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Waterflooding Effect on Oil production in Sharyoof Oil Field Block 53, Masila Basin

A PROJECT SUBMITTED IN PARTIAL FULFILLMENT
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IN OIL AND GAS ENGINEERING

BY

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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 **Waterflooding Effect on Oil production in Sharyoof Oil Field Block 53, Masila Basin**

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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ABSTRCT

Sharyoof oil field is located in masilah basin ,Yemen. It is characterize by a good reservoir rock . The exploration begun in 1999 while the production begun at 2001. More than 23 wells have been drilled in the field .This oil field is operated by Dove Company. Qishn clastics formation is the main reservoir rock in Sharyoof Oil field . Excessive water production is one of the major problems in masilah oil fields. The main purpose of this project is to diagnose the effect of waterflooding on productivity in Sharyoof oil field. The history performance of production, injection rates and bottom hole pressure on sharyoof-2 and sharyoof-9 is applied using petrel program to understand the mechanisms that had created the problem, considering two examples of a sharyoof oil well's data. The upper Qishn clastics divided into three zones named S1 ,S2 and S3 . The S1 zone is divided into three sub-zones :- namely S1A, S1B and S1C .The S1A is the main pay zone for sharyoof oil field. Three reservoir zones of good hydrocarbon potentiality are indicated and named from above to below as S1A, S1C and S2. So in this stage waterfiooding process is not suitable because the sweeping efficiency is getting low.

ACKNOWLEDGMENTS

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CHAPTER ONE

1. Introduction

1.1 General Information

Petroleum reservoir is accumulations of oil and gas in underground traps that are formed by structural and /or stratigraphic features. A reservoir is the portion of the trap that contains the oil and/or gas in a hydraulically connected system.

Many reservoirs are hydraulically connected to water-bearing rocks or aquifers that provide a source of natural energy to aid in hydrocarbon recovery, So the recovery of hydrocarbon without any external Source called a **primary recovery**. Oil and gas may be recovered by: fluid expansion, fluid displacement, gravity drainage, and or capillary expulsion. In the case of a reservoir with no aquifer (which is referred to as volumetric reservoir), hydrocarbon recovery occurs primary by fluid expansion, which, in case of oil, may be aided by gravity drainage. If there is water influx or encroachment from the aquifer, recovery occurs mainly by the fluid displacement mechanism which may be aided by gravity drainage or capillary expulsion. In many instances, recovery of hydrocarbon occurs by more than one mechanism.

When the natural reservoir energy has been depleted, it becomes necessary to augment the natural energy with an external source. This is usually accomplished by the injection of fluids, either a natural gas or water, the use of this injection scheme is called a **secondary recovery** operation. Hence, the term water flooding is sometimes used to describe a secondary recovery process. Waterflooding sometimes used for the purpose of disposing of the produced water or for maintaining the stability of reservoir pressure or for improving oil displacement efficiency, So the most amount of original oil in place around the world produced as average recovery (32%) by secondary recovery. **Tertiary Recovery** (EOR) is the recovery of hydrocarbon by adding thermal or chemical materials to water for improve water injection properties which that optimize water flooding efficiency

1.2 Geology of Yemen

Geological surveying and petroleum exploration in Yemen date back to the early decades of the 20th century from the 1930s–60s, the Iraq Petroleum Company conducted exploration in the

Hadramout and Mahrah areas in north-east Yemen, during which period Ziad Rafiq Beydoun (1924–1998) pioneered geological studies of the country.

Between 1962 and 1967, Pan American Oil continued exploration in Hadramout (in South Yemen) and drilled a number of wells, with the non-commercial discovery of several barrels of oil from the fractured carbonates of the Cretaceous Qishn Formation in Tarfayt-1.

During the 1970s and 80s both North and South Yemen began offering concession blocks to a number of foreign oil companies. The first commercial discovery came in 1984 when the American company Hunt Oil drilled Alif-1 in the Marib sector of the onshore Sab'atayn Basin in North Yemen, penetrating a total depth at 4,182m and hitting oil (40.4º API) in the Alif Member of the Sab'atayn Formation (Middle–Upper Tithonian age) with an initial flow of 7,800 bopd.

In 1986, the Russian company Techno-Export, which was operating in South Yemen, drilled West Ayad-1 in the Shabwa sector of the Sab'atayn Basin, encountering 35º API oil in the Jurassic. Petroleum exploration by Canadian company Nexen in the Say'un-Masilah Basin, led to an oil discovery in 1991: Sunah-1 drilled to the total depth at 2,917m and discovered oil (36º API) in sandstones of the Lower Cretaceous Qishn Formation. Twelve onshore and offshore sedimentary basins have been identified in Yemen, categorised into three groups as shown in Figure 1.1. based on the geological era in which they originated: (1) Rub' Al-Khali; (2) San'a; (3) Suqatra; (4) Siham-Ad-Dali'; (5) Sab'atayn; (6) Say'un-Masilah; (7) Balhaf; (8) Jiza'-Qamar; (9) Mukalla-Sayhut; (10) Hawrah-Ahwar; (11) Aden-Abyan; (12) Tihamah. Of these, only two onshore sedimentary basins, Sab'atayn and Say'un-Masilah, where oil was discovered in 1984 and 1991 respectively, are currently the only petroleum-producing basins in Yemen, while the other basins, including the onshore Paleozoic and offshore Cenozoic basins, remain little-explored.(Al-Areeq, N.M.,2013)

1.2.1 The Say'un-Masilah basin

The Say'un-Masilah basin is a major hydrocarbon productive sedimentary basin in the Republic of Yemen, this basin was formed as rift during the Late Jurassic (Kimmridgian) due to the Goundwana breakup, when the African-Arabian plate was separated from the Indian Madgascar plate (Beydoun, Z.R 1998).

The Say'un-Masilah rift basin is a symmetrical graben made up of mid Jurassic to Palaeocene sediments which overlie Pre-Cambrian igneous and metamorphic rocks. The structural trends of the basin are defined by NW-SE and ENE-WSW orientated faults. Producible quantities of oil are found in a number of different reservoirs including Pre-Cambrian / Archean granitic basement, Lower Cretaceous Saar Formation carbonates and dolomites, and Middle Cretaceous Qishn clastic Formation deposits. Fig 1.1. Showing the Location map of the general geology of Yemen (A), the study area and oil fields (B), (Beydoun Z.R, 1998).

1.2.2 Block -53 Overview

Located in the N/W sector from the of Masilah- Say'un basin, with area of 474 Km2. Block (53) is operated by DOVE Energy- British Company. The main reservoirs in the block are (Qishn Clastic), (Saar Sand, Saar Carbonate), and expected to be produce from the fracture basement rocks in the future. The partners in the Production Sharing Agreement with the Yemen government are:

- DNO (24.45%)

- Dove Energy (24.45%)

- MOE (16.10%)

- PETOIL (10%)

- YCO (25%).

1.2.2.1 Sharyoof field

Sharyoof field is among the most interesting hydrocarbon-bearing fields that are located in Masila basin and produces oil from the Lower Cretaceous clastic deposits (Qishn Formation). The area is nearly flat with no topographic features and is located about 950 m above sea level.

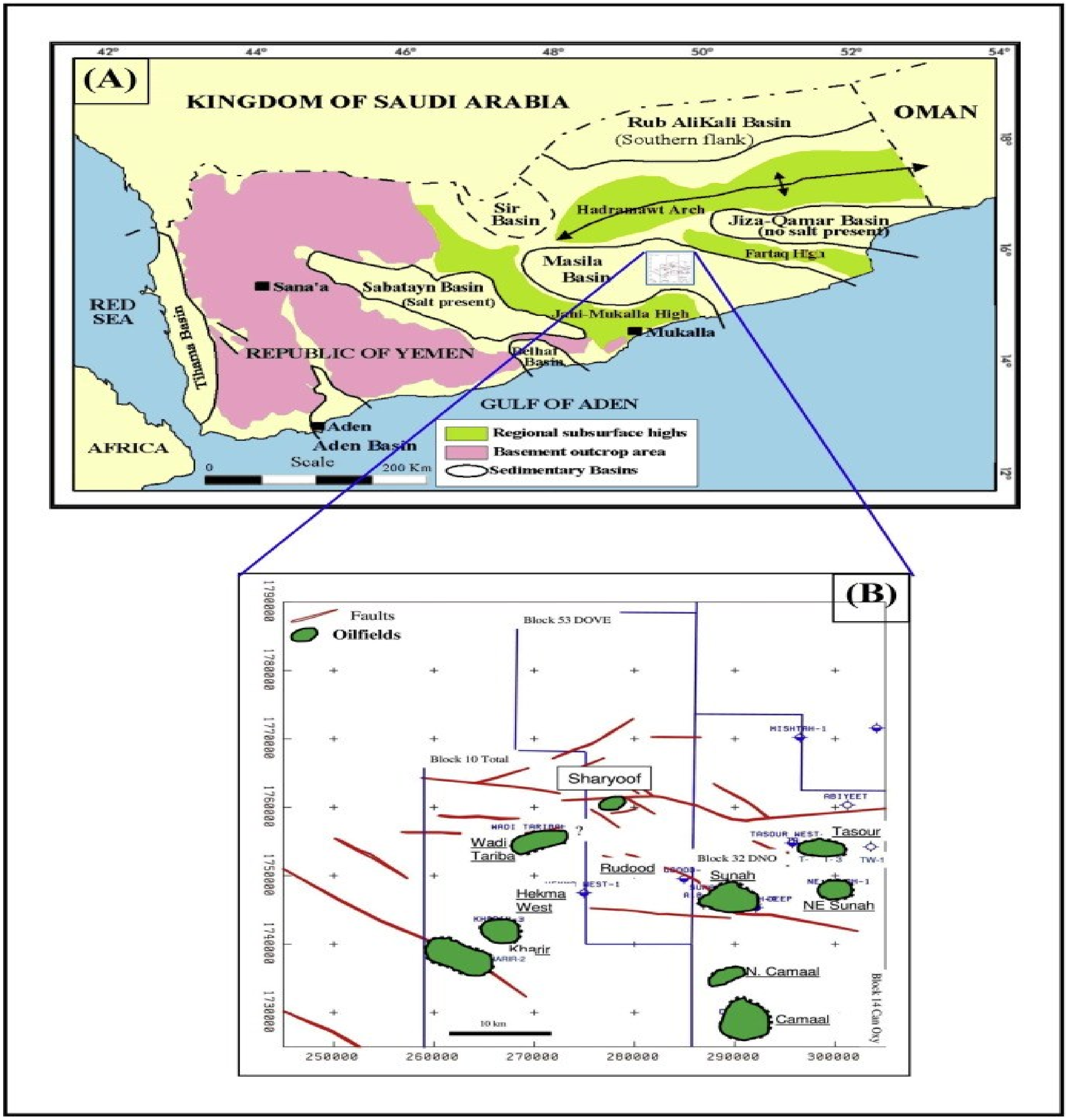


Figure 1.1 Location map showing the general geology of Yemen (A), the study area and oil fields (B), (Beydoun Z.R, 1998)

1.2.3 Sharyoof field petroleum system

Source and Migration

The likely source for prospect 2 is the Kimmeridge Madbi Shales. It is expected that it is present in the deeper parts of the Sayun Masilah Basin. It is also possibly present and mature in the basinal areas just to the south of the prospect and possibly to the north east of the prospect. It is likely that the onset of maturation was in the Early Cretaceous, with generation through until the present day. The Madbi Shale has been penetrated in the Kharir-3 and Sunah-4 wells. In the Kharir-3 well a 50 meters' shale section was penetrated with an average total organic content of approximately 5%. It showed good oil to source correlation with oil reservoir in the Qishn Clastics Formation. PEPA. EAST SAAR - Blocks (53).

Additional source potential also exists in the Naifa and Saar Formations. However the shallower burial of the Saar Formation means it is unlikely to have reached maturity in this area all penetrated in excess of 110 meters of micritic limestone with shaley inter beds, including the Red Shale. The throws on the faults associated with the Sharyoof structure do not exceed the likely Qishn Formation Carbonate thickness, and thus trap integrity is likely to be maintained. In the Tasour-1 well the Sl sand was underlain by limestone which could act as a base seal to the S 1 as well as top seal to S2 reservoir. Saar Formation Dolomites and/or Clastics are likely to be overlain by Saar Formation limestone, which in Tasour-1 provided a top seal.

Reservoir Rock

The primary appraisal objective for this well is the Lower Cretaceous Upper Qishn Clastics Formation that are regionally widespread and have been encountered in all nearby wells. In block 53 area the Upper Qishn Formation Clastics have been subdivided into 3 units: The S 1 (top), S2 (middle) and S3 (base). The SI is divided into three sub units SIC, SIB and SIA (Lashin, A., Marta, E.B., Khamis, M., 2016).

The upper SIA unit comprises good quality reservoir sand (Sharyoof-l average porosity 18.4%, NTG 85%), and are between 8 to 15 metres thick in Block 53. The underlying SIB comprises of non-reservoir, possibly sealing carbonates and mudstones.The basal S1C comprises of poor quality reservoir sands and shales.The SI sands provide the main reservoir in the region, including Tasour, Kharir, Sunah and Camaal fields. It also tested oil in the Sharyoof-l discovery well, producing at a rate of 4900 BOPD during an ESP cased hole production test. The best quality SlA sands are understood to have been deposited in a marine near shore environment (eg. sub-tidal shoals): sand passes eastwards into poor quality muddy offshore deposits and westwards into variable quality estuarine and fluvial depsoits. Evidence from the presence of poorer quality SIA sands in Rudood-l (14% average porosity) suggests there was a lateral facies shift to lagoonal and/or estuarine conditions. The S2 and S3 sands form a estuarine and fluvial sand package, with diffuse boundary between the two. The combined thickness varies between 40 and 80 meters in Block 53 and is expected to be 80 meters in the Sharyoof area. Net to gross ranges between 60 to 80% and porosity between 18 and 20% in the Sharyoof area. Saar Formation Dolomites and Clastics Saar Formation dolomites are several hundred meters thick in Tasour-l, thinning onto adjacent fault highs and also thinning to the west (56 metres in Rudood-l, 30 meters in Kharir-3). NTG is likely to be near 100% in the Tasour area, but porosity is expected to be around 10%. The Saar Formation was not included as a possible reservoir in Sharyoof-2. The well program intended 50 m to be drilled to leave sufficient rathole for logging the primary Qishn Clastics sands. (Omran, A.A., Alareeq, N.M., 2014.)

Seal Potential

The Cap Rock Seal for the Upper Qishn Formation Clastics is the overlying Qishn Formation Carbonate (Red Shale).

