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FACULTY OF ENGINEERING AND INFORMATION TECHNOLOGY

OIL AND GAS ENGINEERING DEPARTMENT

OPTIMIZATION WELLS PERFORMANCE IN KHARIR OIL FIELD, BLOCK 10 USING NODAL™ ANALYSIS SYSTEM TECHNIQUE

A PROJECT SUBMITTED IN PARTIAL FULFILLMENT

OF THE REQUIREMENTS FOR THE DEGREE

OF BACHELOR OF SCIENCE

IN OIL AND GAS ENGINEERING

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DECLARATION

We hereby declare that this Bachelor's Project is the result of our own work, except for quotations and summaries which have been duly acknowledged.

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APPROVAL

This is to certify that the project titled **Optimization Wells Performance in Kharir Oil Field, Block 10 Using NODAL^{TM} ANALYSIS SYSTEM Technique** has been read and approved for meeting part of the requirements and regulations governing the award of the Bachelor of Engineering (Oil and Gas) degree of Emirates International University, Sana'a, Yemen.

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ABSTRACT

Nodal™ analysis System considers as one of functional approach or technique in analyzing the performance of any petroleum production system through putting solution nodes and studying the changes happen within it, wherever any node point at production system consist of one flow rate and one flowing pressure (**Q_o, P_{wf}**).

Production well Kharir1-25 was targeted in this project, the performance of this well has analyzed at its initial conditions and therefore optimization has been done to it in order to find out whether fluid flow subjected to restrictions or not. "**PROSPER"**™ software has used to analysis the available data. After the optimizations has been done on Kharir1-25 actually some flow restrictions have been discovered, those restrictions were represented by tubing size, choke size, and GOR value which came out with increasing in daily production rate and increasing the longevity of the well from the current production rate.

Finally, this project show that application of NODAL™ ANALYSIS SYSTEM technique helped in finding solutions for Kharir1-25, based on logical scientific engineering bases, and to some extent meets part of economical satisfaction.

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A	Drainage Area
μ_g	Gas Viscosity
μ_L	Liquid Viscosity
μ_n	Gas/Liquid Viscosity
AOF	Absolute Open Flow
API gravity	American Petroleum Institute Gravity
B_O	Oil Formation Volume Factor
C_A	Drainage Area Shape Factor
C_t	Total Compressibility
d	Tubing Inner Diameter
ESP	Electrical Submersible Pumps
F	Friction Factor
g	Gravitational Acceleration
g_c	Unit Conversion Factor
GLR	Gas Liquid Ratio
GOR	Gas Oil Ratio
h	Reservoir Thickness
H_g	Gas Holdup
HL	Liquid Holdup
HSP	Hydraulic Submersible Pump
ID	Internal Diameter
IPM	Integrated Production Modeling
IPR	Inflow Performance Relationship
J	Productivity Index (Pi)
k	Effective Permeability
MD	Measured Depth
OPR	Outflow Performance Relationship
$\bar{p}$	Average Reservoir Pressure
PCP	Progressing Cavity Pump
PEPA	Petroleum Exploration And Production Authority
PEtex	Petroleum Expert's Company
P_i	Initial Reservoir Pressure
P_{SC}	Production Sharing Contract
P_{wf}	Flowing Bottom-Hole Pressure
q_b	The Flow Rate At Bubble Point Pressure
q_g	Gas Production Rate
q_o	Oil Production Rate
q_o (max)	Maximum Flow Rate (AOF)
q_o, Test	Stabilized Oil Production Rate
q_v	Vogel Flow Rate Or Additional Flow Rate
q_W	Water Production Rate
re	Drainage Radius
R_s	Solution Gas Oil Ratio
r_w	Wellbore Radius
S	Skin Factor

SSSV	Sub-Surface Safety Valve
T	Temperature
t	Flow Time
TPR	Tubing Performance Relationship
TVD	True Vertical Depth
Vg	Gas Velocity
VL	Liquid Velocity
V_m	Two-Phase Or Mixture Velocity
V_S	Slip Velocity
V_{sg}	Superficial Gas Velocity
V_{sl}	Superficial Liquid Velocity
WOR	Water Oil Ratio, Water Cut
γ	Euler's Constant
θ	Angle
Φ	Porosity
$\boldsymbol{\lambda}_g$	No-Slip Gas Holdup
$\boldsymbol{\lambda}_L$	No-Slip Liquid Holdup
$\boldsymbol{\rho}_g$	Gas Density
$\boldsymbol{\rho}_L$	Liquid (Oil/Water Mixture) Density
$\boldsymbol{\rho}_o$	Oil Density
$\boldsymbol{\rho}_s$	Fluid (Gas/Liquid Mixture)Density
$\boldsymbol{\rho}_w$	Water Density

CHAPTER ONE

1. INTRODUCTION

1.1. Overview

Development of oilfields demands an integrated proficient work team of engineers; those engineers must own the scientific capability in order to execute the task in complete way to satisfy the main goals of oilfield development workshop. One of those scientific sources that can build the engineer mind to make it capable in contributing with the remarkable progression in oil industry is petroleum production engineering.

This science is one of substantial pillar for oil industry next to other sciences in oil and gas engineering such as reservoir engineering, drilling engineering, geophysics and etc.….

Generally, petroleum production engineering principles pour the whole attention in the explanation the methodology of producing the hydrocarbons from the subsurface petroleum reservoir unto the stock tanks at the surface interweaving with demonstration of hydrocarbons motion through the production system components. So that, understanding this concept which petroleum production engineering supplies is going make you obtain the ability and skill to figure out the problems and difficulties that restrain the hydrocarbons from being produced to the surface at optimum production rate, as well as makes you appropriately put the solutions that fit the production system characterizations and hydrocarbon properties, and that what we call it production system optimization process.

Indeed, Production optimization is considered as the heart of development operations for oilfields, and participation of production engineers in designing the development plans plays a serious and extremely effective role in effortlessly reaching to the aim of development plans. In another words, success indicators of economic projects in oil industry which subjected to production system optimization procedures are distinctly increase. But why?!, basically this type of procedures is going to contribute in reducing the investments and expenses for the economic project. Therefore, the project revenues are going to rise with short payback time.

For many years, the experts in oil industry have been endeavoring to optimize the production system via innovating methods, improving device performance or discovering a new technique. although, there are so many methods and techniques related to optimize the production system, but we are going to shed light on one of common optimization technique, whereas it is characterized by studying the performance of production system as a one unit. This technique is famous by **Nodal**^{tm} Analysis System and it will be discussed in details in the coming chapters of this project.

Actually, the details of this optimization technique or approach make it takes lot of time in order to let the production engineers come out with reliable analysis results, so that the technologic renaissance in oil industry and especially in petroleum software assisted to solve the issue of wasted time and the reliability of the results for petroleum engineers. In petroleum production engineering section, many of software have been appeared to make the practical life easier.

Consequently, this project will aim to elucidate the mechanism that should be under taken to optimize the performance of production system via using **Nodal**^{tm} Analysis System approach. In addition, this project will offer a real case study for a production well existed in one of Yemen oilfields, whereas the results of this case study are supported by one of Petroleum Experts Company (PTEx) software to provide the researcher or the reader by more reliability about the validity of this study.

1.2. Aim and Objectives

1.2.1. Aim

Performing an applied and analytical study about the performance of Kharir field and optimizing the well production capacity by utilizing Nodal^{TM} Analysis System.

1.2.2. Objectives

In order to reach the aim of the project, we had to state the following objectives: -

1. Describing Kharir oilfield's production system.
2. Explicating Nodal^{TM} Analysis System technique and how it is used for optimizing the production in petroleum industry.
3. Giving a Clarification about the effect of the drilling operation and the well completion design on production capacity of a production well.
4. Recourse to the mathematical models that used to simulate the fluid passing through the production system.

5. Shedding light on the type of data needed to be used in order to optimize the production capacity of Kharir field.
6. Defining the **PROSPER**TM software which will apply and facilitate the **Nodal**tm **Analysis System** for Kharir field.
7. Analysis the **PROSPER**TM software results, so as to initially evaluate the production system performance and guess the flow restrictions in Kharir field.
8. Putting the options that may contribute to optimize the production capacity of Kharir field.

1.3. Project Statement

Studying the fluid flow behavior inside the production system is a significant issue for petroleum engineers, due to what a fluid encounters while flowing through a specific media of the production system of losing its internal energy which is represented by pressure losses therefore reduction of the fluid flowrate, so the petroleum engineers painstakingly seek to find out the fluid flow restrictor so as to eliminate, replace or redesign it in order to give the optimum flowrate of that fluid. Therefor understanding the mechanism of Nodaltm Analysis System as a perfect tool in optimizing the petroleum production is an important matter for those students who study oil and gas engineering.

1.4. Project Question

How could we find out the flow restrictions in Kharir field oil wells in order to optimize its production capacity?

1.5. Significance of The Project

Making the fresh graduate petroleum engineers able to work on real petroleum field data based on the theoretical academic study in order to optimize oil fields production systems by using software.

1.6. Scope of The Project

Our project framework will be done only on studying the wellbore performance of one production well in Kharir oilfield by utilizing Nodal Analysis system. with considering the other production system parts and their influence on our project framework.

1.7. Block 10 And Field Brief

The Republic of Yemen is located at the south-western most tip of the Arabian Peninsula, limited to the West by the Red Sea, to the South by the Gulf of Aden and to the East-Northeast by the Oman/Saudi Rub Al Khali desert.**Fig. 1-1**.

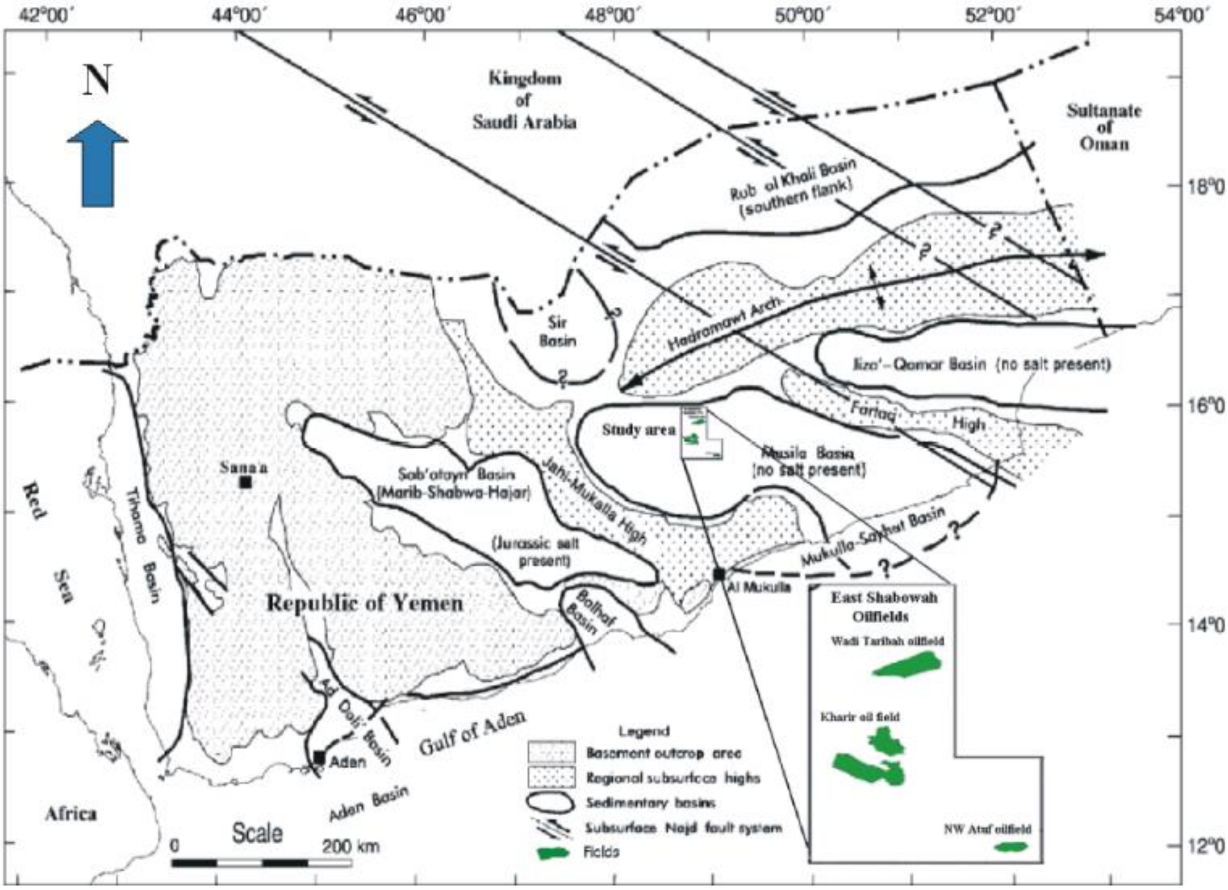


Figure 1-1 Location Map of The East Shabwa Oilfields in The Masila Basin Republic of Yemen

1.8. Location Details

The PSA-Block 10 (East Shabwa) extends in the oriental part of the Republic of Yemen, in the Hadhramaut Province, in the Jurassic/Cretaceous and Sayun/Masilah Basin.

This basin is trending WNW-ESE. It is bounded to the North by the Hadhramaut Arch, to the South by the Al-Aswad High, to the West by the Jahi- Mukulla High and to the Northeast by the Fartaq High. The basin stratigraphy encompasses Middle Jurassic to Early Eocene time period, and the underlying crystalline basement is Precambrian to Early Paleozoic in age.

Table 1-1 Location Details

Country	Republic of Yemen
Region	Hadhramaut – East Shabwa
Block & Field	Block 10 – Kharir Field
Drilling rig name	HTC 4 (top hole)– ZPEB 906 (UBD)
Drilling rig type	Land rig
Ground level above MSL	+999.69 m
Rotary table elevation Above ground level	+9.1 m (HTC4) / +7.8 m (ZPEB 906)
Drilling depth origin	Rotary table (RT)
Log depth origin	Rotary table (RT)

1.8.1. Petroleum Production System

Primary accumulation is at basement level in a fault-bounded structural high in the middle of Sayun/Masilah Basin. Kharir Basement structure is divided into 3 individual non-communicating compartments (**Fig. 1-2**):

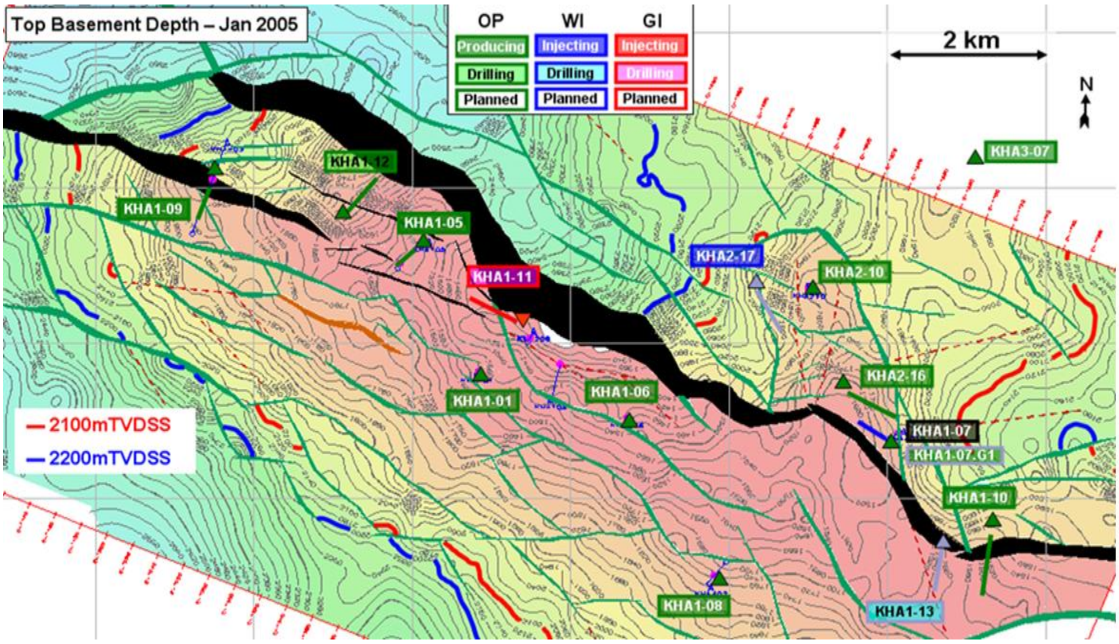


Figure 1-2 Kharir Field Basement Structure Non-Communicating Compartments

1. KHARIR-1 is the main tilted block (KHA-1) and is bounded by a WNW-ESE regional normal fault.

2. KHARIR-2 (KHA-2) closure consists in fault-bounded structural steps extending in the down thrown compartment North of KHA-1.
3. KHARIR-3 (KHA-3) closure is located north of KHA-2.

Table 1-2 Contract and operator of this field

Contract Area	On shore Yemen – Hadhramaut East Shabwa – Kharir Field
Contract Type	Production Sharing Contract (PSC)
Partners	TOTAL E&P YEMEN (28.57%) OCCIDENTAL (28.57%) COMECO (28.57%) KUFPEC (14.29%)
Operator	TOTAL E&P YEMEN on behalf of the PEPA

1.8.1.1. Type of The Reservoir and Reservoir Characteristics

The reservoir type in this field is defined as basement; reservoir pressure equal 3215psi; reservoir temperature equal 218.8 F; reservoir depth equal 3075m.

