Ros Original	0.2	0.2	67.1431
Petroleum Experts 3	0.2	0.2	113.994
GRE (modified by PE)	0.2	1	81.146
Petroleum Experts 4	0.2	0.2	82.5596
Hydro-3P	0.199	0.2	77.339

Table 5 B029 correlation parameters

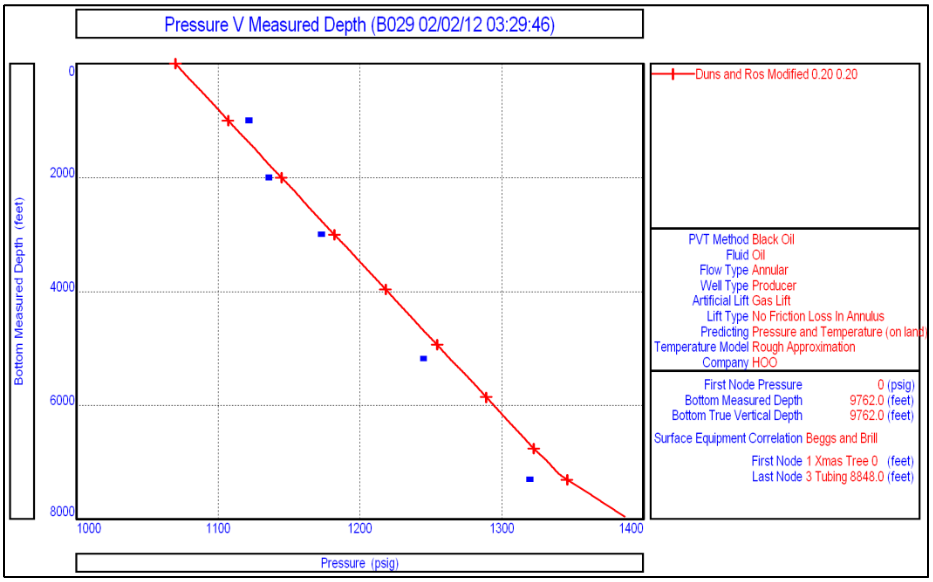

Figure 19 B029 gradient survey plot

The production history chart figure (20) shows that the liquid rate has the potential to be increased as the injected gas is increased.

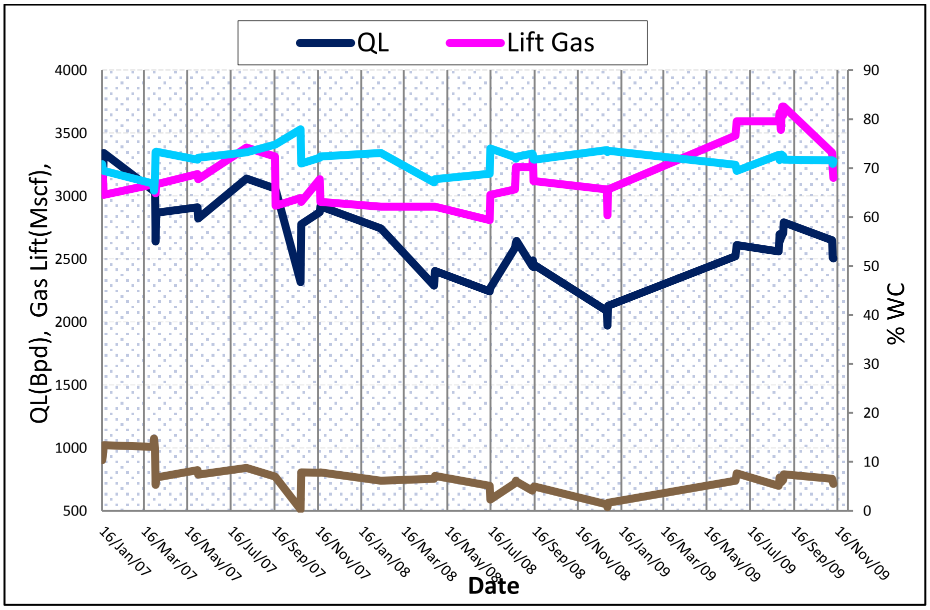

Figure 20 B029 Production history chart

The gas lift performance curve figure(21) shows that the optimum injection rate is 3 mmscf/day with oil production rate of 731 bbl/day.

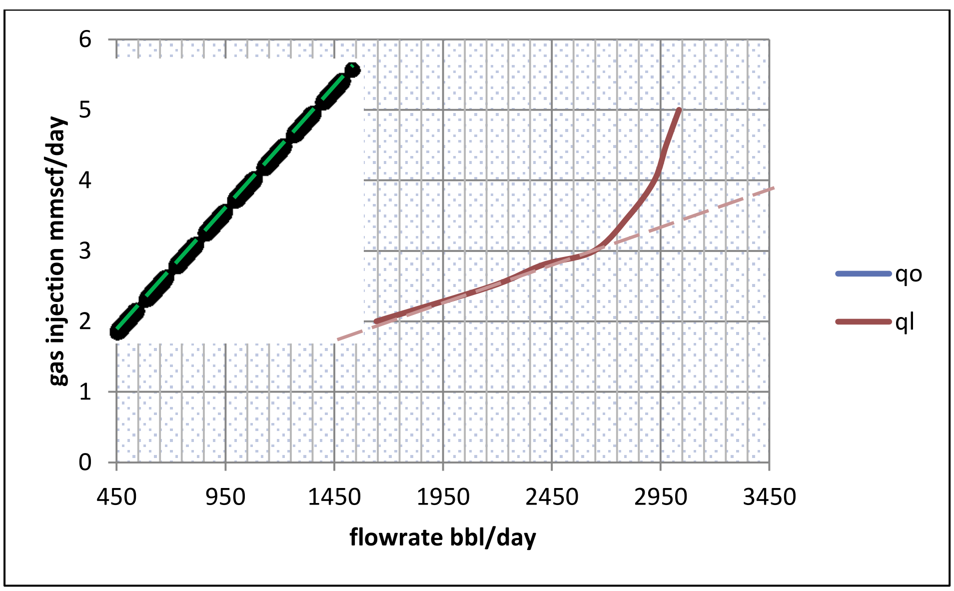

Figure 21 B029 Gas lift design performance curve

Figures (22),(24) show the gas lift design and the well completion sketch

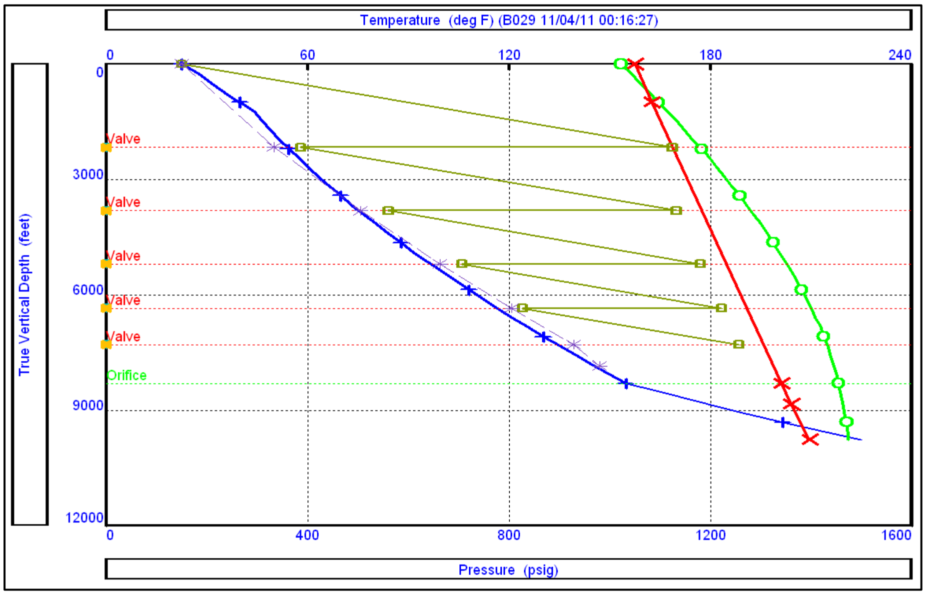

Figure 22 B029 New gas lift design

Water cut sensitivity

Figure (23) shows that oil production will drop to less than 100 bbl/day when the water cut exceeds 95%.

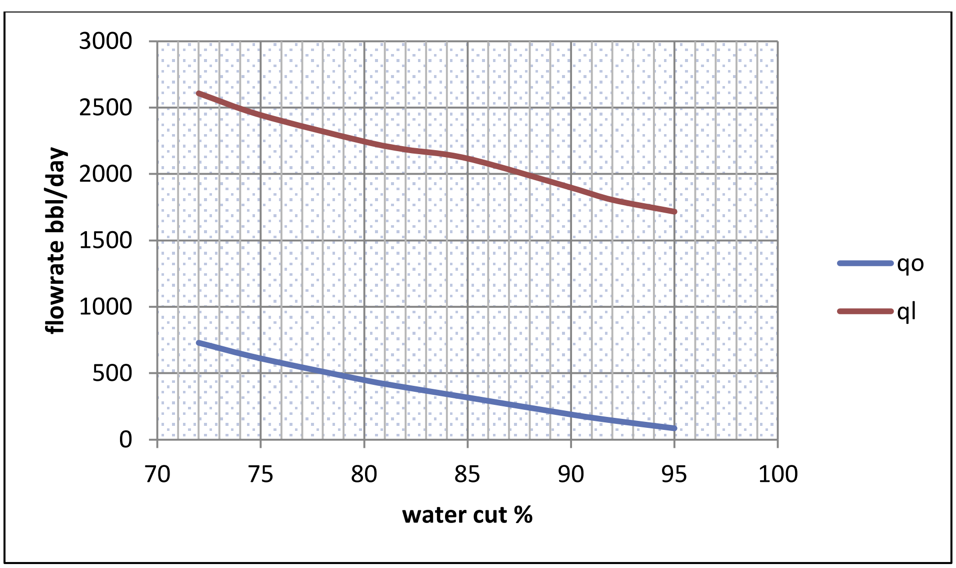

Figure 23 well B029 water cut sensitivity

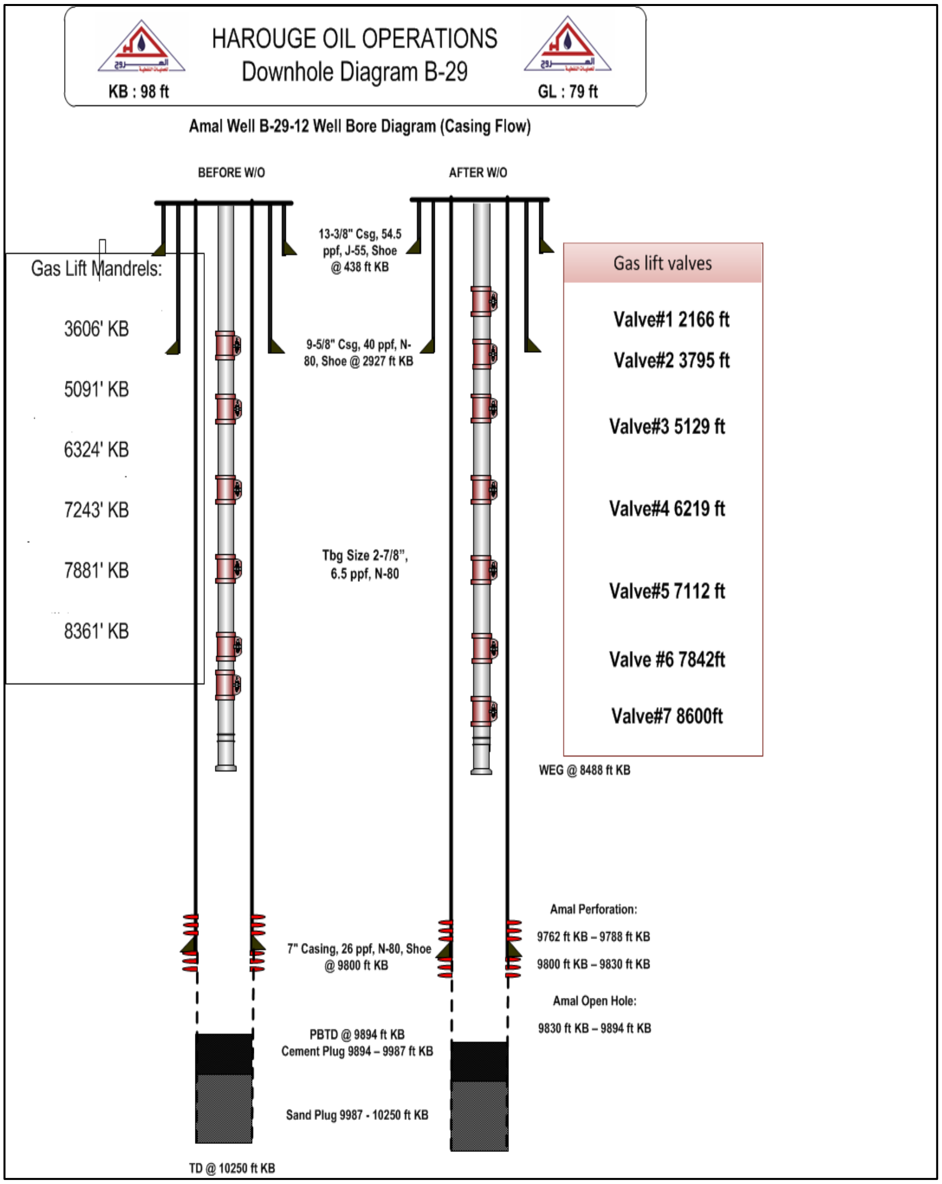

Figure 24 B029gas lift completion sketch

ESP design

The separation sensitivity plot shows that no downhole gas separator with efficiency of 10% is needed.

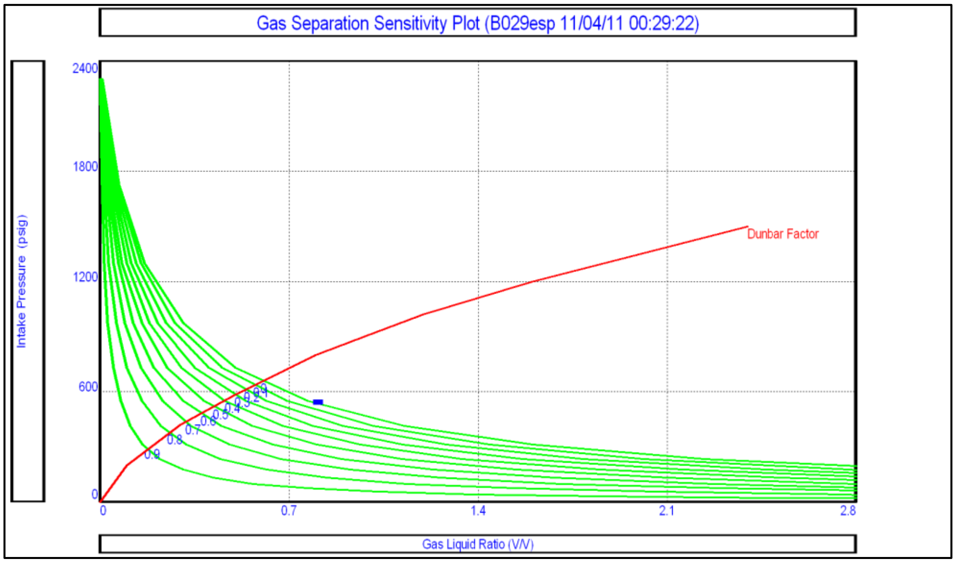

Figure 25 B029 gas separation sensitivity plot

Figure (26) shows that the optimum pump setting depth is 7000 ft with surface production rate 3200 bbl/day.

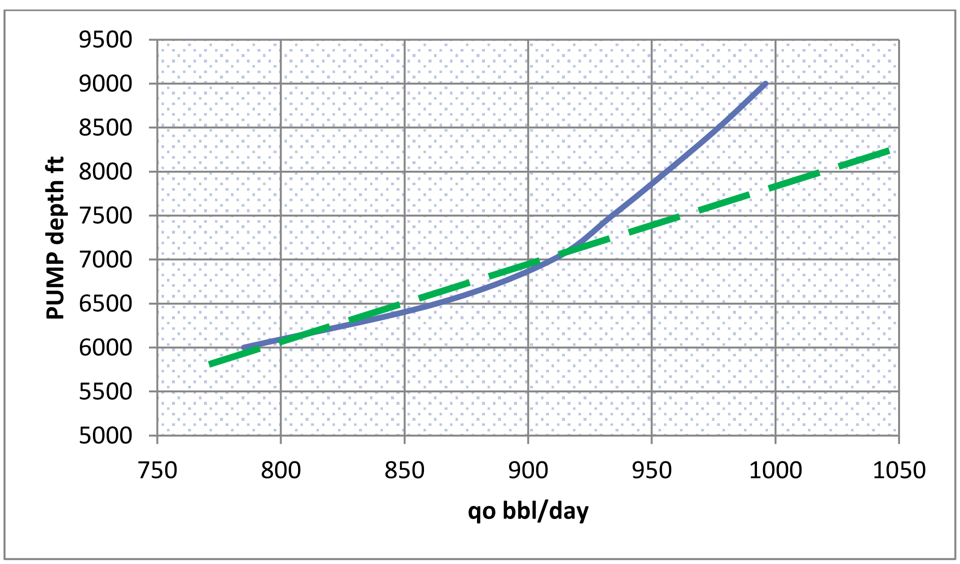

Figure 26 B029pump setting depth vs the produced oil rate

RedaD4300Nis being chosen as it gives the best performance with the design rate figure (27).

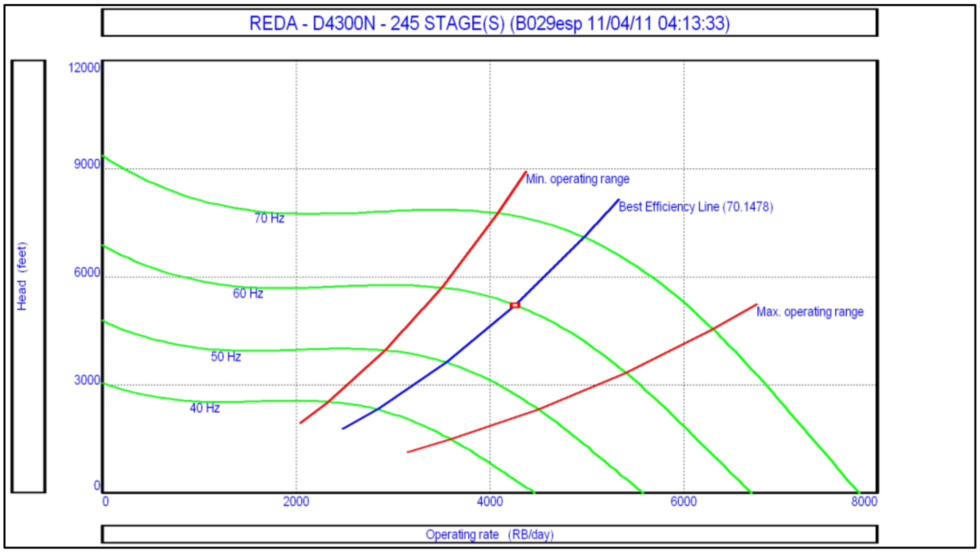

Figure 27 B029 ESP Pump design

Table (6) shows the ESP parts used in this design

Part's name	Specification
motor	Reda 540_90-0_std200HP1220V99A
pump	RedaD4300N 4 inches
Cable	1# Copper 0.26(volts/1000ft)

Table 6 ESP Parts and specifications

4.3 Well B035

This is connected to station 4 and it contains 6 mandrel , as it can be seen in table(7) the well matches with petroleum expert 3 correlation as it has the lowest standard deviation factor.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.78986	3.75666	69.599
Hagedorn Brown	1.04867	3.48622	65.6518
Fancher Brown	1.19759	4.80463	60.5097
Mukerjee Brill	0.81585	3.76576	71.4641
Beggs and Brill	1.00204	1.08898	69.9366
Petroleum Experts	1.01633	1.4928	64.8769
Orkiszewski	1.23471	4.91124	122.283
Petroleum Experts 2	1.0109	1.37714	64.7896
Duns and Ros Original	0.92758	4.47107	71.5061
Petroleum Experts 3	1.13766	2.08942	57.9309
GRE (modified by PE)	1.04852	2.68443	59.3228
Petroleum Experts 4	1.09334	2.9504	73.8634
Hydro-3P	0.91655	2.04444	68.5141

Table 7 B036 tubing correlation parameters

Figure (28) shows that the injection point is at 8025ft from the forth valve.

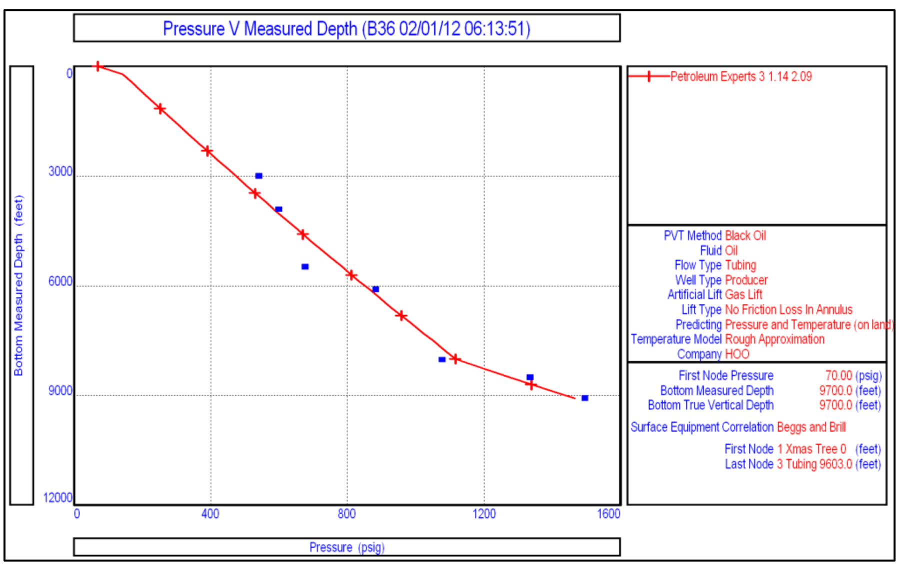

Figure 28 B035 gradient match plot

The production history figure(29) shows a direct response in the change of the gas injection rate and the produced liquid.