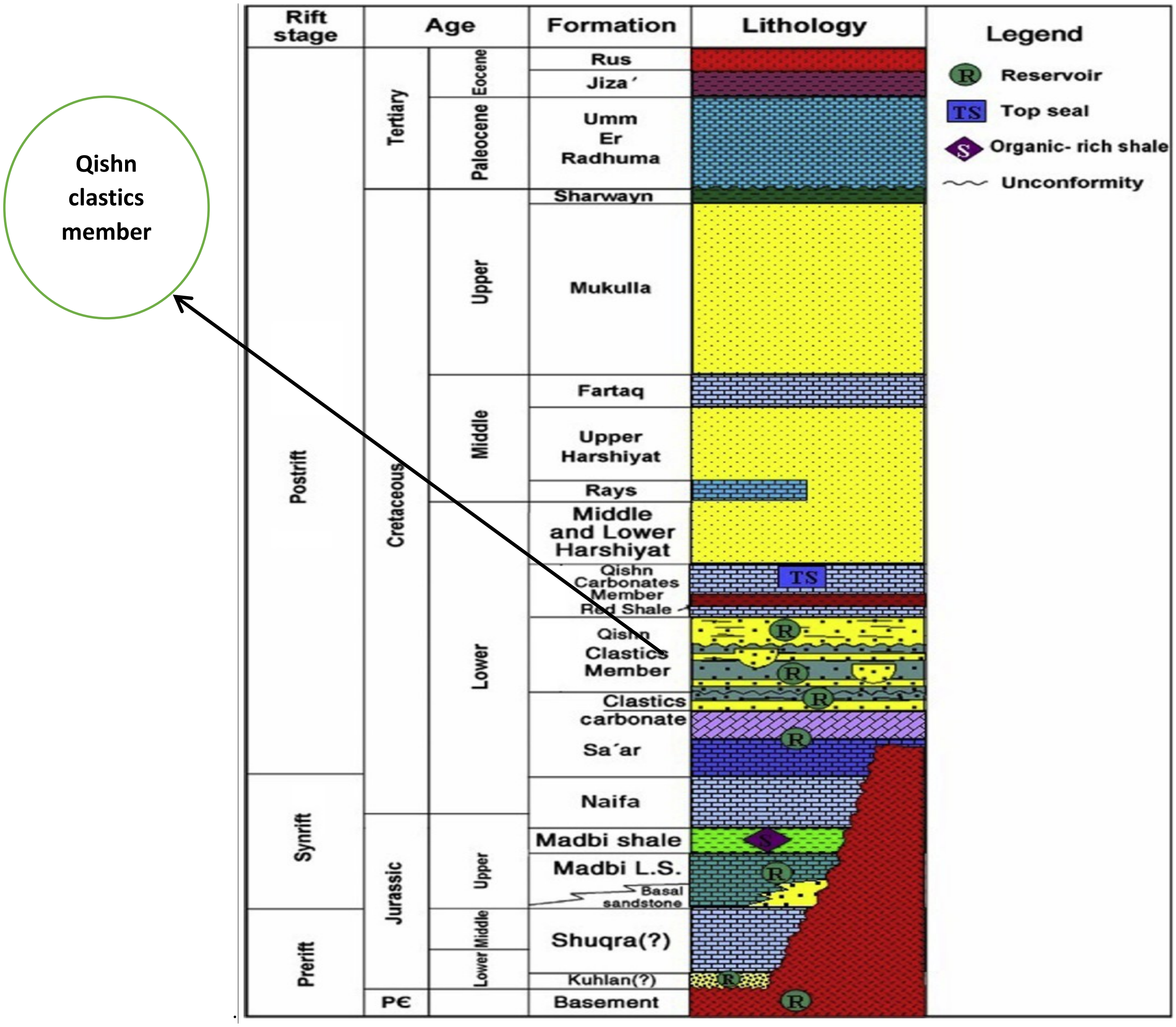


Figure 1.2 Lithostratigraphy of the Sayun-Masila basin (, Canadian Oxy Comp., 2002)

1.3 Objectives

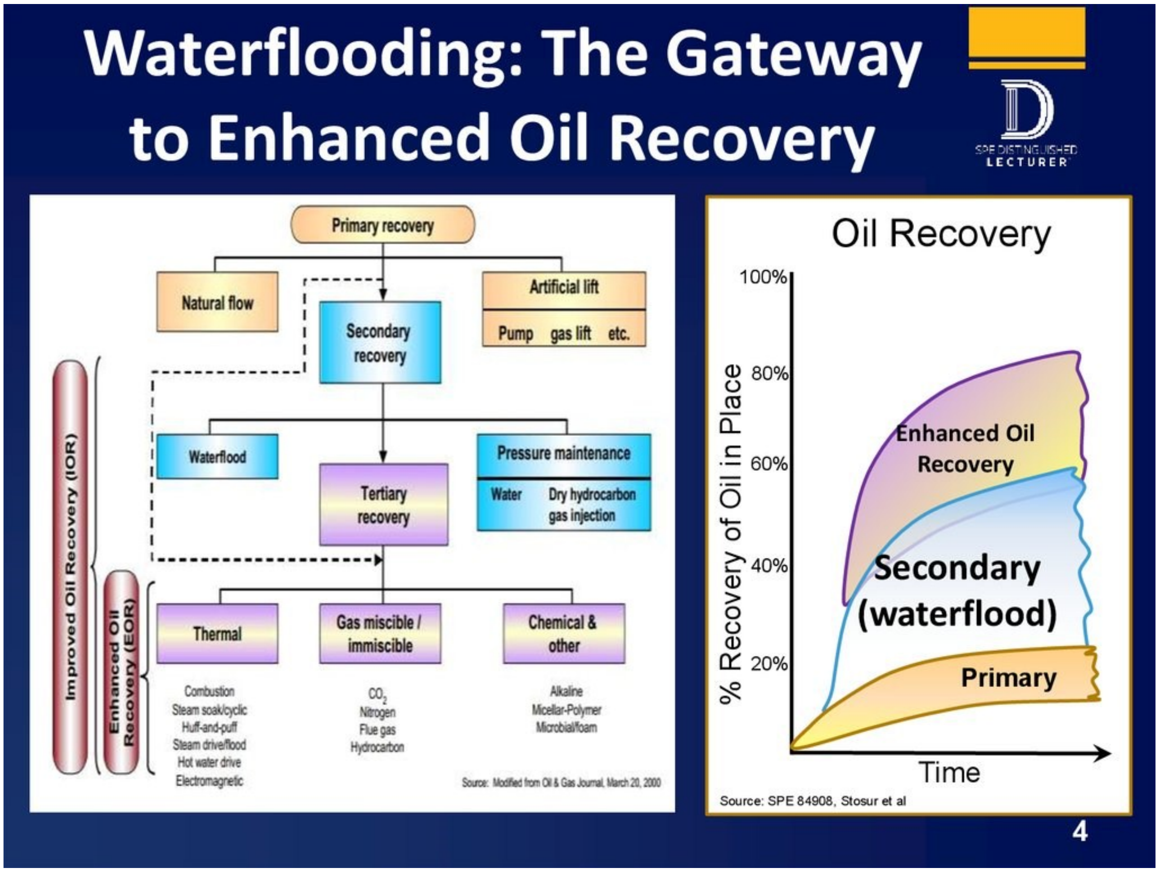
1. Studying the geological and geophysical Data and its interpretation, analyze reservoir characterization and drive mechanism of the field.
2. Review Wells production history and conduct performance analysis..
3. Using Combination of production/injection history with analytical approach, to diagnosis the effect of water flooding to productivity of sharyoof-2 and sharyoof-9
4. Find the optimum solution to improve oil productivity.

1.4 Problem statement

Understand the effect of waterflooding to productivity (production of oil and water)with pressure changes and fluid properties ,reservoir characteristic of sharyoof field are important for selection the optimum waterflooding strategies and give some solutions to improve oil production rate in this method. So the knowledge of the geological of the upper Qishn clastics sharyoof field using petrel and production , injection life using petrel to analysis . therefore this graduation project will suggest the solution to optimize the waterflooding efficiency to displace the oil to be producing with minimize water production rate .

CHAPTER TWO

2. Theoretical background and literature Review



2.1 Primary Recovery

The recovery of oil by any of the natural drive mechanisms is called primary recovery. The term refers to the production of hydrocarbons from a reservoir without the use of any process (such as fluid injection) to supplement the natural energy of the reservoir. Muskat (1907) defines primary recovery as the production period "beginning with the initial field discovery and continuing until the original energy sources for oil expulsion are no longer alone able to sustain profitable producing rates.

The approximate oil recovery range is tabulated below for various driving mechanisms. Note that these estimates are only approximations and, therefore, oil recovery may fall outside these ranges.

There are basically six driving mechanisms that provide the natural energy necessary for oil

recovery

- Rock and liquid expansion drive
- Depletion drive Gas cap drive
- Water drive
- Gravity drainage drive
- Combination drive

Driving Mechanism	Oil Recovery Range, %
Rock and liquid expansion	3–7
Solution Gas-cap drive	20–35
Gas-cap drive	20–45
Water drive	35–75
Gravity drainage	<80
Combination drive	30–60

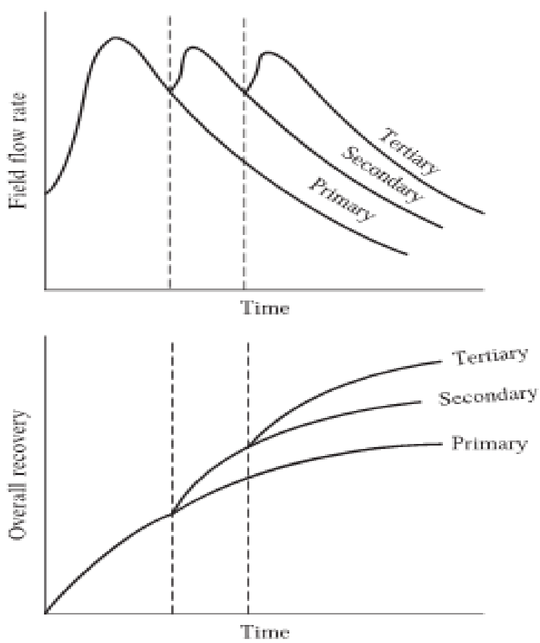


Figure 2.1 Oil recovery categories.

2.1.1 Rock and Liquid Expansion

When an oil reservoir initially exists at a pressure higher than its bubble point pressure, the reservoir is called an under saturated oil reservoir. At pressures above the bubble-point pressure, crude oil, connate water, and rock are the only materials present. As the reservoir pressure declines, the rock and fluids expand due to their individual compressibilities. The reservoir rock compressibility is the result of two factors: Expansion of the individual rock grains and formation compaction. Both of the above two factors are the results of a decrease of fluid pressure within the pore spaces, and both tend to reduce the pore volume through the reduction of the porosity.

As the expansion of the fluids and reduction in the pore volume occur with decreasing reservoir pressure, the crude oil and water will be forced out of the pore space to the wellbore. Because liquids and rocks are only slightly compressible, the reservoir will experience a rapid pressure decline. The oil reservoir under this driving mechanism is characterized by a constant gas-oil ratio that is equal to the gas solubility at the bubble point pressure. This driving mechanism is considered the least efficient driving force and usually results in the recovery of only a small percentage of the total oil in place.

2.1.2 The Depletion Drive Mechanism

This driving form may also be referred to by the following various terms: Solution gas drive, dissolved gas drive or internal gas drive. In this type of reservoir, the principal source of energy is a result of gas liberation from the crude oil and the subsequent expansion of the solution gas as the reservoir pressure is reduced. As pressure falls below the bubble-point pressure, gas bubbles are liberated within the microscopic pore spaces. These bubbles expand and force the crude oil out of the pore space as shown conceptually in Figure (2.2).

2.1.3 Gas Cap Drive

Gas-cap-drive reservoirs can be identified by the presence of a gas cap with little or no water drive as shown in Figure (2.3).

Due to the ability of the gas cap to expand, these reservoirs are characterized by a slow decline in the reservoir pressure. The natural energy available to produce the crude oil comes from the following two sources:

I. Expansion of the gas-cap gas
II. Expansion of the solution gas as it is liberated

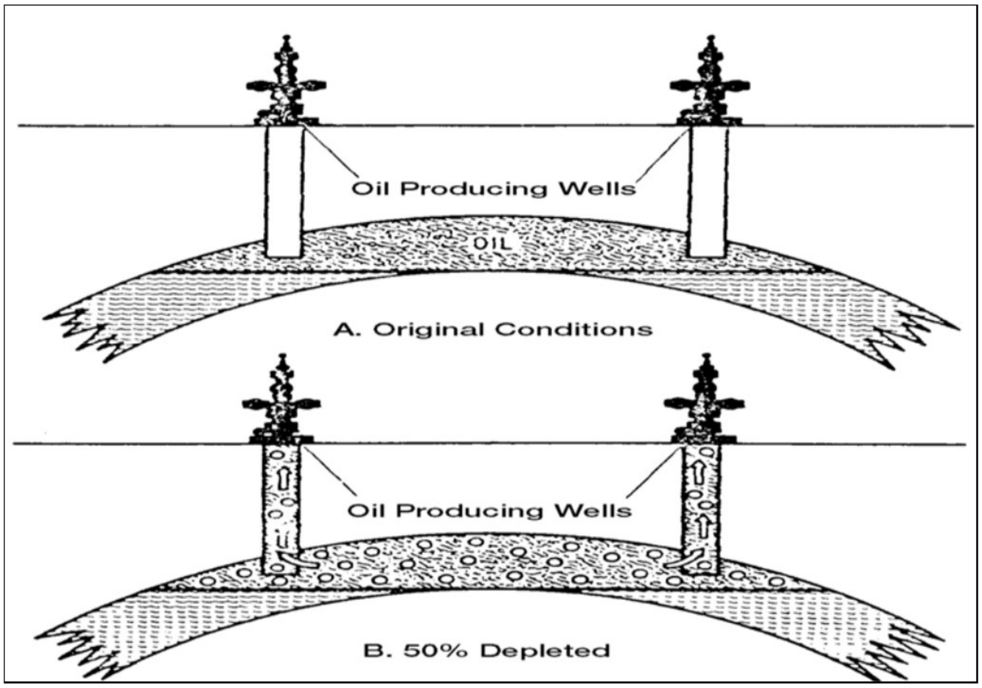


Figure 2.2 Solution (Depletion) Gas Drive Reservoir. (After Clark, N. J., 1969).

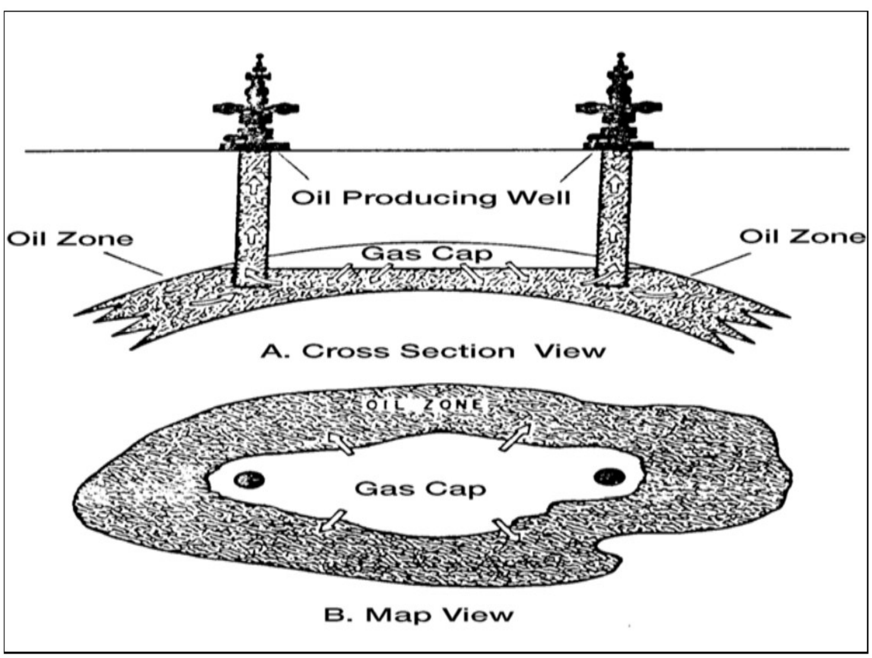


Figure 2.3 Gas-Cap-Drive Reservoir. (After Clark, N. J., 1969).

2.1.4 The Water-Drive Mechanism

Many reservoirs are bounded on a portion or all of their peripheries by water bearing rocks called aquifers. The aquifers may be so large compared to the reservoir they adjoin as to appear infinite for all practical purposes, and they may range down to those so small as to be negligible in their effects on the reservoir performance. The aquifer itself may be entirely bounded by impermeable rock so that the reservoir and aquifer together form a closed (volumetric) unit. On the other hand, the reservoir may be outcropped at one or more places where it may be replenished by surface water. Water drives are also classified as edge water or bottom water drives, depending on the nature and location of the water encroachment into the reservoir. Bottom water occurs directly beneath the oil and edge water occurs off the flanks of the structure at the edge of the oil.