The most important reservoir properties of the formation and liquid (oil) are shown in the following table:

Table 1-3 Reservoir Properties of The Formation and Liquid (Oil)

Parameter	Unit		Value
Net reservoir	(m)	=	200-400
Reservoir Geometry – No flux limits	(m)	=	
+Y / -Y / +X / -X	Case 1		300 / 1500 / 600 / 200
+Y / -Y / +X / -X	Case 2		300 / 1500 / 1100 / 400
Average Porosity	(%)	=	0.7 – 2.0
Average Water Saturation	(%)	=	0.0
Permeability	(mD)	x 3	5, 10, 20
Oil formation Volume factor,	[m3/m3]	=	1.5
Oil Viscosity, μ	[Cp]	=	0.4
Oil Compressibility, Co	[1/psi]	=	0.2×10^{-4}
Water Compressibility, Cw	[1/psi]	=	0.1×10^{-4}
Rock Compressibility, Cr	[1/psi]	=	0.1×10^{-4}
Total Compressibility, Ct	[1/psi]	=	0.3×10^{-4}
Storage capacity	[m3/psi]	=	0.001, 0.020
Skin		=	2

1.8.1.2. Kharir Wells

The wells for this field are shown in the following table:

Table 1-4 Wells Name for Kharir field Until 2006

No.	Well Name	No.	Well Name	No.	Well Name	No.	Well Name
1	KHA1-01	17	KHA1-18	33	KHA2-02	49	KHA2-17
2	KHA1-02	18	KHA1-19	34	KHA2-03	50	KHA2-18
3	KHA1-03	19	KHA1-20	35	KHA2-04	51	KHA1-50
4	KHA1-04	20	KHA1-21	36	KHA2-05	52	KHA1-74
5	KHA1-05	21	KHA1-22	37	KHA2-06	53	KHA1-53
6	KHA1-06	22	KHA1-23	38	KHA2-07	54	KHA1-35
7	KHA1-07	23	KHA1-24	39	KHA2-08	55	KHA1-73
8	KHA1-08	24	KHA1-25	40	KHA2-09	56	KHA1-78
9	KHA1-09	25	KHA1-26	41	KHA2-10	57	KHA1-80
10	KHA1-10	26	KHA1-27	42	KHA2-11	58	KHA1-81
11	KHA1-12	27	KHA1-28	43	KHA1-11	59	KHA1-88
12	KHA1-13	28	KHA1-29	44	KHA2-12	60	KHA3-01
13	KHA1-14	29	KHA1-30	45	KHA2-13	61	KHA3-02
14	KHA1-15	30	KHA1-31	46	KHA2-14	62	KHA3-03
15	KHA1-16	31	KHA1-32	47	KHA2-15	63	KHA3-04
16	KHA1-17	32	KHA2-01	48	KHA2-16	64	KHA3-05

1.8.1.3. Surface Production Facilities

Kharir field actually produce from low Qishn sandstone pressure system as well as high-pressure basement system. **Fig. 1-3**.

These two production system includes : three phase (Oil, Gas, and water), on project will be implemented on high basement pressure system, as the produced fluid comes out from well bore if goes through three first stage separation in order to separates the mixed fluid into gas, oil, and water and every phase will take independent stream, the oil result from first stage continues its path into three phase second stage separation to confirm a huge amount of gas and water separated from the crude oil then crude is transferred into stage tanks to before refinery unit or termite station.

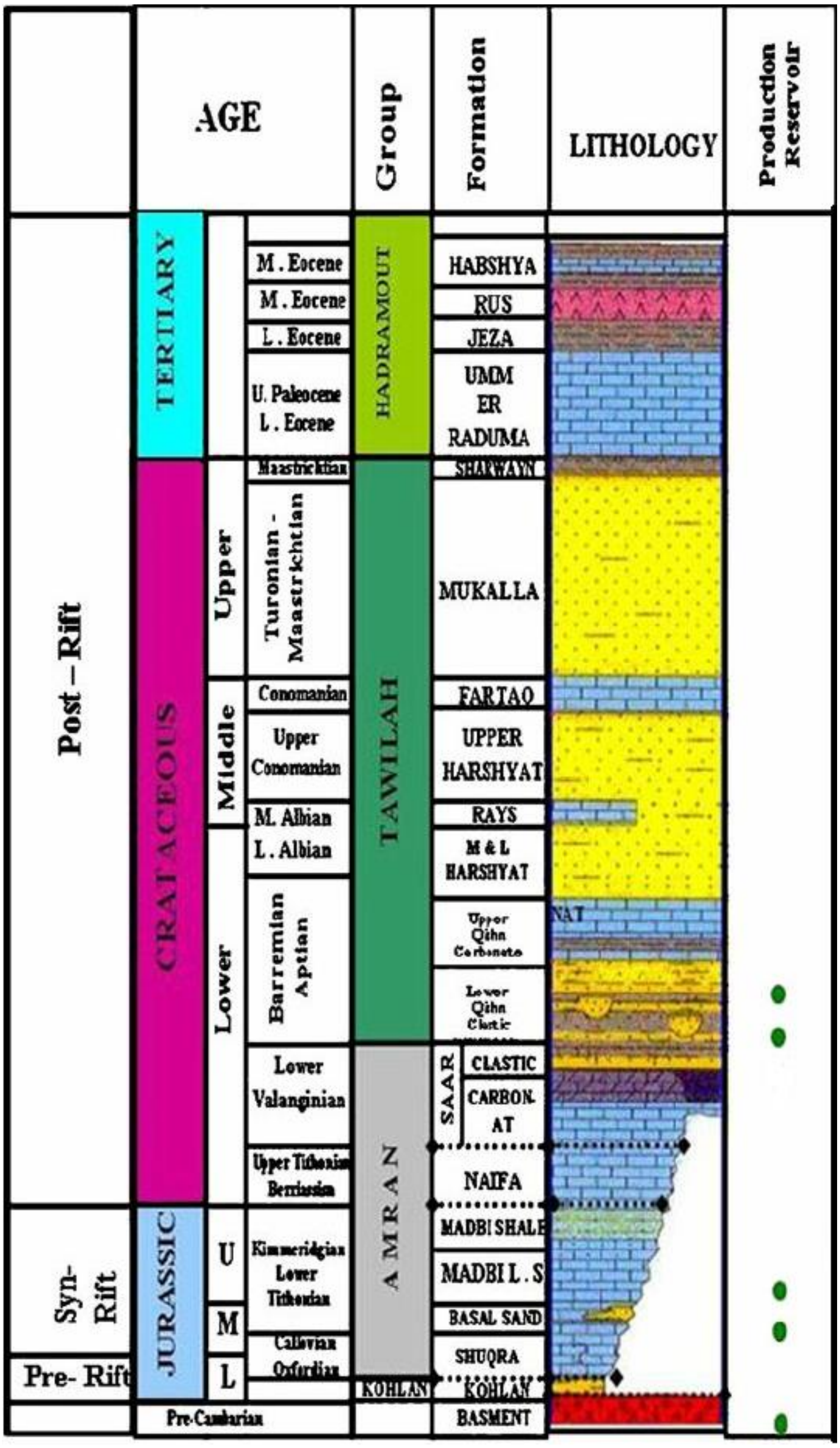


Figure 1-3 Lithostratigraphic Column of Study Area Yemen - Block 10

CHAPTER TWO

2. LITERETURE REVIEW

2.1. NODAL ANALYSIS SYSTEM

2.1.1. Introduction.

Nodal analysis is used to optimize the completion design to suit the reservoir deliverability identify restrictions or limits present in production system and identify any means of improving production efficiency.

The nodal is divided in tow part first part upstream is from reservoir to well bore and downstream is well bore to surface.

Nodal analysis this tool is also can model the oil and gas well it can simulate a single or multi wells performance including such component flow as the flow line a surface or down hole choke, tubing performance completion effect like a perforations and inflow performance vertical flow and approximately horizontal well.

The first application to well producing system was first proposed by GILBERT in 1954 and discussed by NIND in 1964 and BROWN in 1978.

Nodal analysis is a modelling tool used by drilling, subsurface and well test to help achieve an optimum well design in terms of perforations, tubing size and fluid to provide some of the key data for the design of the surface facilities.

It is used to evaluate thoroughly a complete producing system for every component in the well can be optimized.

It can have used as gait for design and optimization, it gets us a estimation depend on input and we looking to the curve that's will gives and chose the best one.

Electrical cirait complex pipeline networks and centrifugal pumping system are all analyzed are using nodal system.

The objectives of nodal analysis:

1. Determine the flow rate from oil and gas wells.
2. Determine the tine of the well is to be die or load.
3. Chose the economical time for installation atrial lift.
4. Check which of the component of the well it restricting the flow.

2.2. Reservoir performance

2.2.1. Introduction

Hydrocarbons reservoirs are one of production system components and one of the parts that must subjected to be analyzed as **Nodal^{tm} Analysis System** technique states. reservoirs differ from each other by the difference in rock and the fluid they contain; this difference gives the reservoir performance an importance to be discussed in our project.

In fact, the reservoir system in oilfields consist of more than one phase (oil/water, gas/water, oil/gas and water) which makes the understanding of those fluids flow behavior much complicated. This number of phase's flows in the oil, gas or condensate reservoirs contribute in variation of fluid flow regime that the fluid takes during the field production life. Logically, due to withdraw the hydrocarbons from the oil reservoirs the pressure of the reservoir is going to decrease, so that reduction in reservoir pressure effects on the stabilization of fluid properties and flow conditions subsequently this variation case impress on reservoir deliverability and reservoir performance in general. Accommodating this complex fluid behavior during the influx from the reservoir into the bottom hole of production well (reservoir performance) can help us to optimize production capacity of the reservoir, performance of the well and also surface facilities via using Nodal^{tm} Analysis System approach.

Accordingly, this part of our project is going to provide you by the principles, concepts, methods and mathematical models that are used to demonstrate the reservoir performance in dynamic state as well as clear up the idea of Inflow performance as much as possible.

2.3. Number of Reservoir Phases Flow: -

As we mentioned previously, the petroleum reservoirs contain more than one phase put while the fluids flowing in specific media they may flow as single phase, two phases or multiphase. This concept can be clarified below: -

2.3.1. Single Phase Flow: -

This type of flow doesn’t refer to exciting of one phase only at any of production system components, it actually means that one phase is dissolved in another and are flowing as one phase. This kind of flow is available in undersaturated reservoirs, which their average pressures are above the bubble point pressures of fluids they contain.

2.3.2. Two Phase Flow (Multiphase Flow): -

After a time of production from the undersaturated reservoirs they start to deplete at their average pressures drop below their fluid bubble point pressures, the oil starts to liberate the dissolved gas to the oil free porous and saturate them until the gas exceeds its critical saturation and begin to flow into the wellbore giving two phases (fluids). This type of flow would be occurred in saturated reservoirs or gas cap reservoirs with noting that difference between those two reservoir types.

In many cases the water shares the production with oil and gas but the while the oil and water flowing in the same time they considered as the liquid phase and the gas is the second phase, so two phase flow expression is also can be used for the reservoir produce three fluids.

2.4. Fluid Flow Regimes in Petroleum Reservoirs: -

Basically, as the field has been explored, the exploration well drilling starts following by appraisal well drilling to confirm the commercial accumulation of hydrocarbons, during this appraisal operation the fluid flow regime in the reservoir varies according to change in the reservoir conditions and that is due to the withdraw the hydrocarbons to the surface.

To make the picture clear, that what also happens to fluid flow regime during the production from the development wells of the wells. In another words, throughout the production life of a well fluid flow in the reservoir goes through two or maybe three flow regimes, understanding or knowledge of current regime at the time of using Nodal[tm] Analysis System approach makes you obtain the best solutions for optimization and make your analysis results more reliable.

Wherefore, we are going to clarify the fluid flow regimes in reservoir that must be understood for obtaining a perfect analysis step.

2.4.1. Unsteady State Flow (Transient Flow) Regime: -

Intentionally we started to describe this type of flow regime because it is the first flow regime that usually the reservoir fluid takes when the new well starts to produce. Here the derivation of the reservoir pressure with time is function of the pressure location and time in the reservoir and that actually occurs when the pressure wave hasn't reach any of reservoir boundary. Describing the reservoir deliverability and inflow performance for this type of flow regimes is coming in the coming sections of this chapter supported with mathematical model simulates it.

2.4.2. Pseudo-Steady or Semi-Steady State Flow Regime: -

This flow regime the transient flow regime if the reservoir is not supported by a high-pressure source such as strong aquifer or injection wells which make the decline in reservoir pressure along the production time be a constant rate at any point of the reservoir. If we speak about a new well in the field then this type of flow will dominate when the pressure wave reaches the reservoir no-flow boundary such as impermeable fault and end limit of pinch out trap during the long time production test is carrying on that well, but if the well is one of development production well and it is excited beside another production wells then this flow regime will exist at the time that the pressure wave or the pressure radius arrives the drainage area of the well.

2.4.3. Steady State Flow Regime: -

Indeed, this type of flow regime is the most preferable for oil reservoir due to what is distinguished by the zero-reservoir pressure reduction over the time at any location in the reservoir. This flow regime prevails at conditions of existing strong water aquifer or reservoirs surrounded by injection wells. The reservoir performance keeps working in good way while the fluids flow in steady state form, and reservoir deliverability will reach its excellent execution in transportation the hydrocarbons to the bottom hole of the production well for long time of reservoir production life.

2.5. Inflow performance relationship and IPR curve:

Inflow performance is a term used to describe the reservoir deliverability under the current whole flowing conditions as well as rock and fluid properties. Actually, the firm interconnection between the flow rate (deliverability) and the bottom hole flowing pressure which reflects the reservoir performance is considered as a main base relationship and what that we call it inflow performance relationship.

In current moments in oil industry, methods are used to simulate evaluate that type of performance those methods will be explained in details in coming sections of this chapter. Substantially, those methods finally provide with graphically straight line or curve shows the behavior of a reservoir based on the relationship between the flow rate and the bottom hole flowing pressure.

IPR curve is a graphical presentation of the relationship between the following bottom hole pressure and liquid production rate. In the theoretical case of a zero pressure at the bottom-hole, the flow rate would reach a value known as the absolute open flow (AOF) of the well as a typical IPR curve is shown in **Fig. 2-1**.

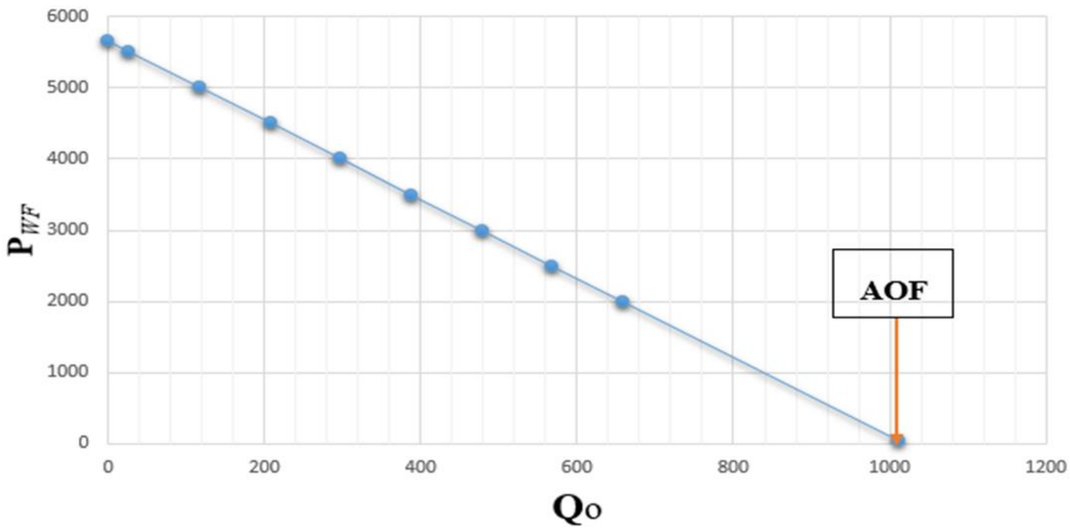


Figure 2-1 IPR straight line and Absolute open flow (AOF)

2.5.1. Productivity Index (PI or J).

This is one of important indicators which must be calculated to light the reservoir deliverability in combination with well completion design. So that the productivity index is defined as the amount of oil barrel produced per day at one pressure drawdown between the reservoir and bottom hole.

Mathematically, this expression typifies the inverse slop of linear or curvature IPR as it is shown in the Figure 2-2 below:

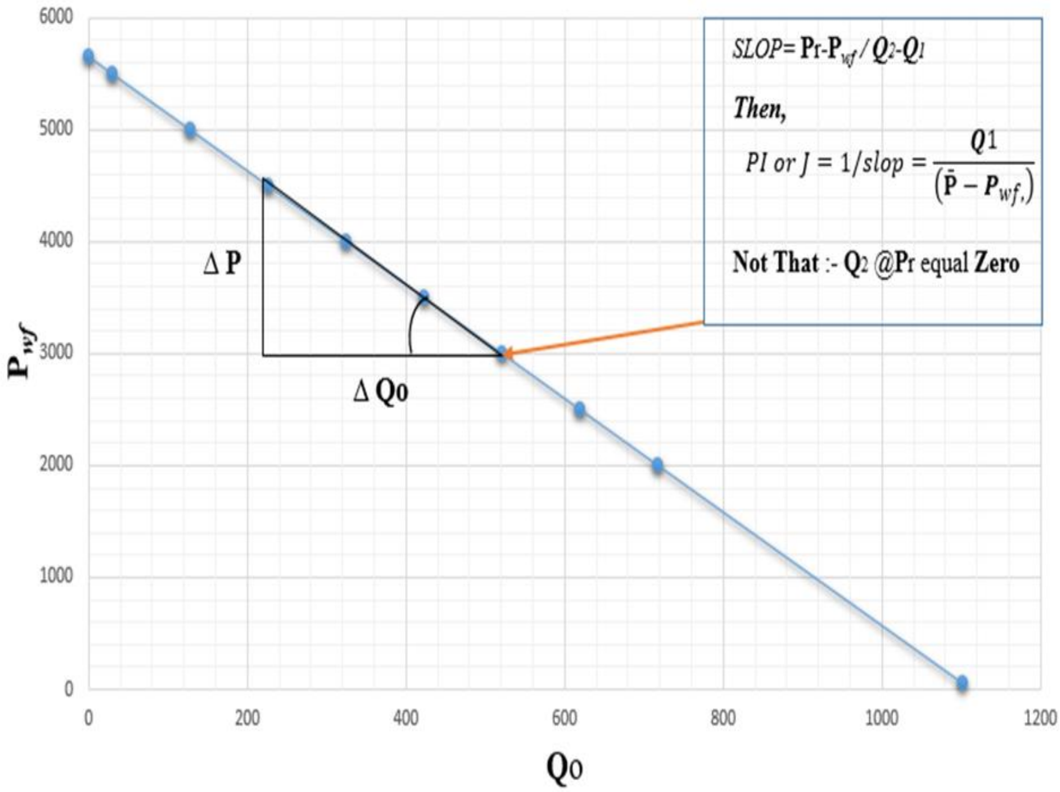


Figure 2-3 IPR straight line and productivity index

Productivity index also can be considered as one of methods that is used to create good results in construction inflow performance relationship, but it requires specific condition such as low gas oil ratio (GOR) and high water cut.

Note that: - productivity index equation is modified as long as the inflow conditions changes, *coming delineations will represent this concept.*

Particularly, Production engineer is interested in savvy those connotations to implement a full analysis via utilizing nodal analysis technique in combination with understanding the rest terms in the vertical lift performance and surface facilities.

concerning to inflow performance relationship, there are points contribute in controlling IPR curve and not related to the reservoir nature, here are the points that must be lucid in order to analyze the created IPR curve correctly.