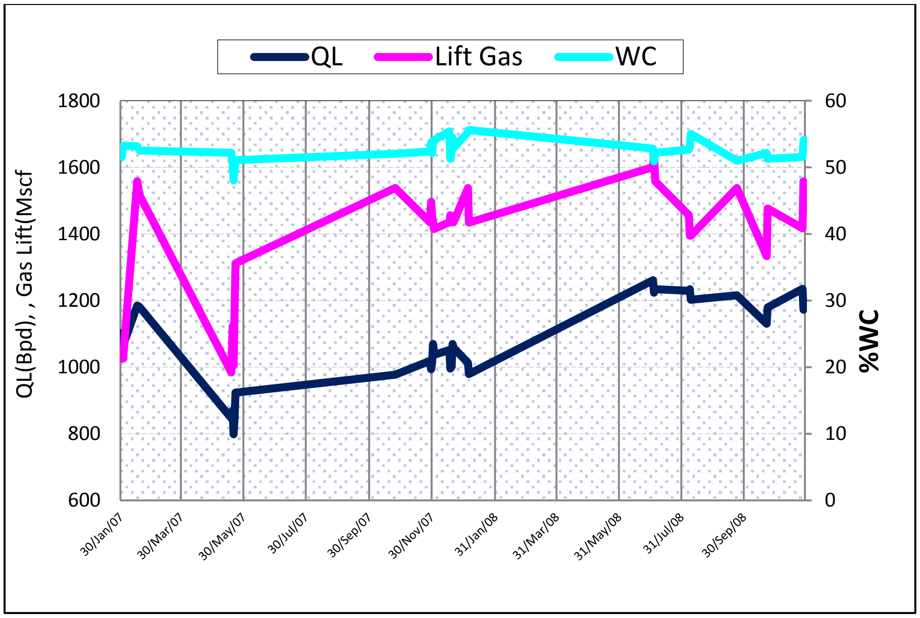

Figure 29 B035 production history

The gas lift performance curve figure (30) shows that the current gas injection rate which is 1.56 mmscf/day is the obtimum rate and there is no need to increase it.

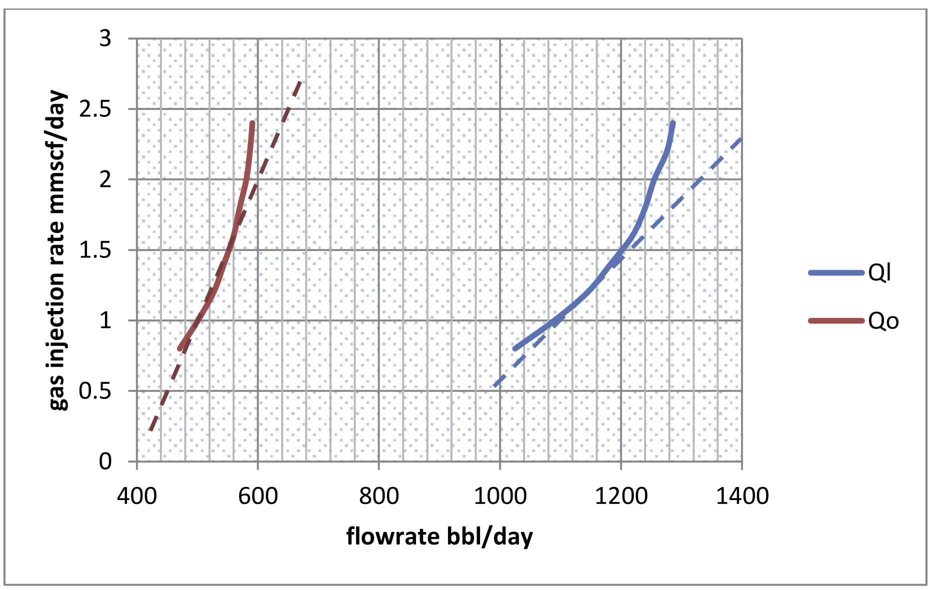

Figure 30 B035Gaslift design performance curve

Figure (31) the completion design of the well.

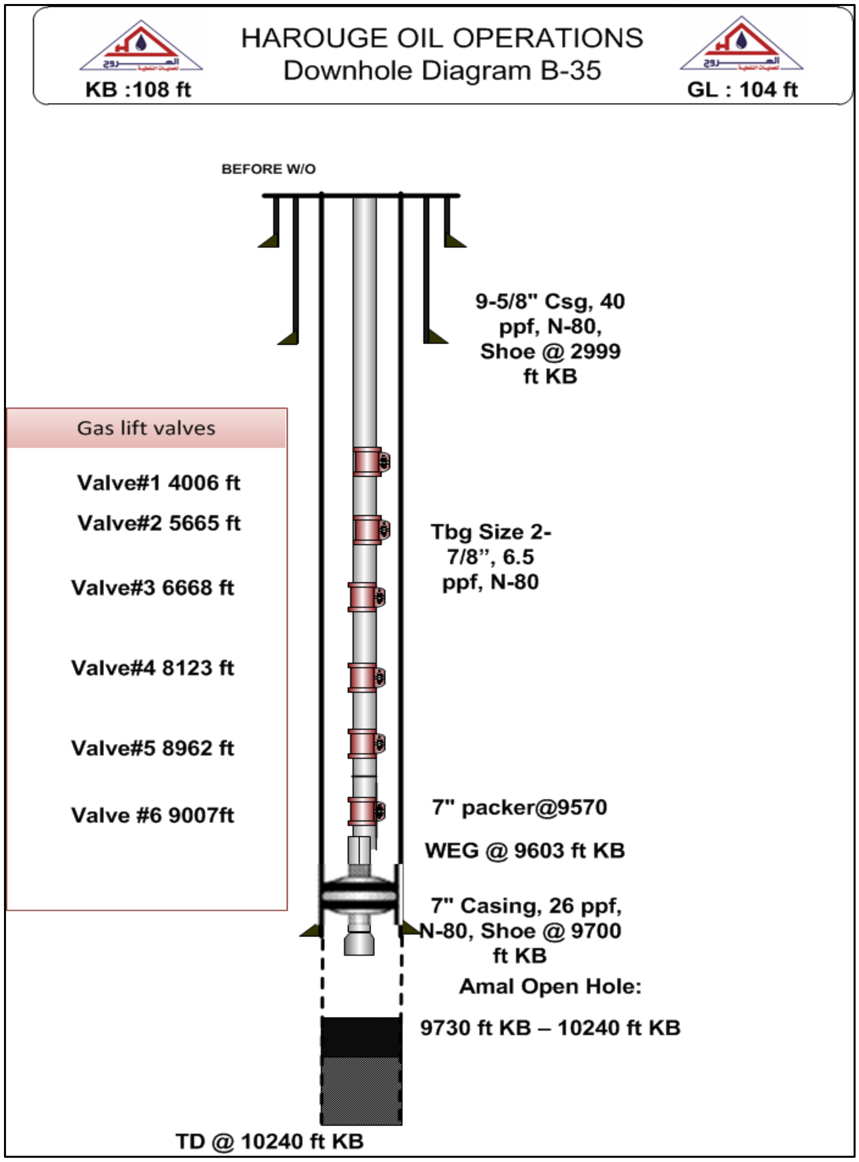

Figure 31 B035 completion sketch

Water sensitivity

Figure (32) shows that with this injection rate the well will be able to deliver less than 50bbl/day as the water cut reaches 95%.

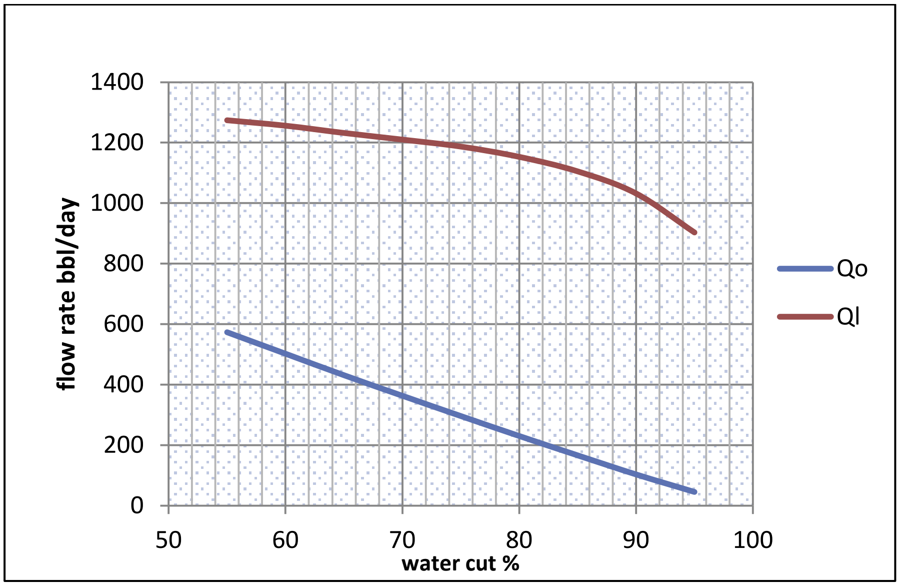

Figure 32 well B035 water cut sensitivity

4.4 Well B065

The well belongs to station 4, and it produces 880 bll/day of oil by injecting 4.03 mmscf/day of gas and as it can be seen in the production history chart figure (33) the well is producing with the maximum possible fluid flow rate , however the well has a high productivity index value which tell that it has a much higher potential, in addition to that he well has a relatively low gas oil ratio and moderate water cut percentage. Thus the well is a good candidate to be converted to an ESP operaterd well.

The gas separation sensitivity plot figure (34) shows that the pump can handle the produced gas without the need of installing a downhole gas separator where the operating point lies above the Dunbar factor represented by the red line.

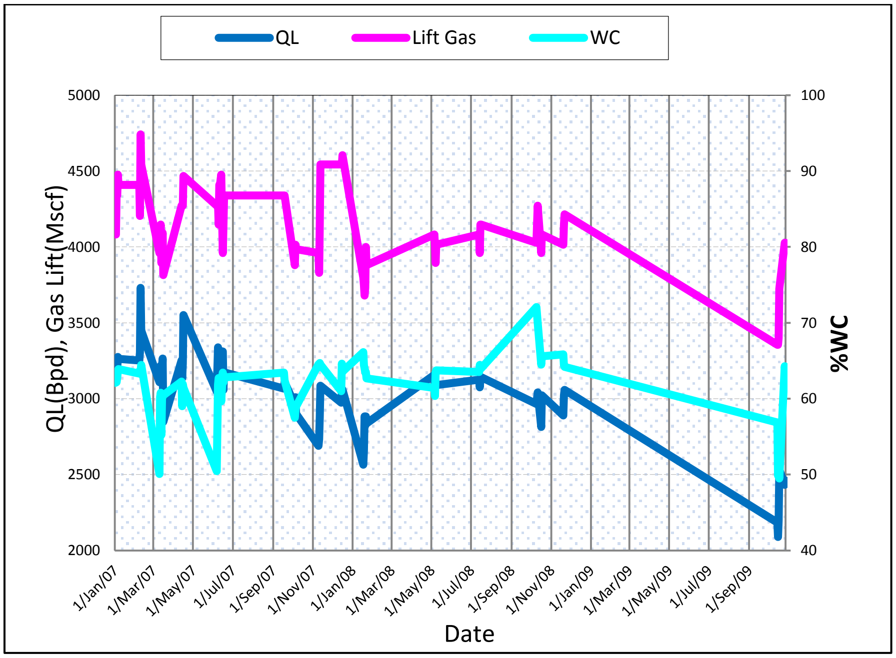

Figure 33 B65 Production history

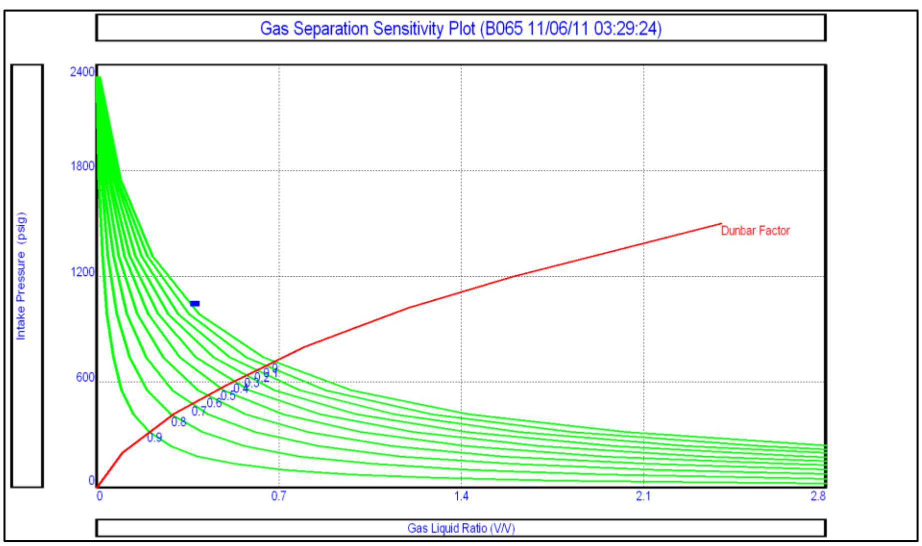

Figure 34 B065 Gas separation sensitivity plot

Figure (35) shows the optimum pump setting depth is 7200ft to produce 1550 bbl oil /day

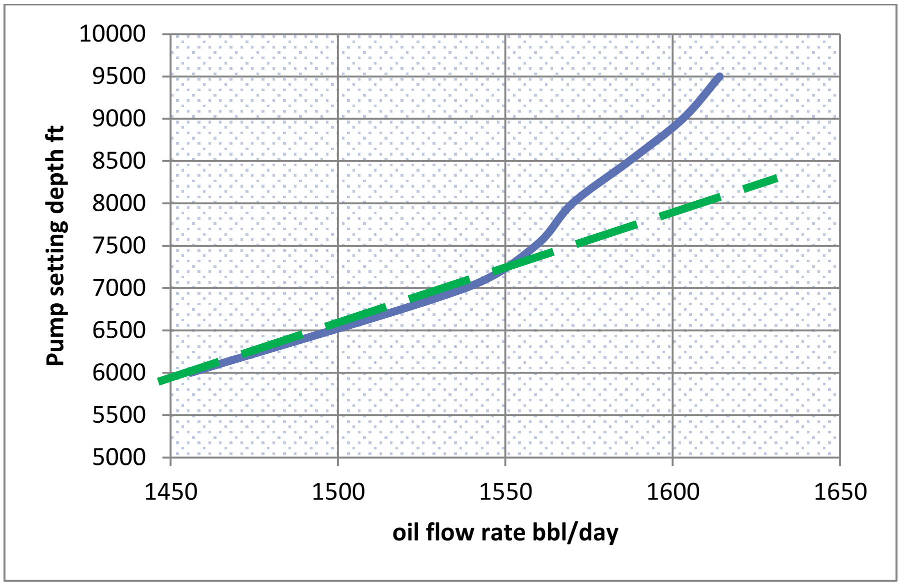

Figure 35 B065 pump setting depth vs. oil flow rate

Reda D5800N has been chosen as it gives the best performance with designed rate figure(36).

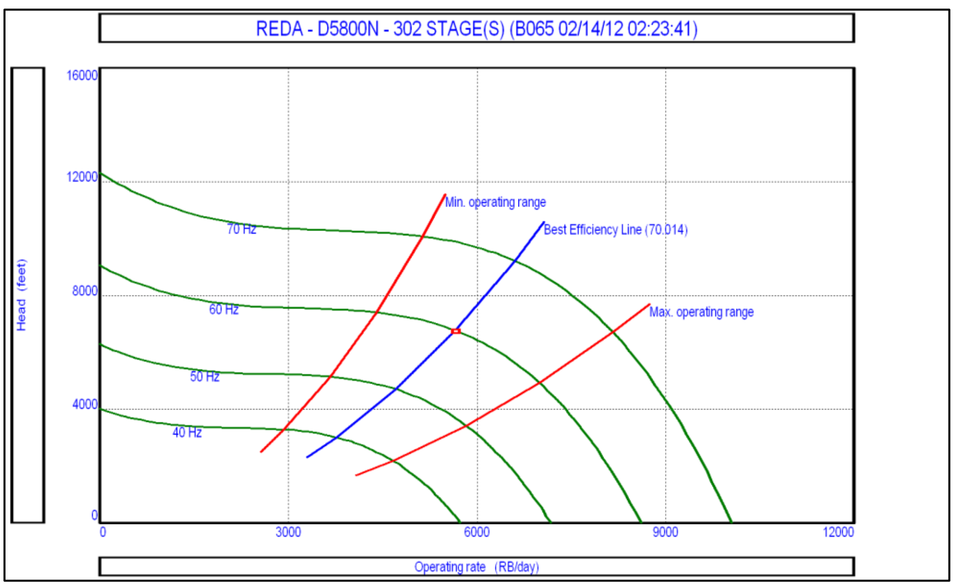

Figure 36 B065 ESP pump design

Figure (37) shows the effect of the installed pump on the IPR curve.

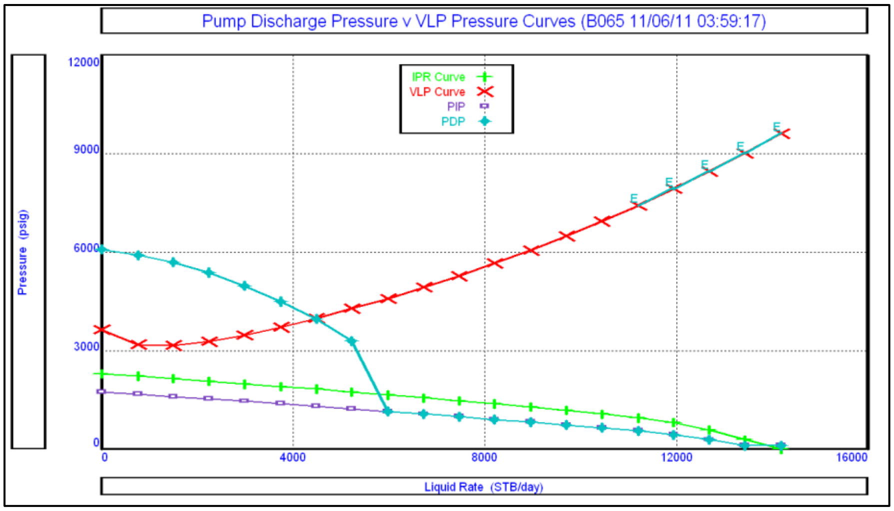

Figure 37 B065 IPR vs. VLP after installing the pump

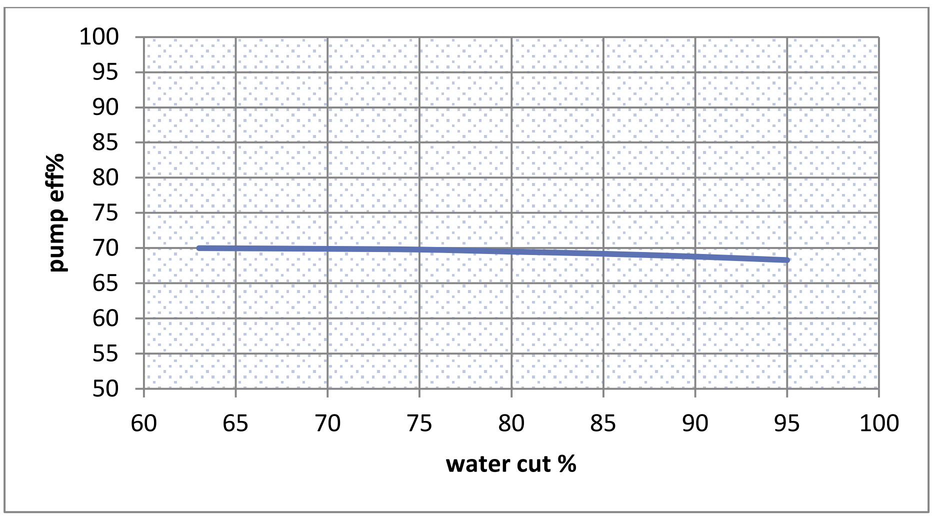

Figure 38 B065 water cut vs. pump efficiency

Figure (38) shows that the efficiency of the pump starts dropping when the water cut exceeds 80%.