Gravitational forces can be a major factor in oil recovery if the reservoir has sufficient vertical relief and vertical permeability. The effectiveness of gravitational forces will be limited by the rate at which fluids are withdrawn from the reservoir. If the rate of withdrawal is appreciably greater than the rate of fluid segregation, then the effects of gravitational forces will be minimized in order to take maximum advantage of the gravity-drainage-producing mechanism, wells should be located as structurally low as possible. This will result in maximum conservation of the reservoir gas. Factors that affect ultimate recovery from gravity-drainage reservoirs are:

I. Permeability in the direction of dip

II. Dip of the reservoir

III. Reservoir producing rate

IV. Oil viscosity

V. Relative permeability characteristics

The natural water drive could be supplemented by water injection in order to:

- Support a higher withdrawal rate.
- Achieve more uniform areal sweep and coverage by better distributing the injected water. volume to different areas of the field
- Better balance Voidage and influx volumes.

Gravitational forces can be a major factor in oil recovery if the reservoir has sufficient vertical relief and vertical permeability. The effectiveness of gravitational forces will be limited by the rate at which fluids are withdrawn from the reservoir. If the rate of withdrawal is appreciably greater than the rate of fluid segregation, then the effects of gravitational forces will be minimized in order to take maximum advantage of the gravity-drainage-producing mechanism, wells should be located as structurally low as possible. This will result in maximum conservation of the reservoir gas. Factors that affect ultimate recovery from gravity-drainage reservoirs are:

I. Permeability in the direction of dip
II. Dip of the reservoir
III. Reservoir producing rates.
IV. Oil viscosity
V. Relative permeability characteristics

2.1.5 The Combination-Drive Mechanism

The driving mechanism most commonly encountered is one in which both water and free gas are available in some degree to displace the oil toward the producing wells.
Two combinations of driving forces can be present in combination drive reservoirs.
These are (1) depletion drive and a weak water drive and; (2) depletion drive with a small gas cap and a weak water drive. Then, of course, gravity segregation can play an important role in any of the aforementioned drives. Combination-drive reservoirs can be recognized by the occurrence of a combination of some of the following factors:

1. Relatively rapid pressure decline, Water encroachment and/or external gas-cap expansion are insufficient to maintain reservoir pressures.
2. Water encroaching slowly into the lower part of the reservoir. Structurally low producing wells will exhibit slowly increasing water producing rates.
3. If a small gas cap is present the structurally high wells will exhibit continually increasing gas-oil ratios, provided the gas cap is expanding. It is possible that the gas cap will shrink due to production of excess free gas, in which case the structurally high wells will exhibit a decreasing gas-oil ratio. This condition should be avoided whenever possible, as large

volumes of oil can be lost as a result of a shrinking gas cap.

4. A substantial percentage of the total oil recovery may be due to the depletion-drive mechanism. The gas-oil ratio of structurally low wells will also continue to increase due to evolution of solution gas throughout the reservoir, as pressure is reduced.
5. Ultimate recovery from combination-drive reservoirs is usually greater than recovery from depletion-drive reservoirs but less than recovery from water-drive or gas-cap-drive reservoirs. Actual recovery will depend upon the degree to which it is possible to reduce the magnitude of recovery by depletion drive. In most combination-drive reservoirs, it will be economically feasible to institute some type of pressure maintenance operation, either gas injection, water injection, or both gas and water injection, depending upon the availability of the fluids.

2.2 Secondary Recovery

Lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water. This technique known as Pressure Maintenance or Reservoir Stimulation, Water flooding, called secondary recovery because the process yields a second batch of oil after a field is depleted by primary production(G.Paul Willhite, 1986)

The practice of water flooding apparently began accidentally as early as 1890, when operators realized that water entering the productive formation was stimulating production. The practice of water flooding expanded rapidly after 1921. The earlier slow growth of water flooding was due to several factors. The oil demand was less and impact of water flooding on oil production was immense However, after 1921 demand of oil picked up and interest for water flooding grew many folds' Separate wells are used for this injection water flooding is now the principal SOR method and it expected to produce between 20% to 40% of the OOIP, Gas injection developed about the same time as the Water flooding and was a competing process in some reservoirs **Cole (1969)** lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

Reservoir oil viscosity. Water injection should be initiated when the reservoir pressure reaches its bubble-point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turns improves the sweeping efficiency. (Emil J.Burcik, 1979)

Free gas saturation. The impact of the free must be considered when plaining field development by water of gas injection:

- In **water injection projects**. It is desirable to have an initial gas saturation, possibly as much as 10%. This suggests that there might be benefits of initiating the waterflood process at a pressure that is below the bubble point pressure (discussed in detailed later in this chapter)
- In **gas injection projects**. Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure exists at or above bubble-point pressure.

2.2.1 WaterFlooding

Water flooding is the most commonly used secondary oil recovery method for both conventional and heavy oil reservoirs because of its relative simplicity, availability of water, and cost-effectiveness. In the case of heavy oil, water is combined with “thermal energy injection” either as hot water or steam, but this is usually treated as a tertiary oil recovery method. Like primary recovery, the efficiency of water flooding is determined by intrinsic factors, such as hydrocarbon properties, microscopic oil displacement efficiency, rock/fluid properties, and reservoir heterogeneities. Water flooding, called secondary recovery because the process yields a second batch of oil after a field is depleted by primary production.

2.2.1.1 History of a WaterFlooding

In the early days of the oil industry, saline water or brine frequently was produced from a well along with oil, and as the oil-production rate declined, the water-production rate often would increase. This water typically was disposed of by dumping it into nearby streams or rivers. In the 1920s, the practice began of reinjecting the produced water into porous and permeable subsurface formations, including the reservoir interval from which the oil and water originally had come. By the 1930s, reinjection of produced water had become a common oilfield practice.

Reinjection of water was first done systematically in the Bradford oil field of Pennsylvania, US. There, the initial "circle-flood" approach was replaced by a "line flood," in which two rows of producing wells were staggered on both sides of an equally spaced row of water-injection wells. In the 1920s, besides the line flood, a "five-spot" well layout was used (so named because its pattern is like that of the five spots on a die). Much of waterflooding's technology and common practice developed in the U.S. between 1940 and 1970. By the mid-1940s, the onshore US oil industry was maturing and primary production from many of its reservoirs had declined significantly, whereas most reservoirs elsewhere in the world were in the early stages of primary production. Also, in the U.S., thousands of wells had been drilled that were closely spaced, so that the effects of water injection were more obvious and so were more quickly understandable. In addition to the need to dispose of saline water that was produced along with the oil, several other factors made waterflooding a logical and economical method for increasing recovery from oil fields. Very early on, it was recognized that in most reservoirs, only aWater injection process may be designed to dispose of brine water, conduct a pressure maintenance project to maintain the reservoir pressure when expansion of an aquifer or gas cap is insufficient to maintain pressure or implement a water drive or water flood of oil after primary recovery (Williamc. Lyons, 1996). small percentage of the original oil in place (OOIP) was being recovered during the primary-production period because of depletion of the reservoirs' natural energy. Additional recovery methods were needed to produce the large quantity of oil that remained. Water injection's early success in lengthening the oil-production period by years made waterflooding the natural step after primary production to recover additional oil from reservoirs whose oil-production rate had declined to very low levels.

2.2.1.2 Important of WaterFlooding

Once the primary energy of the reservoir tends to deplete it becomes necessary to maintain the pressure inside the reservoir to achieve optimum production and maximize ultimate recovery. In such condition the pressure maintenance can be done by injecting water into the reservoir which is compatible to the formation water present in the reservoir through several water injection wells. In this process, the primary objective is to fill the voidage created by the produced oil fractions thus avoiding the reservoir pressure to decrease with the increased production, displacing fluid is injected in the oil zone through the surrounding water injection wells creating an edge water drive flooding oil towards the production well. For better efficiency, the pressure of the reservoir should be such that no secondary gas cap is formed .(Larry W. Lake, 2007)

2.2.1.3 Disadvantages of Water Injection

I. Reaction of injected water with the formation water can cause formation damage.
II. Corrosion of surface and sub-surface equipment.

2.2.1.4 Water Flooding Candidate Reservoir Conditions

Thomas, Mahoney, and Winter (1989) pointed out that in determining the suitability of a candidate reservoir for waterflooding, the following reservoir characteristics must be considered: Reservoir geometry, fluid properties, reservoir depth, lithology and rock properties, fluid saturations, reservoir uniformity and pay continuity and Primary reservoir driving mechanisms.

I. Reservoir Geometry

The areal geometry of the reservoir will influence the location of wells and, if offshore, will influence the location and number of platforms required.

II. Fluid Properties

The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by waterflooding. The viscosity and Density of the crude oil are considered the most important fluid properties that affects the degree of success of a waterflooding project. The oil viscosity has the important effect of determining the mobility ratio that, in turn, controls the sweep efficiency.

III. Reservoir Depth

Reservoir depth has an important influence on both the technical and economic aspects of a secondary or tertiary recovery project. Maximum injection pressure will increase with depth.

The costs of lifting oil from very deep wells will limit the maximum economic water–oil ratios that can be tolerated, thereby reducing the ultimate recovery factor and increasing the total project operating costs. On the other hand, a shallow reservoir imposes a restraint on the injection pressure that can be used, because this must be less than fracture pressure. In waterflood operations, there is a critical pressure (approximately 1 psi/ft of depth) that, if exceeded, permits the injecting water to expand openings along fractures or to create fractures. This results in the channeling of the injected water or the bypassing of large portions of the reservoir matrix. Consequently, an operational pressure gradient of 0.75 psi/ft of depth normally is allowed to provide a sufficient margin of safety to prevent pressure parting.

IV. Lithology and Rock Properties

Reservoir lithology and rock properties that affect flood ability and success are: porosity, permeability, clay content and net thickness

In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations. In these cases, a water-injection program will have only a minor impact on the matrix porosity, which might be crystalline, granular, or vugular in nature. Although evidence suggests that the clay minerals present in some sands may clog the pores by swelling and deflocculating when waterflooding is used, no exact data are available as to the extent to which this may occur. Tight (low-permeability) reservoirs or reservoirs with thin net thickness possess water-injection problems in terms of the desired water injection rate or pressure.

V. Fluid Saturations

A high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility that, in turn, gives higher recovery efficiency

VI. Reservoir Uniformity and Pay Continuity

If the formation contains a stratum of limited thickness with a very high permeability, rapid channeling and bypassing will develop. Unless this zone can be located and shut off, the producing water–oil ratios will soon become too high for the flooding operation to be considered profitable. The lower depletion pressure that may exist in the highly permeable zones will also aggravate the water-channeling tendency due to the high permeability variations. Moreover, these thief zones will contain less residual oil than the other layers, and their flooding will lead to relatively lower oil recoveries than other layers.

Areal continuity of the pay zone is also a prerequisite for a successful waterflooding project. Isolated lenses may be effectively depleted by a single well completion, but a flood mechanism requires that both the injector and producer be present in the lens. Breaks in pay continuity and reservoir anisotropy caused by depositional conditions, fractures, or faulting need to be identified and described before determining the proper well spanning and the suitable flood pattern orientation.

VII. Primary Reservoir Driving Mechanisms

The primary drive mechanism and anticipated ultimate oil recovery should be considered when reviewing possible waterflood prospects:

- **Water-Drive Reservoirs**

That are classified as strong water-drive reservoirs are not usually considered to be good candidates for waterflooding because of the natural ongoing water influx. However, in some instances a natural water drive could be supplemented by water injection in order to:

I- Support a higher withdrawal rate
II- Better distribute the water volume to different areas of the field to achieve more uniform areal coverage.
III- Better balance voidage and influx volumes.

- **Gas-Cap Reservoirs**

Are not normally good waterflood prospects because the primary mechanism may be quite efficient without water injection. Smaller gas-cap drives may be considered as waterflood prospects, but the existence of the gas cap will require greater care to prevent migration of displaced oil into the gas cap. This migration would result in a loss of recoverable oil due to the establishment of residual oil saturation in pore volume, which previously had none. If a gas cap is repressured with water, a substantial volume may be required for this purpose, thereby lengthening the project life and requiring a higher volume of water. However, the presence of a gas cap does not always mean that an effective gas-cap drive is functioning. If the vertical communication between the gas cap and the oil zone is considered poor due to low vertical permeability, a waterflood may be appropriate in this case.

Analysis of past performance, together with reservoir geology studies, can provide insight as to the degree of effective communication. Natural permeability barriers can often restrict the migration of fluids to the gas cap. It may also be possible to use selective plugging of input wells to restrict the loss of injection fluid to the gas cap.

- **Solution Gas-Drive Mechanisms**

Generally, are considered the best candidates for waterfloods. Because the primary recovery will usually be low, the potential exists for substantial additional recovery by water injection.

- **Volumetric Under Saturated Oil Reservoirs**

These reservoirs will offer an opportunity for greatly increasing recoverable reserves if other conditions are favorable.

2.2.1.5 Optimum Time to Water Flooding

Many calculations are used as procedure to determine time to water flooding:

1. Anticipated oil recovery.
2. Fluid production rates.
3. Monetary investment rates.
4. Availability and quality of the water supply.
5. Costs of water treatment and pumping equipment.
6. Costs of maintenance and operation of the water installation facilities.
7. Costs of drilling new injection wells or converting existing production wells into injectors.

These calculations should be performed for several assumed times and the net income for each case determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected.

2.2.1.6 Water Flooding Design

Water flooding is similar to water injection including selection parameters of the displacing fluid, the only difference being the displacing phenomenon.

The design of a waterflood involves both technical and economic considerations; Economic analyses are based on estimates of waterflood performance. These estimates may be rough or sophisticated depending on the requirements of a particular project and the philosophy of the operator. Technical analysis of a waterflood produces estimates of the volumes of fluids and rates.

Those estimates are used also for sizing equipment and fluid-handling systems; design includes arrangements for proper disposal of produced water.

2.2.1.6.1 Water Flooding Design Steps

I. Evaluation of the reservoir, including primary production performance.
II. Selection of potential flooding plans.
III. Estimation of injection and production rates.
IV. Projection of oil recovery over the anticipated life of the project for each flooding plan.
V. Identification of variables that may cause uncertainty in the technical analysis.

2.2.1.7 Selection of Water Flooding Pattern

One of the first steps in designing a waterflooding project is flood pattern selection. The objective is to select the proper pattern that will provide the injection fluid with the maximum possible contact with the crude oil system.(Guliyev, R, 2008) . This selection can be achieved by:

I. Converting existing production wells into injectors or
II. Drilling infill injection wells.

2.2.1.8 Water Flood Patterns Selection Criteria

1. Reservoir heterogeneity and directional permeability
2. Direction of formation fractures
3. Availability of the injection fluid (water)

4. Desired and anticipated flood life
5. Maximum amount of residual oil.
6. Well spacing, productivity, and infectivity.

2.2.1.9 water Flood Pattern Methodology

1. Irregular injection patterns.
2. Peripheral injection patterns.
3. Regular injection patterns.
4. Cristal and basal injection patterns.

- **Irregular Injection Patterns**

Willhite (1986) points out that surface or subsurface topology and/or the use of slant-hole drilling techniques may result in production or injection wells that are not uniformly located.

In these situations, the region affected by the injection well could be different for every injection well. Some small reservoirs are developed for primary production with a limited number of wells and when the economics are marginal, perhaps only few production wells are converted into injectors in a no uniform pattern. Faulting and localized variations in porosity or permeability may also lead to irregular patterns.

- **Peripheral Injection Patterns**

In peripheral flooding, the injection wells are located at the external boundary of the reservoir and the oil is displaced toward the interior of the reservoir, as shown in Figure (2-3).