2.5.1.1. Effect of and Well Completion Design Well Completion Operation on Production System Performance.

As all indicators are evidence of commercial hydrocarbons accumulation the decision of preparing the well for production should be done and that what we call it well completion operation. This operation contributes in making the production at its optimum rate or versa, and all that lies behind the dexterity of completion and production engineer in dealing with the reservoir and wellbore conditions. some of those persuaders' effects on the performance of the reservoir and while others are related to the tubing performance (vertical lift performance).

We will start with explaining the persuaders relate to inflow performance and the coming sections will cover the persuaders of completion operation effects on well performance.

Setting Depth of Production Casing.

The setting depth of production casing or partially penetration of pay zone plays a critical role with performance of production system, during interpretation of well testing data skin factor value determination must be confirmed if its value is totally a result of formation damage due to drilling mud invasion or incorrectly setting depth of production casing gives an addition part to its value [5].

Prominently, the applied methods for simulating fluid flow in the petroleum reservoirs are submissive to radial flow geometry and as this geometry varies the results of applied methods carry mistakes and will not give a closer picture about what is going on in the subsurface system, so that radial flow must be obtained by installation the production casing to the right reservoir lower boundary or penetrating the whole reservoir thickness that meets the requirements of reservoir engineer to avoid the conversion of radial flow into hemispherical flow it is clear in the below **Fig. 2-3**and **Fig. 2-4.**

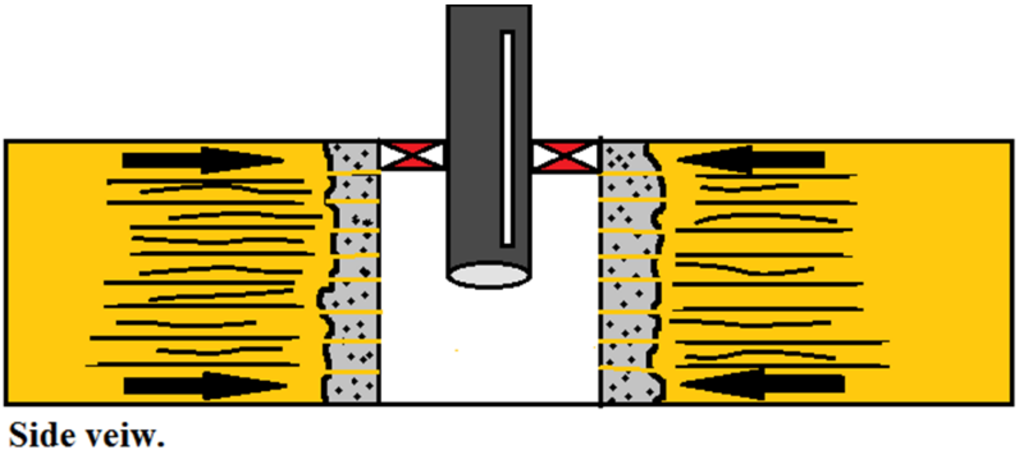


Figure 2-4 Radial flow geometry

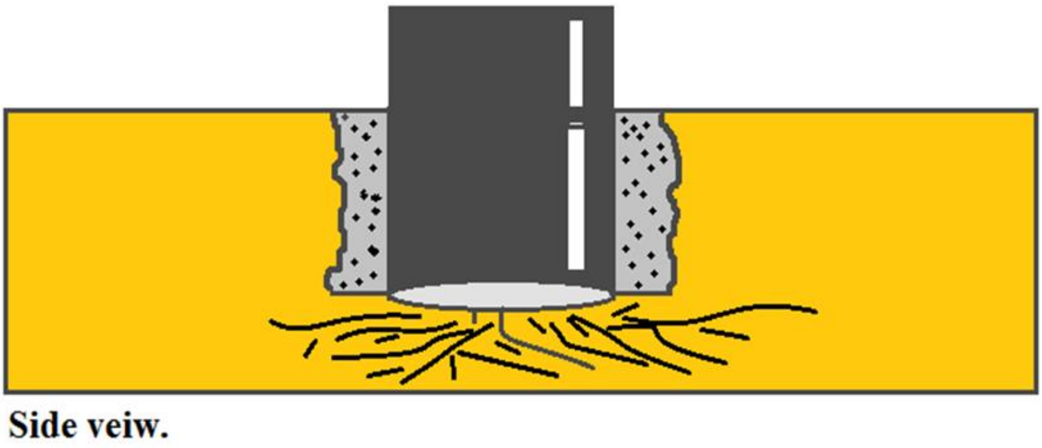


Figure 2-5 Hemispherical flow due to partially penetration

Perforation Design.

As we know that Perforation process provides a connected path between the reservoir and bottom of the well, this process also participates in adding an extra value to the skin due to formation damage as a wrong production casing setting depth does, that is because of incompletely perforated intervals and converted flow geometry from radial to spherical flow as it is shown in the following **Fig. 2-5**.

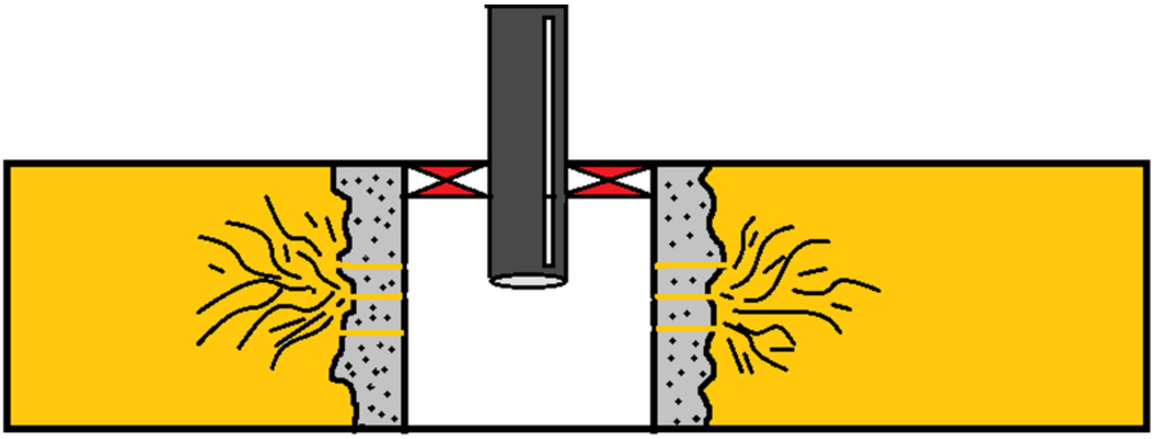


Figure 2-6 Spherical flow due incompletely perforated interval

Furthermore, there is an additional pressure drop appears due to skin and negatively impacts on flow efficiency of the fluid from the reservoir into the well and therefore cause a reduction in production system effectiveness.

So That: -

- Shot density
- Shot interval
- Perforation or shot diameter

Those three criteria or parameters should be carefully designed otherwise they will be considered as one of flow restrictions beside to the rest of flow restrictions reservoir and vertical lift system flow restrictions.

2.5.2. Methods of The Construction IPR of Oil Well:

Firstly, it should be noted that determination of the type of reservoir is very important to choose a suitable method to construct IPR. The pressure temperature diagram is a very useful tool to define the oil reservoir type, which might be saturated (oil and gas), under saturated (oil phase) or gas cap reservoir, depending upon the initial reservoir pressure [9]. Also it is useful tool for describing the phase behavior of oil and gas mixture when they flow in a production system as shown in Figure 2-7. As an example, the path in the figure is describing in general the phase behavior of oil flowing initially from undersaturated reservoir to the wellbore, the production tubing, chock and finally to the separator.

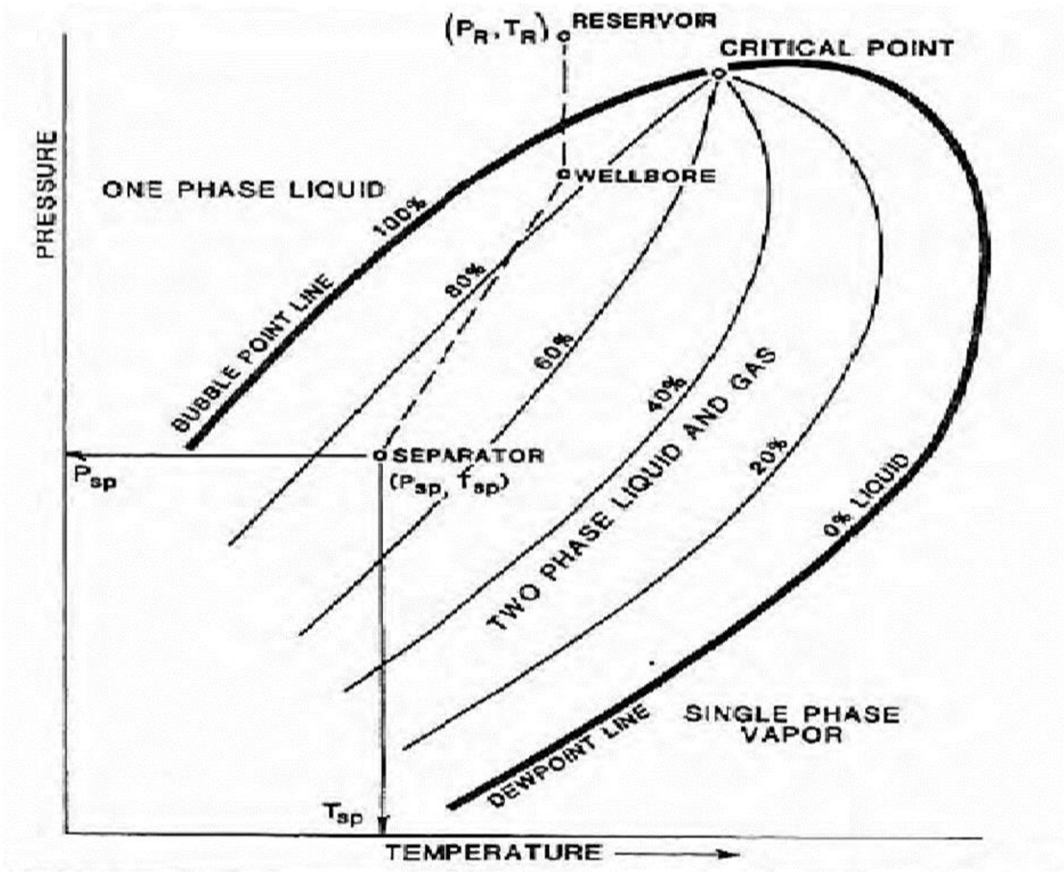


Figure 2-8 Phase Behavior of Oil and Gas Mixture

2.5.2.1. Darcy's Law:

It's considering as the fundamental law of fluid motion in porous media. Generally, the mathematical expression developed by Henry Darcy 1856 [1]. Darcy's law can be used in Nodal Analysis to describe the fluid flow behavior from reservoir to wellbore by contraction the IPR which describes the relationship between the flow rate, pressure drop [5]. By the way, the using of Darcy's law depends on the flow conditions, that is, unsteady, pseudo-steady or steady state flows which are determined generally by reservoir boundary conditions. Darcy's law applied only when the following conditions exist:

Unsteady state flow:

Earlougher (1977) developed Darcy's Law to find the oil flow rate by using a constant bottom hole pressure which is more desirable for well inflow performance analysis especially in oil production wells [3]. Therefore, the following mathematical equation used to find and construct the reservoir deliverability and IPR for oil wells (under saturated reservoir), respectively:

$$q = \frac{kh(p_i - p_{wf})}{162.6 B_o \mu_o \left(log\, t + log \frac{k}{\phi \mu_o Ct\, r_w{}^2} - 3.23 + 0.87 S \right)} \qquad 2\text{-}1$$

Where:

q = oil production rate, STB/day

p_i=Initial Reservoir Pressure, psia

p_{wf} = Flowing Bottom-Hole Pressure, psia

k = Effective Horizontal Permeability to Oil, md

h =Reservoir Thickness, ft.

B_O = Formation Volume Factor of Oil

μ_o = Viscosity of Oil, cP

t = Flow Time, hour

log = 10-Based Logarithm

Φ =Porosity, Friction

C_t= Total Compressibility, psi-1

r_w= Wellbore Radius to The Sand Face, ft.

S = Skin Factor

Pseudo-steady state flow:

Under this state, the flow occurs only as a result of the expansion of fluid remaining within reservoir. Also, in this flow the p_e is not known at any given time so that the $\bar{p}$ (volumetrically average reservoir pressure) is more useful. Therefore, assuming single phase flow the following mathematical equation can be derived from Darcy's Law for an oil reservoir under Pseudo-steady state flow condition due to a circular no-flow boundary at distance r_e from wellbore **[3]**:

$$q = \frac{kh(\bar{p}-p_{wf})}{141.2B_o\mu_o\left(ln\frac{r_e}{r_w}-\frac{3}{4}+S\right)} \qquad \textbf{2-2}$$

It should be noted that Darcy's Law can be modified for a bounded drainage radius of different shapes of boundary as follows [3]:

$$q = \frac{kh(\bar{p} - p_{wf})}{141.2B_o\mu_o\left(\frac{1}{2}ln\frac{4A}{\gamma C_A r_w^2} + S\right)} \qquad 2\text{-}3$$

Where:

$\bar{p}$ = *Average Reservoir Pressure, psia*

A = Drainage Area, ft2

C_A = *Drainage Area Shape Factor, this value can be found from* **Fig. 2-7**

γ = *1.78 = Euler's Constant*

r_e= *The Distance from Pressure Boundary To The Wellbore*

Steady state flow:

This flow condition is that when the reservoir is infinite in size, has a constant pressure boundary such as (aquifer or a water injection well) so that no pressure depletion occurs with time. Therefore, assuming single phase flow, the mathematical flow rate equation can be derived from Darcy's Law for an oil reservoir under steady state flow condition due to a circular constant pressure boundary at distance r_e from wellbore [3]:

$$q = \frac{kh(p_e-p_{wf})}{141.2B_o\mu_o\left(ln\frac{r_e}{r_w}+S\right)} \qquad \textbf{2-4}$$

The Parameters That Effects on Flow Rate and IPR Are:

1. Effective permeability(k_o): the oil flow rate is directly proportional to the permeability which it can be either increased around the wellbore by well

simulation or decreased by formation damage or as the depletion reservoir is increased and gas saturation started to increase.

2. Average reservoir pressure ($\bar{p}$): it can be a constant value or as declines because of depletion depending on the drive mechanism of the reservoir.
3. Bottom hole pressure (p_{wf}): the value of oil flow rate is inversely proportional to bottom hole pressure or directly related in general to drawdown change ($p - p_{wf}$).
4. Reservoir thickness (h): it is a constant value from reservoir to another. Generally, the oil flow rate is directly related to reservoir thickness.
5. Oil formation volume factor (B_O): As pressure is decreased on a liquid, the B_O will increase until the bubble point of this liquid is reached then the shrinkage of the oil will start due to the reduction of B_O. Therefore, generally the oil flow rate is inversely related to B_o.
6. Oil viscosity (μ_o): As pressure is decreased from initial reservoir to bubble point pressure, the viscosity of oil saturated with gas will decreased. But below the bubble point pressure, the viscosity will increase as the dissolved gas comes out of solution, so that the flow rate is inversely proportional to oil viscosity.
7. Skin factor(S): formation damage and insufficient perforations or stimulation around the wellbore are factors which can be affected positively or negatively the value of skin factor. Therefore, the oil flow rate is inversely related to the value of skin.

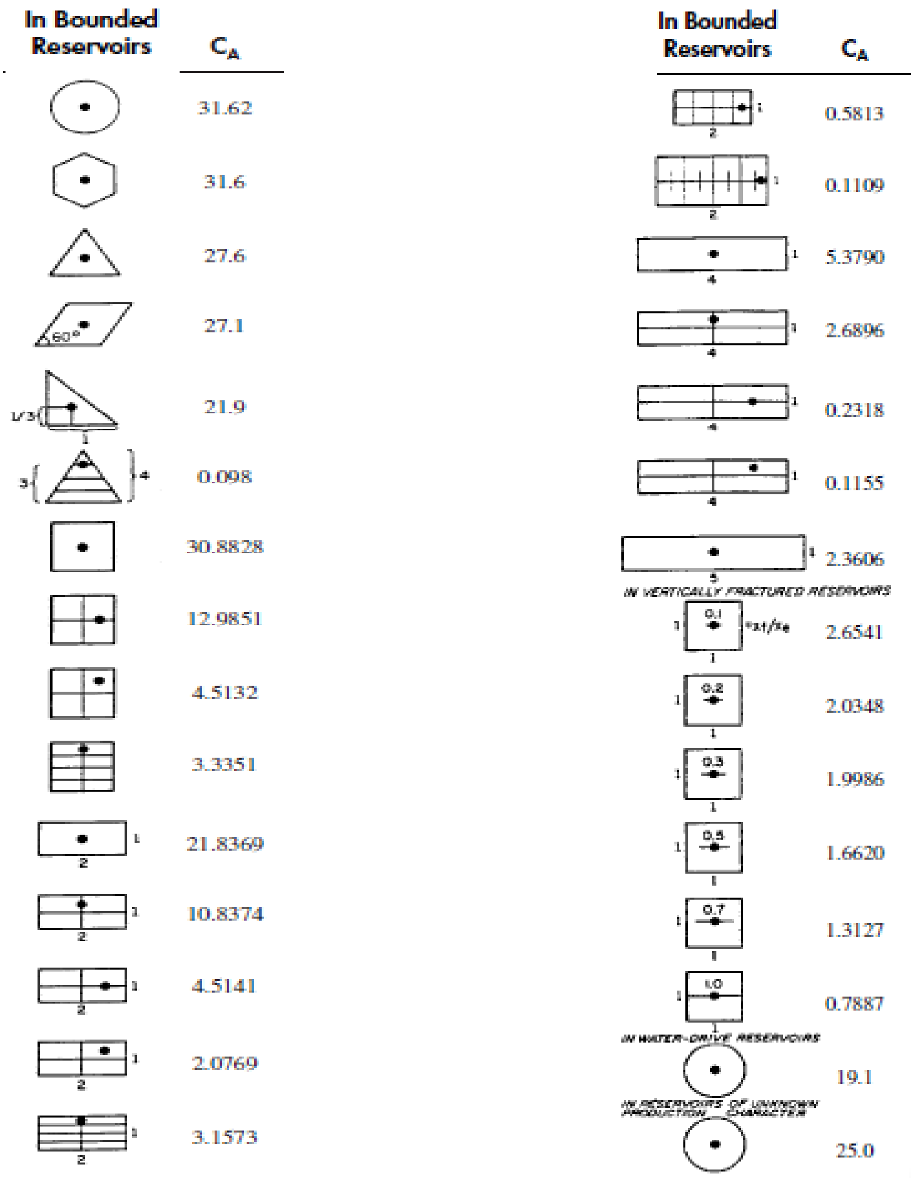


Figure 2-9 Drainage Area Shape Factor

2.5.2.2. Vogel's Method:

In 1968, Vogel proposed an empirical inflow performance relationship IPR for saturated, solution-gas drive reservoirs based on numerical simulation results, and a wide range of rock and fluid properties. The final equation for Vogel's method was based on calculation made for 21 reservoir conditions. This relationship is shown in the below graph [5]:

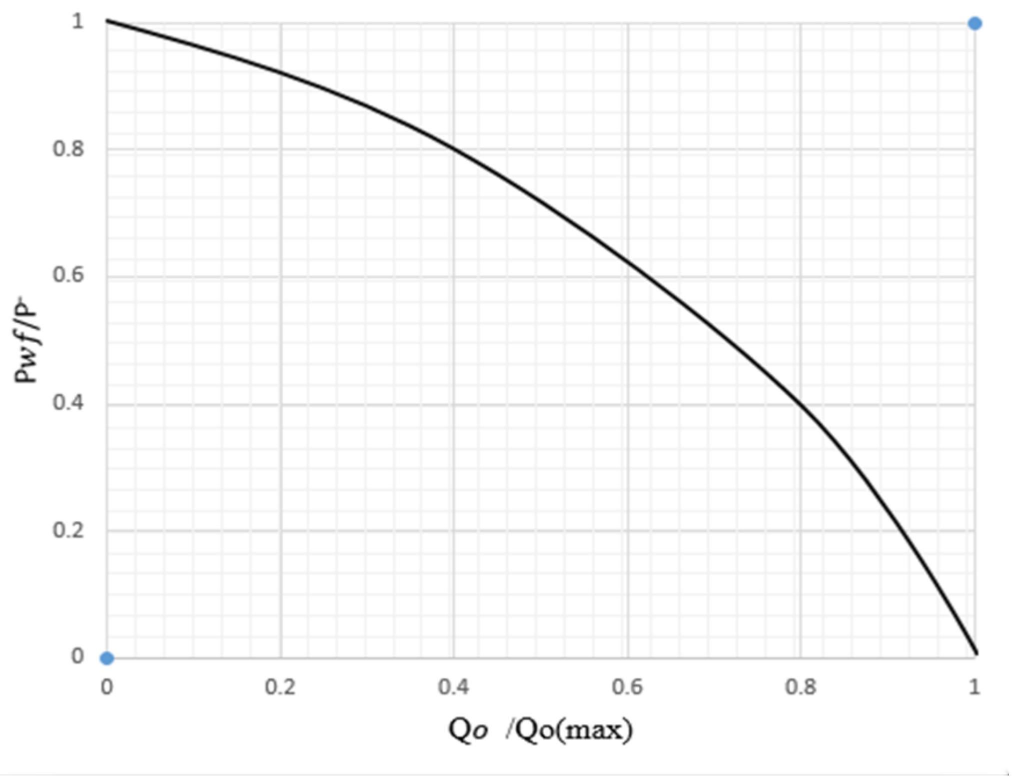


Figure 2-10 Vogel’s IPR for saturated oil reservoirs

This above graph actually has been built based on Vogel’s mathematical equation Eq. (5) which simulates the inflow performance (reservoir performance) and used to construct IPR curve

$$\frac{q_o}{q_{o(max)}} = 1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2 \qquad 2\text{-}5$$

Vogel's IPR is independent of the skin factor and thus, applicable to undamaged wells only. Although Vogel's equation was originally developed for solution-gas drive mechanism reservoirs, it is generally accepted for other drive mechanisms as well [5]. This method required only the knowledge of a single flow rate, flowing wellbore pressure from well test data. By the way, Vogel's method can be applied also for under saturated reservoirs. Therefore, the conditions for using Vogel's method can be divided for:

Two Phase Reservoirs:

This kind of two-phase reservoir is available in saturated-dissolved gas reservoirs which their average pressures are at and below the bubble point pressure, so that for this case, Vogel's equation is valid where two-phase flow exists (liquid and gas) to determine and construct the reservoir deliverability and IPR, respectively. It is written as:

$$q_{o(max)} = \frac{q_{o,Test}}{\left[1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2\right]} \qquad 2\text{-}6$$

$$q_o = q_{o(max)}\left[1 - 0.2\left(\frac{p_{wf}}{\bar{p}}\right) - 0.8\left(\frac{p_{wf}}{\bar{p}}\right)^2\right] \qquad 2\text{-}7$$

where:

$q_{o\,(max)}$: is an empirical constant which equal the value of AOF, mathematically:

$$q_{o(max)} = \frac{J\bar{p}}{1.8} \qquad 2\text{-}8$$

Fig. 2-11. shows the IPR curve when two phases flow through the reservoir into the bottom of the well.

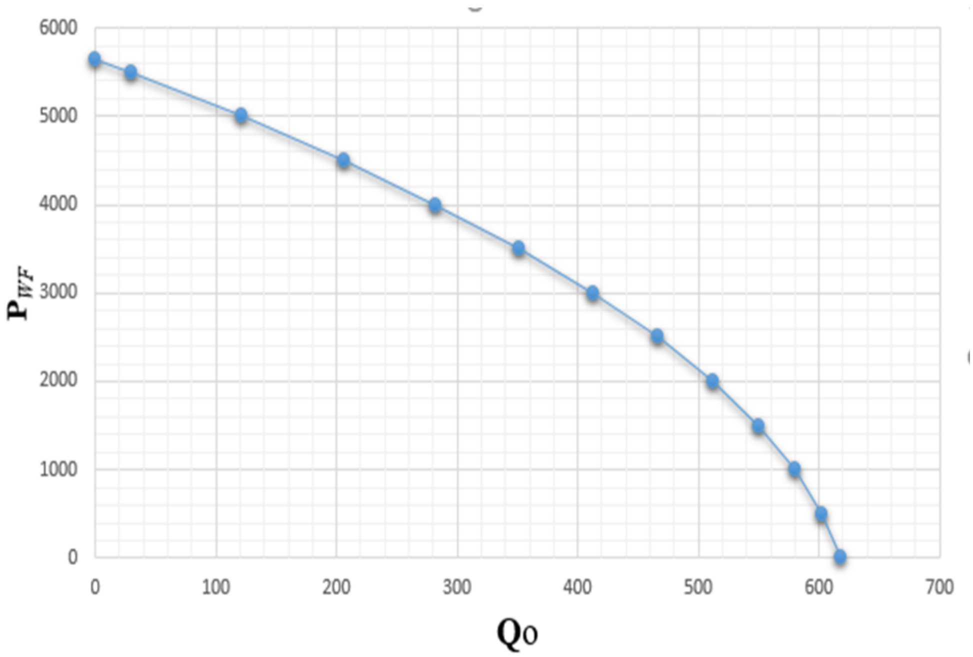


Figure 2-11 Two phase reservoir IPR curve

Partial Two-Phase Oil Reservoirs:

When the reservoir was under saturated ($\bar{p} > p_b$) and the following bottom hole pressure was below the bubble point pressure which means in the reservoir the fluid was being one phase but when It arrived to the bottom hole, it was separated into two phase. Therefore, the method can be applied to under saturated reservoirs by applying the following Vogel's equation only for values of ($p_{wf} < p_b$) to generate the IPR and calculate the corresponding oil flow rate:

$$q = q_b + q_v \left[1 - 0.2\left(\frac{p_{wf}}{p_b}\right) - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right] \qquad 2\text{-}9$$

As show in **Fig. 2-12** this generalized Vogel's equation is combining the straight-line IPR model for single-phase flow with Vogel's IPR model for two phase flow.

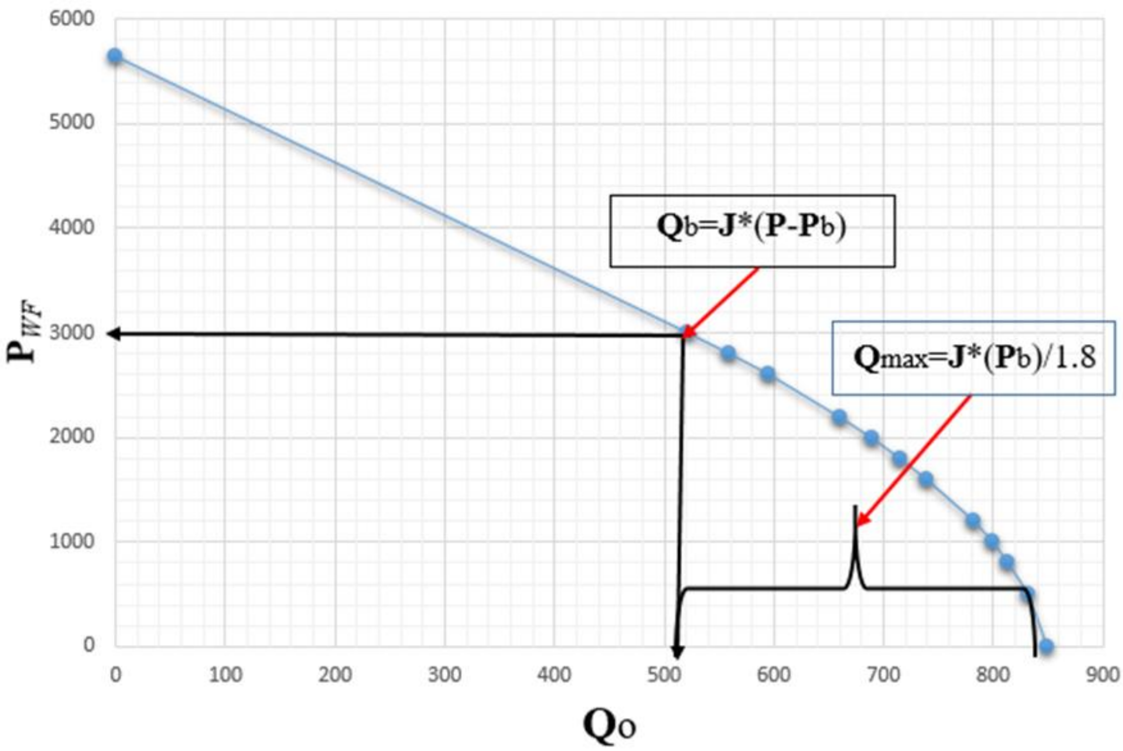


Figure 2-12 Generalized IPR curve

Where:

(q_b) the flow rate at bubble point pressure is:

$$q_b = J * (\bar{p} - p_b) \qquad 2\text{-}10$$

(q_v) the additional flow rate caused by a pressure below p_b:

$$q_v = \frac{J * p_b}{1.8} \quad 2\text{-}11$$

Eq. 2-9 becomes:

$$\boldsymbol{q = J\left[(\bar{p} - p_b) + \frac{p_b}{1.8}\left\{1 - 0.2\left(\frac{p_{wf}}{p_b}\right) - 0.8\left(\frac{p_{wf}}{p_b}\right)^2\right\}\right]} \quad 2\text{-}12$$

When productivity index (J) can be determined from a test on the well or from Darcy's Law:

1. From test data:

The first case, if the tested flowing bottom hole pressure is taken below the bubble point pressure, the following equation can be used to determine PI:

$$\boldsymbol{J = \frac{q_{o,Test}}{\left[(\bar{p} - p_b) + \frac{p_b}{1.8}\left\{1 - 0.2\left(\frac{p_{wf,Test}}{p_b}\right) - 0.8\left(\frac{p_{wf,Test}}{p_b}\right)^2\right\}\right]}}$$

The second case, if the tested flowing bottom hole pressure is taken above the bubble point pressure, the following equation can be used:

$$\mathbf{J = \frac{q_{o,Test}}{\left(\bar{p} - p_{wf,Test}\right)}}$$

2. From Darcy's Law:

$$\mathbf{J = \frac{7.08 * 10^{-3} kh}{B_o \mu_o \left(\ln \frac{r_e}{r_w} - \frac{3}{4} + S\right)}}$$

It should be noted that the maximum oil flow rate occurs when the value of $\mathbf{p}_{wf} = 0$. Therefore, after compensation for $\mathbf{p}_{wf}$ in **Eq. 2-9**, the following equation can be applied to find the maximum oil flow rate in this case [9]:

$$\boldsymbol{q_{o(max)} = q_b + q_v} \quad 2\text{-}13$$

2.6. Well Performance

2.6.1. Introduction:

It is a term used to describe the well deliverability, which means the achievable oil production rate from well to surface, under the current whole flowing conditions as well as the flow performance of production string (tubing, casing, or both). The pressure drops required to lift a fluid through the production tubing at a given flow rate is one of the main factors determining the deliverability of a well. Well performance generally relates to production capacity of well and reservoir condition **[2]**. Understanding well performance is vitally important to production engineers for designing oil well equipment and optimizing well production condition. Therefore, the resulting relationship between bottom-hole flowing pressure and production rate is called tubing performance relationship.

2.6.2. Tubing Performance Relationship (TPR)

It named also Vertical Lift Performance (VLP), Outflow Performance Relationship (OPR). It describes the flow from the bottom-hole of the well to the wellhead and how this flow rate is affected by the pressure drop in the tubing. Therefore, the TPR represents what the well can deliver to the surface. A well's production is dependent on the mechanical configuration of the wellbore, fluid properties, reservoir conditions and several other factors [5]. There are two versions of the TPR curve in practice. The first depicts the relation between the pressure drop of the well and the flow rate at the well head i.e. the top site flow rate. The second depicts the relation between the bottom-hole pressure and the top site flow rate. In the case of single-phase flow, liquid or gas, the pressure drop can be calculated easily as long as component characteristics are known, but in case of multiphase flow correlations are used in calculation the TPR. The most common way to analyze this performance starts with a fixed back pressure (determined by wellhead pressure or separator pressure) and according to the pressure losses the flowing bottom-hole pressure can be calculated.

In this project we will cover the all information and guidelines that helps the reader to understand the two-phase flow as it is the real case that occurs during production of oil wells.

2.6.2.1. Two-Phase Flow in Oil Wells:

As the fluid comes out from the reservoir it passes through production tubing trying to reach the wellhead and then surface facilities, during the fluid flowing within specified velocity and fluid properties there is a pressure loss occurs due to one of the mechanical factors mentioned in the previous lines. this reduction in fluid pressure makes its dissolved gas starts to expand within the oil and make flow regime changes from one to another and this deformation in flow regime creates more complexity in describing the exact well performance or vertical lift performance, for this two phase flow case in oil wells a software simulators are used to simplify the analysis and evaluation process for engineers.

In another words, these flow regimes occur as a progression with increase gas flow rate for a given liquid flow rate, the oil may enter the tubing at a flowing pressure above the bubble point where no separate gas phase exists.

There are Four flow regimes have been identified in liquid-gas (two-phase) flow: -

1. Bubble flow: - free gas phase is present in small bubbles dissolved in continuous oil phase.
2. Slug flow: - gas bubble coalescence into larger bubble almost fill the pipe cross-section within oil continues phase as the reduction in pressure increase.
3. Transition flow: - the change from a continuous liquid phase to continuous gas phase as the gas oil ratio increases.
4. mist flow: - the gas phase is continuous, and the bulk of liquid is entrained as droplets in the gas phase.

so that one to three flow regimes may encountered in the same oil well and make the analysis for the fluid flow harder than single phase flow.

2.6.3. Effect of Variables on Well Performance:

the effect of variables on the performance of the well during the life of the production of the well or field can change many conditions that affect the performance of the flow well and can change condition from well to well at a certain time.

some of these variables are:

1. Liquid flow rate (q_L),

2. Gas liquid ratio (GLR),
3. Water oil ratio (WOR), water cut
4. Oil or liquid viscosity
5. Tubing size (d).

When the mixture fluid is separate from ether because decrease of the pressure less than bubble point pressure. The fluid may separate because of different in densities and flow at different velocities in the pipe [5]. Properties such as densities and velocity and viscosity can be identified easy by calculation them individual to be used in pressure gradient equation.

A. Liquid Holdup (H_L): Is the ratio of a volume of pipe that is occupied by liquid at some instant.

$$\mathbf{H_L = \frac{Volume\ of\ Liquid\ in\ a\ Pipe\ Element}{Volume\ of\ the\ Pipe\ Element}}$$

For determine liquid holdup we must calculate such things as mixture.

Density and actual gas liquid velocities and effective viscosity and heat transfer. The value of liquid holdup varies from zero for single-phase gas flow to one for single-phase liquid flow it is determine from empirical Correlation and is function of variables such as liquid and gas properties and flow pattern and pipe diameter and pipe inclination. Gas holdup is ratio of a volume of pipe that is occupied by gas

$$\mathbf{H_g = 1 - H_L}$$

B. No-slip liquid holdup: Is ratio of the volume of liquid in a pipe Element that would exist if that no slipping divided by the volume of the pipe element

$$\boldsymbol{\lambda_L = \frac{q_l}{q_l \times q_g}}$$

The no-slip gas holdup

$$\boldsymbol{\lambda_g = \frac{q_g}{q_l \times q_g}}$$

C. Density: The fluid density is the mass a unit volume of the fluid at specified pressure and temperature. The density of fluid flow be available and density is interested in evaluating the total energy alteration because to potential energy and kinetic energy changes [3]. The density of the flowing gas/liquid mixture is very difficult to evaluate because of the gravitational separation of the phases and the slippage between the phases. The density of an oil/water mixture may be calculated from rates if no slippage between the oil and water phases is assumed.

$$\boldsymbol{\rho_l = \rho_o f_o + \rho_w f_w}$$

Where:

$$\mathbf{f_o = \frac{q_o}{q_o + q_w}}$$

And

$$\mathbf{f_w = 1 - f_o}$$

With determining of the density of a gas/liquid mixture need information of the liquid holdup

$$\boldsymbol{\rho_S = \rho_L H_L + \rho_g H_g}$$

That is used determine the pressure gradient due to elevation change.