Part's name	Specification
motor	Reda 540_90-0_std400HP2440V99A
pump	RedaD5800N4 inches
Cable	1# Copper 0.26(volts/1000ft) 115A max

Table 8 B065 ESP's parts and specifications

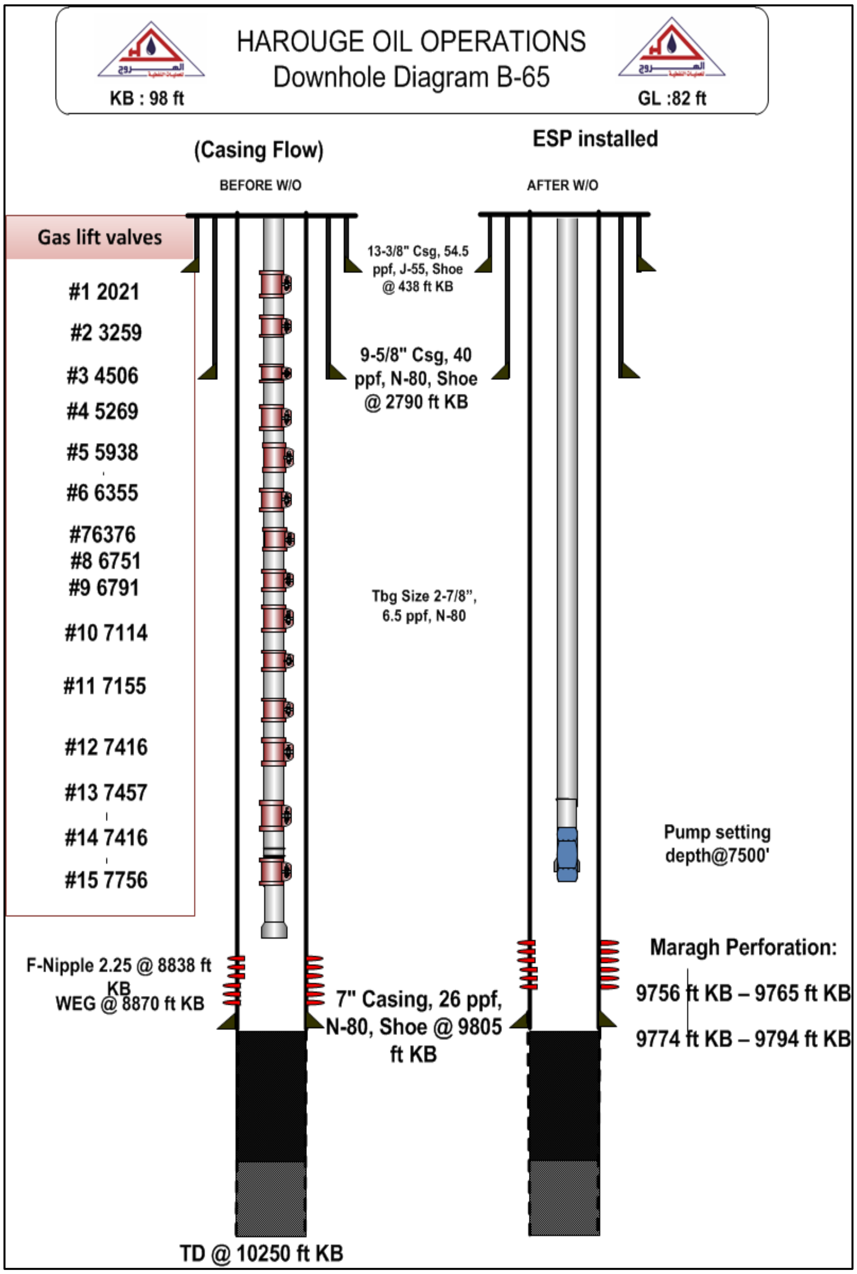

Figure 39 B065 new ESP installation sketch

4.5 Well B045

This is connected to station 5, the tubing corellation match parameters table (9) shows that petroleum expert 4 correlation has the lowest standerd deviation.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.944	0.56733	44.8069
Hagedorn Brown	1.12245	0.2	40.101
Fancher Brown	1.25002	1.67611	32.8103
Mukerjee Brill	1.18176	0.2	54.5997
Beggs and Brill	1.0652	0.40508	53.9399
Petroleum Experts	1.00001	0.99964	73.4271
Orkiszewski	1.34247	1.78029	18.0615
Petroleum Experts 2	1.06059	0.2	50.6418
Duns and Ros Original	1.12263	1.86263	16.0934
Petroleum Experts 3	1.25544	0.35921	54.7344
GRE (modified by PE)	1.28119	0.67837	49.3158
Petroleum Experts 4	1.13951	1.75229	11.1024
Hydro-3P	1.1892	0.50584	45.3665

Table 9 B045 correlation parameters

Figure (40) shows that the gas is being injected from the second valce which located on the depth of 5400".

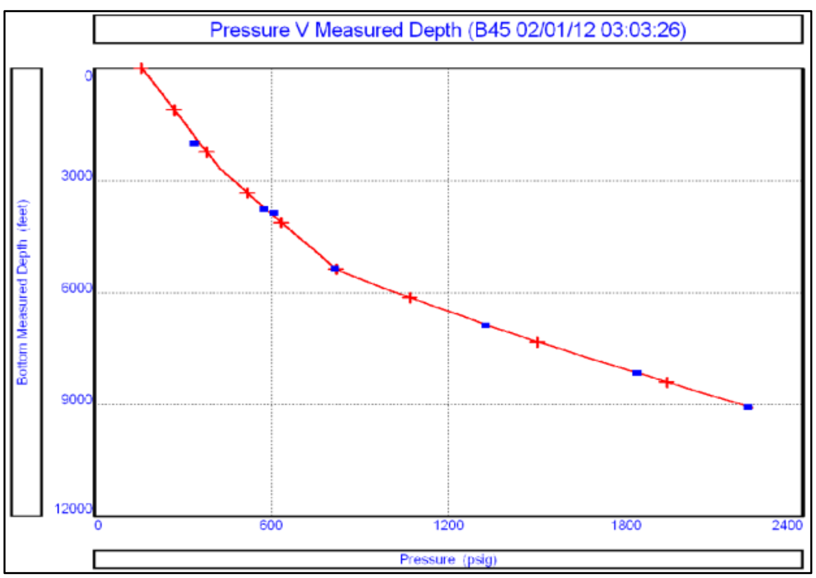

Figure 40 B045 gradient survey

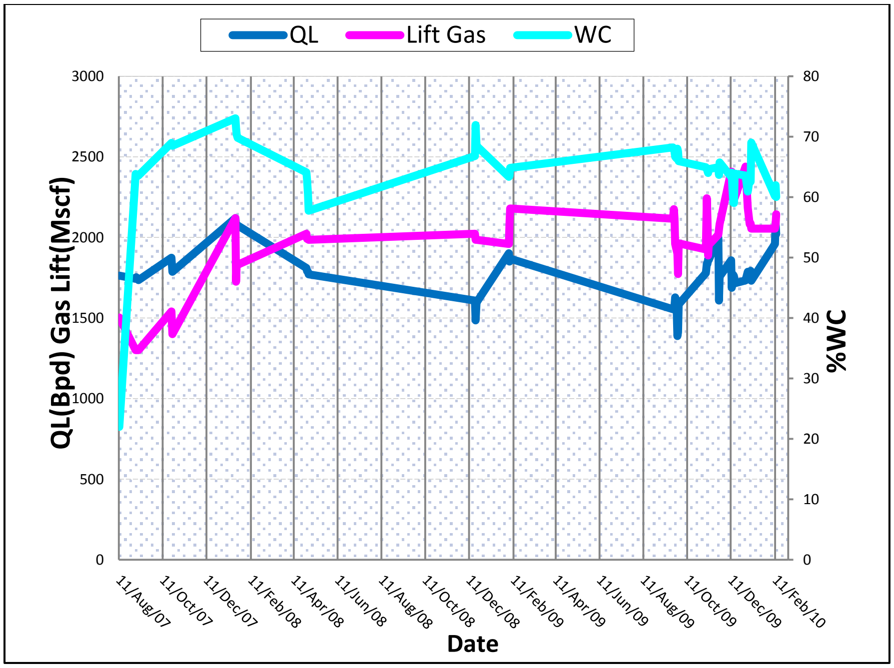

Figure 41 B045 Production history

The production history chart figure (41) shows inconsistancy and flactuation in the produced fluid and the gas rate of injection, this production instablity mighty be caused by the inaprobriate gas lift design figure(44) where it shows that the gas has been injected from the second valve.

Figure (42) shows that well has 3 design points, however the second point is more likely to be used as only0.2 mmscf/day of the injected gas is needed to be added to the current injection rate.

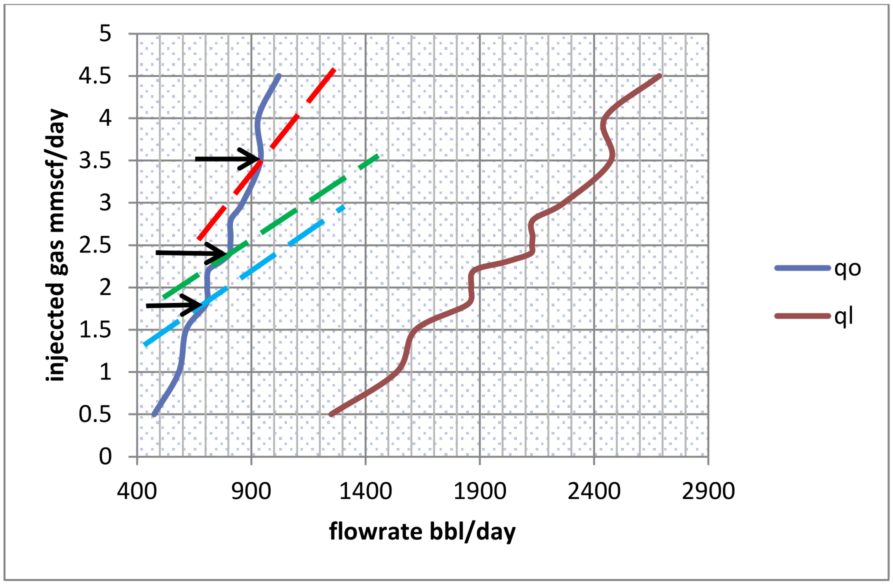

Figure 42 Gas injection performance curve

Figure (43) show a new gas lift design where it shows that the gas is injected into the deepest possiple depth.

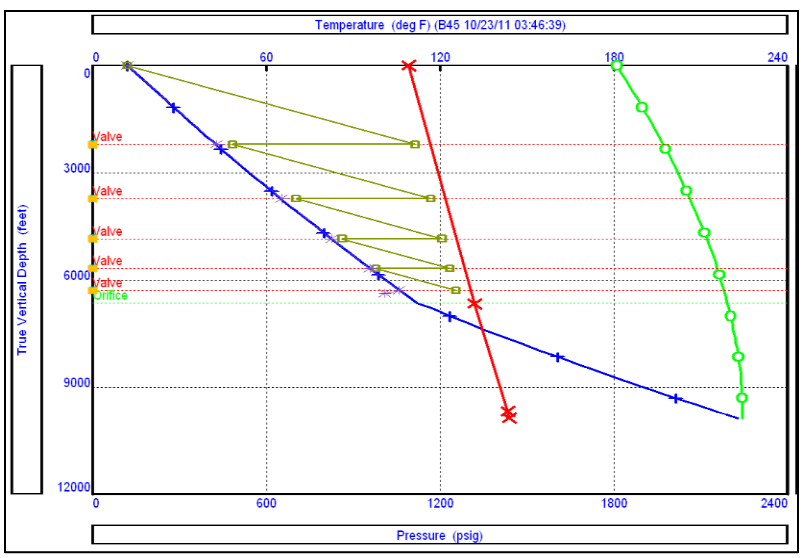

Figure 43 B045 Gas lift design

The valves spesifications and depths are illustrated in figure(44)

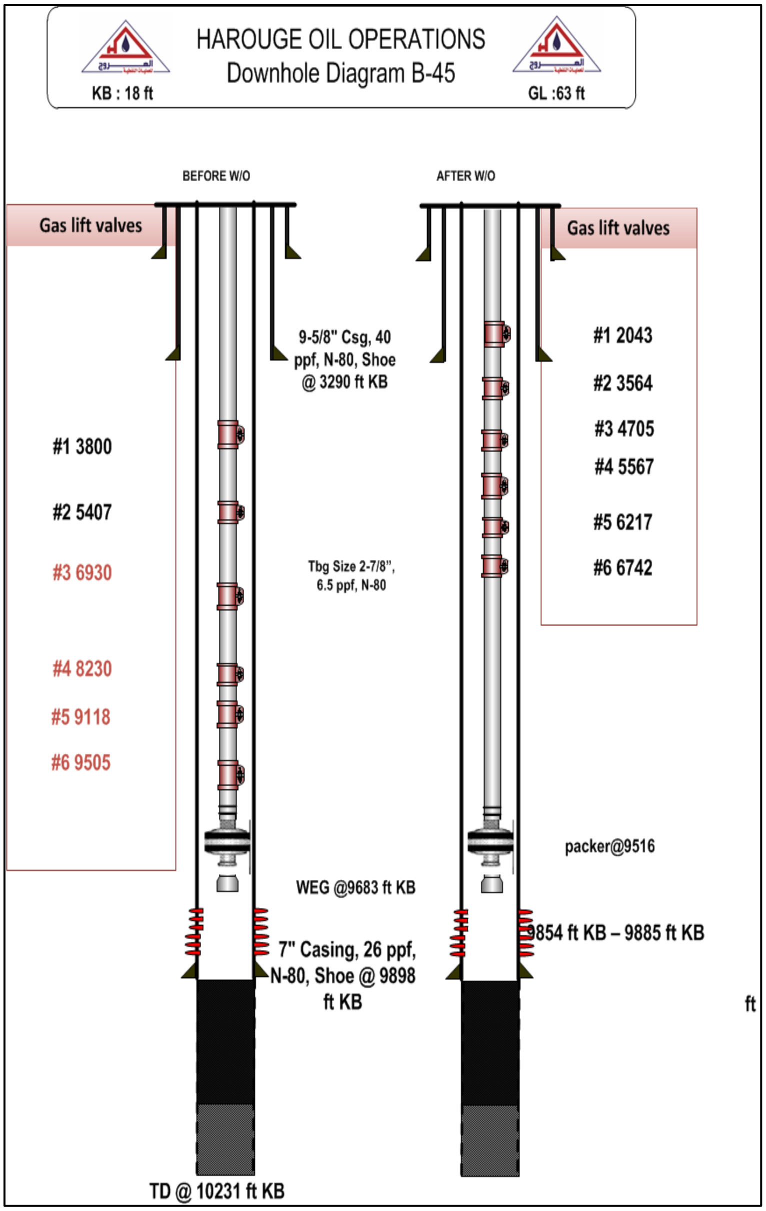

Figure 44 B045gas lift completion sketch

Water cut sensitivity

As it can be seen in figure (45) the oil production well drop to about 70 bbl/day when the water cut exceeds 95%.

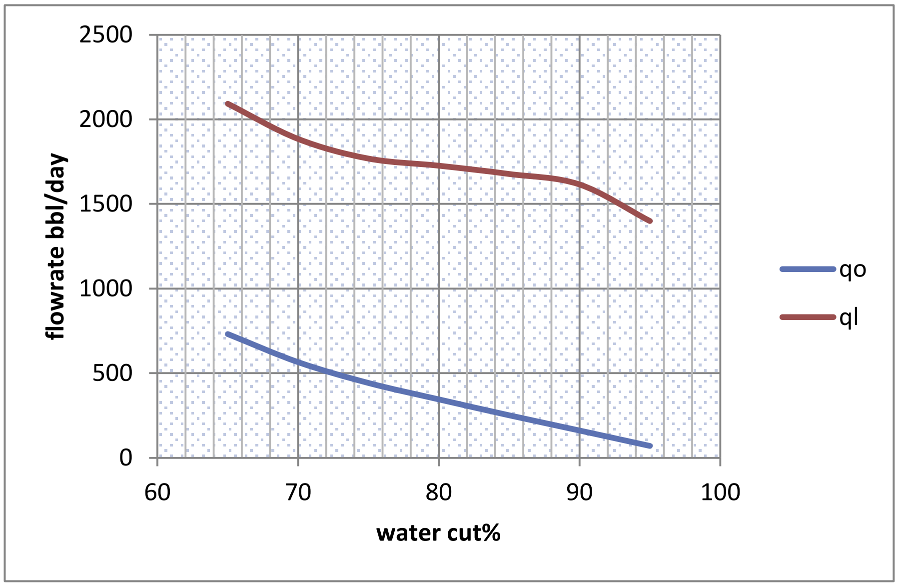

Figure 45 B045 water cut sensitivity

4.6 Well B079

The well belongs to station 7, as it can be seen in table(10) the well matches with Hydro-3P.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.54151	2.61152	88.902
Hagedorn Brown	1	1.00049	87.4247
Fancher Brown	0.63264	4.27682	94.0662
Mukerjee Brill	0.87713	0.76065	94.9304
Beggs and Brill	0.2	4.35012	108.964
Petroleum Experts	0.99998	1.00023	94.981
Orkiszewski	0.2	1.79546	114.264
Petroleum Experts 2	0.71353	2.84349	90.2037
Duns and Ros Original	1.04264	2.1263	84.4196
Petroleum Experts 3	1.02095	1.34467	84.0289
GRE (modified by PE)	1.01112	1.22819	84.2241
Petroleum Experts 4	1.01763	1.32952	84.45
Hydro-3P	1	1.00042	84.4639

Table 10 B079 tubing corealation parameters

Figure (46) shows that the gas is injected through the deepest point possible. This can be seen in the production history chart figure(47).

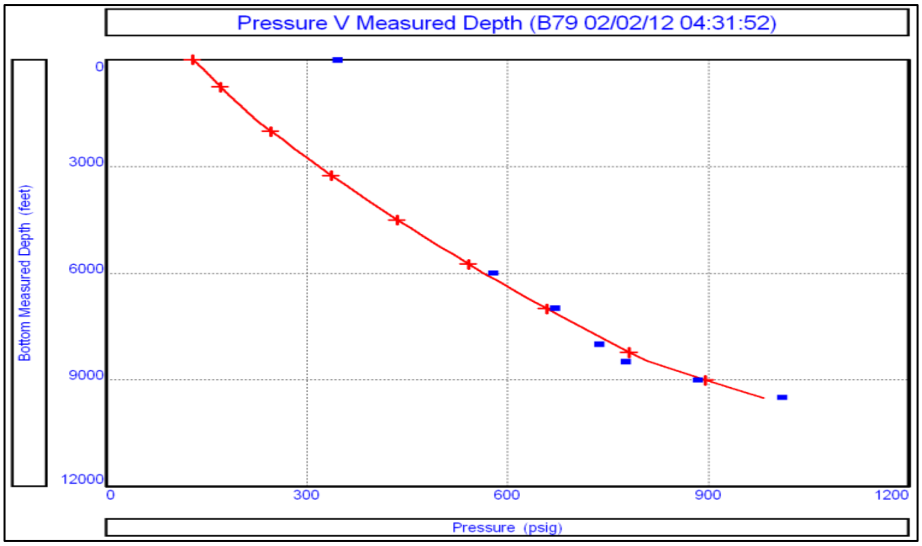

Figure 46 B079Gradient survey plot

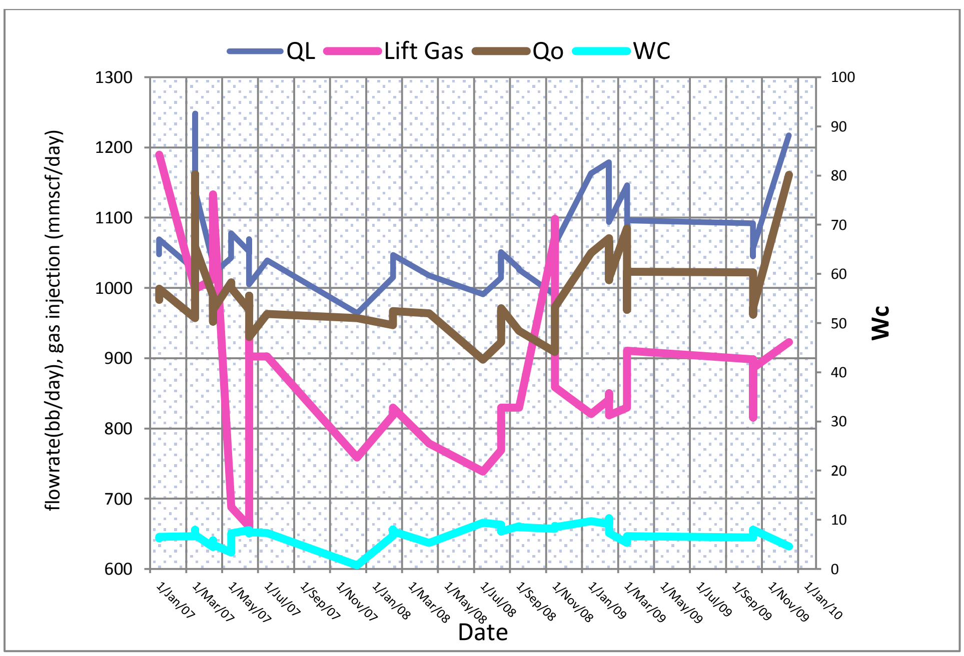

Figure 47 B079 Production history

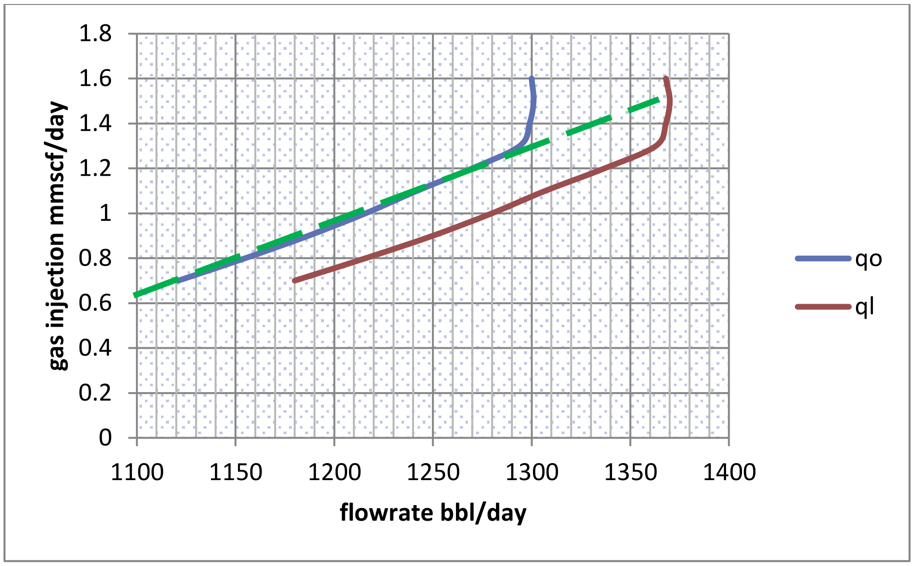

Figure 48 gas injection performance curve

as illustrated earlier the gas is being injected from the deepest possible point, therefore there is no need to make a new design, the production however can be increased by 140bblo/day by increasing the gas injection 0.45 mmscf/day.