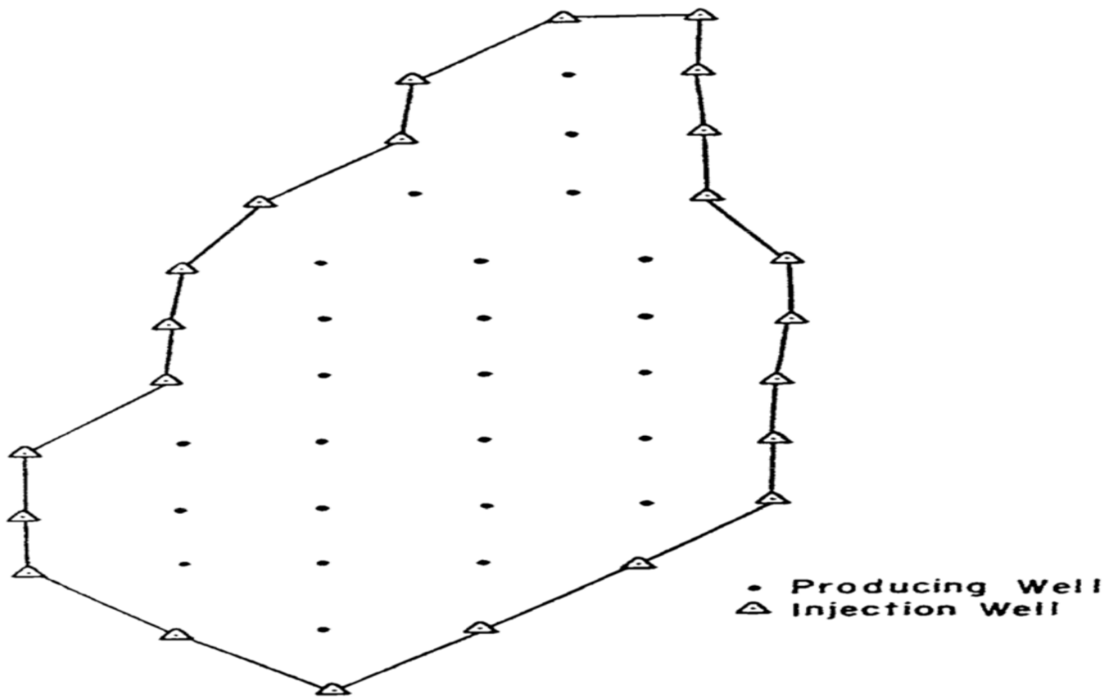


Figure 2.4 Typical Peripheral Waterflooding *(*After Cole, F., 1969.)

- **<u>Regular Injection Patterns</u>**

I. Direct Line Drive

The lines of injection and production are directly opposed to each other. The pattern is characterized by two parameters: a = distance between wells of the same type, and d = distance between lines of injectors and producers.

II. Staggered Line Drive

The wells are in lines as in the direct line, but the injectors and producers are no longer directly opposed but laterally displaced by a distance of a/2.

III. Five Spot

This is a special case of the staggered line drive in which the distance between all like wells is constant, i.e., a = 2d. Any four injection wells thus form a square with a production well at the center.

IV. Seven Spot.

The injection wells are located at the corner of a hexagon with a production well at its center.

V. Nine Spot.

This pattern is similar to that of the five spot but with an extra injection well drilled at the middle of each side of the square. The pattern essentially contains eight injectors surrounding one producer.

The patterns termed inverted have only one injection well per pattern. This is the difference between normal and inverted well arrangements. Note that the four-spot and inverted seven-spot patterns are identical. Figure 2-4 show the different regular injection flood patterns.

- **<u>Cristal and Basal Injection Patterns</u>**

In crystal injection, as the name implies, the injection is through wells located at the top of the structure. Gas injection projects typically use a crystal injection pattern. In basal injection, the fluid is injected at the bottom of the structure.

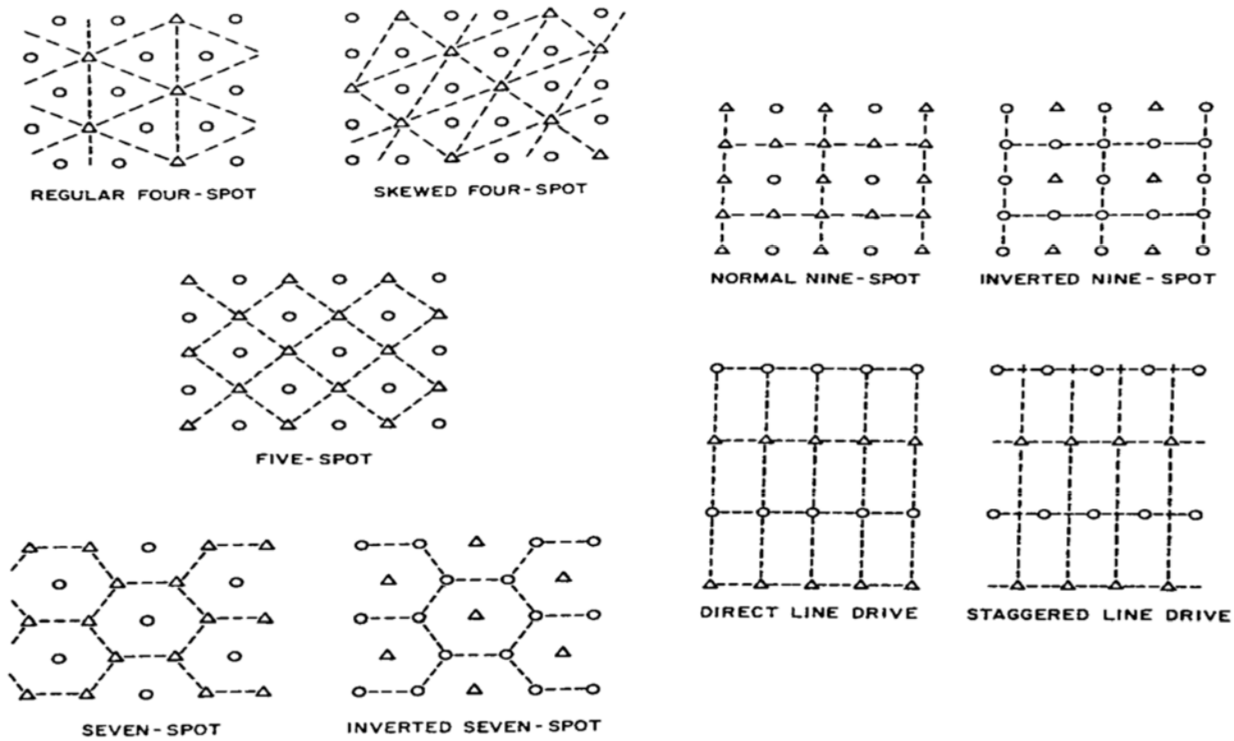


Figure 2.5 Flooding Patterns (Craig, F.F. Jr. 1971)

2.2.1.10 Cost of injection equipment

This is related to reservoir pressure which indicates that at higher pressures, the cost of injection equipment increases. Therefore, a low reservoir pressure at initiation of injection is desirable.

2.2.1.11 Productivity of producing wells

A high reservoir pressure is desirable to:

- ➢ Increase the productivity of producing wells
- ➢ Extend the flowing period of the wells
- ➢ Decrease lifting costs
- ➢ Shorten the overall life of the project

2.2.1.12 Effect of delaying investment on the time value of money.

A delayed investment in injection facilities might be desirable for the standpoint that an opportunity might exist to use the available fund for another investment.

2.2.1.13 Overall life of the reservoir

Because operating expenses are an important part of total costs, the fluid injection process should be started as early as possible. Some of these six factors act in opposition to others. Thus, the actual pressure at which a fluid injection project should be initiated will require optimization of the various factors in order to develop the most favorable overall economics. The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after primary operations have ceased to render economic the secondary recovery operations. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the displacing fluid.

On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time.

2.2.1.14 Overall Recovery Efficiency of Water Flooding

The overall recovery factor (efficiency) RF of the water flooding or any secondary or tertiary oil recovery method is the product of a combination of three individual efficiency factors displacement efficiency, areal sweep efficiency and vertical sweep efficiency as given by the following generalized expression:

RF = ED EA EV ………………………………………………………………… (2-1)

Where RF = overall recovery factor

ED = displacement efficiency

EA = areal sweep efficiency

EV = vertical sweep efficiency

2.2.1.15 Displacement Efficiency of Water Flooding

The fraction of movable oil that has been displaced from the swept zone at any given time or pore volume injected. Because an immiscible gas injection or waterflood will always leave behind some residual oil, ED will always be less than 1.0.

Vertical Sweep Efficiency

The fraction of the vertical section of the pay zone that is contacted by injected fluids.

The vertical sweep efficiency is primarily a function of:

I. Vertical heterogeneity
II. Degree of gravity segregation
III. Fluid mobilities
IV. Total volume injection

Areal Sweep Efficiency

The fractional area of the pattern that is swept by the displacing fluid mathematically expression as:

$$EA = \frac{AS}{AT} \quad \text{....(2-2)}$$

Where:

EA = areal sweep efficiency

AS = the swept area ft^2

AT = the total area ft^2

It increases steadily with injection from zero at the start of the flood until breakthrough occurs, after which continues to increase at a slower rate.

The areal sweep efficiency depends basically on the following three main factors:

I. Mobility ratio M

II. Flood pattern

III. Cumulative water injected

2.2.1.16 Mobility and Mobility Ratio

The mobility of any fluid defined as the ratio of the effective permeability of the fluid to the fluid viscosity:

$$\lambda_o = \frac{k_o}{\mu_o} = \frac{k\,k_{ro}}{\mu_o} \quad \text{....(2-3)}$$

$$\lambda_w = \frac{k_w}{\mu_w} = \frac{k\,k_{rw}}{\mu_w} \quad \text{....(2-4)}$$

$$\lambda_g = \frac{k_g}{\mu_g} = \frac{k\,k_{rg}}{\mu_g} \quad \text{....(2-5)}$$

Where

$\lambda_o, \lambda_w, \lambda_g$ = mobility of oil, water, and gas, respectively
k_o, k_w, k_g = effective permeability to oil, water, and gas, respectively
k_{ro}, k_{rw} = relative permeability to oil, water, and gas, respectively
k = absolute permeability

The mobility ratio M is defined as the mobility of the displacing fluid to the mobility of the displaced fluid and mathematically:

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} \quad \text{......(2-6)}$$

For waterflooding then:

$$M = \frac{\lambda_w}{\lambda_o} \quad \text{......(2-7)}$$

Substituting for λ_0 and λ_w :

$$M = \frac{k_{rw}}{k_{ro}} \frac{\mu_o}{\mu_w} \quad \text{...... (2-8)}$$

2.2.1.17 Relative Permeability

Define as the ratio of the effective permeability for a particular fluid to a reference or base permeability of the rock and it is characteristics are a direct measure of the ability of the porous system to conduct on fluid when one or more fluids are present. These flow properties are the composite effect of pore geometry, wettability, fluid distribution, and saturation history mathematical expression:

$$k_{ro} = \frac{k_o}{k}$$
$$k_{rg} = \frac{k_g}{k} \quad \text{...... (2-9)}$$
$$k_{rw} = \frac{k_w}{k}$$

Where:

k_{ro} = relative permeability to oil
k_{rg} = relative permeability to gas
k_{rw} = relative permeability to water
k = absolute permeability
k_o = effective permeability to oil for a given oil saturation
k_g = effective permeability to gas for a given gas saturation
k_w = effective permeability to water at some given water saturation

2.2.1.18 Fluid Injectivity

Injection rate is a key economic variable that must be considered when evalu-ating a waterflooding project. The waterflood project's life and, consequently, the economic benefits will be directly affected by the rate at which fluid can be injected and produced. Estimating the injection rate is also important forthe proper sizing of injection equipment and pumps. Several studies have been conducted to determine the fluid injectivity at mobil-ity ratios other than unity. All of the studies concluded the following:

- At favorable mobility ratios, i.e., **M < 1,** the fluid injectivity declines as theareal sweep efficiency increases.
- At unfavorable mobility ratios, i.e., **M > 1,** the fluid injectivity increases with increasing areal sweep efficiency.

2.2.1.19 Impact of Water Fingering and Tonguing

In thick, dipping formations containing heavy viscous oil, water tends to advance as a **"tongue**" at the bottom of the pay zone. Similarly, displacementof oil with a gas will result in the gas attempting to overrun the oil due to gravity differences unless stopped by a shale barrier within the formation or by a low overall effective vertical permeability. In linear laboratory experiments, it was observed that the fluid interface remains horizontal and independent of fluid velocity when the viscosities of the two phases are equal. If the oil and water have different viscosities, the original horizontal interface will become tilted. In a dipping reservoir, Dake (1978) developed a gravity segregation model that allows the calculation of the critical water injection rate icrit that is required to propagate a stable displacement.

2.2.1.20 Pattern Balancing

Balancing injection and production rates can significantly enhance the profit-ability of a waterflood project by:

- Minimizing or migrating across pattern boundaries
- Improving the capture of the mobilized oil
- Reducing the volume of recycled water
- Increasing sweep efficiency
- Providing more opportunity to increase oil recovery In balanced patterns, important events such as fill-up or water breakthrough forthe various patterns should occur at the same time. Several authors have suggested that the injection rate in each pattern should being proportion to the displaceable hydrocarbon pore volume, V_D. V_D is defined as:

$$V_D = V_p(1 - S_{wc} - S_{or})$$

Where:

V_D = displaceable hydrocarbon pore volume, bblu
V_P = pore volume, bbl
S_{wc} = connate water saturation, fraction
S_{or} = residual oil saturation, fraction

$$(i_w)_{pattern} \left[\frac{(V_D)_{pattern}}{(V_D)_{field}} \right] (i_w)_{field}$$

where

$(i_w)_{pattern}$ = injection rate in the pattern, bbl/day
$(i_w)_{field}$ = total target field injection rate, bbl/day
(VD)field = total field pore volume, bbl

It should be pointed out that the production and injection rates must be simul- taneously, a task that can be difficult to achieve in practice. However, pattern balancing calculations must be performed and should be supplemented by con- ducting numerical simulation studies to account for the deviation from ideal state. Patterns with substantially different average absolute permeability should be considered for additional allocation volume for water injection by redistri buting the field injection rate based on the following expression:

$$(i_w)\text{pattern} = \left[\frac{(V_D)_{\text{pattern}}(1/k)_{\text{pattern}}}{\sum_{\text{pattern}} \left[(V_D)_{\text{pattern}}(1/k)_{\text{pattern}} \right]} \right] (i_w)_{\text{field}}$$

where $(k)_{\text{pattern}}$ is the pattern average absolute permeability. The concept of pattern balancing can be further clarified by considering the following from the following example.

p_{inj} = water-injection pressure
i_w = water-injection rate
h = net thickness
k = absolute permeability

2.2.2 Gas Injection

Historically, both natural gas and air have been used in gas injection projects, and in some cases nitrogen and flue gases have been injected. Many of the early gas injected projects used air to immiscibly displace crude oil from reservoirs. The injection of hydrocarbon gas may result in a miscible or immiscible process depending on the composition of the injected gas and crude oil displaced reservoir pressure, and reservoir temperature. Hydrocarbon miscible injection is considered as an enhanced recovery process. Although the ultimate oil recovery from immiscible gas injection projects will normally be lower than for water flooding, gas injection may be the only alternative for secondary recovery under certain circumstances. if permeability is very low, the rate of water injection may be so low that gas injection is preferred. In reservoir with swelling clays, gas injection may be preferable. In steeply dipping reservoirs, gas that is injected up dip can very efficiently displace crude oil by a gravity drainage mechanism; this technique is very effective in low permeability formations such as fractured shales. In thick formations with little dip, injected gas (because of its lower density) will tend to override and result in vertical segregation if the vertical permeability is more than about 200 md. In thin formations especially if primary oil production has been by solution gas drive, gas may be injected into a number of wells in the reservoir on a well pattern basis; this dispersed gas injection operation attempts to bank the oil in a frontal displacement mechanism. In addition to the external gas injection into reservoirs with dip as just described (which may be into a primary or secondary gas cap), a variation called attic oil recovery involves injection of gas into a lower structural position. If there is sufficient vertical permeability, the injected gas will migrate upward to create a secondary gas cap that can displace the oil downward where it is recovered in wells that are already drilled Williamc (Lyons, 1996).