D. Velocity: The superficial velocity of a fluid phase is the velocity that phase would exhibit if it flowed through the total cross-sectional area of the pipe alone calculate of the superficial gas velocity

$$\mathbf{V_{sg} = \frac{q_g}{A}}$$

Calculated of the actual gas velocity

$$\mathbf{V_g = \frac{q_g}{AH_g}}$$

Calculation of the superficial and liquid velocity

$$\mathbf{V_{sL} = \frac{q_L}{A}}$$

$$\mathbf{V_L = \frac{q_L}{AH_L}}$$

The total in-situ flow rate used by determining the two-phase or mixture velocity

$$\mathbf{V_m = \frac{q_L + q_g}{A} = V_{SL} + V_{Sg}}$$

The slip velocity is the difference between the gas and liquid velocity

$$\mathbf{V_S = V_g - V_L = \frac{V_{sg}}{H_g} - \frac{V_{sL}}{H_L}}$$

Determine the no-slip actual liquid holdup

$$\mathbf{\lambda_L = \frac{V_{sg}}{V_m}}$$

$$\mathbf{H_L = \frac{V_S - V_m + [(V_m - V_s)^2 + 4V_sV_{sL}]^{\frac{1}{2}}}{2V_s}}$$

E. Viscosity: The viscosity of flowing fluid determine a Reynolds number gas/liquid viscosity calculate

$$\mathbf{\mu_n = \mu_L\lambda_L + \mu_g\lambda_g}$$

$$\mathbf{\mu_s = H_LH_L + \mu_gH_g}$$

Viscosity of an oil/water mixture calculate

$$\mathbf{\mu_L = \mu_of_o + \mu_wf_w}$$

Pressure Gradient Equation for Two- Phase Flow.

The pressure gradient equation, which is applicable to any fluid flowing in a pipe inclined at a given angle ϴ from horizontal, is give below [5].

$$\frac{dp}{dl} = \left(\frac{dp}{dl}\right)_{el} + \left(\frac{dp}{dl}\right)_{f} + \left(\frac{dp}{dl}\right)_{acc}$$

This equation is modified to meet the condition changes during fluid flow through the production tubing up to surface, three main components or energies this equation rely on:

A. Elevation change component due to potential energy or elevation.

The potential energy is the energy hold by an object because of position relative to other objects stress within itself [Wikipedia].

Elevation change component for two- phase becomes:

$$\left(\frac{dp}{dl}\right)_{el} = \frac{g}{g_c}\rho_s \sin\theta \quad 2\text{-}14$$

Where:

ρ_s: fluid density Ibm/ft^3.

g: gravitational acceleration 92.17

g_c: unit conversion factor 32.17 Ibm. Ft / Ib$_f$ –s^2

θ: angle of the well from horizontal

B. Friction component is a component of dray, the force resisting the motion of fluid across the surface of a body [Wikipedia].

The motion component for two – phase becomes:

$$\left(\frac{dp}{dl}\right)_{f} = \frac{(fp\, v^2)f}{2g_c\, d}$$

Where:

f: friction factor

d: tubing inner diameter, ft.

C. Acceleration component is the component due to kinetic energy change:

Kinetic energy is the energy that it possesses due to its motion, it is defined as body a given mass from rest it is stated velocity.

The acceleration component for two- phase becomes:

$$\left(\frac{dp}{dL}\right)_{acc} = \frac{(\rho v dv)_k}{g_c dL}$$

Where:

ρ = fluid density Ibm/ft^3

v= fluid velocity, ft./s^2

g_c = unit conversion factor 32.17 Ibm.ft^2

$\frac{dv}{dl}$ = The amount of deformation velocity accreting to differentiation in tubing or pipe length

***This component is usually ignored in calculating the pressure drop due to its small affect**

2.6.4. Pressure Traverse or Gradient Curves

It's at manually method can be used be calculate the pressure drop occurring in the well producing under similar condition instead of using computer software because in some cases it is not desirable or practical for engineer be used a computer study [5].

Used of gradient curves will not be as accurate as computer calculations, but the more closely the curves match actual well conditions, the more accurate the results will be.

A. Preparation of Pressure Travers Curves:

They are being developed by Gilbert and calculated using the hegemon and brown correlation.

To prepare a curve such this figure, the following parameters are selected:

1. Pipe inside diameter, d
2. Liquid flow rate, Q_L

3. Water fraction, F_w
4. Average flowing temperature, T
5. Oil, gas, and water gravities.

B. Generalized Curves:

Sets of gradient curves, which were prepared using average fluid properties and flowing temperature are available from several sourer, and using an oil API gravity of 35^o, gravity of 0.6 to 0.7 and water gravity of 1.0 to 1.10 [5].

C. Application of Traverse Curves

The application of the curves for estimating either a bottom hole flowing pressure from a known flowing wellhead pressure or vice versa (Boggs).

Note: *In the depth axis, the zero-depth axis does not actually represent the wellhead unless the wellhead pressure is zero.*

If the actual wellhead pressure is greater than zero, then some number greater than zero on depth axis will represent the wellhead and some the number on the depth axis are reference numbers only a mean that some number on the depth axis greater than the actual well depth will represent the location of the bottom of the well (Boggs).

D. The Procedures for Estimating an Unknown Pressure Are:

1- Select the chart that most identically corresponds to the known condition of tubing ID, liquid production rate, water fraction, average fluid properties, and flowing temperature.

2- Insert the pressure axis at the known pressure, move perpendicularly from this pressure the intersection of the GLR curve, move horizontally to the left to the intersection of the depth axis.

- This locates the number on the depth axis, which shows the equivalent depth of which the known pressure exists.

3- If the known pressure is the wellhead pressure, add the actual well depth to the equivalent depth exist in step **2**, this shown the axis depth which is equivalent to the actual depth.

- If the known pressure is bottom hole pressure, subtract the actual well depth from the number found in step 2, it is equivalent to the actual wellhead.

4- From the point located in step **3,** move horizontally to the right to the intersection of the some GLR line from this point move perpendicularly upward to the pressure axis.

Example:

Finding the required flowing bottom hole pressure:

Tubing size: 2.441 In

Liquid rate: 1000 STB/D

Water fraction: 0

Gas gravity: 0.65

Oil API gravity: 35

Water specific gravity: 1.07

Average flowing temperature: 150 °F

Wellhead pressure: 240 psi

Well depth: 11000 ft

Gas liquid ratio: 500 SCF/STB

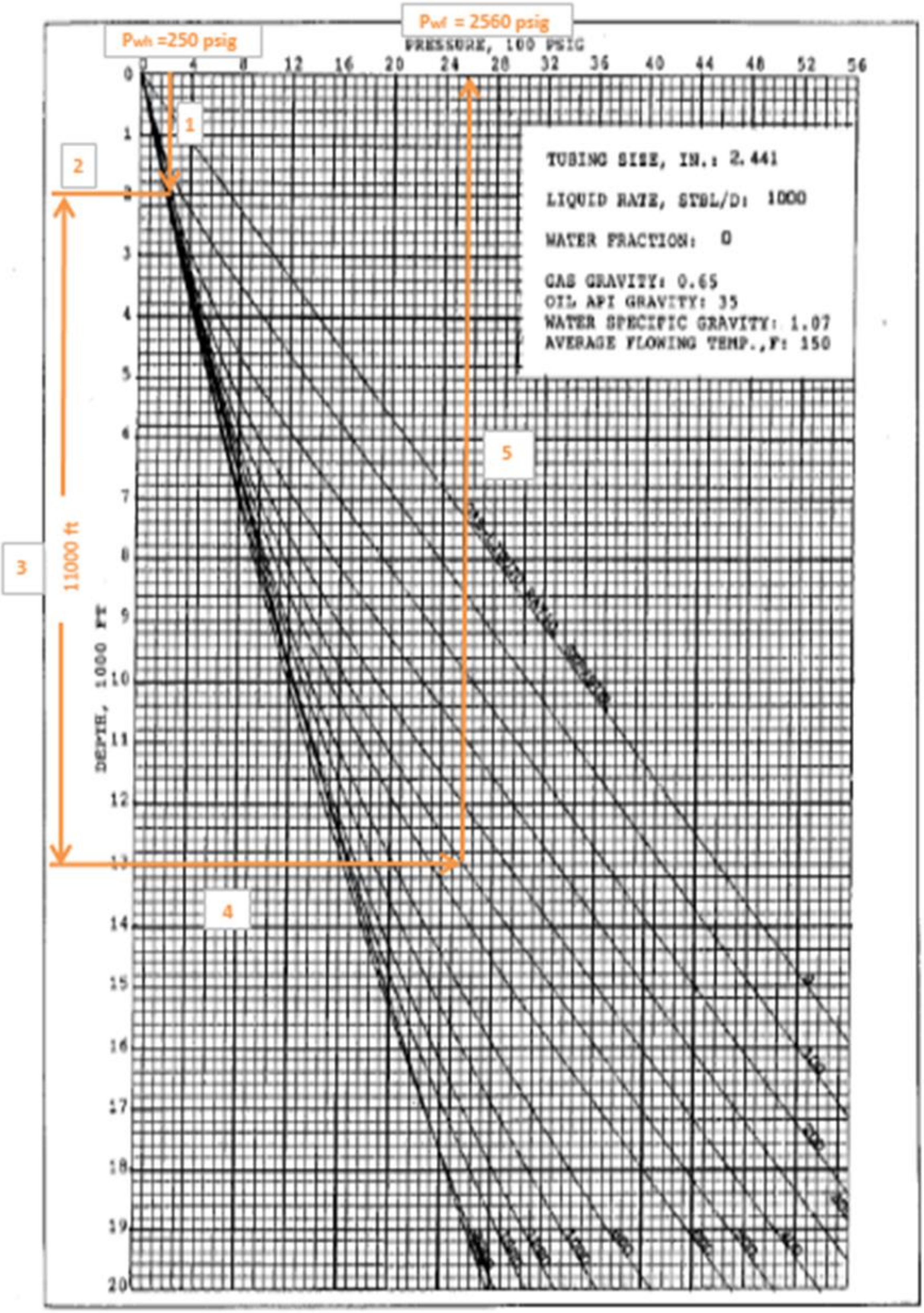


Figure 2-13 GLR curve

2.6.5. Correlations are Used to Perform Tubing Performance Relationship:

To solve this impediment in vertical lift performance or tubing performance relationship numerous studies have been carried out by researchers but in many cases the study was conducted primarily to demonstrated superior performance of some newly proposed pressure measurement method. The following table summarizes the data type, data rang, pipe size and fluid used to develop diverse correlations or methods [5].

Table 2-1 Correlations Are Used to Perform Tubing Performance Relationship:

Investigator	Year Presented	Type of Study	Pipe Sizes, in	Fluids Used	Remarks
Poettmann & Carpenter	1952	Field, Experimental	2, 2.5, 3	oil, water, gas	Correlation developed from well tests with q' > 420 STB/D, GLR < 1500 scf/STB.
Baxendell & Thomas	1961	Field, Experimental	2.5, 3, 3.5	oil, water	Based on well data from Lake Maracaibo Field. Very high flow rates.
Francher & Brown	1963	Field, Experimental	2	water, gas	Date from one well, used GLR much higher than Poettman & Carpenter.
Hagedorn & Brown	1963	Intermediate, Experimental	1, 1.25, 1.5	oil, air, water	Date from 1500 ft. experimental well. Used wide range of oil viscosity.
Duns & Ros	1963	Laboratory Experimental	1.5, 2, 2.5, 3	oil, water, gas	Correlation developed from large number of laboratory data points.
Orkiszewski	1967	Field, Experimental	1, 1.5, 2, 3	oil, water, gas	Utilized some field data and Hagedorn-Brown data. New method for slug flow only.
Aziz, et al.	1972	Theoretical	—	—	Revised Orkiszewski extensions of Griffith-Wallis data. New flow pattern map.
Chierici, et al.	1974	Laboratory Experimental & Theoretical	0.5, 0.75, 1.0	water, oil, gas	Used Walls & Nicklen data. New method for slug flow. New flow pattern map.
Beggs & Brill	1973	Laboratory Experimental	1.0, 1.5	water, air	Method is primarily for inclined flow. Large number of low-pressure data points.
Asheim	1986	Theoretical	—	—	Based on work done previously by Dukler
Hassan & Kabir	1986	Laboratory Experimental& Theoretical	5, with some annular cases	—	Primarily for directional wells.

2.6.6. Wellhead and Choke Performance:

Most flowing wells will be equipped with surface chokes to control the surface pressure and production rate from a well, protect surface equipment from slugging, avoid sand problems due to high drawdown, and control flow rate to avoid water or gas coning [9]. Two types of wellhead chokes are used either positive (fixed) chokes or adjustable chokes. These chokes are usually located at the wellhead, placing a choke at the wellhead means fixing the well head pressure and, thus, the flowing bottom-hole pressure and production rate, but in some cases, they may be located near the separator. The location can have a considerable effect on the well's producing capacity, especially, if the well has a long flow-line.

When the produced oil reaches the wellhead choke, the wellhead pressure is usually below the bubble point pressure of the oil, so that the free gas exists in the fluid stream flowing through choke.

Therefore, the wellhead pressure effects on production rate as a result of a changing choke size, so that, controlling production is often done by adjusting the choke size, which results in a change in wellhead pressure.

As shown in **Fig.2-12**, for each wellhead pressure there is a different tubing performance, each intersecting the inflow performance curve at a different point.

Generally, as a result of increasing choke size, the wellhead pressure decreases, and the flow rate increases. So, determining the effect of choke size on production rate is an important task for production engineer **[2]**.

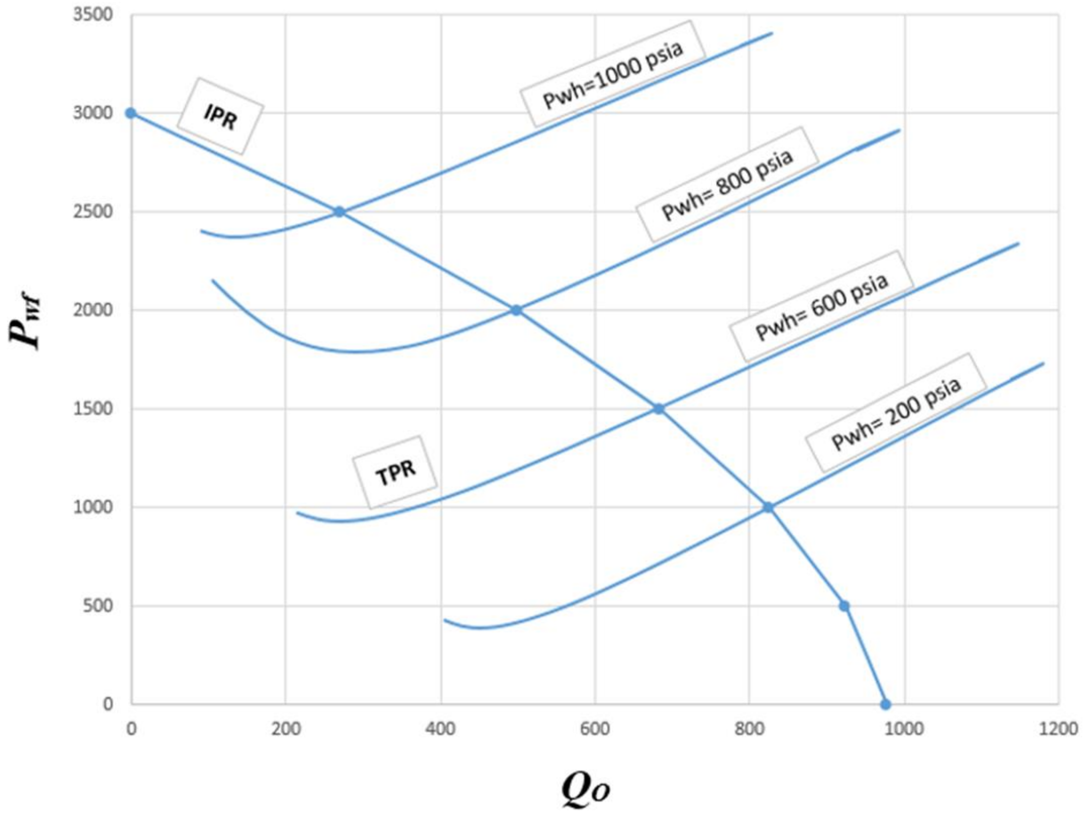


Figure 2-14 Effect of Choke Size on Production Rate

2.7. Case Study 1:

A case study by Muhammad R. Hashmet and others, (Muhammad R. Hashmet, et.al, 2012), this case study entitled: Production Optimization Using Nodal Analysis. It aimed mainly to optimize the production of oil and carry out a filed level optimization [6], well No. 1A in reservoir "A" in U-oil field in the Northern areas of Pakistan, by using Nodal Analysis concept. The software used for this purpose is PERFORM 3.0. The following table shown in brief that the components which affects the IPR and TPR, the procedures that they used for each component, and their results:

Table 2-2 Components Which Affects the IPR and TPR

The Component	The Procedure and Result
Effect of damaged zone permeability	They tried to reduce the permeability of damaged zone for optimize the production by increasing the perforation shot density, but for this case study, this component has not much effect on the production.
Effect of perforation diameter	The larger the diameter of the perforation, the butter the flow performance. But they fund that this parameter has not much effect on productivity for this case study.
Effect of perforation interval	The larger the perforation interval, the butter the flow performance or productivity. In this case, the effect is not significant.
Effect of perforation density	As the perforation increases, the productivity will increase. But in this case, they found that productivity of the well under observation is insensitive to the change in any of the perforation parameter in general.
Effect of declining reservoir pressure	The purpose of studying this effect is to keep the production stable for longer periods by using secondary recovery.
Effect of flow efficiency	They found that this effect is not considerable for this case.
Effect of tubing size	In this case, they found that as the tubing diameter increases, the production capacity of the system increases, but in a diameter of 3.640 in and above, there will be liquid loading.

After performing the different optimization techniques, and comparing the results of them. Finally, they selected the optimum solution which is changing the tubing size from 2.441 in to 2.992 in, with the increasing in production from 1912 bbl./day to 2250 bbl./day as shown in **Fig. 2-13** [6].