Water cut sensitivity

The water sensitivity plot (49) illustrates that the oil production drops sharply till it reaches 160 bbl/day at 60 percent water cut, then drops gradually till it becomes less than 10 bbl/day at 955 water cut

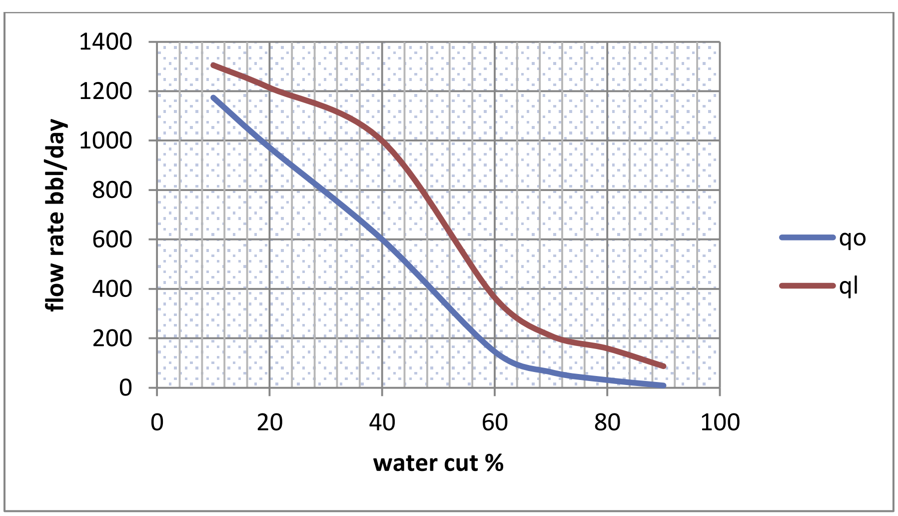

Figure 49 B079 water sensitivity

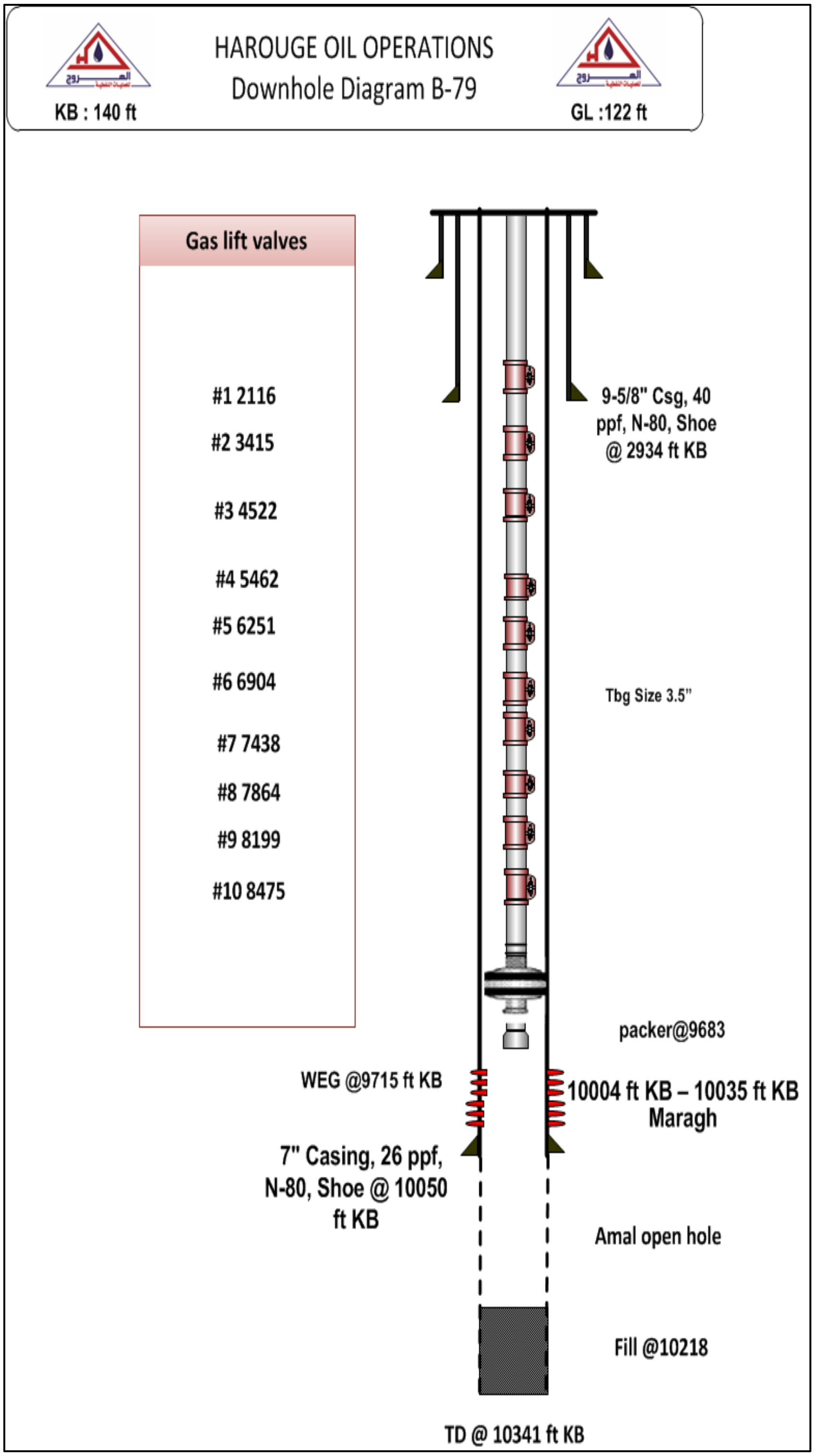

Figure 50 B079 gas lift completion sketch

Well completion sketch is illustrated in figure(50).

4.7 Well B101

This well belongs to station 3 according to the FGS dated Nov 25 2008 table (11) the well current conditions matches with petroleum expert 4 correlation figure (51) shows that the well is being injected through the fifth valve which located at the depth of 6700ft. the valves might need to be inspected.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.84513	0.85057	79.0925
Hagedorn Brown	1.28774	1.66355	52.3203
Fancher Brown	1.9573	1.25395	46.1524
Mukerjee Brill	0.199	0.2	400.785
Beggs and Brill	0.199	0.2	392.188
Petroleum Experts	1.26635	1.25791	52.4491
Orkiszewski	0.56491	1.04231	98.8709
Petroleum Experts 2	1.25598	1.18908	50.9101
Duns and Ros Original	0.558	1.30224	111.414
Petroleum Experts 3	1.35088	1.40322	67.4707
GRE (modified by PE)	0.71421	1.18028	55.7401
Petroleum Experts 4	0.76713	1.10479	44.3426
Hydro-3P	0.79601	1.02763	79.5396

Table 11 B101 tubing corellation paramerters

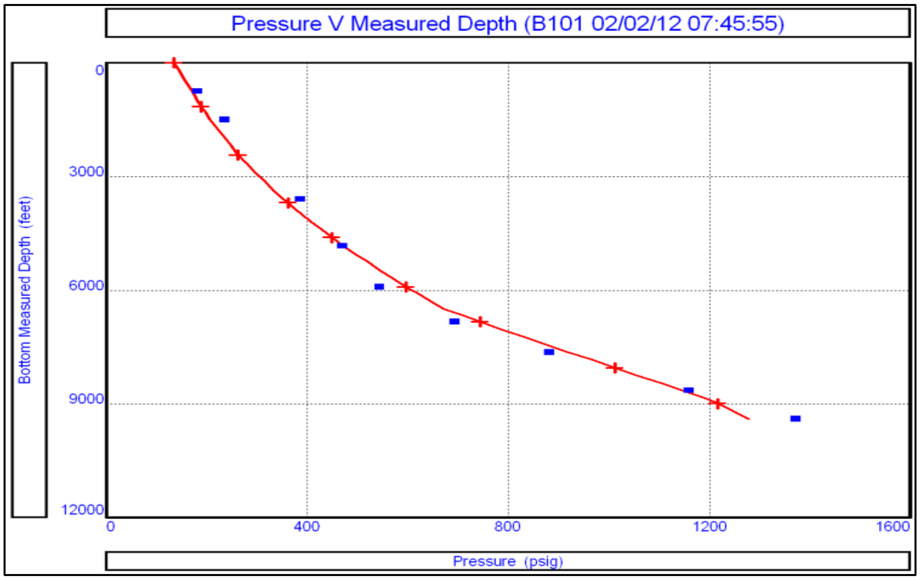

Figure 51 B101 gradient survey plot

The production history figure(52)shows a harmony between the produced liquid rate and the injected gas, where it shows that with any gas injection there was a corrodponding increament or reduction in the produced fluid.

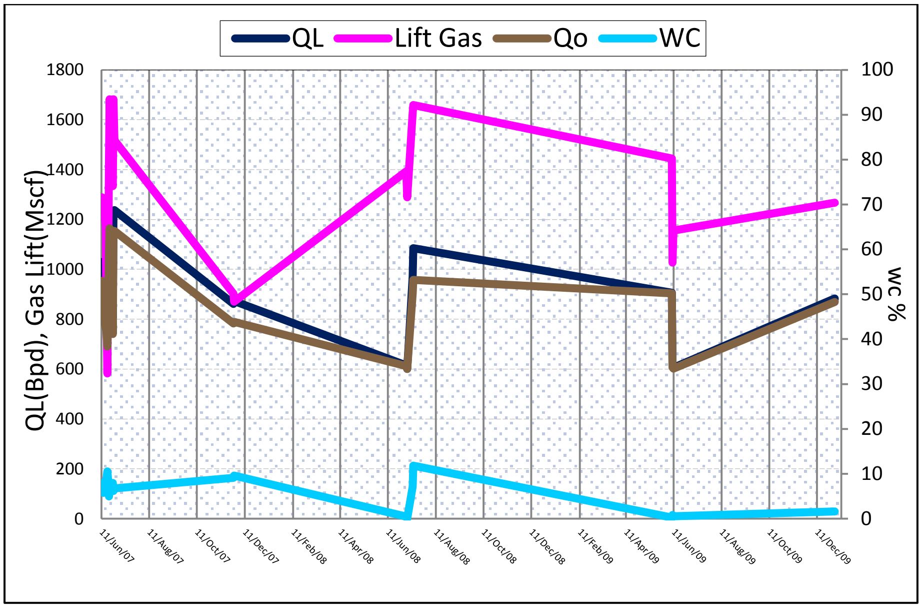

Figure 52 B101 Production history

The gas lift peformance curve figure(53) shows that the obtimum gas injection rate is 3mmscf/day as after this rate the increament of the produced flow rate is started to decline.

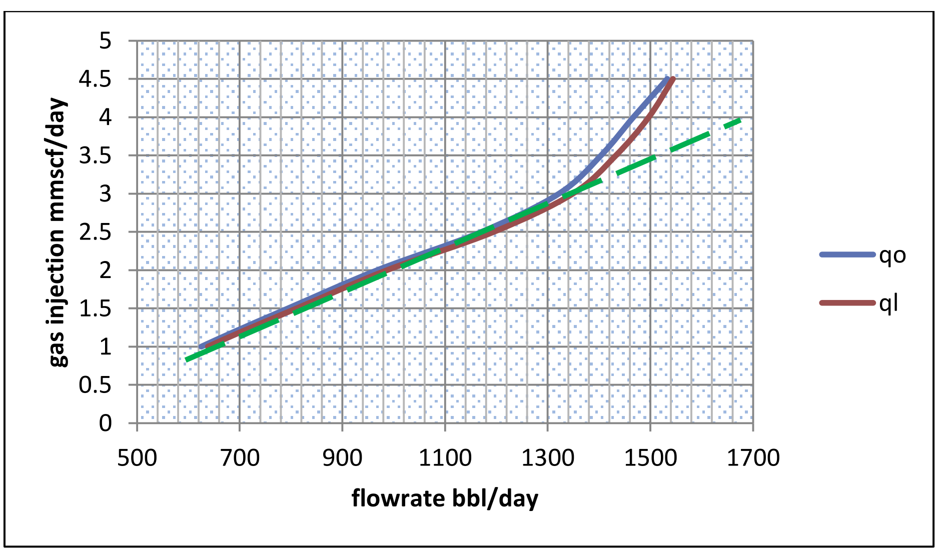

Figure 53 B101 gas lift performance curve plot

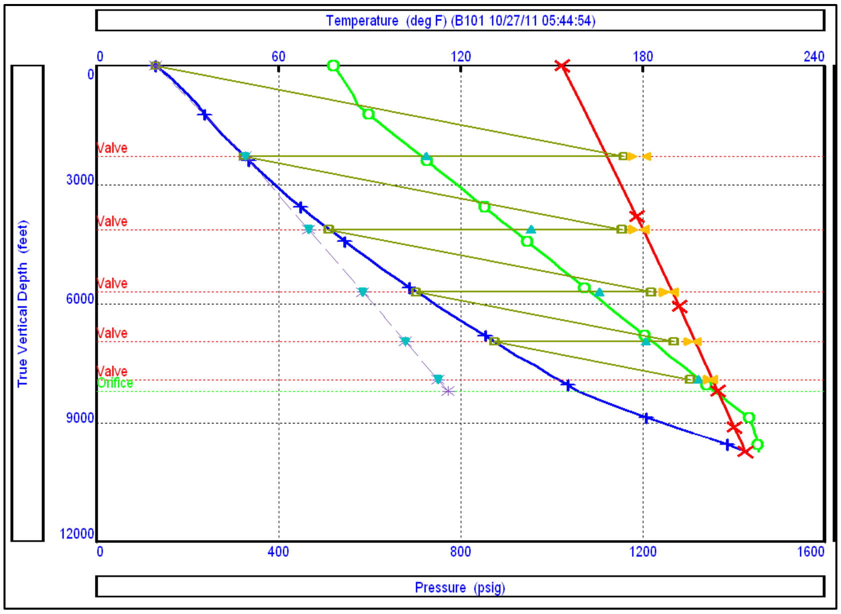

Figure 54 B101 Gas Lift design

Figure (54) illustrates that the new design proposed by the simulator and the current are pretty much the same, thus only valves check is recommended for this well.

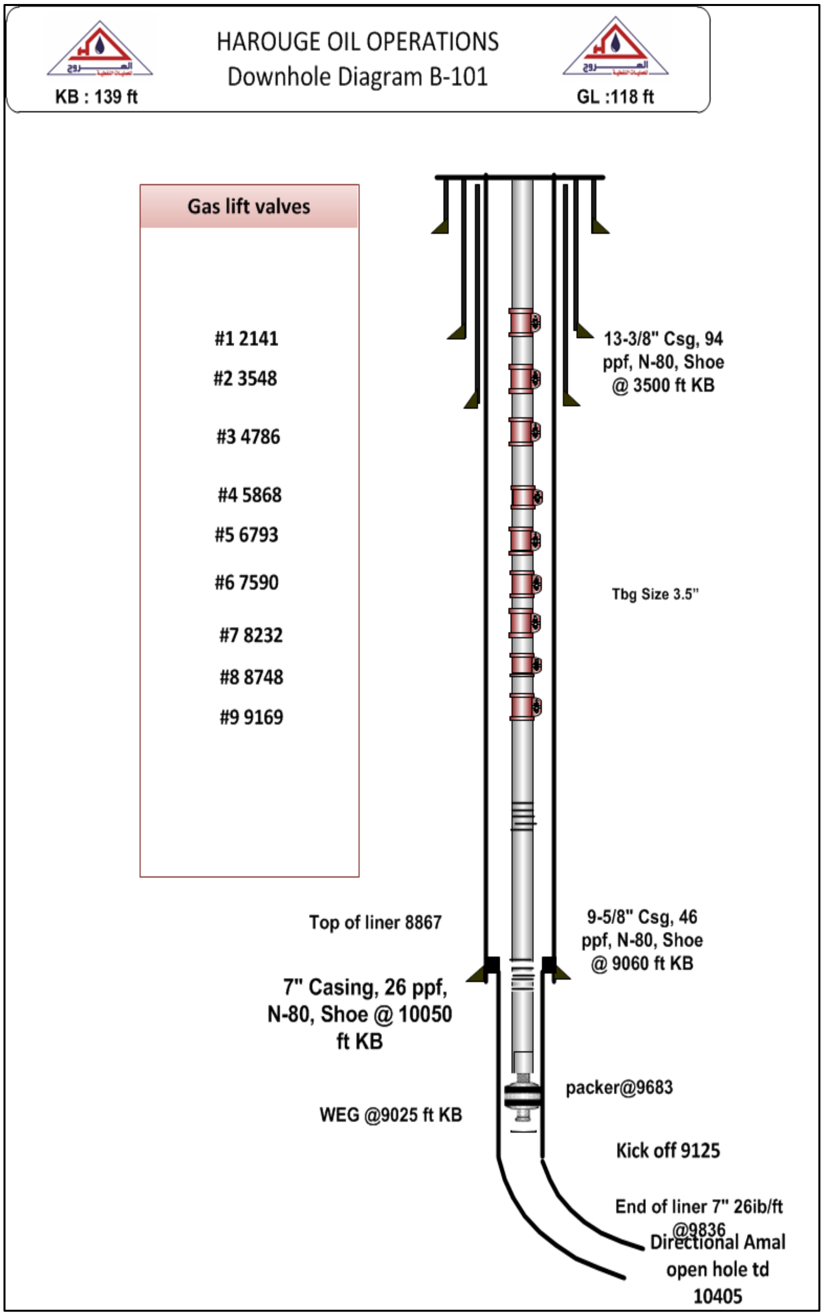

Figure 55 B101 Gas lift design results

4.8 Well B 103

The well is produced by electrical submersible pump RedaGN 1600, two scenarios have been made.

ESP design

The well currently produces 1950 bbl/day liquid rate, however the rate, which the pump installed operates with best efficiency performance is 1250 bbl/day figure (56), thus a new ESP design is recommended to choose a different pumping unit.

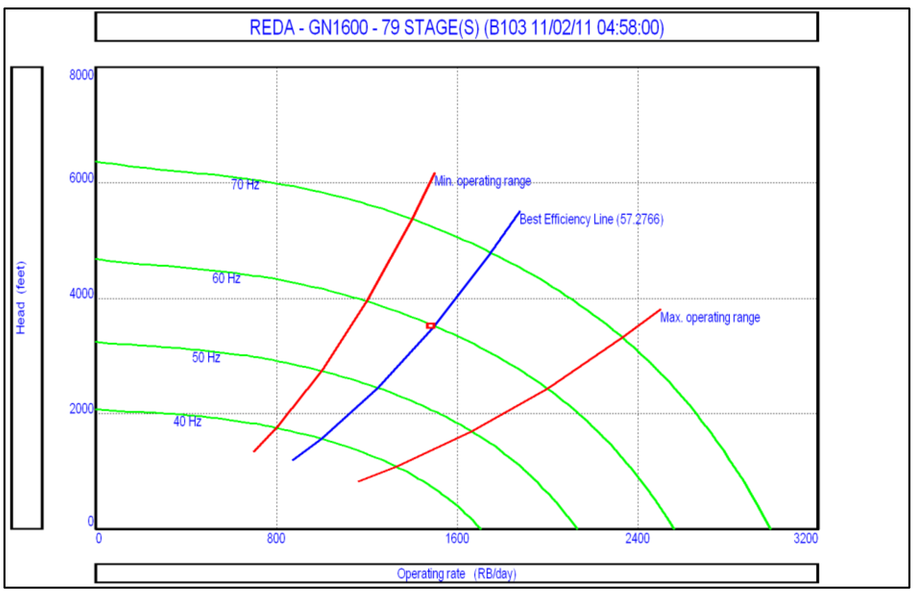

Figure 56 B103Reda pump design old rate

New ESP design

The gas sensitivity plot figure (57) shows that downhole gas lift is not needed for this well.

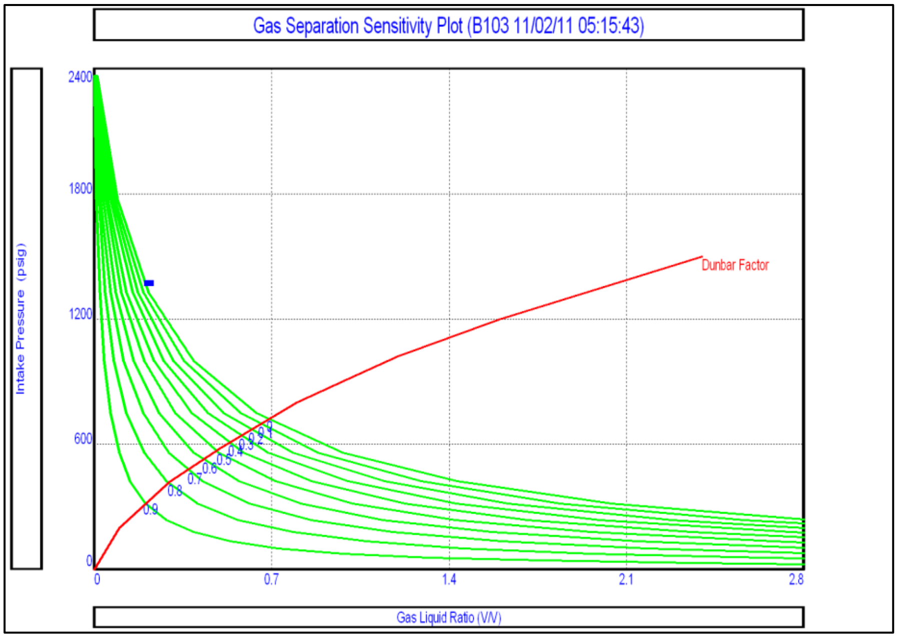

Figure 57 B103 gas separation sensitivity

Figure (58) illustrates the effect of the pump on the IPR curve.