2.3 Tertiary (Enhanced Oil Recovery)

Enhanced oil recovery (EOR) is an engineering activity concerned with increasing the recovery of hydrocarbons from various types of petroleum reservoirs and it is generally refers to oil recovery over and above that obtained through the natural energy of the reservoir (Erle C. Donaldson, 1989). According to American Petroleum Institute estimates of original oil in place and ultimate recovery, approximately two-thirds of the oil discovered will remain in an average reservoir after primary and secondary production.

The EOR processes can be divided into four major categories:

- **Chemical**
- **Thermal**
- **Miscible and Other.**

2.4 Literature Review

Many studies were directed to evaluate and develop the water flooding include relations between sweep efficiency and reservoir or fluid characterization parameters, breakthrough. Some these studies listed below.

Pitts, Gerald N., Crawford, Paul B. (1971):

This study describes the possible effect of heterogeneous media on the areal sweep efficiencies for different pattern distributions. The direct streamline method was applied to three well known reservoir patterns: five-spot, direct-line drive (square) and staggered line drive patterns. Each pattern was simulated with three different permeability ranges. The ranges were (a) 100 to 50 md, (b) 100 to 1.0 md and (c) 100 to 0. 1 mi. These distributions were used along with a random process to distribute the permeabilities throughout a 20 x 20 matrix yielding a 400 block system.

It was found that areal sweeps for very heterogeneous five-spot patterns were reduced to nearly 25 percent or about one-third of the sweep expected in homogeneous media.

The heterogeneous staggered line drive pattern gave surprisingly low areal sweeps, the average areal sweep for the (100 to 50) md range was 76 percent, 65 percent for the (100 to 1.0) md range, and 26 percent sweep for the (100 to 0.1) md range. The two smaller permeability ranges resulted in a larger areal sweep for the staggered line-drive than the five-spot or direct-line drive patterns. However, for the wide permeability range of (100 to 0. 1), about the same areal sweep was obtained for the staggered-line drive and the five-spot patterns, but both gave smaller sweeps than the direct-line drive square pattern.

Brigham, William E., Kovscek, Anthony R., Wang, Yuandong (1998):

In this particular research it was found that for unit mobility ratio, unfavorable mobility ratios and some favorable mobility ratios (M 0.3) in a staggered line-drive pattern has higher areal sweep efficiency than a five-spot pattern. However, for very favorable mobility ratios (M 0.3), a five-spot pattern has better sweep efficiency than a common staggered-line-drive. The reason for this behavior was the change of streamline and pressure distributions with mobility ratios. For very favorable mobility ratios, the displacing front is near an isobar and intersects the pattern boundary at 90 degrees. That causes the fronts at times near breakthrough to become radial around the producer for a five-spot pattern. This displacing front shape is due to the symmetry of the five-spot pattern. Also, noticed more numerical dispersion in results for unfavorable mobility ratio cases ($M > 1$).

For a staggered line drive, the displacing front is also perpendicular to the border of the pattern. However, because the pattern is not symmetric, sweep out at breakthrough is not complete. So theoretically it seems that only in the limit of very large d/a will the areal sweep efficiency approach 1.

R. E. COLLINS and L.H. SIMONS (2000):

The purpose of study is to present a mathematical method for calculating the reservoir volume swept by a pilot flood. The method is applicable to any well pattern and can be used for field-wide floods as well as pilot floods. However, certain simplifying assumptions made about the nature of the reservoir and its contained fluids.

The effects of anisotropic permeability are included in the analysis. Used four examples for two wells and five examples for five wells spots calculated The position of the front at various times and some of the stream-lines the flood was balanced; that is, the injection and production rates were equal.

CHAPTER THREE

3. Methodology

3.1 Introduction

This study is interesting on looking for the effect of waterflooding to productivity based on various data from two well logs and performance history on sharyoof oilfield namely sh-2 and sh-9 and then we used petrel program in order to analysis history of production rate, injection rate, bottom hole pressure and history strategy.

3.2 Type Of Data That Needed For This Project

Data Require to Improving Waterflooding Efficiency present in Table 3.1

Table 3.1 Data required for the Project

No	Data Require
1	Seismic Data
2	Geological report
3	Well logging report
4	Production Data
5	Contour map
6	Completion report
7	Core report

Because of lack in data, this study was based on the quality of data available on hand, Table. 3.2 shows the data that will be used in our study:

Table 3.2 Data uses in this project

No	Available Data
1	Seismic Data
2	Geological Data
3	Well logging report
4	Production Data

3.3 Research Approach

The analysis and descriptive methods will be the main approach for the results that done by petrel program So the results are density –GR well logs of sh-2 and sh-9 to describing and zonate the reservoir in sh-2 and sh-9 and applying the historical performance of production , injection rates and bottom hole pressure in sh-2 and sh-9.

3.4 Some available figures that clarify sharyoof condition.

Relative Permeability Curve for Qishn clastic Formation in Sharyoof-2

The bellow figure (3.1) showed the relative permeability for the wells Sharyoof -2 which located in Qishn Clastic formation.

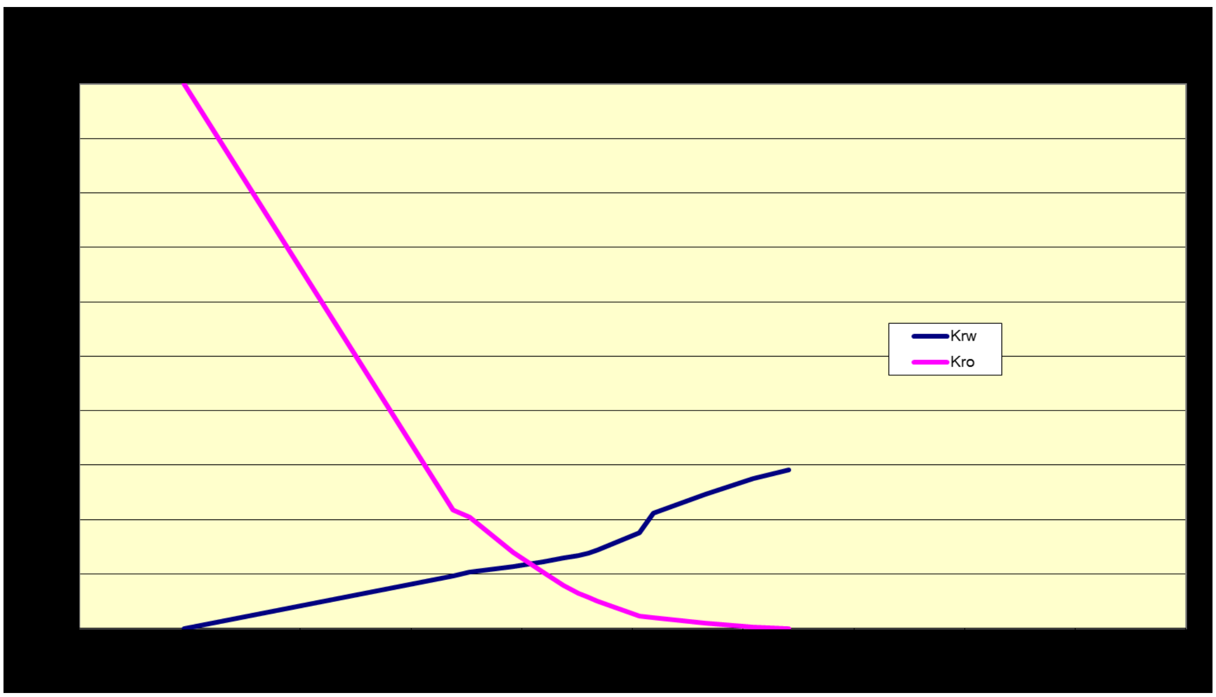


Figure 3.1 Relative Permeability for Qishn clastic Formation (Dove-Energy, 2001)

The permeability vs. depth from core on sharyoof-2

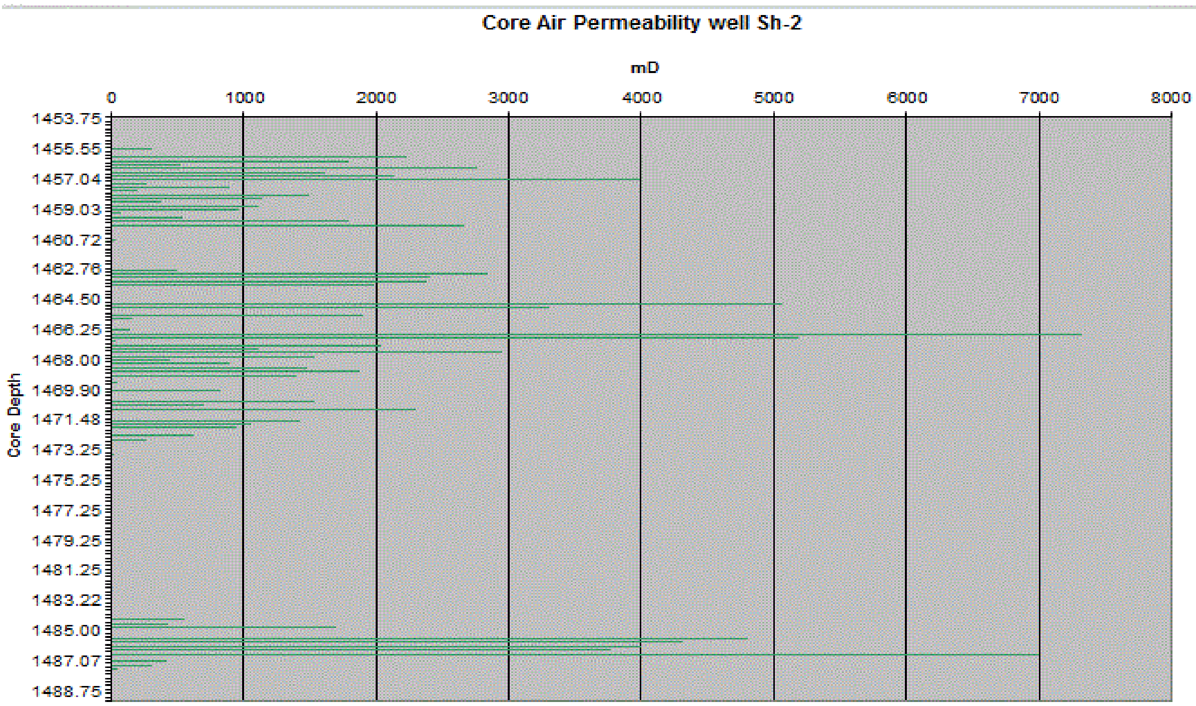


Figure 3.2 Permeability vs. depth from core on sharyoof-2

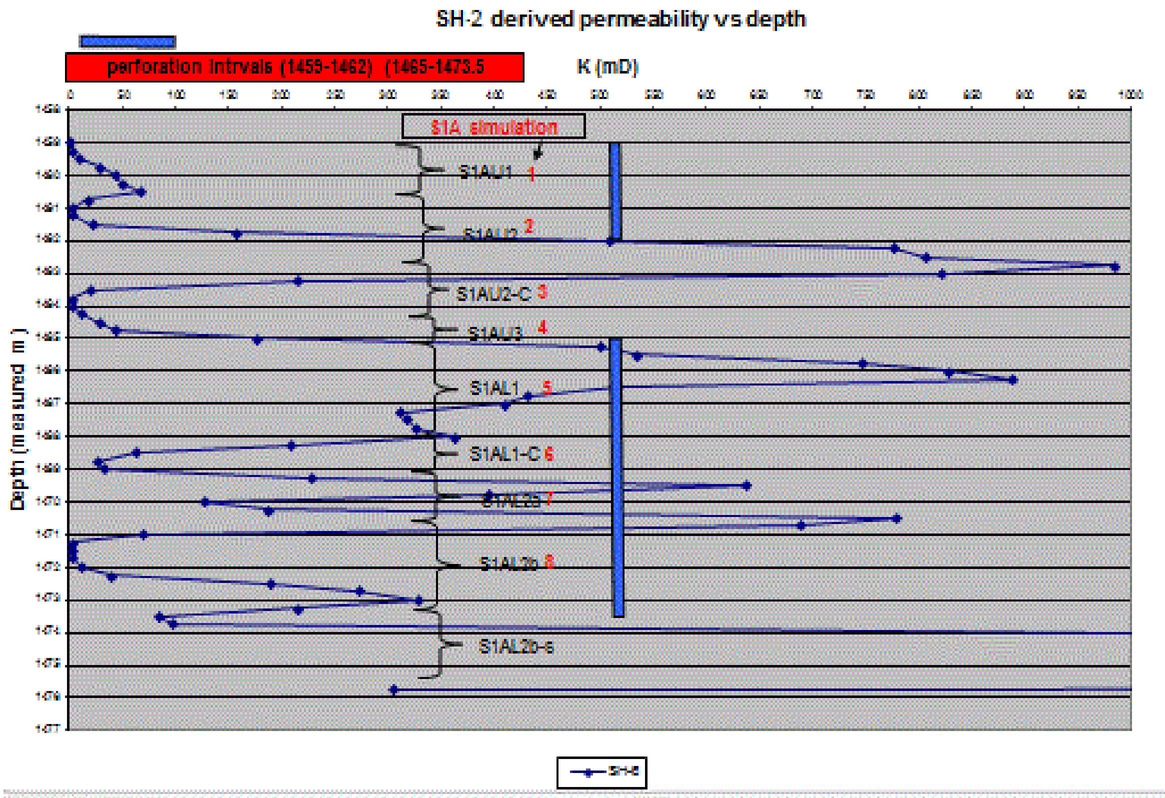


Figure 3.3 Permeability vs. depth from core on sharyoof-2

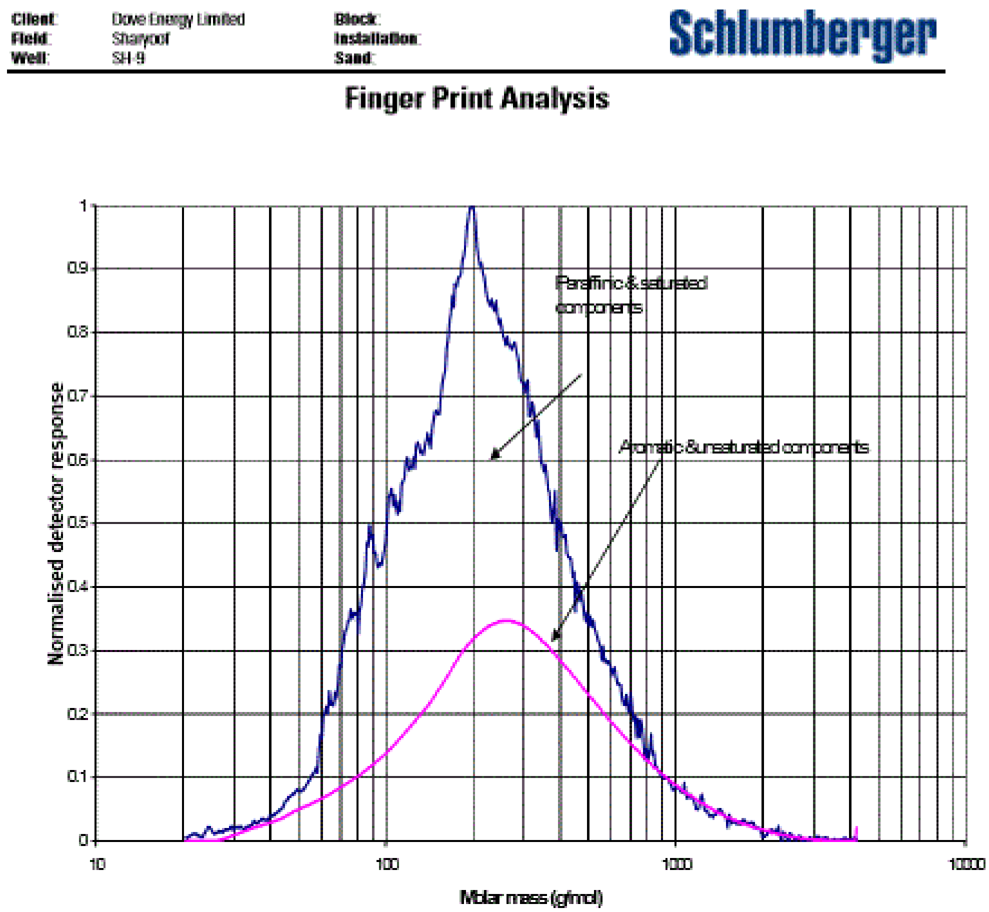


Figure 3.4 The Water fingering performance on sharyoof-9

CHAPTER FOUR

4. Analysis and Results Discussing

4.1 Correlation between sharyoof-2 and sharyoof-9

Upper Qishn clastics formation is a sandstone rock, total depth is 1453m, its thickness about **125**m, it divided into three zones S1(S1A, S1B, S1C), S2, S3, the pay zone is S1A with thickness is 17m which has a rich oil saturation with high porosity and permeability. Although S1B, S1C occupied oil but the porosity and permeability are low. S3 zone has high aquifer in thickness about 75m. So the water production rate appears after one year with pressure dose not decline and the oil production rate decrease. upper clastic Qishn Formation in only two wells Sharyoof 2 and Sharyoof 9 as show in figure 4.1.