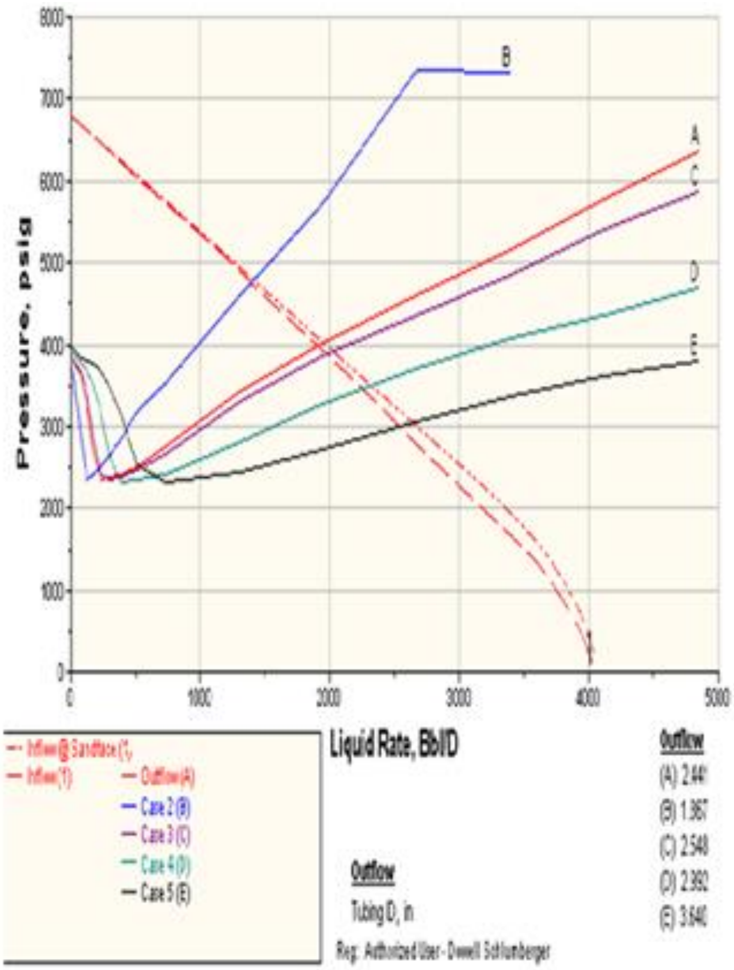


Figure 2-15 Optimum Solution Which Is Changing the Tubing Size and The Increasing in Production

2.8. Case Study 2:

A research by Ogbeide P.O. and Igbinere S.A, (Ogbeide, Igbinere.al, 2015), this research entitled: Nodal Analysis Approach in Minimizing Pressure Losses to Improve Well Productivity, It aimed to use nodal analyses for studying how a well productivity can be improved as a result of minimizing the pressure losses by using tapered internal diameter completion instead of conventional tubing and estimation the optimum length of a duplex combination [7]. This research uses both a descriptive and analytical approach. Also, the software being used for analysis is PIPESIM and the data which used in this research is strictly secondary and selected from **Beggs (1991)**. Therefore, the following table shown in brief that the result approached of using different scenarios comparing different tubing combination.

Table 2-3 Using Different Scenarios Comparing Different Tubing Combination Result

Reservoir pressure	Scenario 1: for single tubing			Scenario 2: for dual tapered tubing		
	Diameter, (in)	Bottom hole pressure, (psia)	Flow rate, (bbl./day)	Diameter, (in)	Bottom hole pressure, (psia)	Flow rate, (bbl./day)
3482	1.995	3200	2380	d_1=2.441 d_2=1.995	3150	6291
	2.441	3120	2878	d_1=2.992 d_2=2.441	3000	4831
	2.992	3769	3026	d_1=3.340 d_2=2.992	2700	4831
	3.340	2684	6291			

The major finding from these results presented is that the duplex string produces with a better flow rate than that of single tubing.

The following figure shows the results of optimizing the length of a duplex 1.995 and 2.441 combination string:

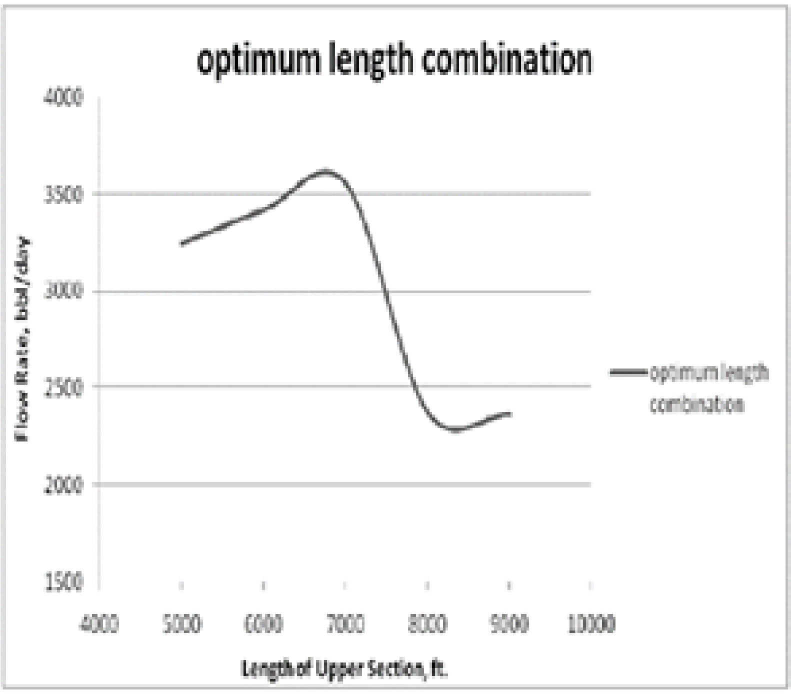


Figure 2-16Results of Optimizing the Length of a Duplex 1.995 And 2.441 Combination String

They noticed that the optimum length for upper section of 1.995 and 2.441 in combination string was 7000 ft. and any length longer than 7000 ft. will only cause well to load because the loss due to elevation and the lower section should be run from 7000 to 100000 ft.

CHAPTER THREE

3. METHODOLOGY

3.1. Introduction

Utilizing and Sorting obtained data in correct way helps to get vail results for analysis. Numerical software are only tools contribute in saving the time lost during analysis process and that software show you the result of inputs you insert so that selection the exact data required to implement any project depends on the determination skills that the engineers own.

Hereby, this chapter will give the clear data wanted to perform such as this project as well as will light up on the software used to fulfill this type of research in order to assistance the interested readers and researchers by developing the perceptions in oil industry.

3.2. Type of Data Required to Implement the Project.

The required data, its source and worth description are clarified in the following table;

Table 3-1 Data Required to Implement the Project

NO.	Data type	Item needed	Source of item	Item worth description
1	**Reservoir Data**	Reservoir Pressure	Well testing final report	• This value is needed to describe the inflow performance of the reservoir. • It is used in determination the type of the reservoir within phase diagram.
		Reservoir Temperature	Formation dynamic tester	• This value is needed for describing the inflow of gas reservoirs. • It is used in determination the type of the reservoir within phase diagram.
		Reservoir Average Permeability	Well testing final report	• It one of main values that demonstrate the flow condition within the reservoir.
		Reservoir Area	Well testing final report or isopach map	• The value of this item participates in building IPR curve.
		Net Reservoir Thickness	Wireline logging	• Provides by the reservoir flow capacity in compensation with other parameters (review Darcy's equation)
		Formation Damage (Skin)	Well testing	• Reflects the amount of fluid inflow restriction due to the damage.

No.	Data Type	Item Needed	Source of Item	Item Worth Description
2	**Fluid Data**	Oil Viscosity	PVT Labs	• This value is multi-using with IPR & TPR calculating as pressure change (Darcy's and pressure gradient equation show that clearly)
		Oil Density	PVT Labs	• This property value is utilized in pressure gradient calculation to find out TPR
		Gas Solubility	PVT Labs	
		Oil Compressibility	PVT Labs	
		Oil Formation Volume Factor	PVT Labs	• Helps to determine reservoir type. • Contribute in calculation IPR.
		Gas Specific Gravity	PVT Labs	• One of important input to pressure gradient equation.
		Bubble Point Pressure	PVT Labs	• Helps to determine reservoir type. • Significant input for IPR & TPR. • Also confirm the flow type.
		Fluid Temperature	PVT Labs	• In combination with pressure, it determines the behavior of fluid properties.
		Water Salinity	PVT Labs	• It shares within fluid density calculation in condition of associated water production.

No	Data type	Item needed	Source of item	Item worth description
3	**Well Data**	Well condition	Completion catalog or report	- Open or cased hole.
		Well deviation	Final Drilling report	- In order to find well inclination well deviation data must be included.
		Wellbore radius	Final Drilling report	- Share in calculating IPR.
		Internal Production casing diameter	Completion catalog or report	- Restrict selection production tubing in case of optimizing production performance.
		Internal & external production tubing diameters	Completion catalog or report	- In case of dual casing-tubing production, its diameter effects on well production rate.
		Tubing length	Completion catalog or report	- This the main parameter (variable)that impact on the performance of fluid flow (TPR), and has a strong effect on friction& acceleration forces.
		Downhole equipment	Completion catalog or report	- This property of tubing has a great influence on hydrostatic force.
		(SSSV)	Completion catalog or report	- Considered as one of downhole restrictions, so that its dimension must be known.
		Perforation interval	Completion catalog or report	- Considers as one of inflow restriction, which strongly effect on IPR calculations in case of wrong design.
		Perforation shot density	Completion catalog or report	- Take the same worth description of perforation interval.
		Perforation diameter	Completion catalog or report	- Take the same worth description of perforation interval.

No	Data type	Item needed	Source of item	Item worth description
		Perforation length	Well testing	- Take the same worth description of perforation interval.
		Well drainage area	Well testing	- This item value reflects the reservoir flow capacity which is translated on IPR.
		Damage zone radius	Well testing	- Take the same worth description of perforation interval.
No	**Data type**	**Item needed**	**Source of item**	**Item worth description**
4	**Production Data**	Gas oil ratio	Daily production report	- This item value will be used to identify the factors (parameters) that influence well performance.
		Water cut	Daily production report	- Used in clarify the exact liquid volume in well path.
		Wellhead pressure	Daily production report	- Also, its value does the same function as GOR value.
		Test points	Well testing	- Required input to TPR calculation, and reflects the well performance in combination with other items.
		AOF	Well testing	- Important to construct IPR in case of using Vogel or Fetkovich methods.
5	**General data**	Fluid system	-	- Oil + water, dry or wet gas, condensates.
		Surface chock size	-	- Due to it remarkable effect on wellhead pressure value and drawdown surface flow line network, this item value should be known.
		Separator stages & separator pressure	-	- Those two values help in designing the optimum production system due to its operation pressure controlling

3.3. IPM Software: -

	Production **S**ystem **Per**formance	Innovative Company Petroleum experts' company (**PEtex**)	Year of innovation & marketing: Beginning of nineteens (90s)
PROSPER™	version 11.5 2010	United Kingdom	

Oil and Gas fields worldwide produce as integrated systems of reservoirs, wells, pipeline networks and process facilities. Oil and Gas companies traditionally discretized the engineering analysis, breaking the system into parts and studying and solving the components individually.

Each silo relied on a variety of analytical techniques which over the years evolved into distinct software products. Each product model being a calibrated mathematical representation of the physical phenomenon, with a view to maximizing economic recovery from the asset [8].

The concept of Integrated Production Modelling (IPM) was pioneered by Petroleum Experts and it involves the elimination of artificial boundary conditions that would be imposed by individual disciplines and facilitates the construction of models that would behave as close to reality as possible [8].

Integrated Modelling is able to capture this behavior, while still allowing the engineers to build models relevant to their discipline in isolation of everything else, as the benefits of integrating all the models together to replicate the natural behavior of the field has transformed the way companies design, operate and optimize their assets.

Petroleum Experts (Petex) is a Research and Development Company that encapsulates innovative engineering research into software.

The Petex Digital Oil Field (DOF) platform includes software allow operators to understand field behavior and replicate this in physical models which are subsequently used to optimize production as well as ultimate recovery.

3.3.1. IPM Software Platform: -

1- MBAL
2- PROSPER
3- GAP
4- RESOLVE
5- REVEAL
6- OPENSERVER
7- PVTp

3.3.2. PROSPER™ Software: -

PROSPER™ is a well performance, design and optimization program for modelling most types of well configurations found in the worldwide oil and gas industry today, it can assist the production or reservoir engineer to predict tubing and pipeline hydraulics and temperatures with accuracy and speed **[8]**.

What is important in **PROSPER™** software is its sensitivity calculation features which enable existing well designs to be optimized and the effects of future changes in system parameters to be assessed. **PROSPER™** is designed to allow building of reliable and consistent well models, with the ability to address each aspect of well bore modelling visa; PVT (fluid characterization), VLP correlations (for calculation of flow line and tubing pressure loss) and IPR (reservoir inflow) **[8]**.

In another words, **PROSPER™** softer ware can be used in: -

1. The tool can be used to model reservoir inflow performance(IPR) for single layer, multi-layered, or multilateral wells with complex and highly deviated completions, optimizing all aspects of a completion design including perforation details and gravel packing **[8]**.
2. It can be used to accurately predict both pressure and temperature profiles in producing wells, injection wells, across chokes and along risers and flow lines [8].
3. The sensitivity calculations capabilities allow engineer to model and easily optimize tubing configuration, choke and surface flow line performance **[8]**.
4. It can be used to design, optimize and troubleshoot the following artificial lift systems: gas lifted, coiled tubing, ESP, PCP, HSP (hydraulic pump), jet pump and sucker rod pump equipped wells **[8]**.
5. Its choke calculator can be used to predict flow rates given the choke size, or the choke size for a specified production rate and of course, the pressure drop across a known choke at a specified rate. It can also be used to generate choke performance curves **[8].**
6. The multiphase flow correlations implemented can be adjusted to match measured field data to generate vertical lift performance curves (VLP) for use in simulators and network models **[8]**.

7. The tool can be used in a matching or predictive mode. Matching of real data is available in the PVT, IPR, Gradient matching and VLP matching sections **[8]**.
8. Unique black oil model for retrograde condensate fluids, accounting for liquid dropout in the wellbore **[8]**.
9. Calculate total skin and determine breakdown (damage, deviation or partial penetration) **[8]**.

3.4. Anticipated Results: -

As the well is in naturally flow circumstance actually it will be subjected to one of flow restrictions mentioned in chapter two, so that we anticipate that:

1. The drilling or completion procedures take its time to confirm enough formation damage causing inflow restriction of the fluid.
2. Wrong perforation design, which deformation the flow geometry.
3. Type of sand control system used in case of four production phase (oil, gas, water and sand) reservoir.
4. Selecting the production tubing size was not proper to induce optimum fluid flow.
5. Unfit designing for downhole equipment causing flow restrictions.
6. Redesign for chock size in order to confirm optimum well performance.

CHAPTER FOUR

4. ANALYSIS AND DISCUSSION

4.1. Input Data to Software

At here, those coming sections are going to light up all software input data to describe and simulate the production system performance of KHARIR1-25.

The following show the general information of KHARIR1-25.

Table 4-1 General Information of KHARIR1-25

Fluid	Oil
PVT Model	Black Oil
Well	Kha1-25
Separator	Two Stage
Viscosity Model	Newtonian Fluid
Flow Type	Tubing
Well Type	Producer
Predicting	Temperature and Pressure On Land
Temperature Model	Rough Approximation
Completion	Open Hole
Inflow Type	Single Branch

Second box in **PROSPER**^{TM} software include the fluid PVT data, **Table. 4-2** is the inserted data to this box and it is sorted as the software arrangement forma required.

Table 4-2 Flashed PVT data of KHARIR1-25.

Temperature (F)	**Pressure** (Psig)	**Bubble Point Pressure** (Psig)	**GOR** (Scf/STB)	**FVF (Bo)** (Rbbl/STB)	**Oil Viscosity** (cp)
218.8	0	3060	0	1.088	1.296
218.8	400	3060	287	1.285	0.75
218.8	800	3060	396	1.347	0.519
218.8	1300	3060	533	1.419	0.41
218.8	1800	3060	676	1.497	0.331
218.8	2300	3060	836	1.577	0.285
218.8	2800	3060	1032	1.673	0.259
218.8	3060	3060	1092	1.746	0.243
218.8	3100	3060	1092	1.744	0.245
218.8	3200	3060	1092	1.741	0.249
218.8	3300	3060	1092	1.737	0.25
218.8	3400	3060	1092	1.734	0.2524
218.8	3500	3060	1092	1.73	0.2541
218.8	4000	3060	1092	1.716	0.2561
218.8	4500	3060	1092	1.702	0.2728

Also, this box includes another PVT data which must be inserted to confirm matching to one of the mathematical PVT correlations, **Table. 4-3** showing this data.

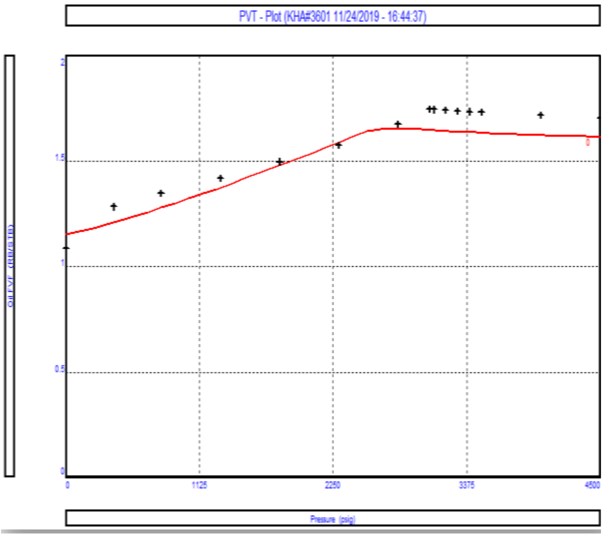
Table 4-3 Multi-Stage separator test data.

Separator Pressure (Psig)	590
Separator Temperature (F)	104
Separator GOR (SCF/STB)	656
Separator Gas Gravity	1.241
Tank GOR (SCF/STB)	354
Tank Gas Gravity	0.954
Oil Gravity (API)	41.7
Water Salinity (ppm)	0

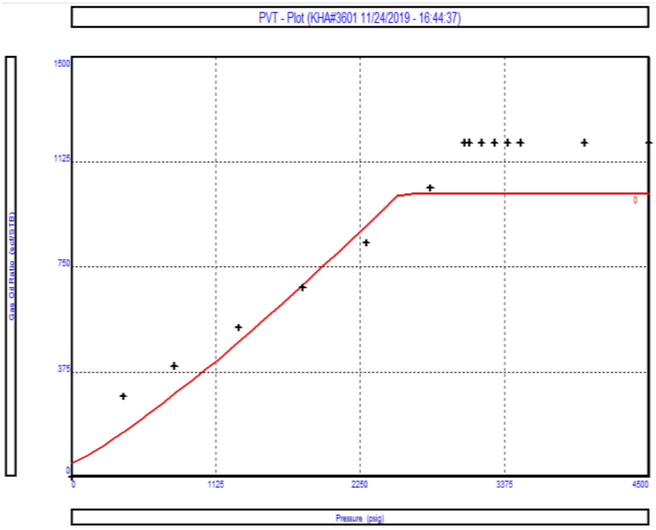
Note That: -

1. Due to high basement pressure production system, we needed to use **Table. 4-3** data.
2. **GOR** value in table (3) actually refers to gas solubility value (**Rs**).