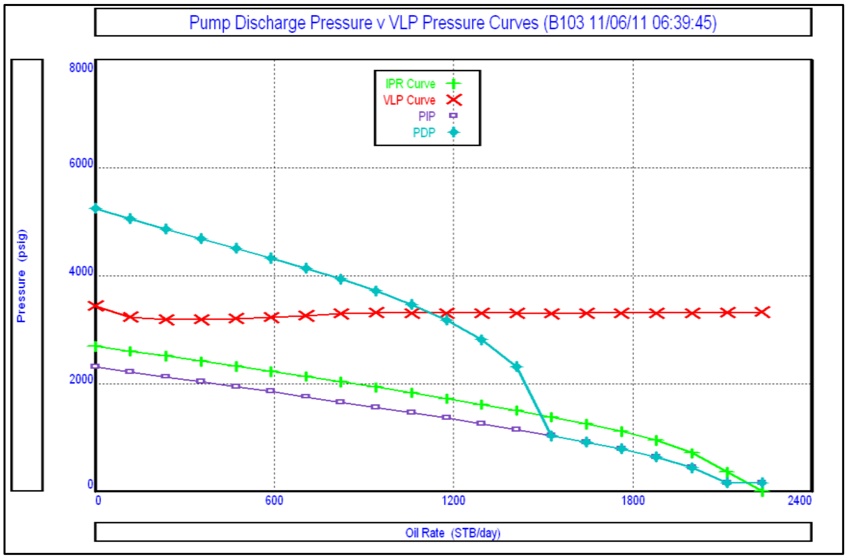

Figure 58 B103The effect of the pump on the IPR curve

Figure (59) shows that the optimum pump setting depth is 7700 ft, to produce 3200 bbl fluid /day.

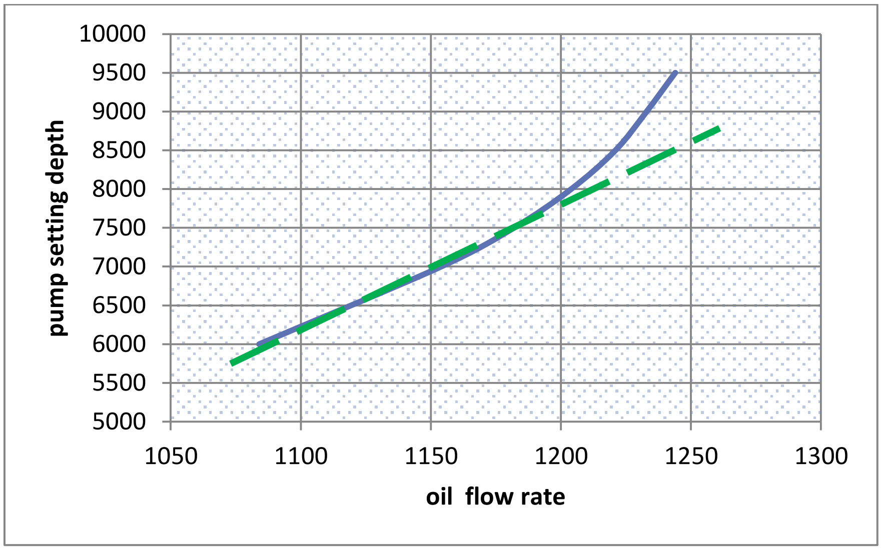

Figure 59 B103 Pump setting depth vs. oil flow rate

RedaGN4000has been chosen for the new design where it gives the best efficiency performance with the designed rate.

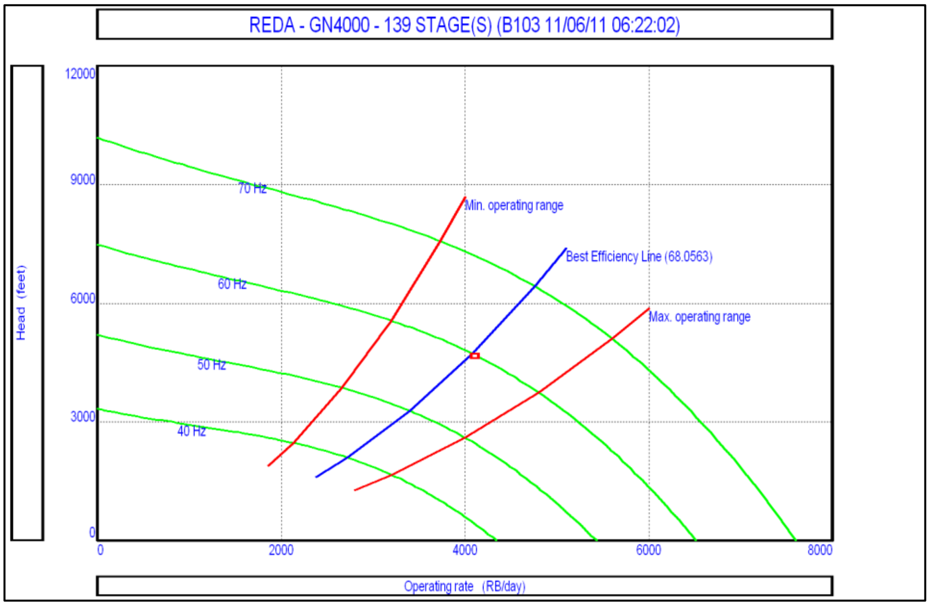

Figure 60 B103 ESP design new rate

Table (4.9) shows the ESP parts used in this design

Part's name	Specification
motor	Reda 540_90-0_std200HP1220V78A
pump	RedaGN4000 5.13 inches
Cable	1# Copper 0.26(volts/1000ft)

Table 12 B103 ESP parts ans spesifications

Figure(61) shows that the pump efficiency will drop from 68.9% at the current conditions to around 65.5% when the water cut reaches 95%.

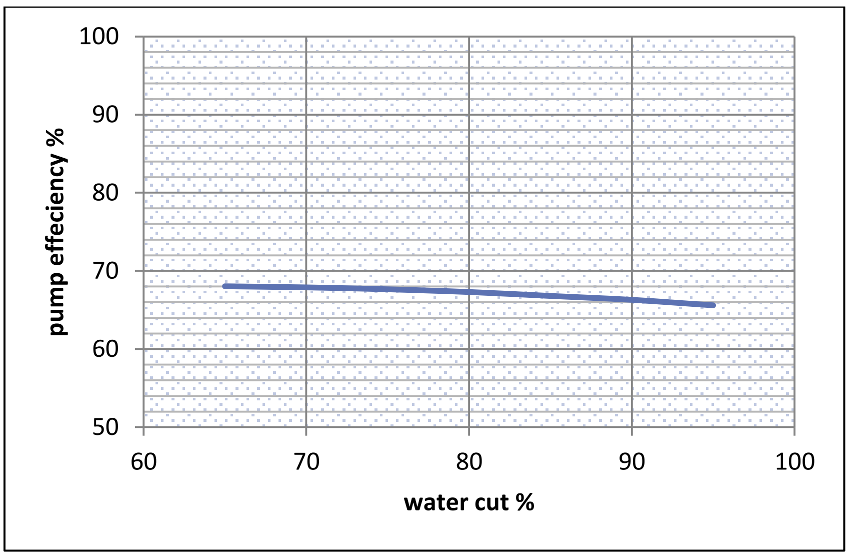

Figure 61 B103 pump efficiency vs. water cut

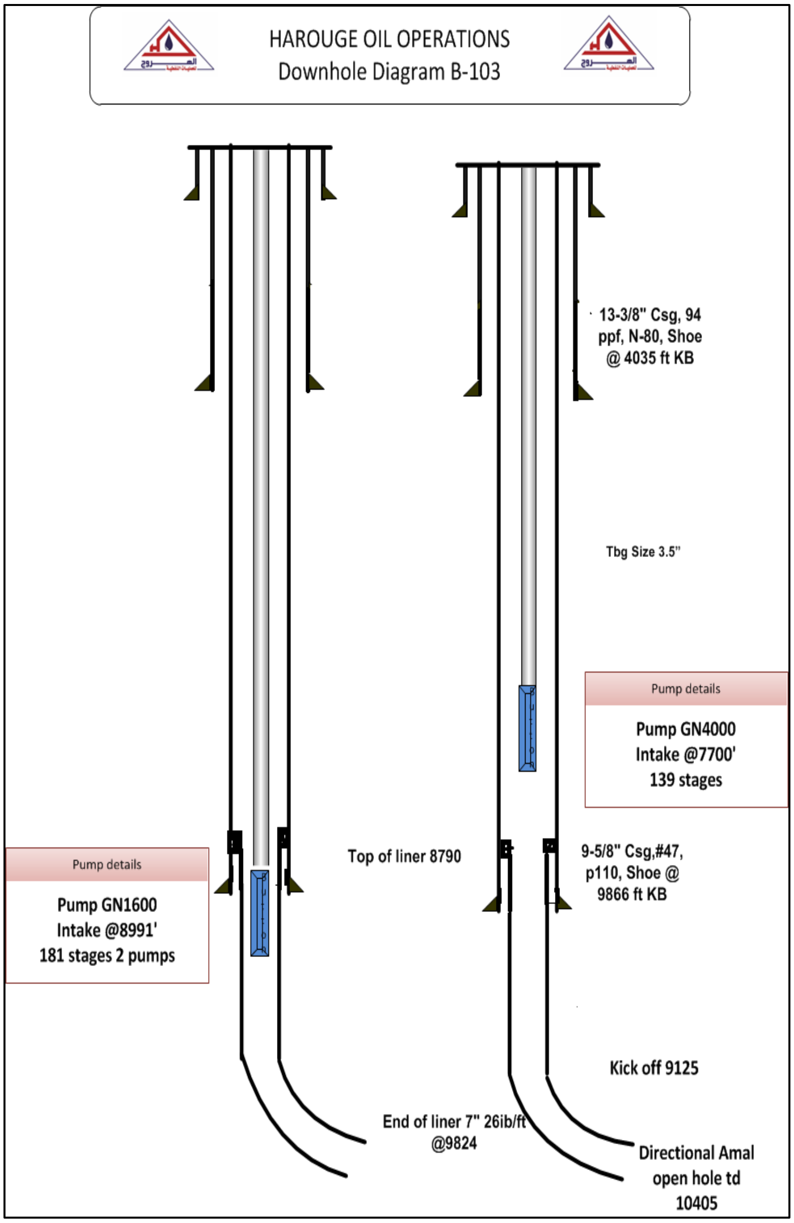

Figure 62 B103 new ESP installation sketch

Gas lift converting scenario

The well has a moderate water cut value, and can be connected to station 3, which makes it a good candidate to be converted from ESP operated well to a gas lift operated well.

The gas lift performance curve figure (63) shows that the optimum gas injection rate is around 3.2mmscf/day.

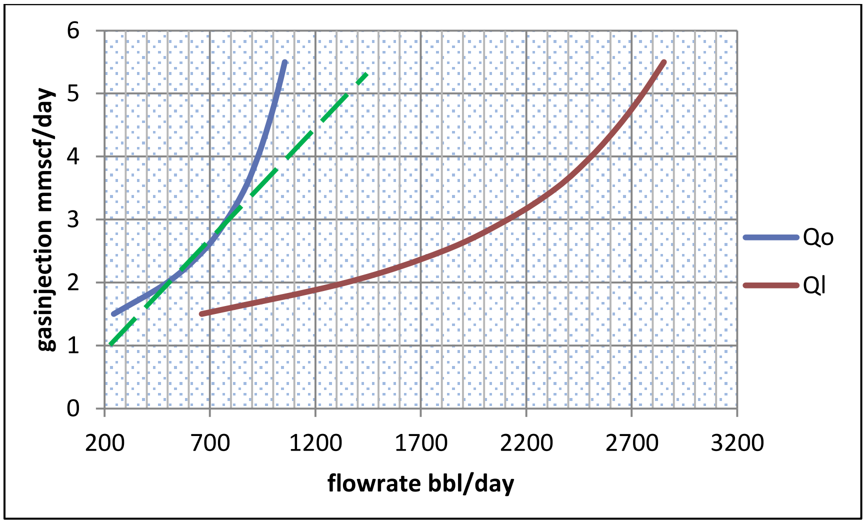

Figure 63 B103 Gas lift design performance curve

The design and the completion sketch are illustrated in figures (64),(65)

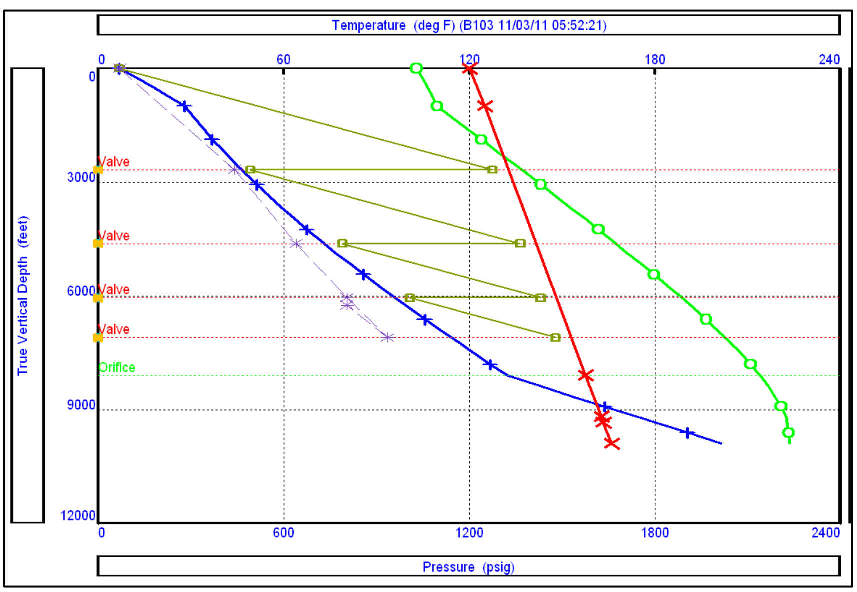

Figure 64 B103gaslift design

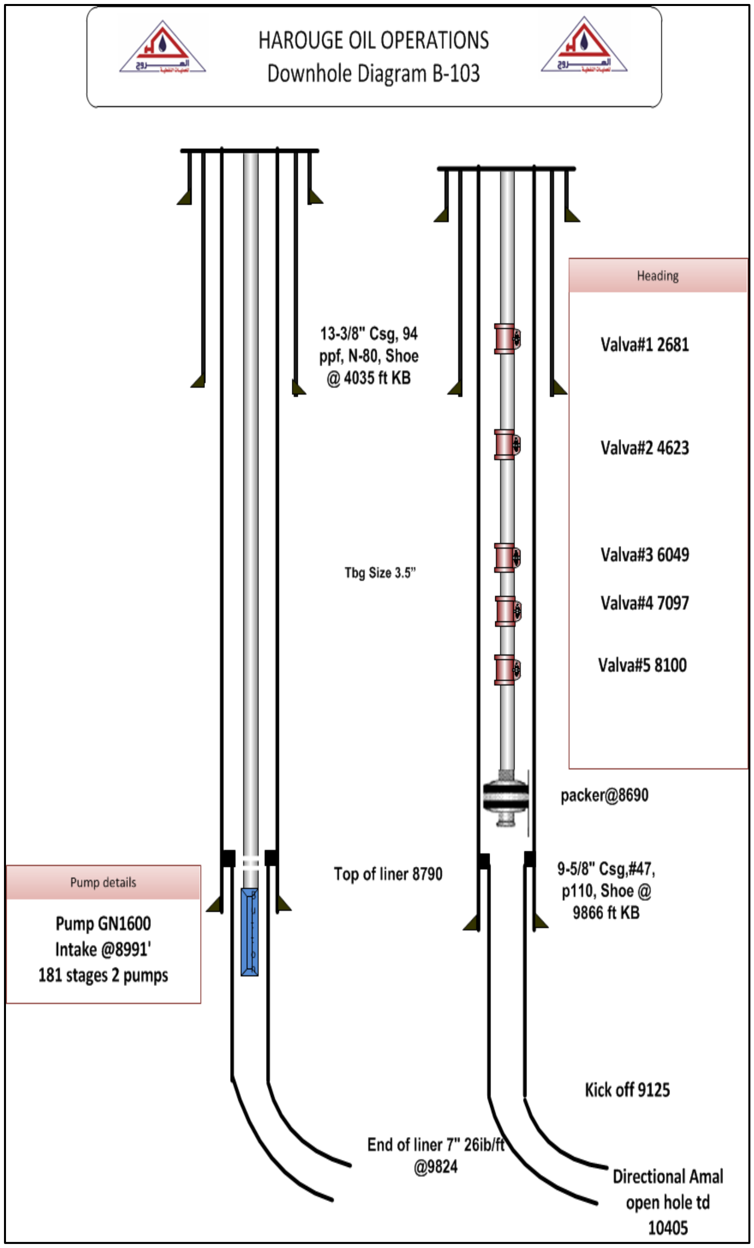

Figure 65 B103 gas lift completion sketch

Water cut sensitivity

Figure (66) shows that the oil production will drop from around 650 bbl/day to less than 100bbl/day as the water cut increased fron 60% to 95%.

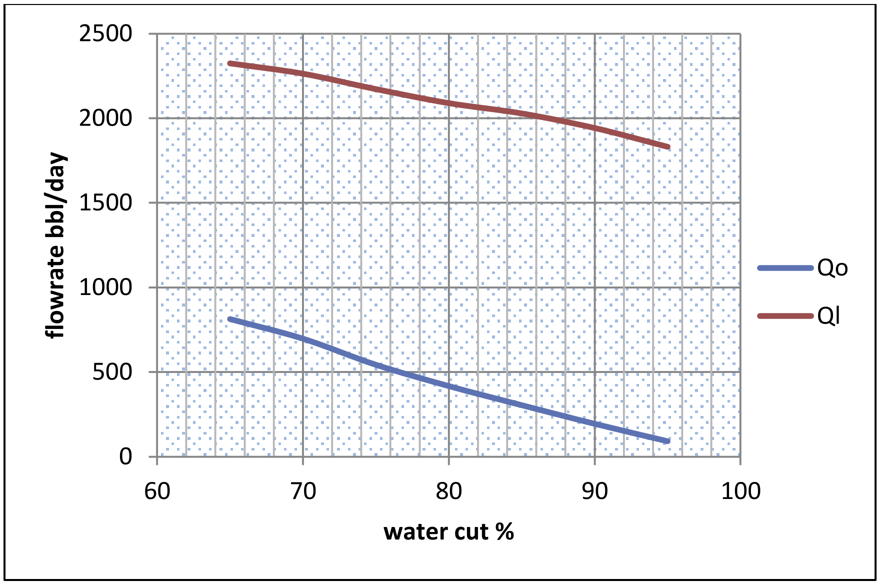

Figure 66 B103 water sensitivity

4.9 Well N003

This well belongs to station 3 according to the FGS dated Oct 15 2008 table (13), the well current conditions matches with Duns modified correlation. The well is being injected at depth of 8950' where the deepest valve is installed as it can be seen in figure(67).

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.87273	1	46.3834
Hagedorn Brown	1.99492	1	50.3308
Fancher Brown	2.93721	63.3543	51.6989
Mukerjee Brill	0.32397	1	39.3744
Beggs and Brill	0.32324	1	39.0889
Petroleum Experts	1.98479	1	50.2276
Orkiszewski	0.99809	0.93185	598.314
Petroleum Experts 2	1.94444	1	49.8147
Duns and Ros Original	0.99813	1	1143.21
Petroleum Experts 3	2.41512	1	43.9614
GRE (modified by PE)	0.87902	1.58504	127.887
Petroleum Experts 4	0.81366	2.1708	395.908
Hydro-3P	0.77398	4.78411	69.3763

Table 13 N003 Tubing Correlation Parameters

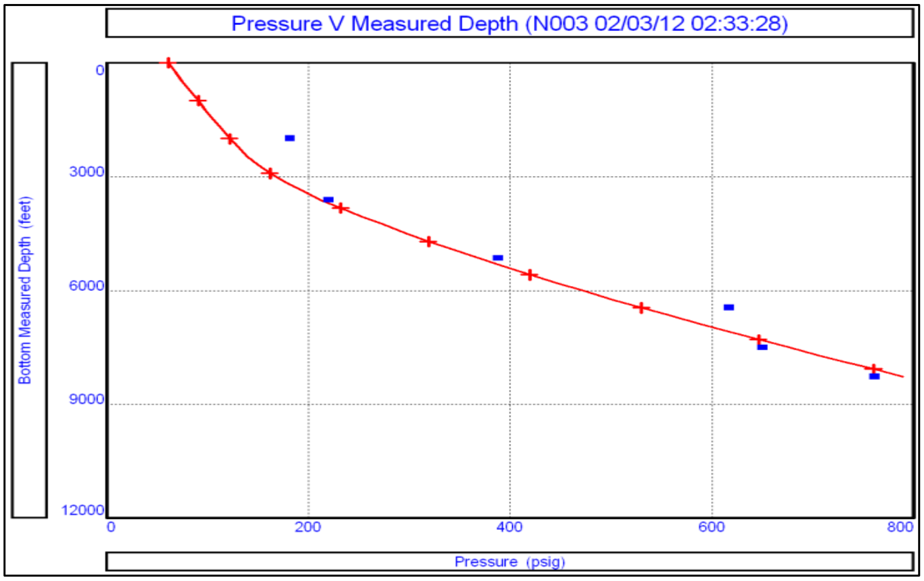

Figure 67 N003 gradient match plot

The production history figure (68) shows that the production can be slightly increased by increasing the lifting gas rate.