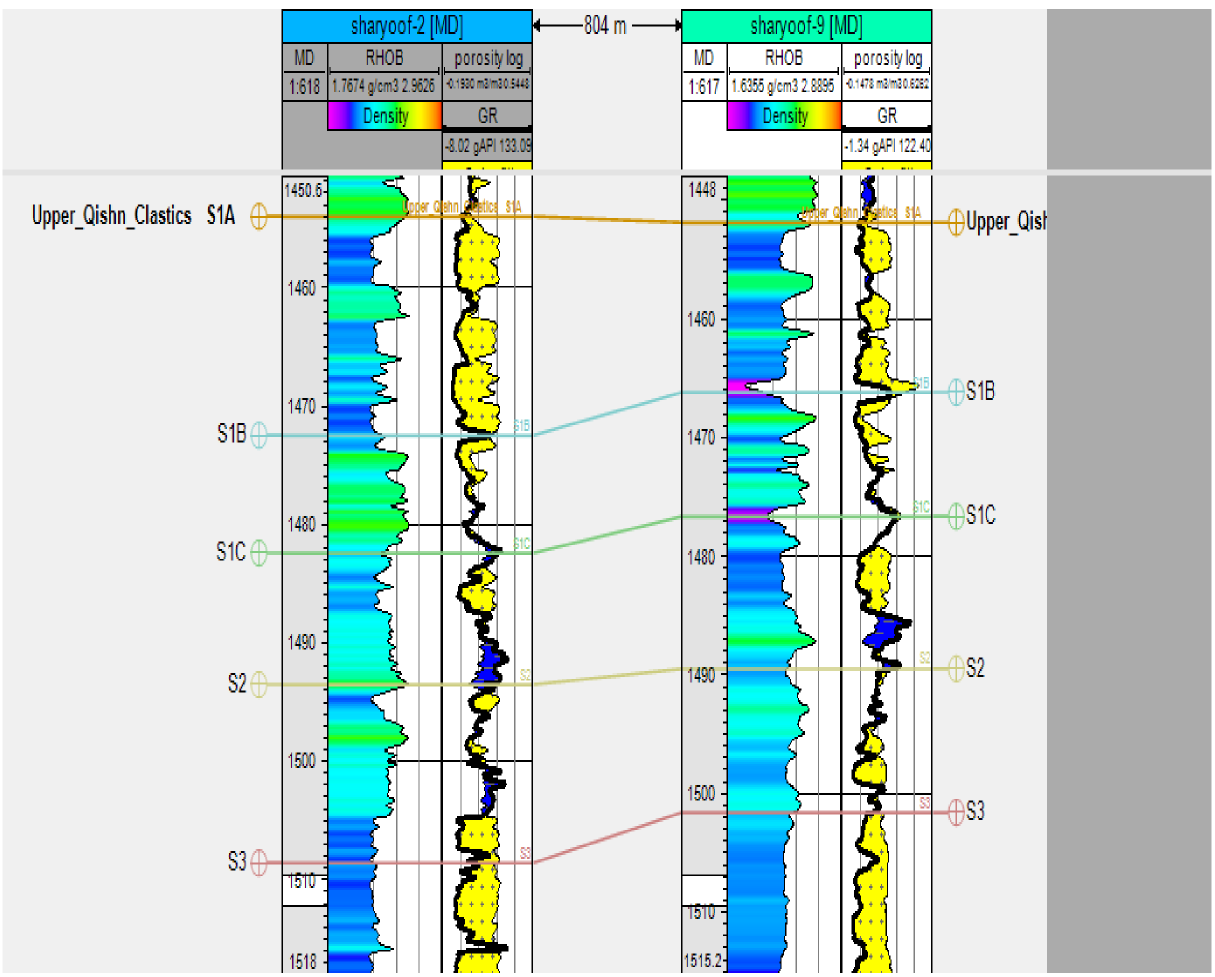


Figure 4.1 The new zones of the Upper Qishn Clastics formation of sh-2,sh-9 by petrel

4.2 Zones Distribution Qishn Clastics Formation

Table 4.1 Zones Qishn Clastics Formation Distribution

WELL NAME	**Sh-2**		
FMT DATE	18-Nov-2004		
Depth m	Zone	Fluid	P (psia)
1468.99	S1A	Oil	1407.80
1470.49	S1A	Oil	1409.90
1471.99	S1A	Oil	1410.90
1475.49	S1A	Oil	1413.00
1476.49	S1A	Oil	1414.30
1477.49	S1A	Oil	1415.60
1479.49	S1A	Oil	1418.10
1480.99	S1A	Oil	1419.90
1481.99	S1A	Oil	1421.05
1497.99	S1C	Oil	1443.60
1498.99	S1C	Oil	1444.90
1507.49	S2	Oil	1456.30
1510.99	S2	Oil	1460.85
1517.49	S2	Oil	1467.70
1518.99	S3	Water	1467.70
1524.49	S3	Water	1476.90
1529.99	S3	Water	1484.40
1531.99	S3	Water	1486.80
1534.99	S3	Water	1491.30
1593.99	S3	Water	1574.50

4.3 The Bottom Hole Pressure Performance of Sharyoof-2 and Sharyoof-9

In sharyoof-2 the pressure performance in this formation had not decline because there was high aquifer, so it was supported the reservoir pressure. When the water flooding begin in Jan 2005 the reservoir pressure was increasing while oil production rate was decreased Figure 4.2 Show Bottom Hole Pressure Performance.

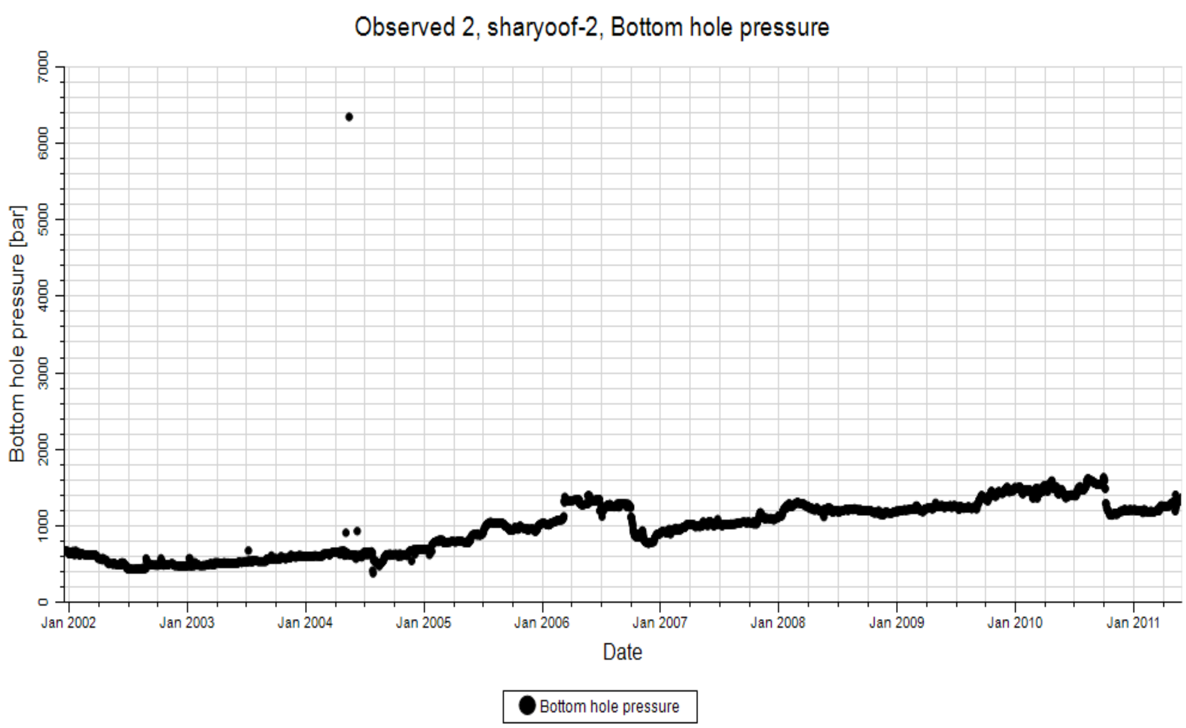


Figure 4.2 Bottom Hole pressure of sharyoof-2

In sharyoof-9 the bottom hole pressure was initially low in 2004,then suddenly Increased until reached to 1000 bar and continued in 1000 bar to 2008 figure 4.3 showing that.

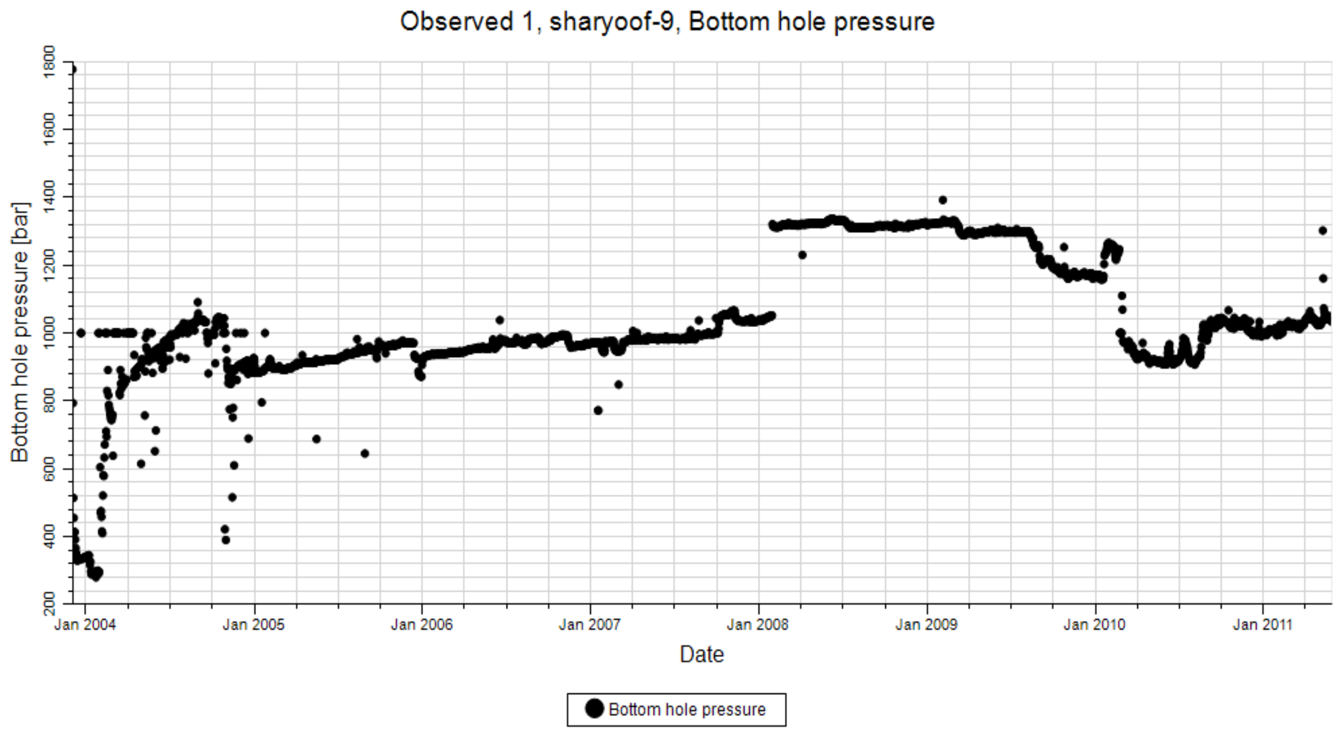


Figure 4.3 The Bottom Hole Pressure of sharyoof-9.

4.4 Oil Production rate of sharyoof-2 and sharyoof-9

Sharyoof-2 began production of oil in December -2001 at high performance 9000 BOPD and continued high a year, then the production of oil decreased gradually. In 2006 the oil production decreased more with decline continually until reach the minimum value in 2011 about 305 BOPD .figure 4.4 showing oil production rate.

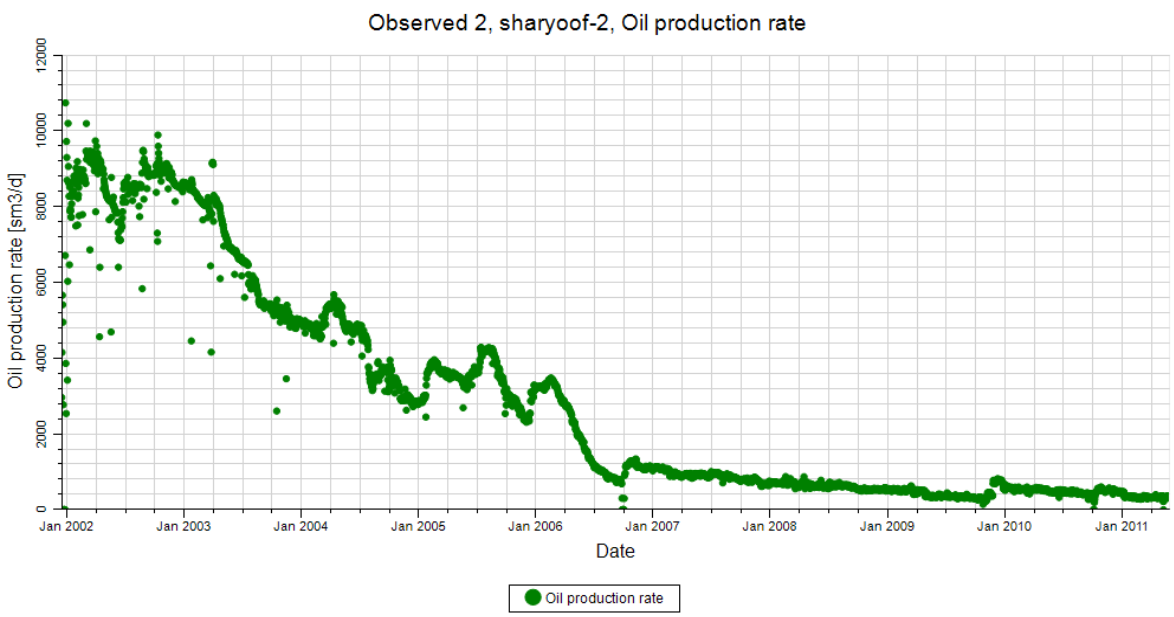


Figure 4.4 Oil Production rate of sharyoof-2

But in sharyoof-9 the performance was a little deferent which the oil production rate decreased in the early life of the well because the well began produced after sharyoof-2 by 2 years, as shown in figure 4.5

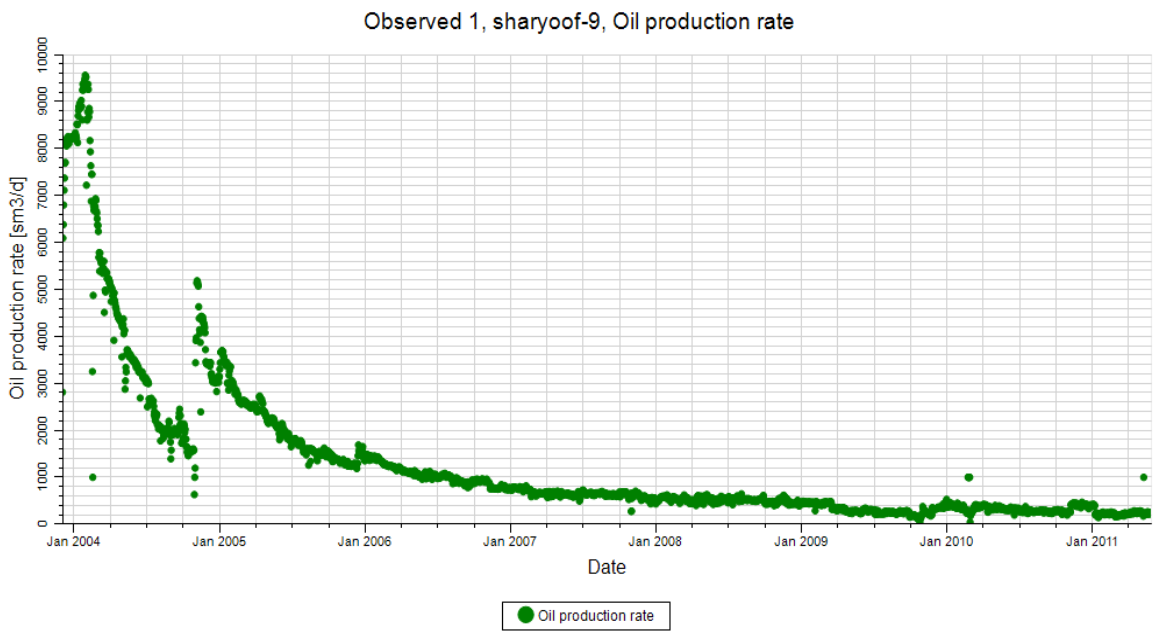


Figure 4.5 Oil Production rate of sharyoof-9.