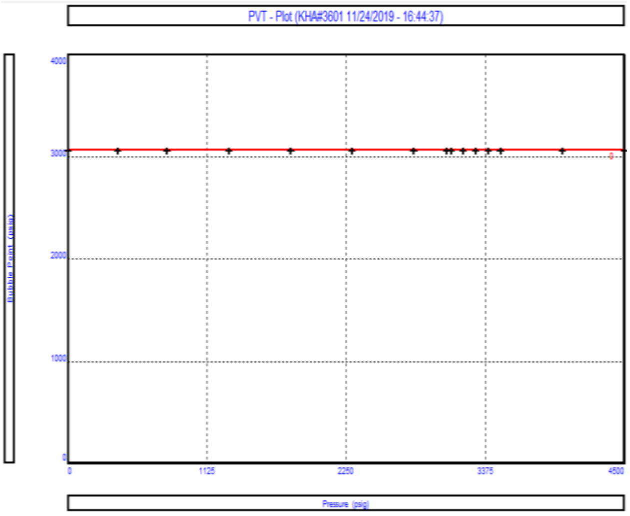
After the PVT data has been inserted and calculated, correlations matching gave the flowing outputs shown in **Fig. 4-1**.



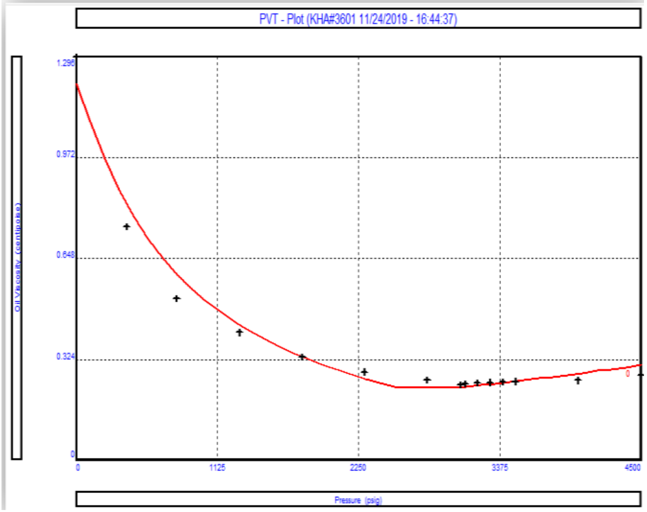
A) Oil Formation volume factor.



B) Gas Solubility.



C) bubble point pressure.



D) Oil viscosity.

Figure 4-1 Correlation matching for PVT data.

Note That: -

- Vazquez-Beggs was the best correlation matched the field PVT data for: -
  - Oil formation volume factor.
  - Gas solubility.
  - Bubble point pressure.
- Beggs et al was the best correlation matched the field PVT data for: -
  - Oil viscosity.

Third box in the software is specialized for IPR, the input data needed to model the reservoir performance of KHARIR1-25 in **PROSPER**^{TM} software is shown in **Table. 4-4**.

Table 4-4 IPR Input Data of KHARIR1-25.

Reservoir Model	Vogel
Reservoir Pressure (Psig)	3200.3
Reservoir Temperature (F)	218.8
Water Cut (%)	0
Total GOR (SCF/STB)	1092
Test Rate (STB/Day)	2952
Test Pressure (Psig)	2790

IPR curve of KHARIR1-25 basement reservoir is showing in following **Fig. 4-2**.

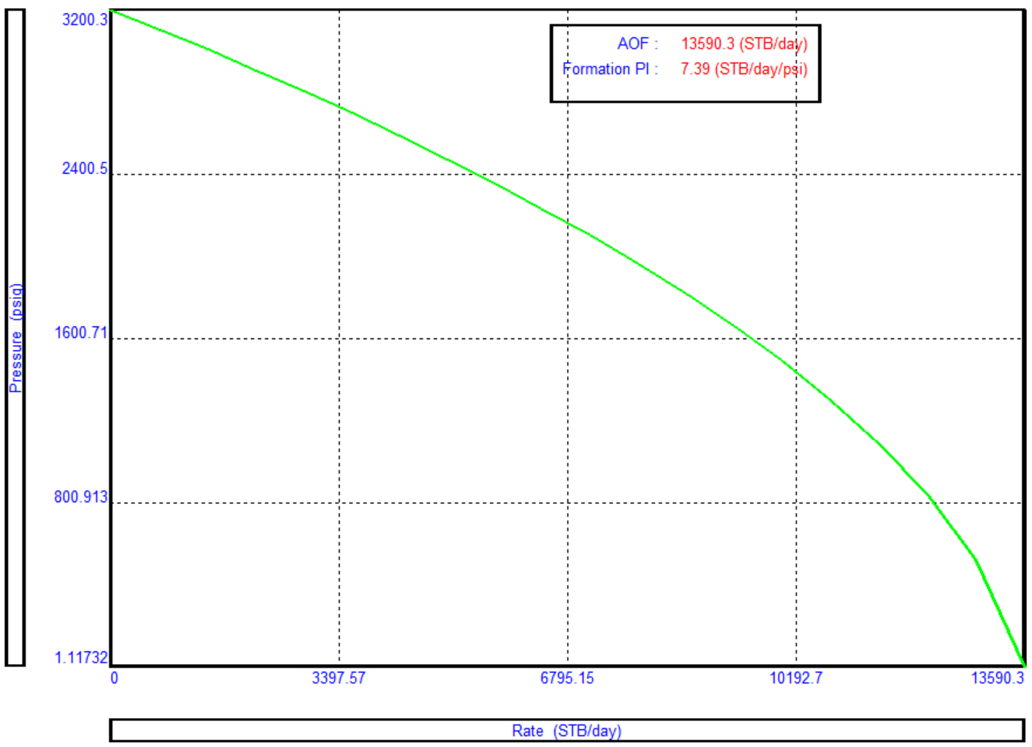


Figure 4-2 KHARIR1-25 IPR Curve.

<u>**Note That: -**</u>

- Absolute Open Flow (**AOF**) of KHARIR1-25 is equal (**13590.3 STB/day**).
- Productivity index (**PI**) of KHARIR1-25 is equal to (**7.39 STB/day/Psi**).

Fourth box of **PROSPER**^{TM} software is related to all TPR (VLP) input data, this coming **Table. 4-5** will clarify the data needed to be inserted in order to model the vertical lift performance of KHARIR1-25.

Table 4-5 TPR input data of KHARIR1-25.

Deviation Survey		**Surface Equipment**		
MD (ft)	**TVD (ft)**	**Equipment**	**MD (ft)**	**Inside Diameter (in)**
0	0	Surface Choke	0	1.75
3062.208	3062.208			
4867.52	4867.52	**Downhole Equipment**		
5195.52	5195.192			
5740.656	5740.328			
5830.2	5829.872	**Equipment**	**MD (ft)**	**Inside Diameter (in)**
5923.352	5922.696	XMASS Tree	0	Not Required
6019.456	6017.816	TRSCSSV	0	3.81
6116.216	6112.936	Baker	Not Required	3.75
6207.728	6202.152	Production Tubing	8499.99	3.96
6299.24	6291.368	Pup Joint	Not Required	2.99
6400.592	6389.112	Production Casing	8625.8	7
6497.68	6481.28			
6591.16	6568.856	**Thermal Gradient**		
6693.824	6664.304			
6788.616	6751.552			
6876.192	6830.928	**MD (ft)**		**Temperature (F)**
6971.968	6917.192	0		87.8
7055.608	6990.992	10112		218.8
7150.728	7074.632			
7821.488	7645.352			
7914.64	7722.104	**Overall Heat Transfer Coefficient BTU/h/ft²/F°**		
8016.32	7805.416			
8121.936	7891.352			
8855.016	8443.704		8	
8953.416	8509.96			
9033.12	8561.784	**Wellhead Pressure (Psig)**	920	
9128.24	8620.824			
9978.416	8935.376			
10066.976	8947.84			
10112.24	8954.4			

KHARIR1-25 Downhole Schematic is showing in **Fig.4-3**.

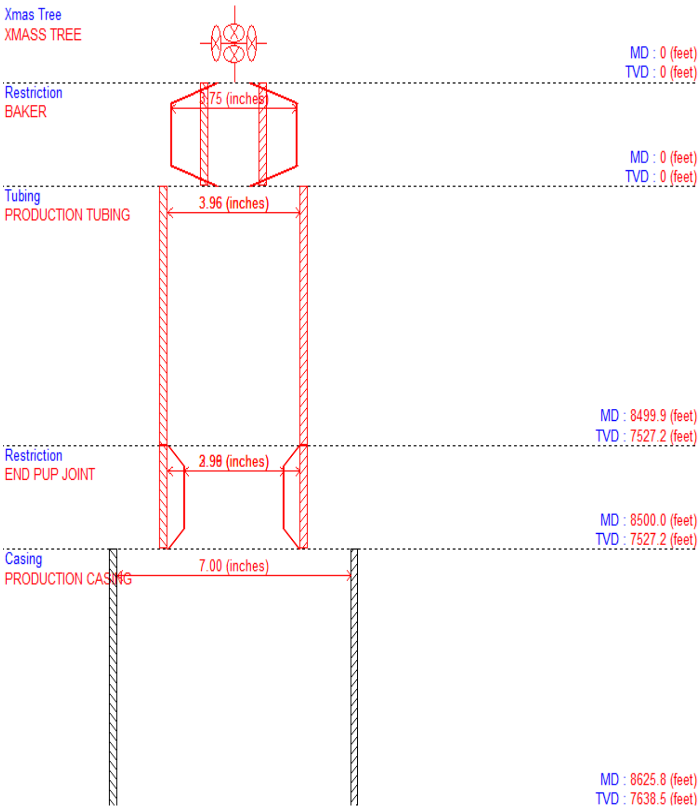


Figure 4-3 KHARIR1-25 Downhole Schematic.

TPR curve of KHARIR1-25is showing in following **Fig.4-4**.

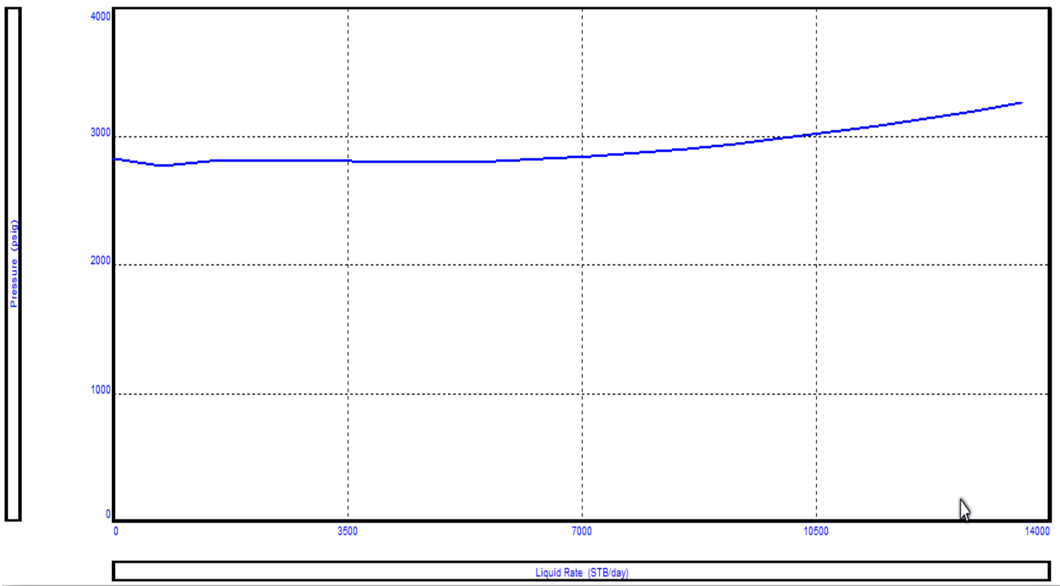


Figure 4-4 TPR curve of KHARIR1-25.

About the multi flow tubing correlations, closely KHARIR1-25 VLP met Duns & Ros Modified Correlation, as the following **Table. 4-6** shows

Table 4-6 Multi-Flow tubing correlations

Correlation	Parameter 1	Parameter 2	Standard Deviation
Duns and Ros Modified	0.96498	1	0
Hagedorn Brown	1.08301	1	0.00073242
Fancher Brown	1.08512	1	0.00048828
Mukerjee Brill	1.05914	1	0.00024414
Beggs and Brill	1.03517	1	0.00024414
Petroleum Experts	1.06739	1	0.00073242
Orkiszewski	1.18303	1	2.33447
Petroleum Experts 2	1.05979	1	0.00073242
Duns and Ros Original	1.02854	1	0.00024414
Petroleum Experts 3	1.07212	1	0.00024414
GRE (modified by PE)	1.0526	1	0.00073242
Petroleum Experts 4	1.06216	1	0
Hydro-3P	1.04844	1	0.00048828
Petroleum Experts 5	1.05601	1	0.00024414
OLGAS 2P	0.59715	0.59715	0.00097656
OLGAS 3P	0.59715	0.59715	0.00097656
OLGAS3P EXT	0.59715	0.59715	0.00097656

4.2. Nodal^{TM} Analysis System Result of KARIR#1-25.

4.2.1. Introduction

KHARIR1-25 is well producing naturally; we could proof that by plotting the IPR curve versus TPR curve. Actually, the two curves cross each other with operating point (**2784.1 STB/day**) flow rate at (**2814.4Psig**) bottom hole flowing pressure, as it is clear in the following **Fig. 4-5.**

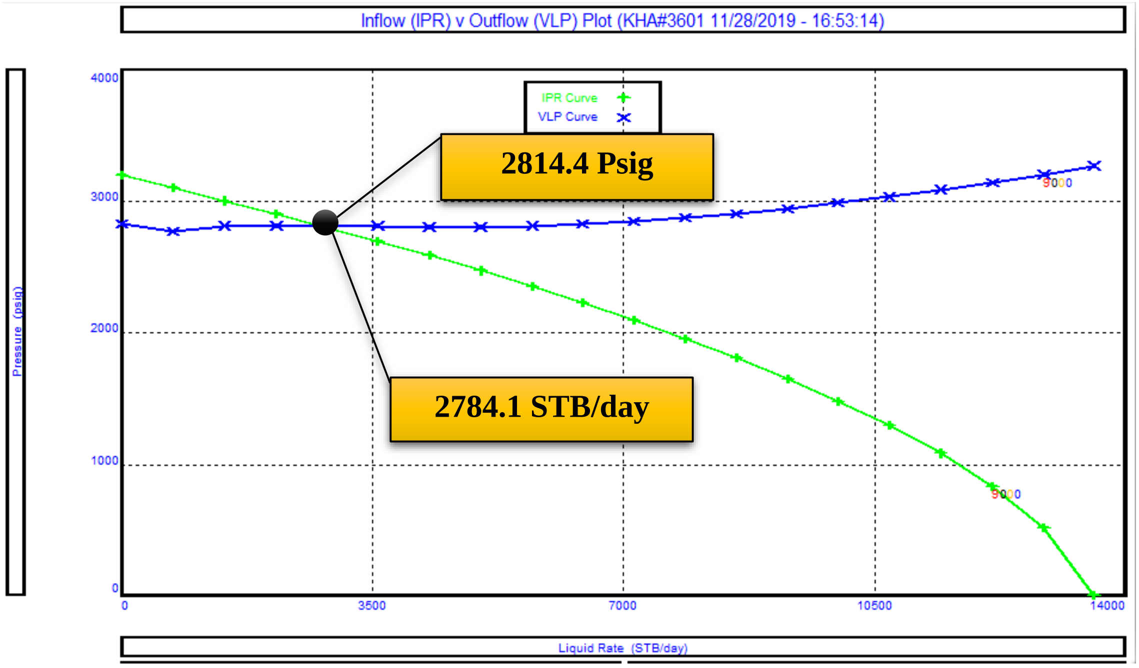


Figure 4-5 Operating Point of KHARIR1-25.

KHARIR1-25 production system configuration that gave the above node solution was (**3200.3 Psig**) reservoir pressure, (**7 in**) casing inner diameter, (**3.96 in**) tubing inner diameter, (**0.0006 in**) tubing roughness, (**3.040 MMscf/day**) and (**1.75 in** (**112/64**)) choke size.

If KHARIR1-25 continues producing within this production system configuration, liquid holdup will appear at (**17.78 MMscf/day**) of free gas rate. As liquid holdup keeps increasing the will load and almost die after (**8 months**) from the first production day with reservoir pressure (**2755.9 psig**) as it is shown in the **Fig. 4-6**).

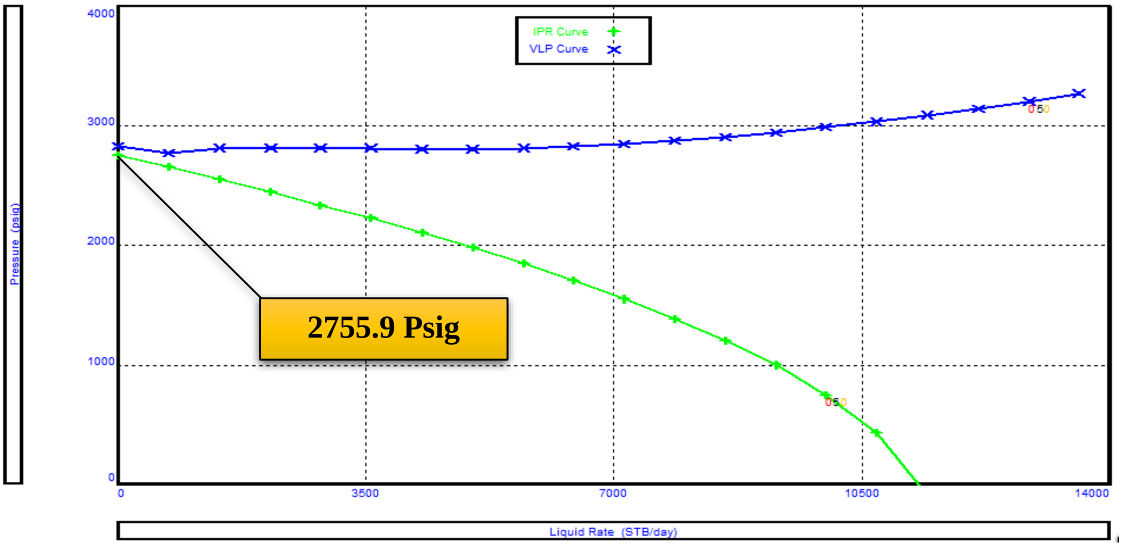


Figure 4-6 Dead point of KHARIR1-25

Based on what is shown in (**Fig. 4-6**), we did start changing on some variables so that to find out the fluid flow restrictions in KHARIR1-25, and tried to choose the best solutions to optimize KHARIR1-25 production system.

At here, some results of the modifications we did on KHARIR1-25 production system. Virtually, we focused on the main variables that strongly would effect on KHARIR1-25 production performance.