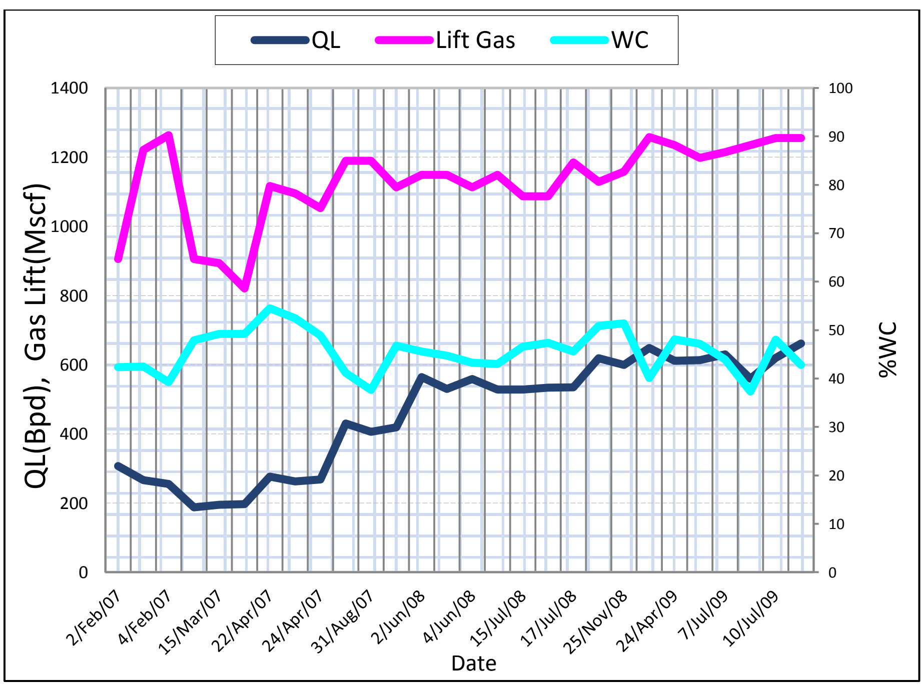

Figure 68 N003 Production history

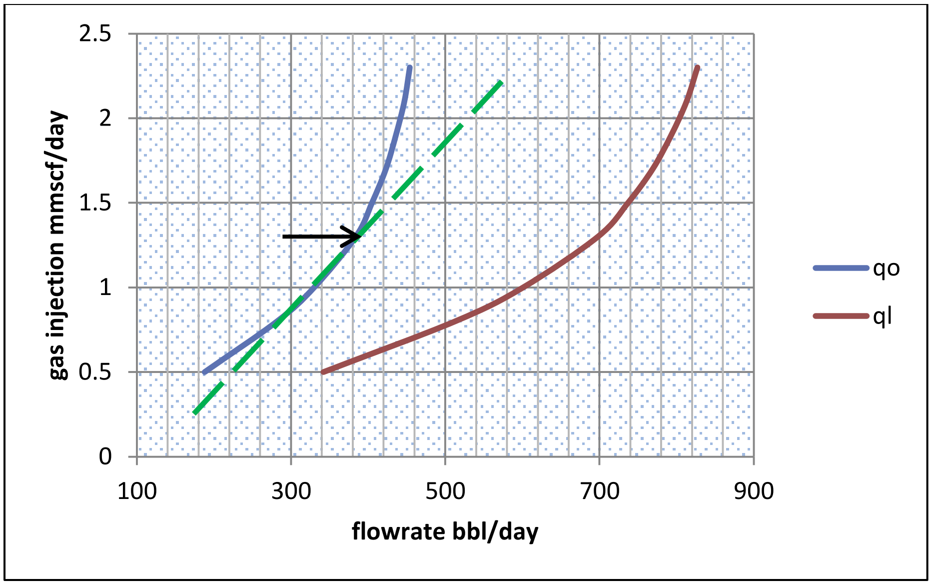

Figure 69 N003 gas injection performance curve

figure (69) shows that the optimum gas injection for well N003 is around 1.4 mscf/day which can increase the oil production to about 80 bbl/day with just adding 0.15 mmscf/day of gas to the current injection rate.

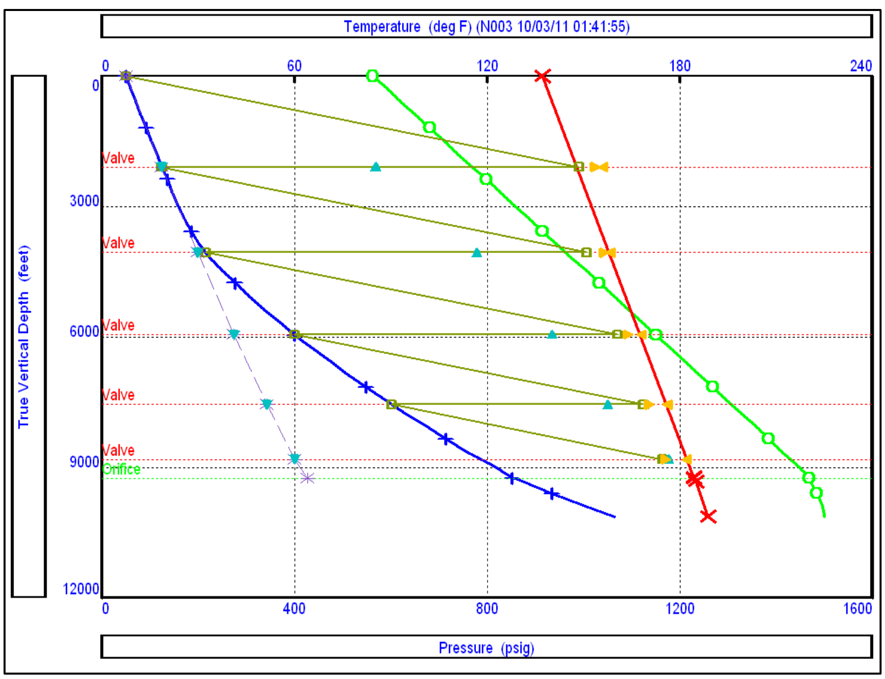

Figure 70 N003 new gas lift design

Water cut sensitivity

Figure (71) shows that the well will be producing less than 30 bbl/day of oil when water cut exceeds 95 %.

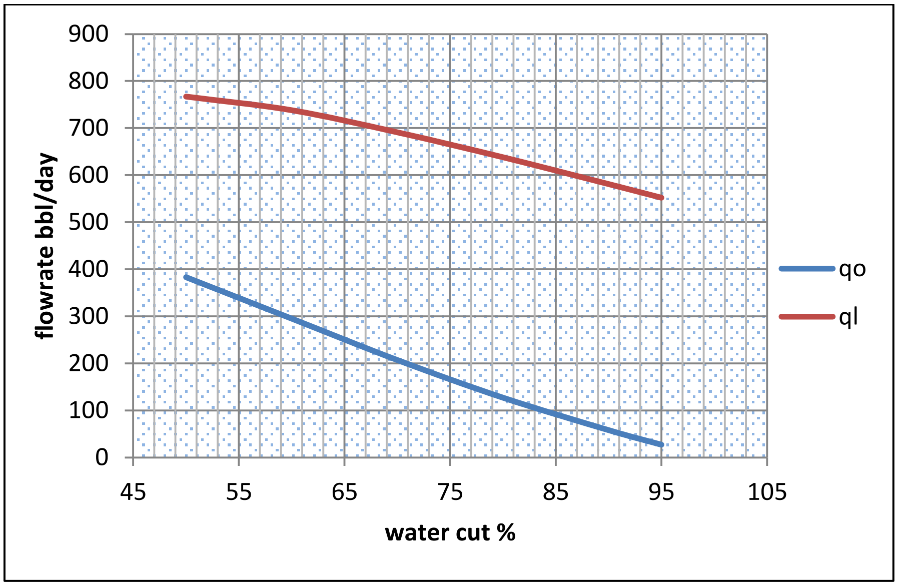

Figure 71 N003 water cut sensitivity

The gas lift design and the completion skitch are illustrated in figures (70),(72) respectivley.

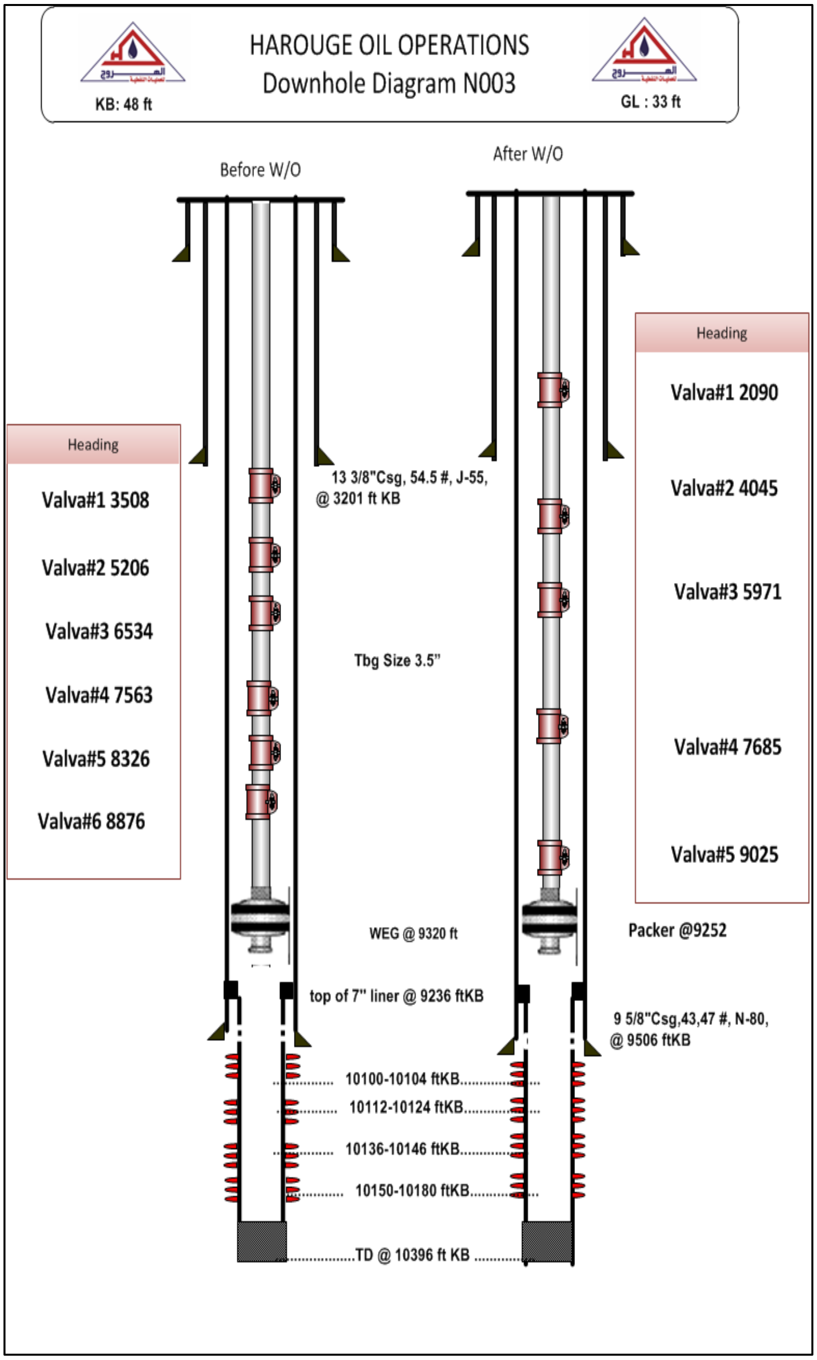

Figure 72 N003 Gas lift design results

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4.10 Well N038

The well flows to Station 6. The well has 7 valves and the deepest one is a dummy. The FGS was recorded on Nov 28 2009, and it shows that the well matches with Hydro-3p correlation table(14),figure (73) shows that the gas is being injected from the fifth valve figure which located in the depth of 6400 ft.

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.92657	1.33767	70.0074
Hagedorn Brown	1.08207	2.12817	44.1282
Fancher Brown	1.28041	2.72268	75.2528
Mukerjee Brill	1.04199	1.31161	47.7647
Beggs and Brill	0.96201	1.09021	66.4013
Petroleum Experts	1.04354	1.45755	44.2935
Orkiszewski	0.96134	1.13877	81.3069
Petroleum Experts 2	1.03468	1.40908	45.1215
Duns and Ros Original	1.08507	3.64506	68.3825
Petroleum Experts 3	1.12375	1.91894	43.4002
GRE (modified by PE)	1.06813	2.04434	51.1756
Petroleum Experts 4	1.17199	1.65164	54.2798
Hydro-3P	1.03384	1.08949	50.704

Table 14 N038 tubing corellation parameters

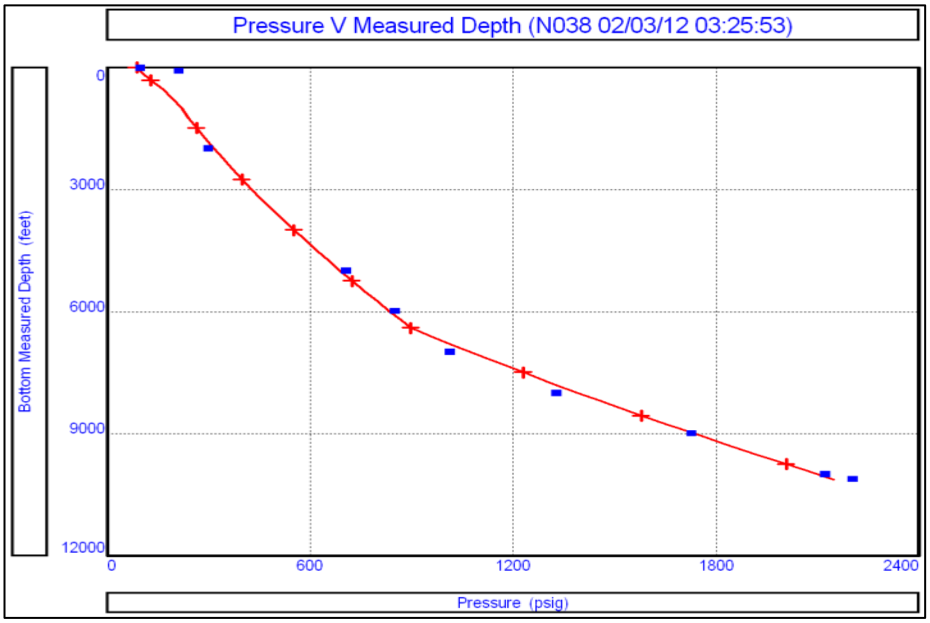

Figure 73 N038 gradient match plot

The production behavior of the well figure (74) shows that the well is stable .

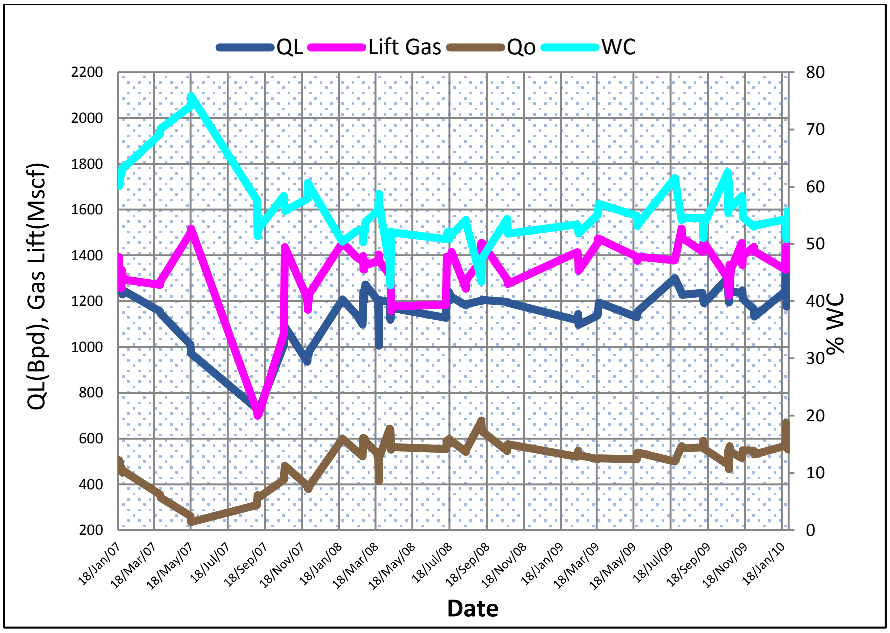

Figure 74 N038 production history

Currently the well produces 567 bbl/day oil rate by injecting 1.42 mmscf/day of gas. Whereas, the gas lift performance curve figure(75) of this well shows the optimum gas injection rate is 2 mmscf/day however in order to achieve the maximum production rate out of this injection rate the depth of injection has to be increased from 7330 to 7619 ft.

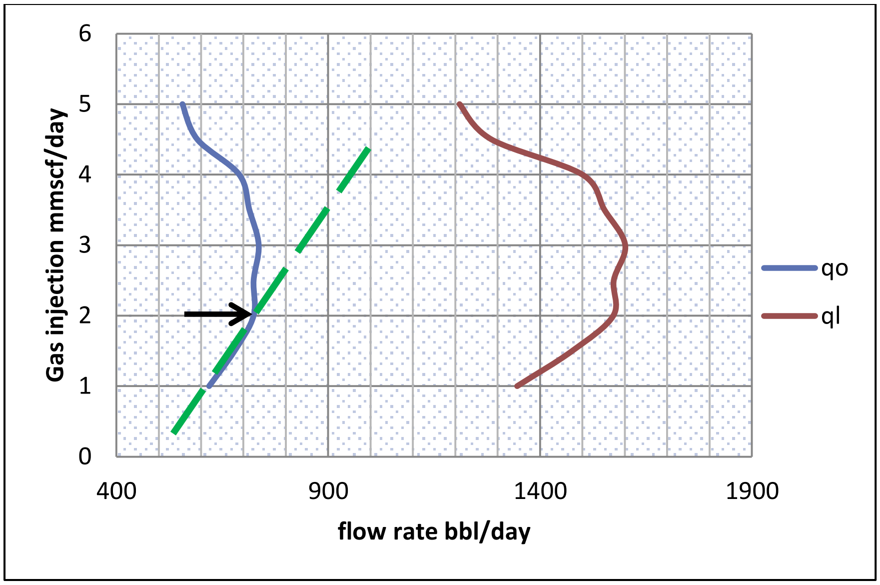

Figure 75 N038 Gas lift design curve plot

Figures (76), (77) show the new gas lift design and the well completion sketch.

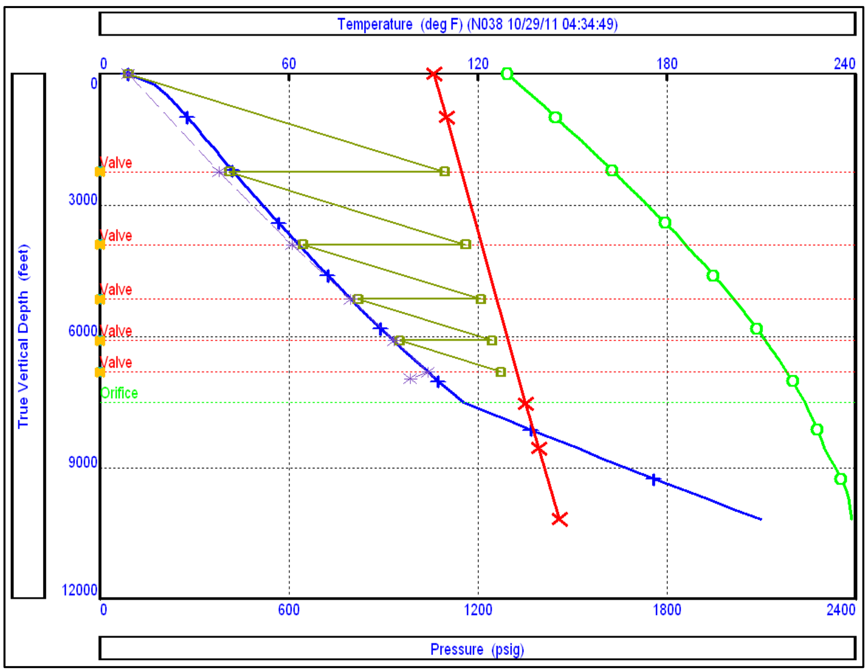

Figure 76 N038 gas lift design

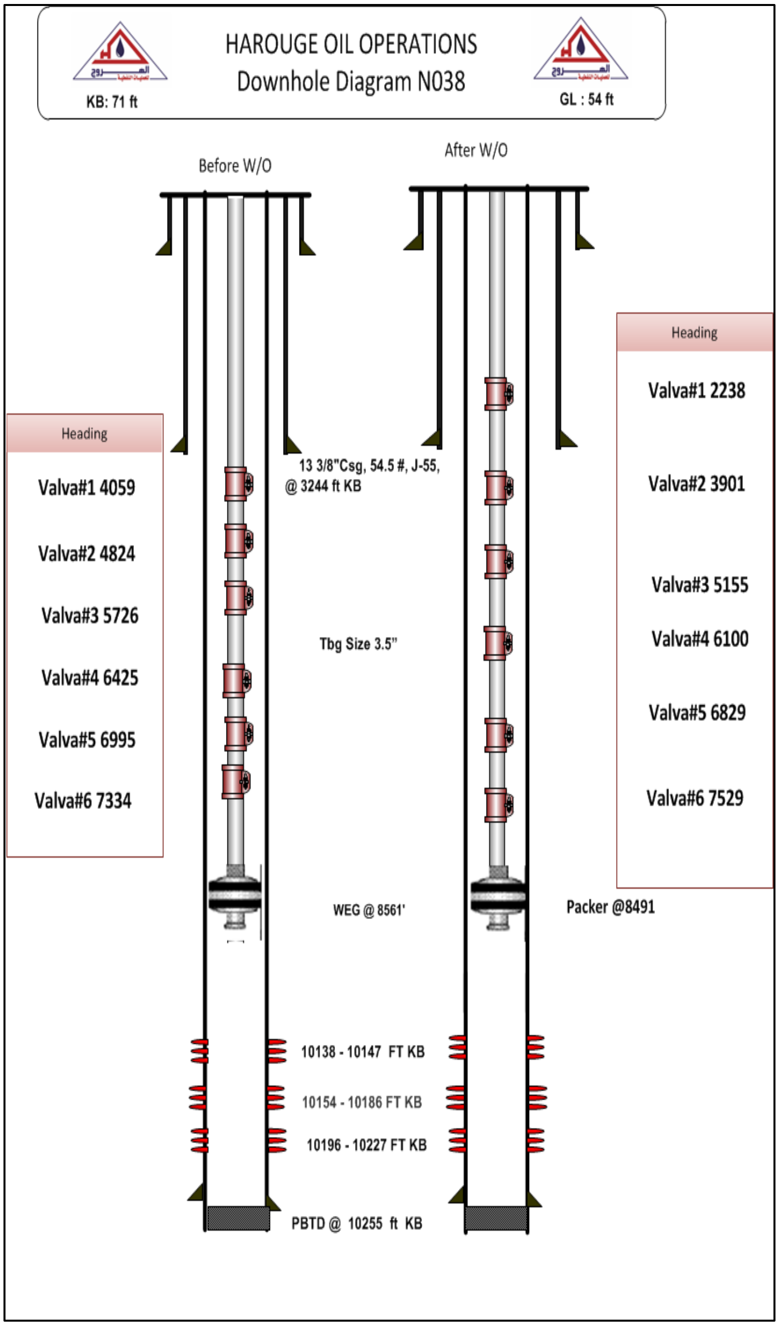

Figure 77 N038 Gas lift completion sketch

Water cut sensitivity

Figure (78) shows that the oil production will drop gradually from 730 till it reaches 70bbl/day when the water cut reaches 95%.