4.5 Water Production Rate of Sharyoof-2 and Sharyoof-9

The water production rate in Sharyoof-2 appear after a year reverse Sharyoof-9 which start water production from the beginning of oil production. That is clear in figure4.6 and figure 4.7.

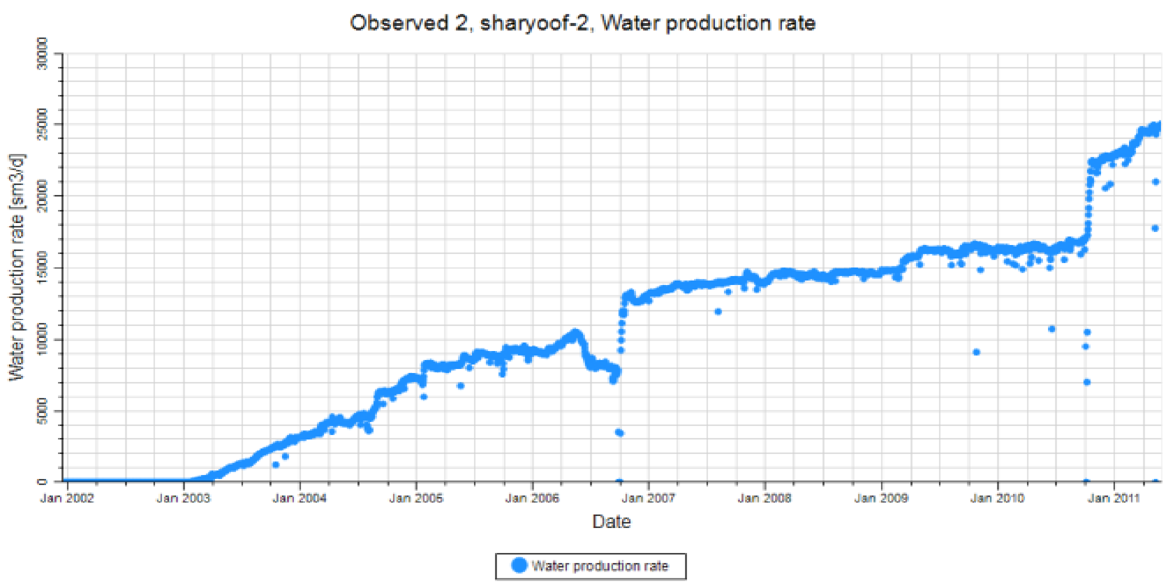


Figure 4.6 Water Production rate sharyoof-2

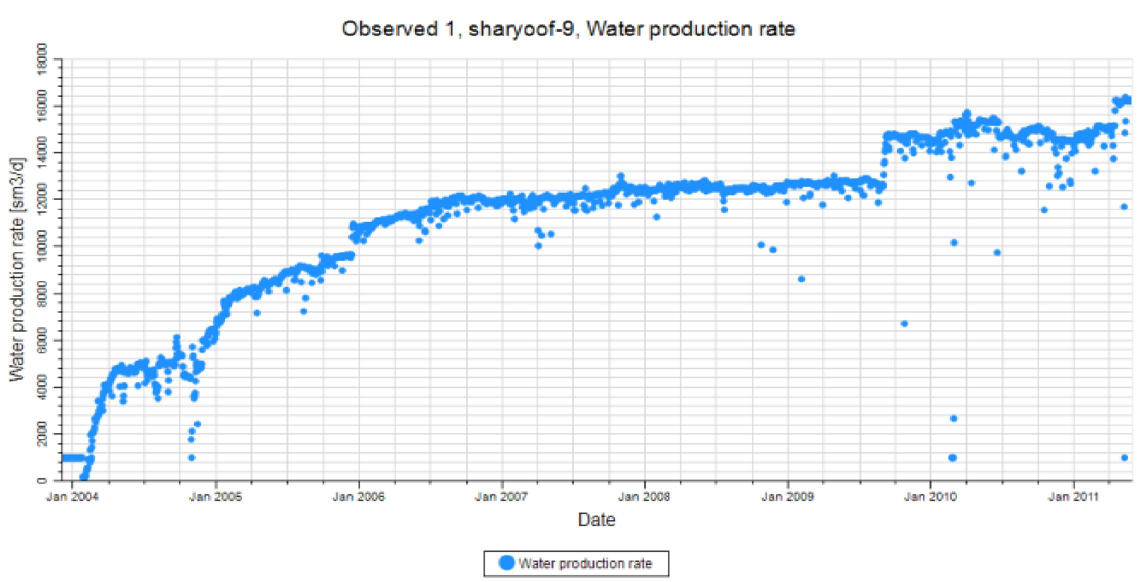


Figure 4.7 Water Production rate sharyoof-9

4.6 The Relationship between oil and water production rates

The oil and water production is reverse relationship because the oil production is high initially, but the water production started as negligible amount and increases with oil production decreases.

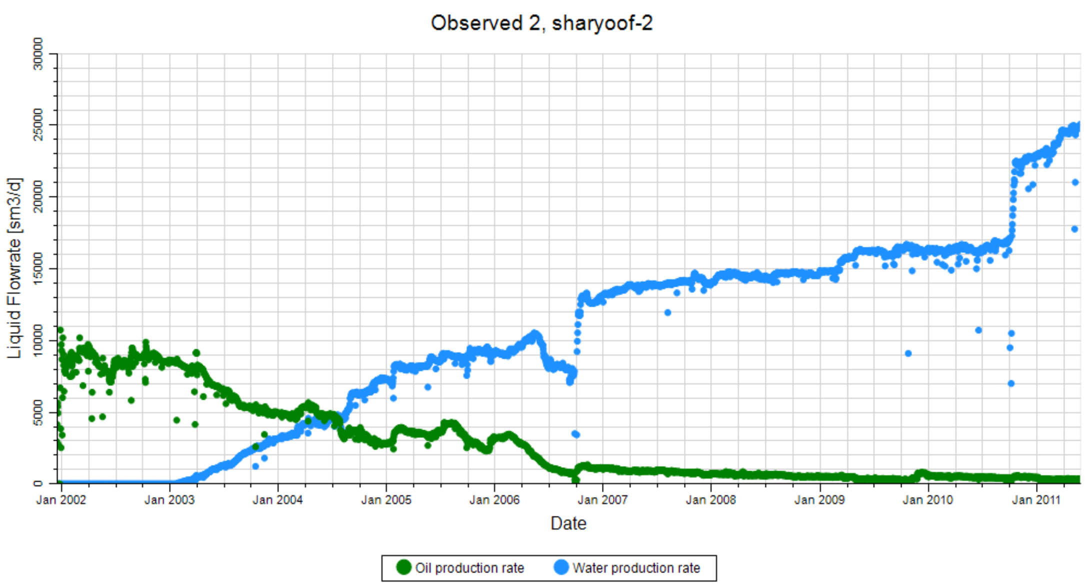


Figure 4.8 Relationship between oil and water production rates sharyoof-2

In sharyoof-9 the beginning of oil production was high for little period of time then declined quickly with increased of water production in the first year .where the oil production rate decreased into 300 BOPD with 98.6% water cut in 2011.

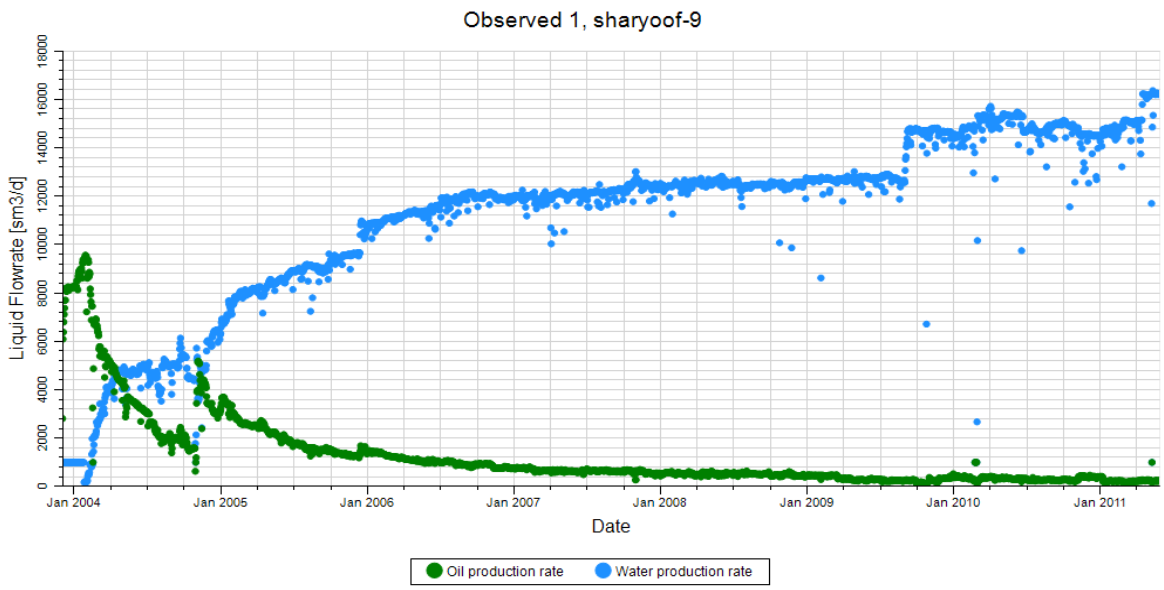


Figure 4.9 Relationship between oil and water production rates sharyoof-9

4.7 water Injection Rate Sharyoof-19

The sharyoof-19 drilled as injection well. when oil production rate was reduced, it began in 2006 to inject water into the reservoir to recover the possible amount of remaining oil.

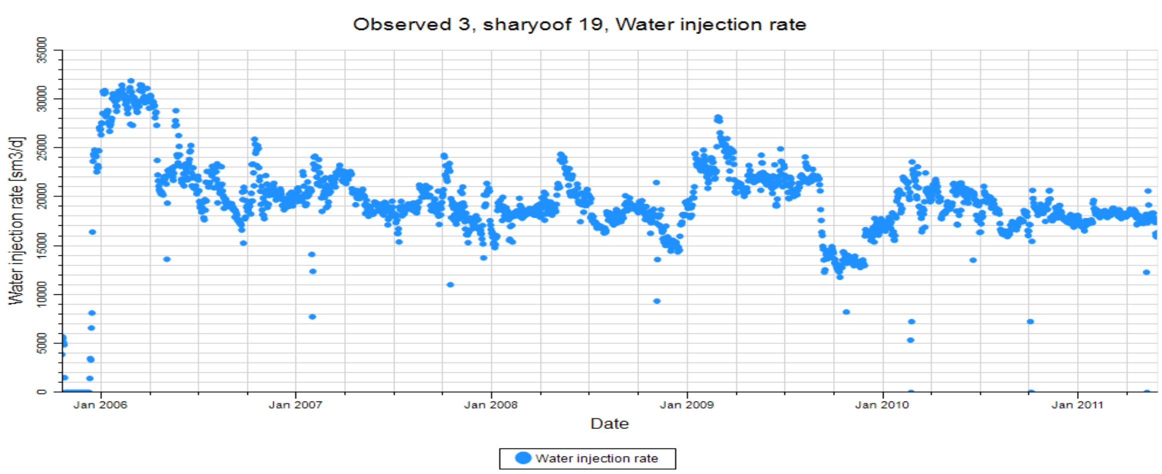


Figure 4.10 Water Injection Rate Sharyoof-19

4.8 History strategy of sharyoof-2 and sharyoof-9:

We recognize the increasing of bottom hole pressure gradually in sharyoof-2 until reached 1300 (bar) in 2006 and decline suddenly, then return to increase to reach 1500 (bar).

Figure 4.11 History strategy of bottom hole pressure of sharyoof-2

Figure 4.12 History strategy of bottom hole pressure of sharyoof-9

In sharyoof-2 the oil production began in rate decline slowly in the early stage from 2004 to 2006 as shown in figure 4.13. But in Sharyoof-9 the oil production rate was 9000bbl/day, then decline Quickly, because this well is later than sharyoof-2 and there is high aquifer as shown in figure 4.14.