List of main variables: -

1. Production tubing size.
2. Tubing roughness.
3. Surface choke size.
4. GOR Value.
5. Reservoir pressure.

➢ **Effect of Tubing size: -**

Fig. 4-7and **Table. 4-7**show the tubing inside diameters used in the sensitivity study to optimize KHARIR1-25 performance, while other parameters were kept constant.

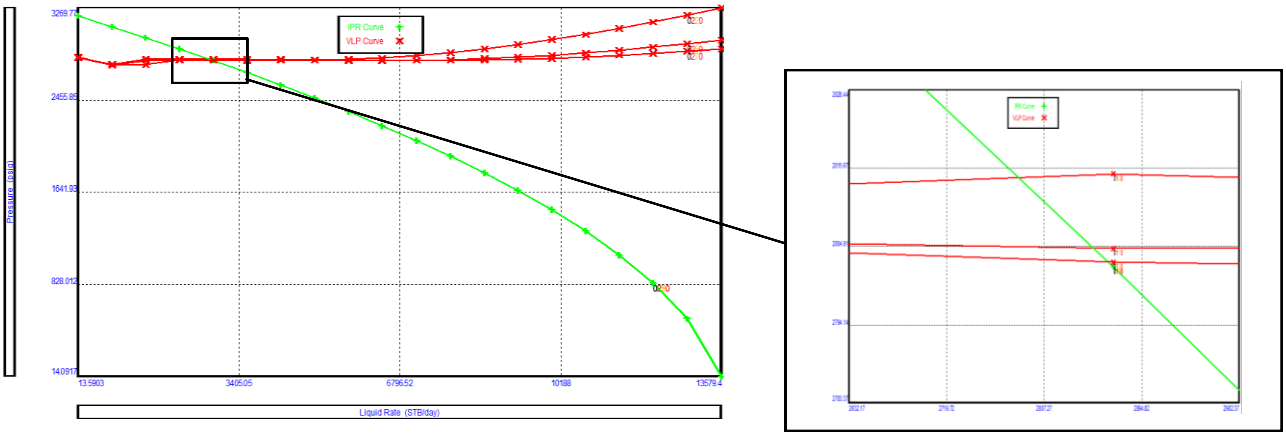


Figure 4-7 Effect of tubing size on KHARIR1-25 performance

Table 4-7 Effect of tubing size on KHARIR1-25 performance.

Tubing inside diameter (in)	Production rate (STB/day)	Extra production rate (%)
3.96	2784.1	0
4.6	2860.5	2.7
5	2867.5	2.9

Increasing tubing diameter for KHARIR1-25 at constant initial reservoir pressure, wellhead pressure will increase the production rate.

Note That: - (**5 in**) tubing size is out of Tubing Classification List (**Not Standard**).

- **Effect of Tubing Roughness: -**

Three different tubing roughness values were considered for the sensitivity study, the simulation results from **PROSPER**TM are shown briefly in the following **Fig. 4-8**and **Table. 4-8**:

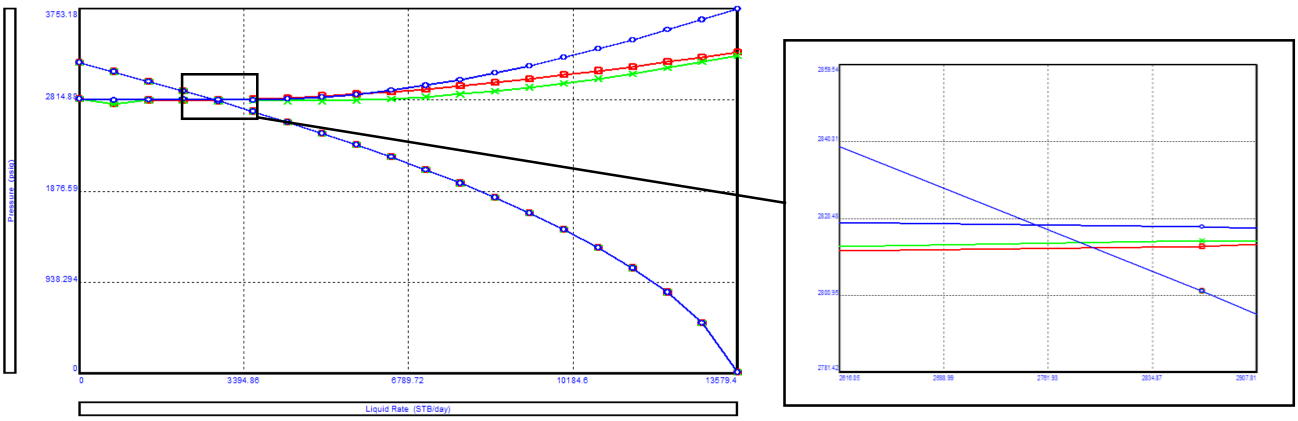


Figure 4-8 Effect of Tubing Roughness on KHARIR1-25 performance.

Table 4-8 Effect of Tubing Roughness on KHARIR1-25 performance

Tubing roughness (in)	Production rate (STB/day)	Extra flow rate (%)
0.00006	2793.5	0.3
0.0006	2784.1	0
0.00197	2753.3	-1.12

➢ **Effect of choke size: -**

A sensitivity analysis was done on choke internal diameter in order to analysis the effect of choke diameter on production rate. Generally, as the internal diameter of choke increases, the flow rate of KHARIR1-25 increased as it is shown in **Fig. 4-9**and **Table. 4-9**.

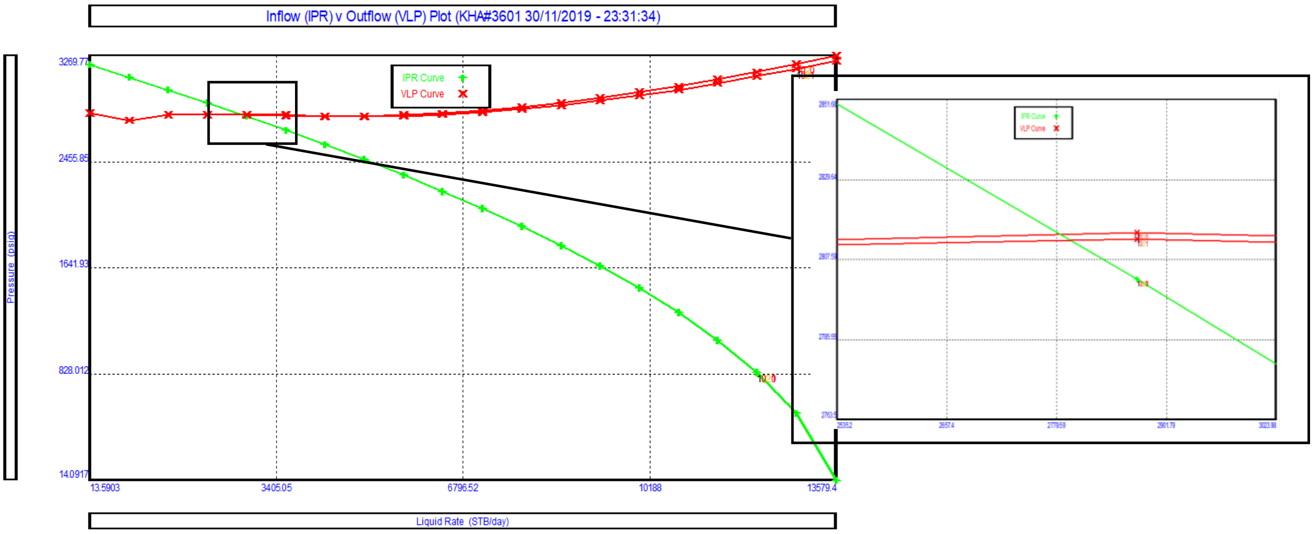


Figure 4-9 Effect of choke size diameter on KHARIR1-25 performance.

Table 4-9 Effect of choke size diameter on KHARIR1-25 performance.

Coke diameter (in)	Production Rate (STB/day)	Extra production rate (%)
1.75	2784.1	0
2	2794.9	0.38

- **Effect of optimum Tubing size and Choke size**

The optimum solution for KHARIR1-25 actually appear in case of using tubing diameter (5 in) in combination with choke size (2 in), the result of this case is showing in below **Fig. 4-10**and **Table. 4-10**.

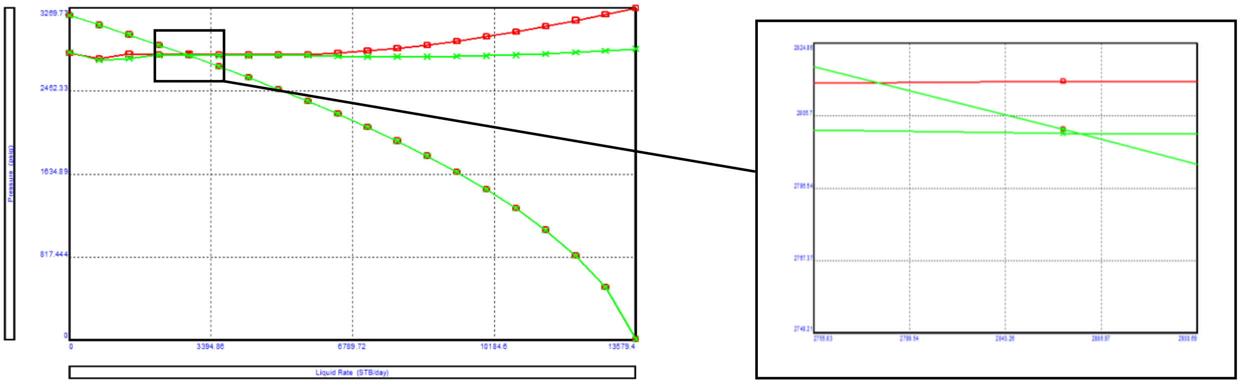


Figure 4-10 Effect of Optimum tubing size and Choke size on KHARIR1-25 Performance.

Table 4-10 Effect of Optimum tubing size and Choke size on KHARIR1-25 Performance.

Tubing inside diameter (in)	Choke diameter (in)	Production rate (STB/DAY)	Extra production rate (%)
3.96	**1.75**	2784.1	0
5	**2**	2980.15	6.6

Actually, this optimization developed KHARIR 1-25 performance with extra production rate (**196.05 STB/day**), as well as expand its production live to (**10 months**).

- **Effect of Gas-Oil Ratio: -**

This last variable subjected to sensitivity study so that the results show the increasing in flowrate of KHARIR1-25 as GOR value increase. Such as results gives an indicate forward using gas lift technique to increase longevity of KHARIR 1-25 productivity wherever at KHARIR 1-25 initial conditions or optimum conditions. As well as, in case of intervention of artificial lift at depilation of reservoir energy Gas lift method is also recommended, **Fig. 4-11**and **Table. 4-11** show the results of GOR changing study on initial condition.

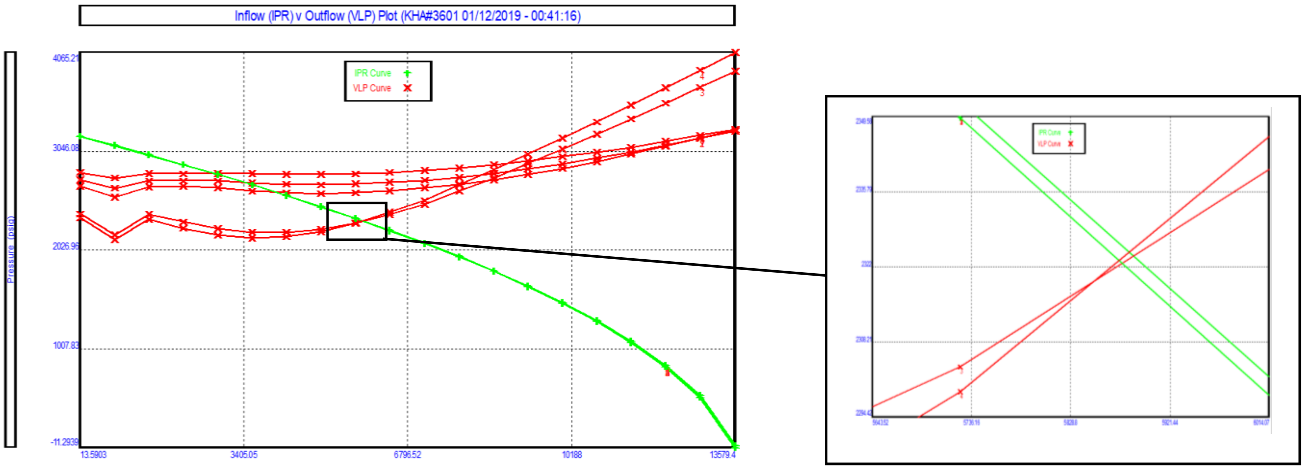


Figure 4-11 GOR Effect on KHARIR1-25 performance at Initial condition.

Table 4-11 GOR effect on KHARIR1-25 performance.

Line No.	GOR (SCF/STB)	Production Rate (STB/day)	Extra production rate (%)
0	1092	2784.1	0
1	1300	3402.9	18.18
2	1500	4062.4	31.5
3	3000	5877.2	52.63
4	3350	5874.2	52.6

Fig. 4-12 show the results of GOR changing study on optimum condition.

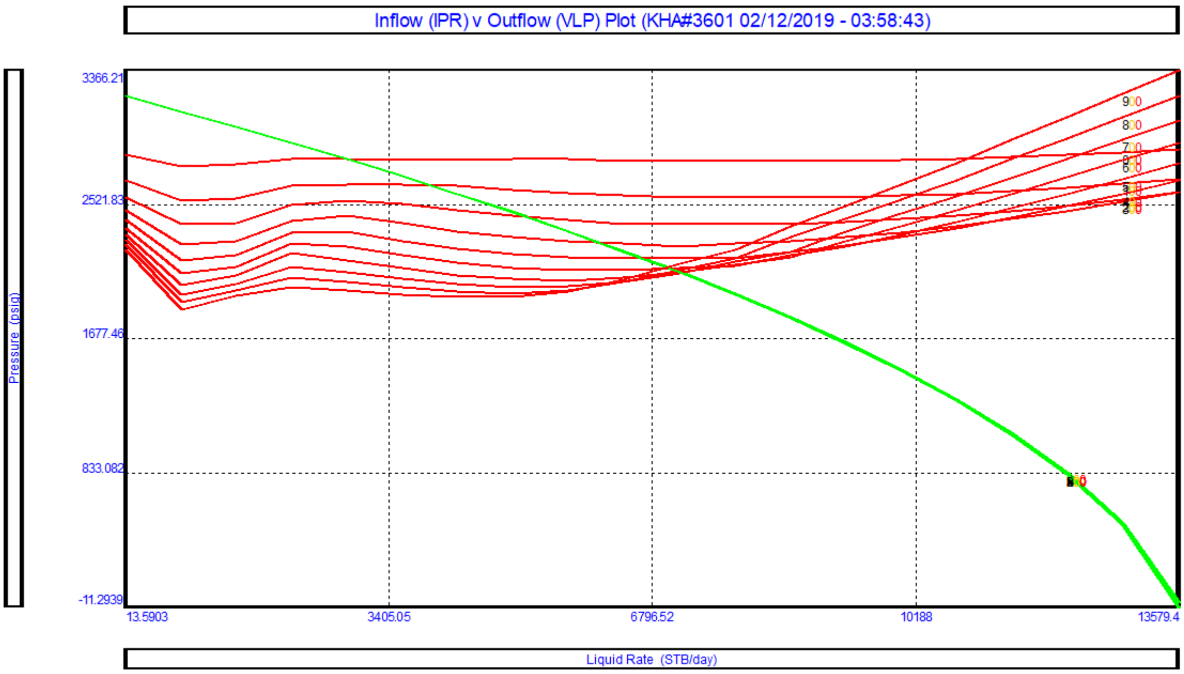


Figure 4-12 GOR Effect on KHARIR 1-25 Performance at Optimum condition

CHAPTER FIVE

5. CONCLUSION, RECOMMENDATIONS AND LIMITATION

5.1. Conclusion:

As it is known that KHARIR basement production system characterized by high pressure. **Nodal™ Analysis System** technique came out with results were satisfied and met the reliability of KHARIR production system nature. Subsequently, if KHARIR1-25 keep producing with the current completion design the well would be dead at reservoir pressure (**2755.9 Psig**) so to avoid this early problem we actually focused on the main variables that would optimize the performance of KHARIR1-25 and delay its death. Actually the modifications on the tubing size from (**3.96 in)** into (**5 in**) and choke size from (**1.75 in**) to (**2 in**) gives good results in increasing the production rate from (**2784.1 STB/day**) into (**2980.15 STB/day**) with (**6.6%**) of extra production rate as it is obvious in chapter four, the other variables (choke size, water cut, wellhead pressure, tubing roughness… etc.). actually all of them did not show the big difference in optimizing production system of KHARIR1-25 as the results of Gas Lift did, and that is due to the high restriction created by hydrostatic pressure loss in the column of the produced fluid in the well and the energy drive of gas expansion to push the fluid to the surface, the increasing of rate at GOR (**3000 SCF/STB**) was around (**58877.2 STB/day**) with extra production rate around (**53%**), and that will make Kharir1-25 keep producing for (**16 months and 24 days**). we took a care about the liquid holdup phenomena at the time of optimizing the tubing size and we found out that at optimum tubing size will make KHARIR1-25 to start holdup at GOR (**4555.56 SCF/STB**). Finally, we would like to say that Gas Lift technique will be the recommended optimization method for Kharir1-25 production system.

5.2. Recommendations

1. Designing Gas lift technique is required to increase the productivity and the longevity of KHARIR 1-25 productivity prior to well die.
2. Develop production tubing size from (**3.96 in**) into (**5 in**) and choke size from (**1.75 in**) to (**2 in**) in order to get extra flow rate around (**196.08 STB/day**), with take in consider the classification of production tubing to avoid any mechanical problem due to dynamic conditions of produced fluid.
3. Control wellhead pressure around (**921.93 Psig)**.

5.3. Limitations: -

1. Shortage in surface facilities data, which put a stop to consider the effect of back pressure on KHARIR1-25 performance.
2. Missing in some of reservoir data which was impediment to implement Darcy model.
3. Geothermal data was not full to perform accurate temperature model, so that we used overall heat transfer coefficient (**8 BTU/h/ft^2/F**) as Petex Company recommended.

5.4. Future works:

1. Restudy the integrated production system in case of availability for surface network and facilities data.
2. Design Gas Lift method to be suitable with Kharir1-25.
3. Preparing a drilling program that meets the optimum tubing size.
4. Make an economical study for the optimization of KHARIR1-25, based on the results of project and determining the net cash flow of the optimization.

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