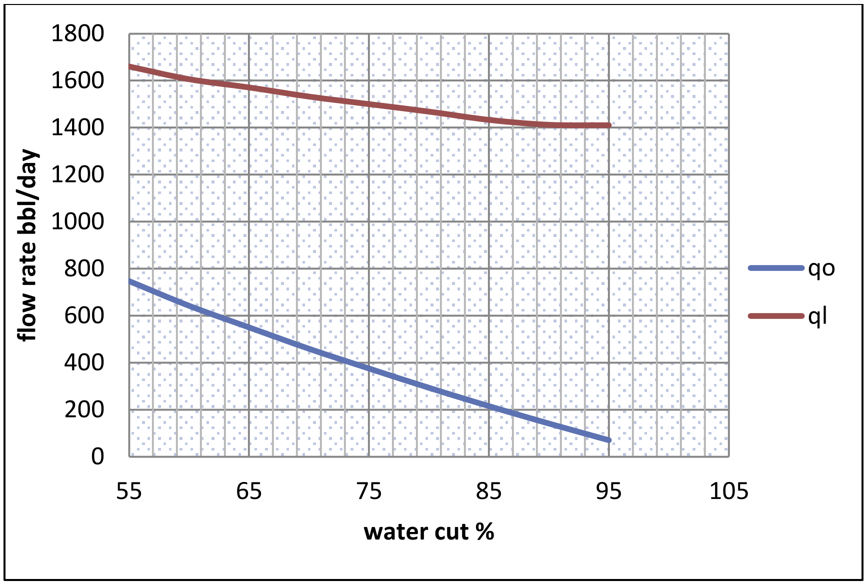

Figure 78 N038 water cut sensitivity

4.11 Well N056

The well flows to Station 5. The well has 6 valves and the deepest one is positioned at depth of 7781 ft. The FGS was recorded on Mar 20 2009, and it shows that the well matches with Duns and Ros Modified correlation table (15) and it is being injected from the fifth valve figure (79).

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.99938	0.95106	100.196
Hagedorn Brown	1.40225	0.2	146.536
Fancher Brown	1.5501	1.05406	179.831
Mukerjee Brill	1.28593	0.2	113.41
Beggs and Brill	1.25561	0.2	112.487
Petroleum Experts	1.33557	0.2	135.722
Orkiszewski	1.38888	1.19548	156.439
Petroleum Experts 2	1.32003	0.2	134.648
Duns and Ros Original	1.37182	1.38095	137.899
Petroleum Experts 3	1.53243	0.2	155.961
GRE (modified by PE)	1.61279	0.37283	174.875
Petroleum Experts 4	1.41643	0.80158	164.414
Hydro-3P	1.55817	0.2	166.24

Table 15 N056 tubing correlation Parameters

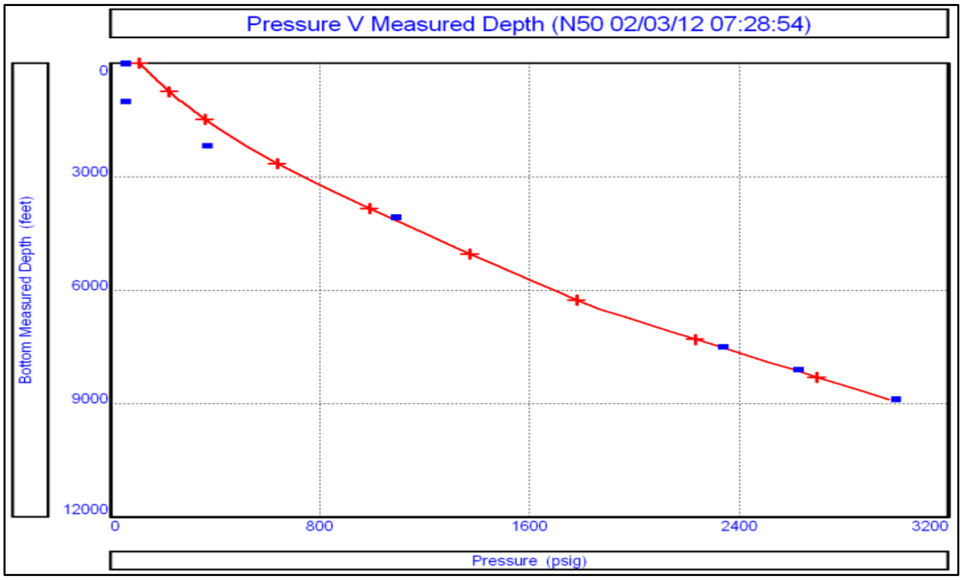

Figure 79 N056 gradient match plot

The gas lift performance curve figure(80) shows that the deference between the current production and the maximum production rate can be achieved is slightly more than 10 bbl/day, thus there is no point of increasing the rate of the injected gas. The production history plot packs this trend up as it can be seen in figure (81).

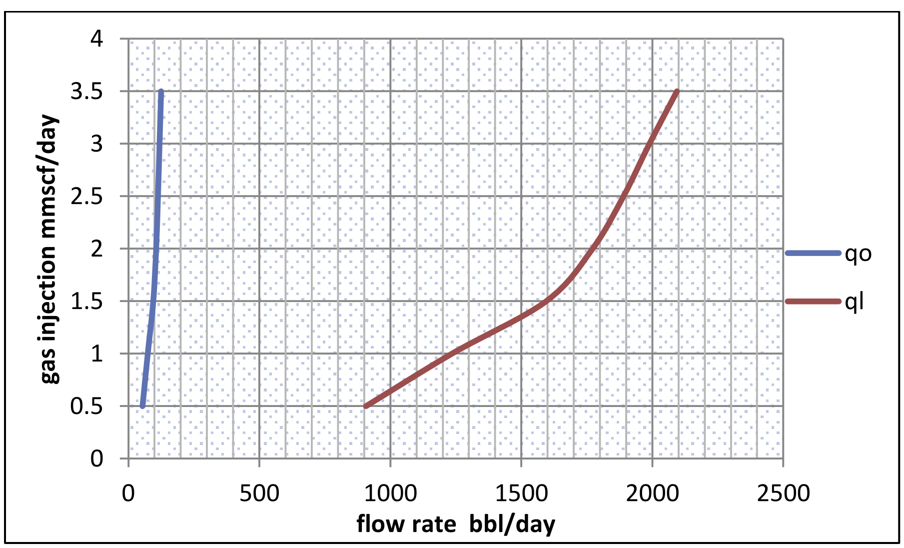

Figure 80 N056 gas lift performance curve

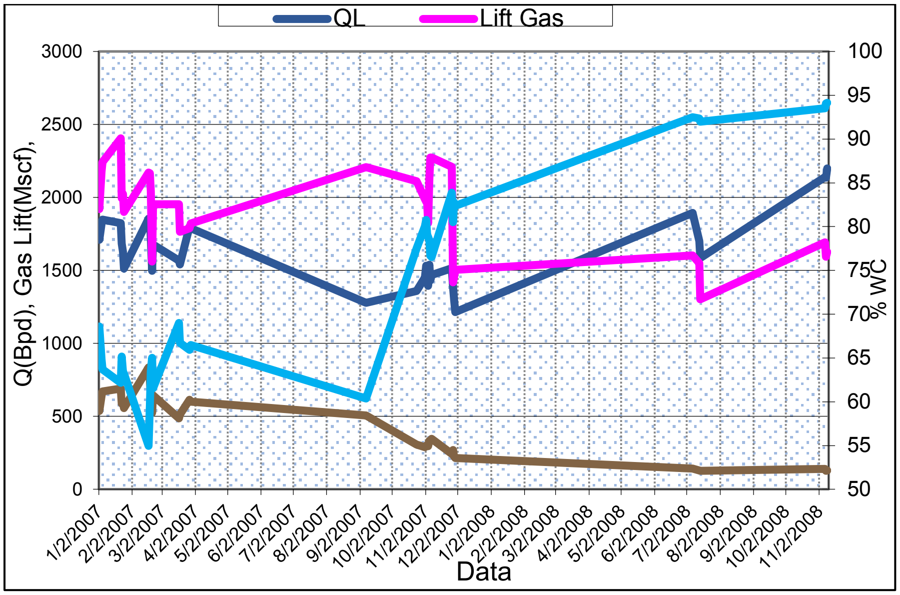

Figure 81 N056 Production history

ESP design

Since the water cut percentage for this well is considerably high and gas liquid ratio is reasonable the well makes a good candidate to be converted to ESP. The gas separation sensitivity plot figure(82), shows that downhole gas separator is not needed for this well.

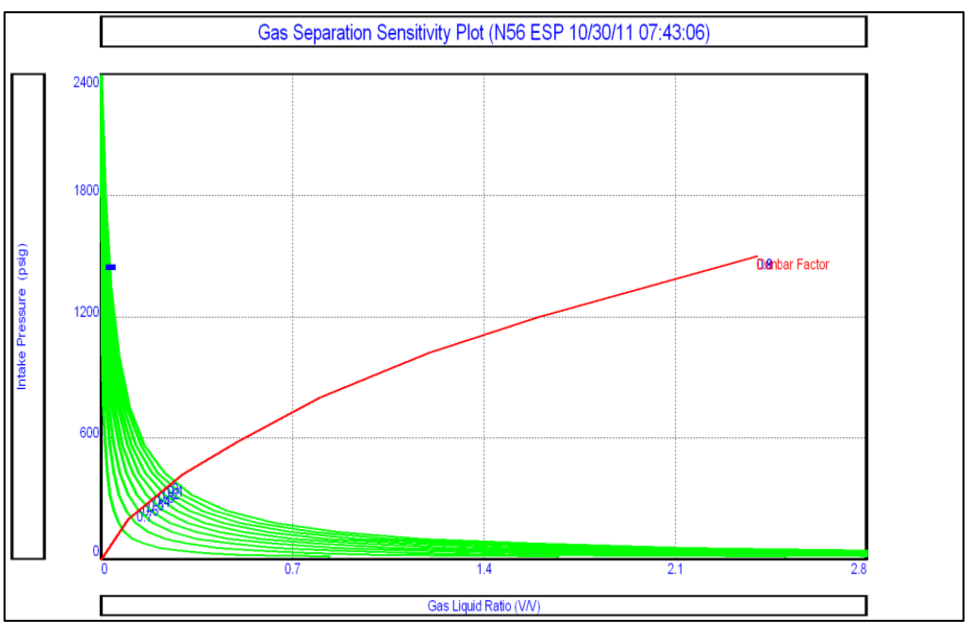

Figure 82 N056 gas separation sensitivity plot

As it can be seen in figure (83) the optimum pump setting depth is 6200ft.

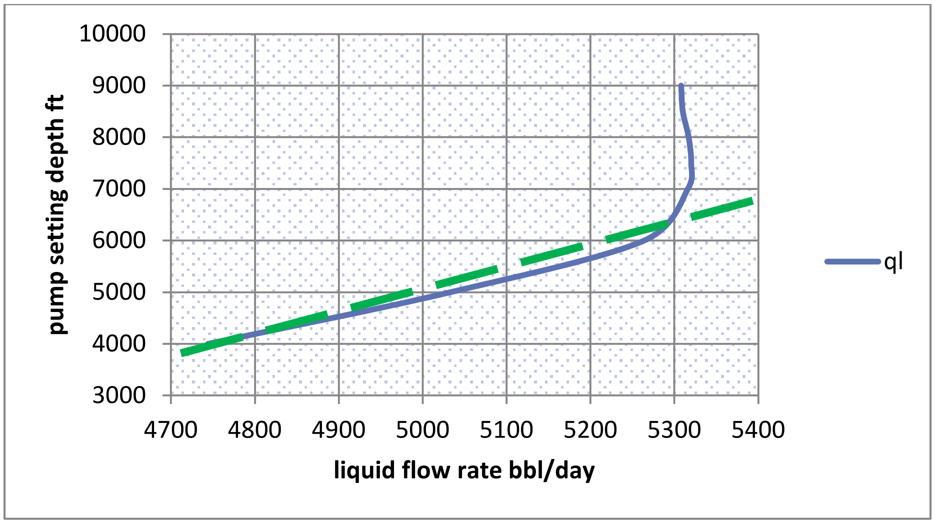

Figure 83 N056 pump setting depth vs. liquid flow rate

Figure (84) shows The IPR vs. out flow after installing the pumping unit

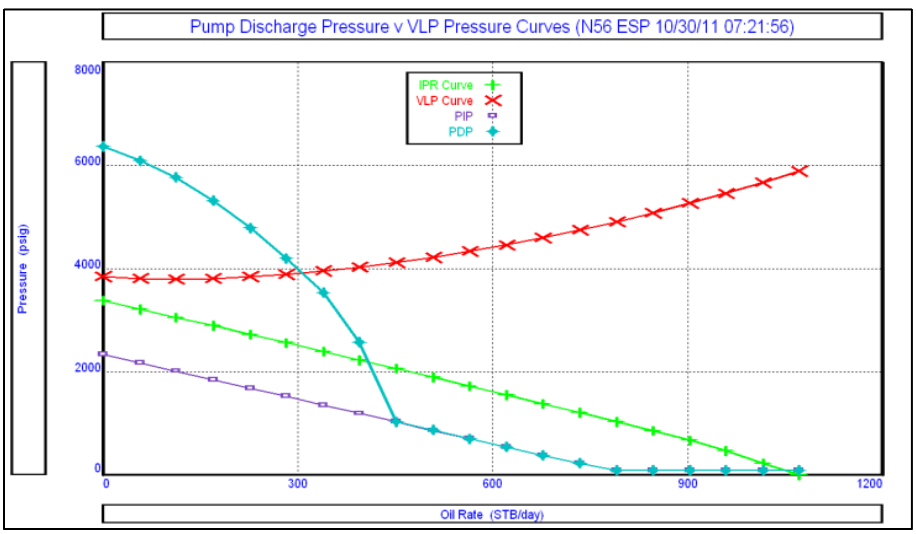

Figure 84 effect of ESP pump on the IPR curve

RedaD8500N gives the best performance to produce the 5200 bbl/day designed rate, as it can be seen in figure(85)

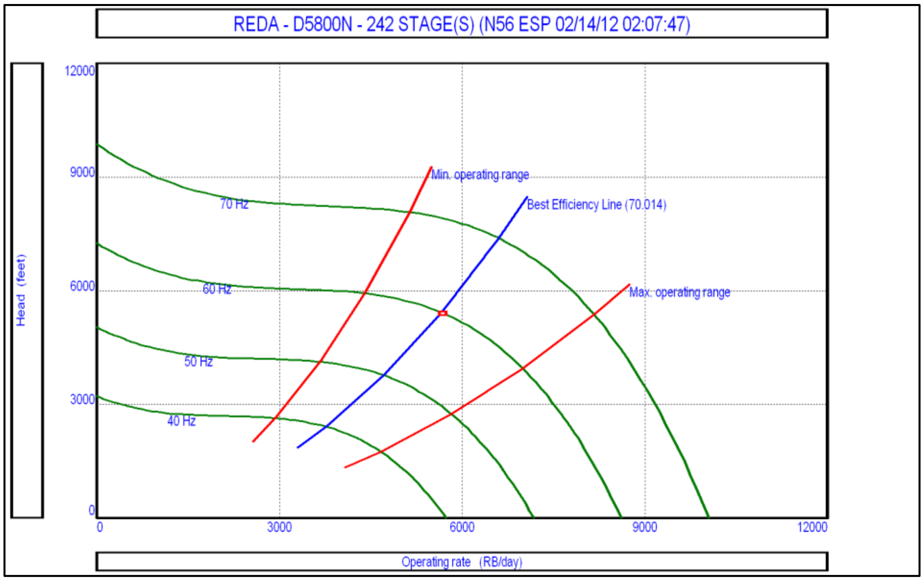

Figure 85 N056 ESP pump design

Table (16) shows the ESP parts used in this design

Part's name	Specification
motor	Reda 540_90-0_std350HP2140V99.5A
pump	RedaD5800N4 inches
Cable	1# Copper 0.26(volts/1000ft)

Table 16 N056 Pump parts and specifications

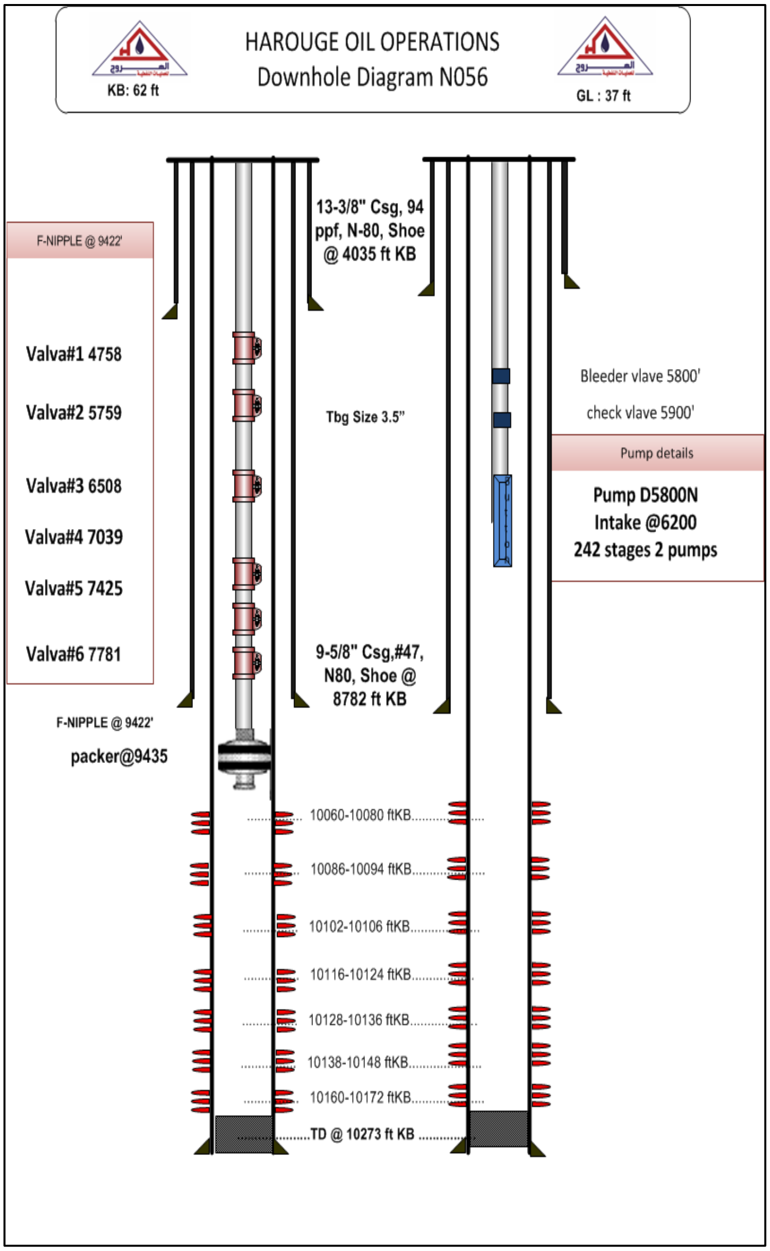

Figure 86 N056 ESP Completion sketch

The rated capacity of the working compressor installed in the field is 148 mmscf/day, however all these compressors are on duty since the 70’s and the 80’s of the last century, therefore they are frequently on maintenance, this well be a problem since it well affect the overall capability of the gas lifting system. Stations 1,2 and 4 are connected by a low pressure loop to transfer the gas to make up any gas shortage in any of these stations, or to make up the incapability of the compressors of a certain station by compressing the gas sent through the low pressure loop and send it back through the high pressure loop to wherever its needed. The excess amount of gas is flared since there are no facilities to treat the produced gas. Thus the goal of this study is to make the most of the gas by injected the largest amount of gas into the well in order to get the highest production rate out of each well table(17) shows a comparison between the current and the new proposed gas injection rate and its corresponding liquid and oil rate.