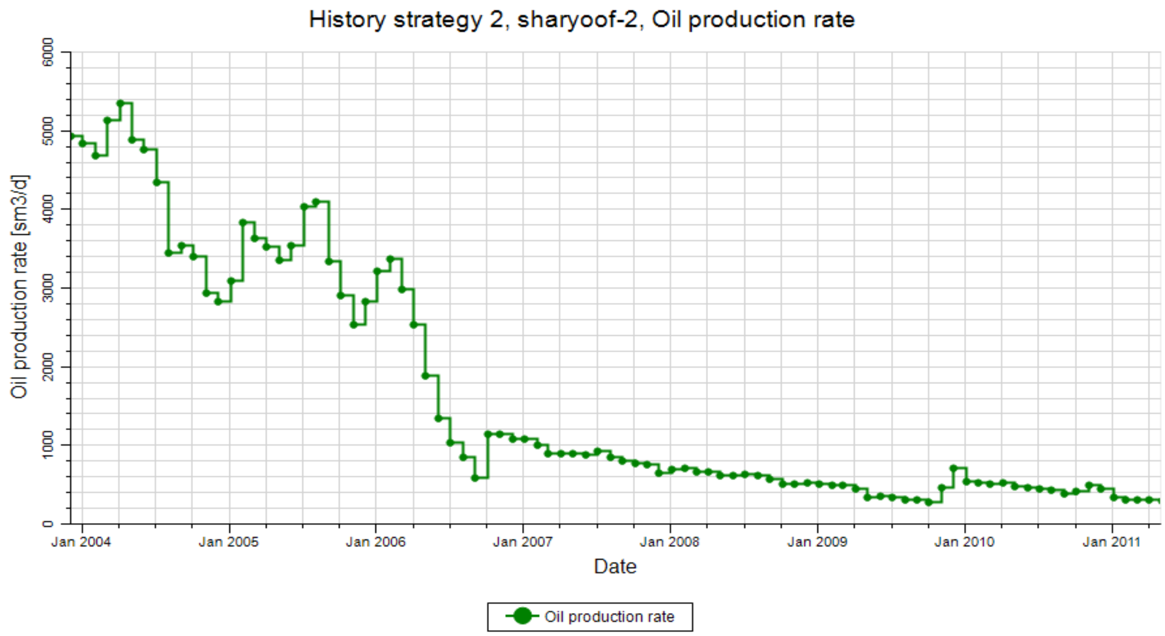


Figure 4.13 History strategy of oil production rate sharyoof-2

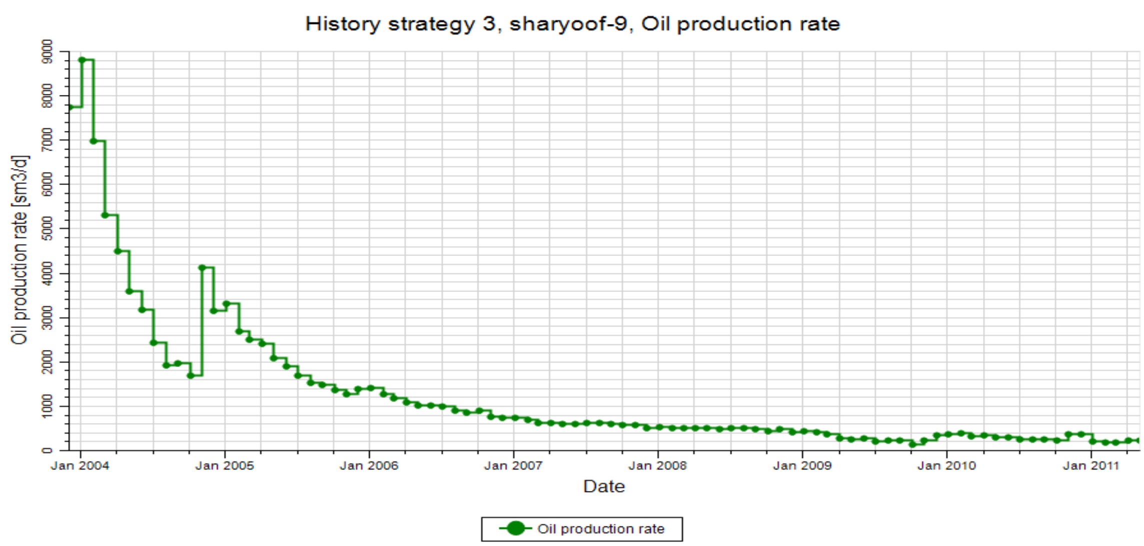


Figure 4.14 History strategy of oil production rate in sharyoof-9

The history of water production in sharyoof-2 is start with negligible and increase gradually until reaches 24000 bbl./day in 2011 as shown in figure 4.15.

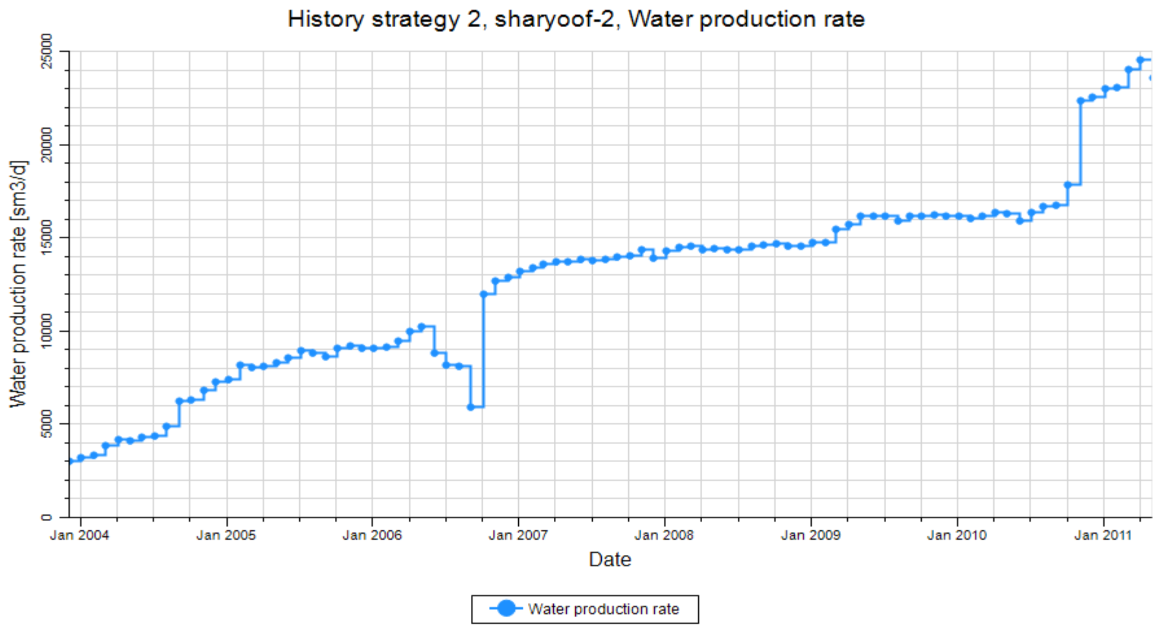


Figure 4.15 History strategy of water production rate sharyoof-2

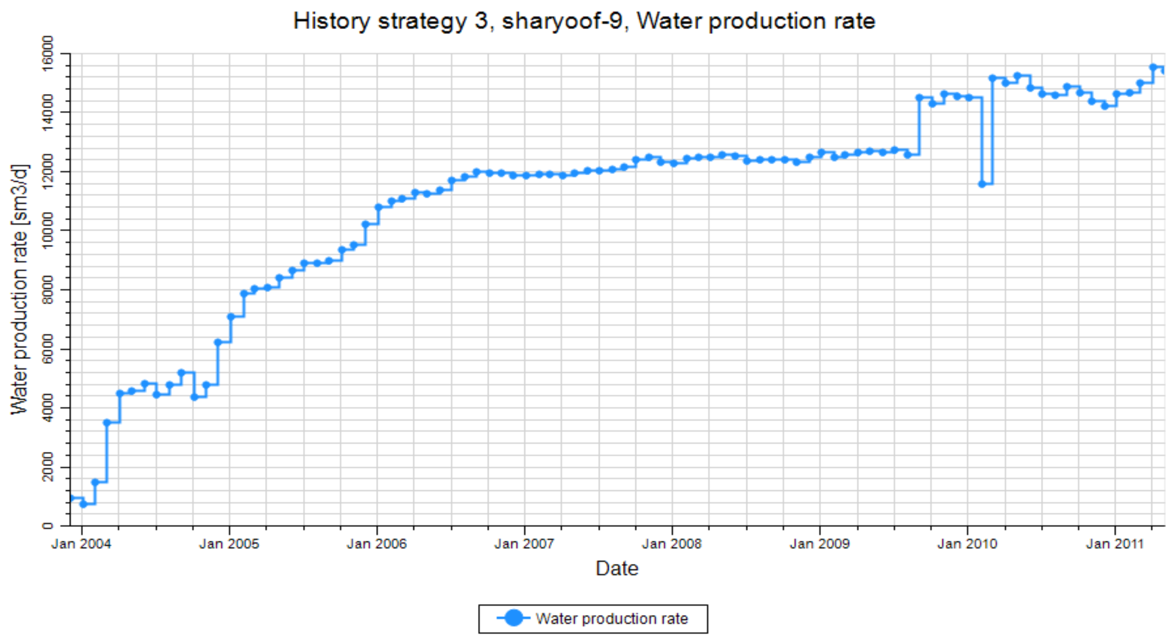


Figure 4.16 History strategy of water production rate sharyoof-9

The next figure 4.17 explain the reverse history strategy between production of water and oil. when production of water increase, the production of oil decrease with time response.

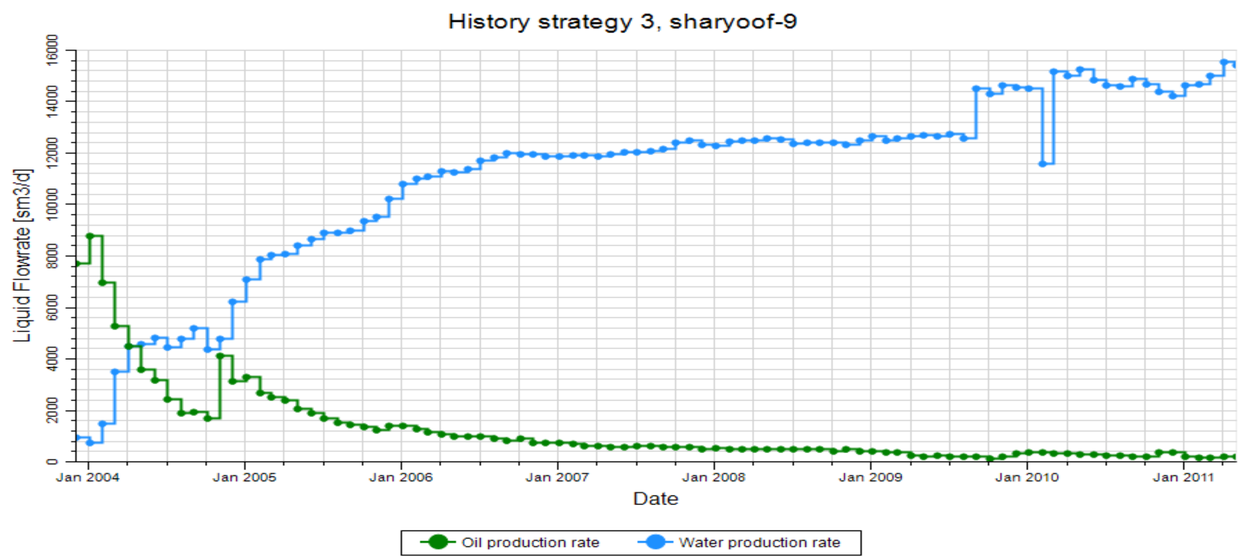


Figure 4.17 History strategy of water production with oil in sharyoof-9

The bellow figure 4.18 indicate the reverse relationship between oil and water production rates So when the water production rate increased, the oil production rate will be decline.

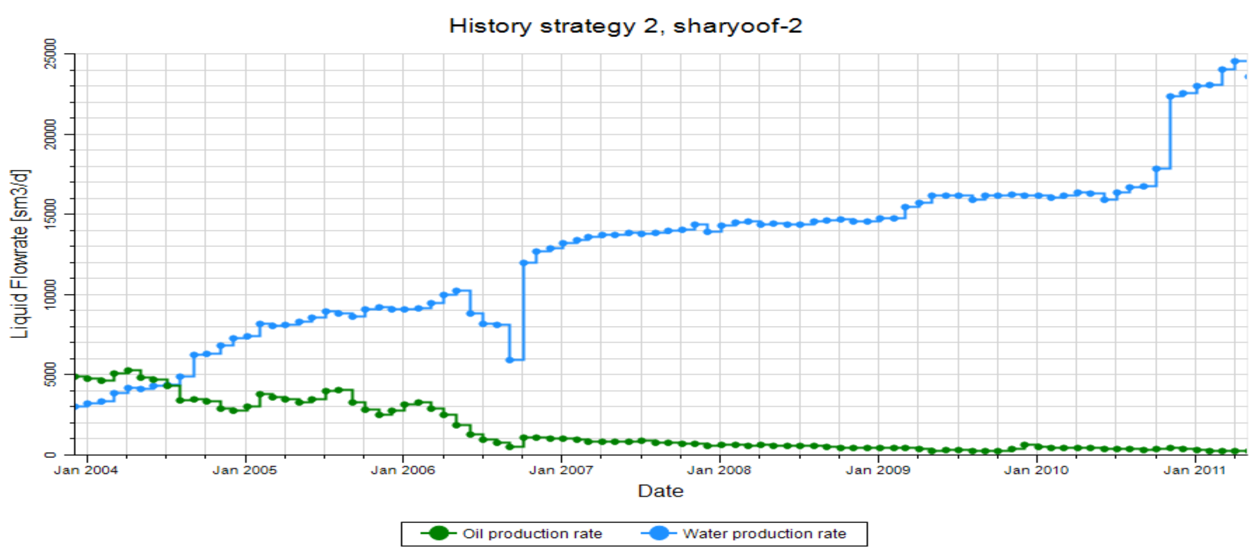


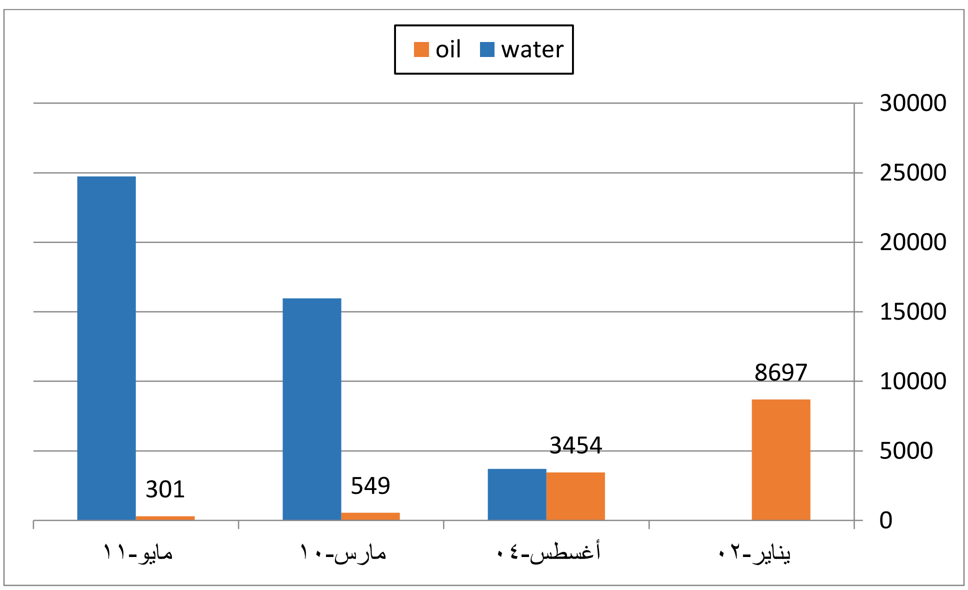
Figure 4.18 History strategy of water production with oil in sharyoof-2

4.9 Result of study

The result of this study summarized as 4 times in table 4.2

Table 4.2 Summary of results

Pressure Gradients, Oil at 0.38 psi/ft. Water at 0.43 psi/ft.	Results of Sharyoof-2 by calculating						
	Date	PR	PWF	Oil		WC	Gross PI
		PSIA	PSIA	BOPD	BWPD	%	BLPD/PSI
S1A	01-Jan-02	1,443	805	8,697	0	0.0	13.6
S1A	01-Aug-04	886	677	3,454	3,712	51.8	34.3
S1A	01-Mar-10	1,975	1,516	529	15,969	96.2	35.9
S1A	15-May-11	1,872	1,439	301	24,730	98.6	57.9



CHAPTER FIVE

5. CONCLUSION, RECOMMENDATIONS

5.1 CONCLUSIONS

1. from the correlating well logs between Sharyoof-2 , sharyoof-9 we divided the upper Qishn Clastics formation into three zones S1,S2 And S3.where S1 has three section S1A,S1B And S1C which have different characterstics.
2. analysis the performance of sharyoof-2 , sharyoof-9 and history strategy where the oil production began in higher rate about 9000 BOPD in 2002 with negligible amount of water production but in the second year the oil production rate decreased and water production rate increased until it reached the maximum ratio in 2011 water cut 98.6%
3. from these studies , we recognized the sweep efficiency in shyroof oil field is poor, because the relative permeability of oil became low with increasing relative permeability of water (increase water saturation).

5.2 RECOMMENDATIONS

- Building Reservoir model of Sharyoof field to select the optimum pattern to increase oil recovery.
- Using the tertiary recovery (Polymer method)
- Estimating the economic value for Development method of oil recovery on sharyoof oil field.

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