		Gas injection (mmscf/day)			Gross production bbl/day		Oil production bbl/day		
well		from	To	save	from	to	from	to	DQo
B027	GL	2.8	2.05	0.75	1418	1418	631	631	-
B029	GL	3.1	4.17	(-) 1.07	2508	2980	727	864	137
B045	GL	2.16	2.48	(-) 0.32	1576	1982	580	733	153
B065	GL	4	4	-	2440	2440	880	880	-
B079	GL	0.84	1.23	(-)0.59	1168	1316	1110	1250	140
B101	GL	1.27	2.9	(-)1.63	883	1313	869	1287	418
N003	GL	1.25	1.4	(-)0.15	609	781	349	430	81
N038	GL	1.48	2	(-)0.52	1280	1587	567	730	223
N056	GL	1.6	2.45	(-)0.85	1453	1710	89	102	13
B035	GL	1.59	1.59	-	1183	1183	572	572	-
B103	Espto GL	-	3.2	(-)3.2	2080	2327	780	861	81

Table 17 Gas lift wells summery

Wells converted from gas lift to ESP's wells

Well B029

well	Gas injection (mmscf/day)	GL production bbl/day		ESP production bbl/day		dQo bbl/d
		gross	oil	gross	oil	
B029	3.1	2500	727	4080	1183	456
item and cost	RedaGN4000 5.13 inches (3200-4800RB) Reda 456 90-0_int240HP2210V69A					47000 $ 62000$

Table 18 B029 ESP vs. GL

Here 3.1 mmscf of gas is saved and the oil production has been increase by 456 bbl day as it can be seen in table (18).however table (17) shows that the production van be increased only by 137 bbl/day if the gas well is redesign to inject 4.17mmscf/day of gas.

Well B065

well	Gas injection (mmscf/day)	GL production bbl/day		ESP production		dQo bbl/d
		gross	oil	gross	oil	
B065	4	2448	880	4550	1593	713
Item and cost	RedaD5800N4 inches (4400-7000RB) Reda 540_90-0_std400HP2440V99A					45000 $ 65000 $

Table 19 B065 Esp vs. GL

Table(19) shows that by converting this well to an ESP well, the daily oil production is doubled, and 1.3mmscf/day of gas can be saved to be cover the gas injection rate increments proposed in table(17).

Well N056

well	Gas injection (mmscf/day)	GL production bbl/day		ESP production		dQo bbl/d
		gross	oil	gross	oil	
N056	1.3	1453	89	5214	317	228
Items and cost	RedaD5800N4inches Reda456_90_Oint160HP3220V 47 A					45000 $ 55000 $

Table 20 N056 ESP vs. GL

Table (17) shows that a slight increase in oil production about 13bbl/day is achieved by injecting extra 0.84 mmscf/day, whereas table (20) shows that the production can be increased by 317 bbl/day if the well is converted to ESP.

Well B103

It's an ESP well operated by RedaGN 1600, however this pump can't handle the amount of produced fluid of this well efficiently where the well produces 1908bbl/day liquid rate whereas the best efficiency rate of the installed pump is 1350bbl/day, therefore a new pump design has been made.

well	ESP old		ESP production		dQo bbl/d
	gross	oil	gross	oil	
B103	1960	665	3350	1139	473
Items and cost	RedaGN40005.13inches Reda456_90_Oint200HP1220V 99 A				55000 $ 60000 $

Table 21 B103 ESP redesign

5.1 Scenario 1

It proposes to keep all the wells the way they are, just increase the gas injection rate for those wells that have the capability to increase the production, in this case some of the wells are needed to be redesigned in order to achieve a deeper injection points.

well		Station #	Gas injection (mmscf/day)				Oil production bbl/day		
			Station capacity	current injection	Total gas inj+form	save	from	to	DQo
B027	GL	2	29.5/23	17.3	20.3	0.75	631	631	-
B029	GL	2	29.5/23	17.3	20.3	-1.07	727	864	137
B101	GL	2	29.5/23	17.3	20.3	-1.63	869	1147	418
N003	GL	3	22.6/16.2	13.518	17.152	-0.15	380	443	63
N056	GL	3	22.6/16.2	13.518	17.152	-0.85	89	102	13
B035	GL	4	37/17.3	16.3	28.7	-	572	572	-
B065	GL	4	37/17.3	16.3	28.7	--	880	880	-
B045	GL	5	12.3/7.1	6.996	8.844	-0.32	580	733	153
N038	GL	6	30.5/16.6	12.137	17.721	-0.52	567	779	223
B079	GL	7	7.5/7.14	6.5	10.3	-0.59	1110	1250	140
						-4.38			1149

As station 1,2, and 4 are connected by a low pressure loop, 5.67 mmscf of gas is transferred from station 4 to station 2 through the low pressure loop. And sending back 0.77 mmscf through the high-pressure loop.

Stations 3, 5, 6 and 7 can handle the new gas injection rate by their own.

5.2 Scenario 2

Converting wells B029, b065, and N056 from gas lifting well into ESP's wells, in addition to changing the pump in well B103to a bigger pump. This can increase the oil production rate by2931bbl/day.

well		Station #	Gas injection (mmscf/day)				Oil production bbl/day		
			Station capacity	current injection	Total gas inj+form	save	from	to	DQo
B027	GL	2	29.5/23	17.3	20.3	0.75	631	631	-
B029	ESP	-	-	-	-	3.1	727	1138	456
B101	GL	2	29.5/23	17.3	20.3	-2.9	869	1147	418
N003	GL	3	22.6/16.2	13.518	17.152	-0.15	380	461	81
N056	ESP	-	-	-	-	1.3	89	317	228
B035	GL	4	37/17.3	16.3	28.7	--	572	572	-
B065	ESP	-	-	-	-	4.03	880	1593	713
B066	GL	4	37/17.3	16.3	28.7	-0.21	82	116	34
B045	GL	5	12.3/7.1	6.996	8.844	-0.32	795	1120	253
N038	GL	6	30.5/16.6	12.137	17.721	-052	567	779	223
B079	GL	7	7.5/7.14	6.5	10.3	-0.59	1127	1226	140
B103	ESP	-	-	-	-	-	665	1139	473
						4.49			3019

5.3 Economic comparison between the two scenarios

Scenario# 1 only will cost the work over cost, which is needed to redistribute the gas lift mandrels in order to achieve the deepest injection point possible, scenario# 2 will include the ESP unit price.

well	Oil price	dQo	workover	Revenue mm$
B029	80	137	100000	3.845
B101	80	418	-	12.205
N003	80	81	100000	2.265
N056	80	-	-	-
B045	80	153	100000	4.3676
B065	80	-	-	-
N038	80	223	100000	6.4116
B079	80	140	-	4.08
				33.169

Well029

item	specification	Price $
motor	Reda 456 90-0_int240HP2210V69A	62000
pump	RedaGN4000 5.13 inches (3200-4800RB)	47000
Switch board	-	28000
Cable (rounded)	1# Copper 0.26(volts/1000ft) 78A max	84000
Cable (flat)	1# Copper 0.26(volts/1000ft) 78A max	3400
		224400

Well B065

item	specification	Price $
motor	Reda 540_90-0_std400HP2440V99A	65000
pump	RedaD5800N4inches	49000
Switch board	-	28000
Cable (rounded)	1# Copper 0.26(volts/1000ft) 78A max	85200
Cable (flat)	1# Copper 0.26(volts/1000ft) 78A max	3400
		230600

Well N056

item	specification	Price $
motor	Reda456_90_Oint160HP3220V 47 A	45000
pump	RedaD5800N4inches	49000
Switch board	-	28000
Cable (rounded)	1# Copper 0.26(volts/1000ft) 78A max	73000
Cable (flat)	1# Copper 0.26(volts/1000ft) 78A max	3400
		198400

Well B103

item	specification	Price $
motor	Reda540_90_Oint120HP1105V 69.5 A	55000
pump	RedaGN40005.13inches (2000-3400)	47000
Switch board	-	-
Cable (rounded)	1# Copper 0.26(volts/1000ft) 78A max	91200
Cable (flat)	1# Copper 0.26(volts/1000ft) 78A max	3400
		196600

well	Dqo BBL/day	Oil price$	Annual revenue (mm$)	Old lift method price+W/O $	New ESP price +W/O $	Net revenue (mm$)
B029	456	80	13.315	-	224000	12.846
B065	303	80	8.847	-	230800	8.326
N056	228	80	2.949	-	198400	5.497
B103	473	80	13.811	160000	196600	13.707
						37.413

Overall revenue ESP's wells and gas lift wells

	Net profit mm$
Gas lift wells	46.661
ESP wells	37.413
Total revenue	**84.047**

ESP wells water cut and oil price sensitivity

Well B029

Figure (87) shows that the well can produce economically with the current oil prices, however if the oil prices have dropped to below 30$ the well will be no longer economic if the water cut exceeded 98%.

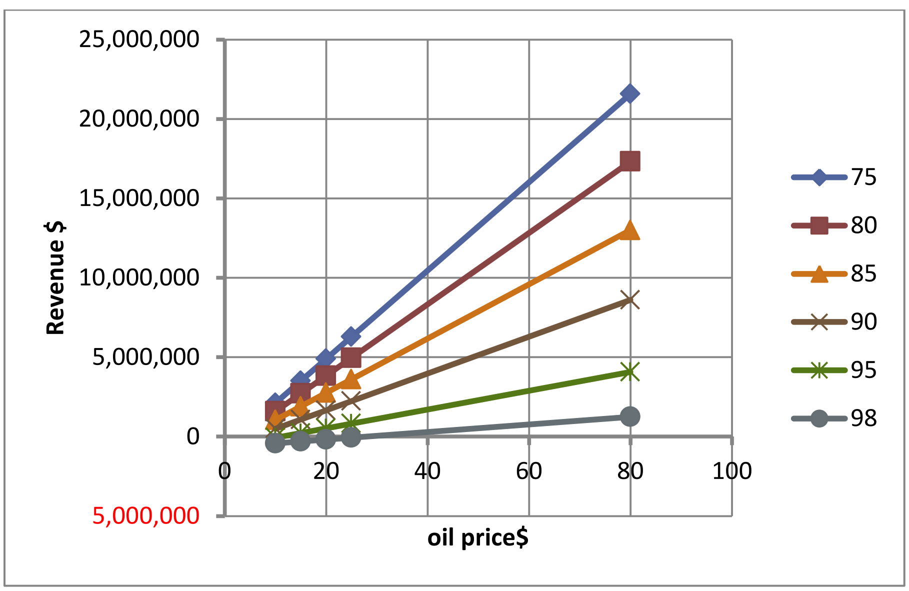

Figure 87 B029 oil price vs. revenue for different water cut values

Well B065

Figure (88) shows that as long the oil prices are over 19$ will be no worry even though the water cut exceeded 98%.

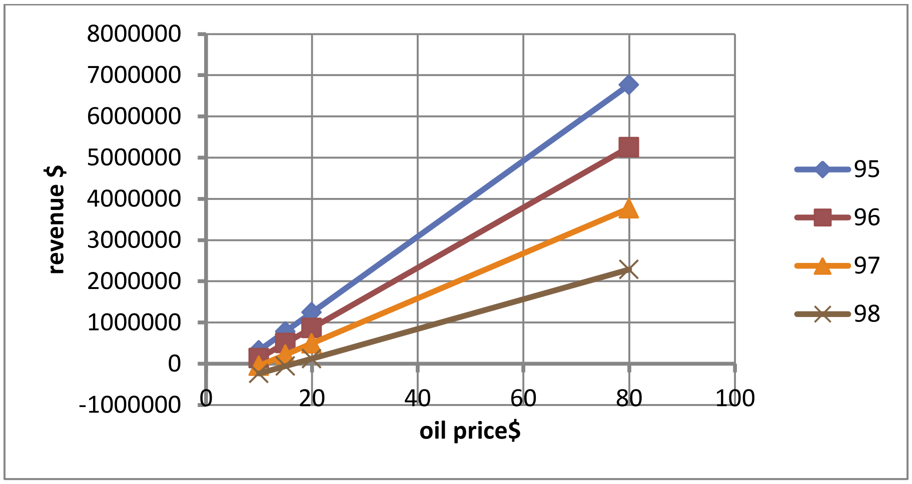

Figure 88 B065 oil price vs. revenue for different water cut values

Well B103

Figure (89) illustrates that if the water cut reached 95% and oil prices declined to less than 16$ the well will be no longer economic. In the other hand when the water cut reaches 98% it will be not economic if the price dropped just to 35$.

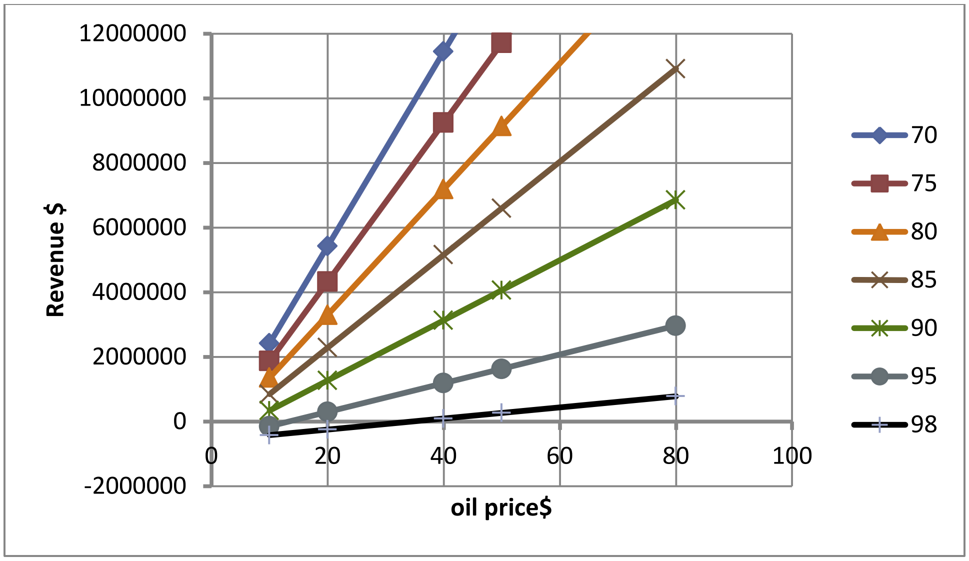

Figure 89 B103 oil price vs. revenue for different water cut values

Well N056

As it can be seen in figure(90) that the well will be no longer economic if the water cut reached 98% and the oil prices reached 18$.

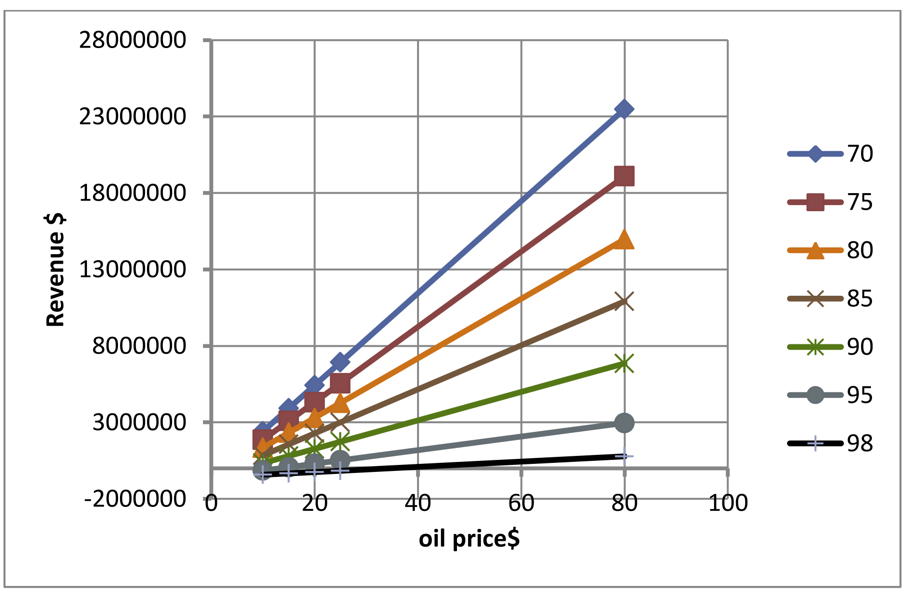

Figure 90 N056 oil price vs. revenue for different water cut values

Recommendations

- Convert wells B65, B029, and N056 from gas lift to ESP.
- Substitute the GN1600Reda Pump used in well B103 by GN4000.
- Wells B027 and B035 need no change in the design or the operational conditions.
- Wells B045, N003 and N038are needed to redesign to achieve deeper injection point in ordered to enhance the production.
- Increasing the injection rate in Well B079 .
- The field is flaring a huge amount of gas which can be used to increase the company profit in the long term if a gas plant is initiated in order sell the gas instead of just flaring it.
- More compressors can be added to station 7 to reduce the gas flaring.

Conclusion

- the recommendations mentioned above which based on scenario 2 and according to the economic study which made earlier can increase the company profits by 84mm$.

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Abbreviations

csg casing

FGS Flow Gradient Survey

F Fahrenheit degree

GL Ground level

kB Kelly bushing

PDP Pump discharge pressure

PIP Pump intake Pressure

tbg tubing

VLP vertical lift performance

ppf pound per foot

WEG Wire line Entry guide

Appendix A

Appendix A wells operational and Productivity index Data

Well	Status	Type	Flow Type	QL STB/day	Qo STB/day	Prod GOR	Water Cut	Qgi MMscf/day	Casing Pressure	THP Psi(g)
B-027	Activated	Gas Lift	Tubular	1,317.00	633.32	640.00	0.55	2.80	974.70	90.00
B-079	Activated	Gas Lift	Tubular	1,170.00	1,110.99	646.00	0.05	0.76	704.70	130.00
B-029	Activated	Gas Lift	Annular	2,508.00	727.57	650.00	0.71	3.05	1,044.70	150.00
N-003	Activated	Gas Lift	Tubular	609.00	349.91	850.00	0.45	1.25	924.70	55.00
B-035	Activated	Gas Lift	Tubular	923.00	526.90	618.00	0.54	1.54	874.70	70.00
B-045	Activated	Gas Lift	Tubular	1,576.00	676.36	790.00	0.62	2.08	1,064.70	158.00
B-101	Activated	Gas Lift	Tubular	1,028.00	862.45	668.00	0.02	1.27	1,054.70	136.00
N-038	Activated	Gas Lift	Tubular	1,150.00	578.96	675.00	0.54	1.42	1,049.70	90.00
N-056	Activated	Gas Lift	Tubular	2,140.00	124.12	641.00	0.94	1.63	1,134.70	110.00
B-103	Activated	ESP	Tubular	1,960	665.93	650.00	0.66	-		105.00

Well	Status	Type	Flow Type	GOR scf/stb	API	Oil Specific gravity	Gas gravity	Salinity ppm	Water specific gravity	Mid-perfdepth(MD)
B-027	Activated	Gas Lift	Tubular	640.00	36.00	0.84	0.90	190,000.00	1.14	9,887.00
B-079	Activated	Gas Lift	Tubular	646.00	36.00	0.84	0.90	190,000.00	1.14	10,173.00
B-029	Activated	Gas Lift	Annular	650.00	36.00	0.84	0.90	190,000.00	1.14	9,825.00
N-003	Activated	Gas Lift	Tubular	850.00	37.00	0.84	0.88	190,000.00	1.14	10,132.00
B-035	Activated	Gas Lift	Tubular	618.00	36.00	0.84	0.90	190,000.00	1.14	9,985.00
B-045	Activated	Gas Lift	Tubular	790.00	36.00	0.84	0.85	190,000.00	1.14	9,870.00
B-101	Activated	Gas Lift	Tubular	668.00	36.00	0.84	0.90	190,000.00	1.14	10,100.00
N-038	Activated	Gas Lift	Tubular	675.00	37.00	0.84	0.88	190,000.00	1.14	10,182.00
N-056	Activated	Gas Lift	Tubular	641.00	37.00	0.84	0.88	190,000.00	1.14	10,116.00
B-103	Activated	ESP	Tubular	650.00	36.00	0.845	0.905	190,000	1.14	9,947

Well	Status	Reservoir Pressure Psig	Productivity Index (J)	Abs. open flow (AOF)
B-027	Activated	1,876.00	5.05	5,262.00
B-079	Activated	2,010.00	1.67	1,865.50
B-029	Activated	1,857.00	8.28	8,538.80
N-003	Activated	2,569.00	0.64	911.70
B-035	Activated	2,277.00	2.11	2,663.90
B-045	Activated	3,035.00	3.16	5,331.10
B-101	Activated	1,930.00	2.56	2,747.10
N-038	Activated	2,534.00	4.05	5,698.20
N-056	Activated	3,385.00	6.88	14,692.30
B-103	Activated	2,696.00	3.4870	5,222.80

Appendix B field PVT Data

Amal PVT
Source HOT Study

Initial pressure (@ 9900 ft ss), psia 4690
Reference depth, ft ss 9900
Oil water contact (free water level), ft ss 10260

Reservoir	B	E	N
Temperature (@ 9900 ft ss), F	225	235	240
Stock tank oil gravity, API	36	36	37
Bubble point pressure Pb, psia	1855	2505	2180
Initial Solution Gas Oil Ratio, SCF/STB	507	735	588
Oil form. volume factor. (@ 4690 psia), RB/STB	1.338	1.483	1.393
Oil formation volume factor (@Pb), RB/STB	1.383	1.533	1.437
Oil compressibility (Pb to 4690 psia), E-5/psi	1.167	1.518	1.253
Oil viscosity (@ 4690 psia), cp.	1.07	0.66	0.785
Oil Viscosity (@Pb) CP	0.84	0.55	0.635
Formation water salinity, ppm	190,000	190,000	190,000
Rock compressibility, E-6/psi	3.06	3.06	3.06
Produced gas specific gravity (air =1)	0.905	0.846	0.879