Republic of Yemen
Emirates International University
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الجمهورية اليمنية
الجامعة الإماراتية الدولية
كلية الهندسة وتقنية المعلومات
قسم هندسة النفط والغاز

EMIRATES INTERNATIONAL UNIVERSITY
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OIL AND GAS ENGINEERING DEPARTMENT

IMPROVE OIL RECOVERY USING WATER AND POLYMER FLOODING IN SHARYOOF FIELD BLOCK-(53)

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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August / 2021

DECLARATION

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APPROVAL

This is to certify that the project titled (**Improve Oil Recovery Using Water and Polymer flooding in Sharyoof Field Block-(53)**) 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

Polymer flooding is one of the most incipient chemical based enhanced oil recovery process that utilizes the injection of polymer solutions into oil reservoirs. The presence of a polymer in water increases the viscosity of the injected fluid, which upon injection reduces the water-to-oil mobility ratio and the permeability of the porous media, thereby improving oil recovery.

This study aims to improve oil recovery using waterflooding and polymer flooding techniques based on data obtained from the sharyoof oilfield in block-(53). Two simulation studies have illustrated the feasibility of polymer flooding and provided the technical knowledge that can be used to study other techniques of improved oil recovery (IOR) to be implemented in Yemen oilfields. Use of polymer increases water viscosity which controls water mobility thus improving the sweep efficiency. The simulations were carried out using the black oil model. In the simulation, factors such as polymer shear thinning effect, adsorption, concentration, permeability reduction, and fluid viscosity have been taken into account when constructing the simulation model. For the Sharyoof reservoir, the polymer slug size was 0.5 PV, polymer concentration was ranging from 800-1600 mg/l, oil recovery was 35.4%, and the incremental oil recovery was about 3.871%. From water flooding ,and 3.64% ,with polymer slug size was 0.1PV,0.3PV. The polymer flooding project in this study has shown no better outcome compared to waterflooding project due to high water cut in the reservoir .

ACKNOWLEDGMENTS

First of all, we owe our most sincere gratitude to Allah the almighty and the most powerful for offering us such a strength, endurance, willingness, and capability to accomplish this project.

We would also like to express our deep and sincere gratitude to our supervisor, **Eng. Mohammed Abbas**, for his valuable and constructive suggestions during the planning and development of this research work and his wide knowledge and his logical way of thinking that have been of great value for us. His willingness to give his time so generously has been very much appreciated. His feedback, support, encouraging, patience and personal guidance have provided a good basis for the present project.

Not to forget thanking **Dr. Ibrahim Farea** the head of the faculty of Oil and Gas Engineering for his great effort and time. Our special gratitude is due to all those who have helped in carrying out the research and contributed in any way for the success of this Project.

Finally, yet importantly, we would like to express our heartfelt thanks to our beloved family for their blessings, our friends/classmates for their help and wishes for the successful completion of this project.

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LIST OF ABBREVIATIONS

Abbreviations

EOR	Enhanced Oil Recovery
IOR	Improved Oil Recovery
BOPD	barrels of oil per day
OOIP	Original Oil In Place
HCPV	Hydrocarbon Pore Volume
API	American petroleum institute gravity
Boi	Initial Oil FVF
Bo	Oil FVF
K	Absolute Permeability Of Reservoir
BHP	Bottomhole Pressure, psia
μo	viscosity of reservoir oil, cp
PVT	Pressure/Volume/Temperature
SCAL	Special Core Analysis
WF	Water Flooding
PF	Polymer Flooding
Sw	Water Saturation
M	Mobility Ratio
P	Pressure
PV	Pore Volume
FOPT	Field Oil Production Total
FGPT	Field Gas Production Total
FWPT	Field Water Production Total
FOE	Field Oil Efficiency
FWIR	Field Water Injection Rate
FWCT	Field Water Cut
FCAD	Field Polymer Adsorption
PLYVISC	Polymer Viscosity
PLYSHEAR	Polymer Shear Thinning Data
POLYADS	Polymer Rock Adsorption

CHAPTER-ONE

1. INTRODUCTION

1.1 Overview

The life of an oil reservoir goes through three different oil recovery mechanisms, Conventional oil recovery methods (primary and secondary) and tertiary or enhanced oil recovery (EOR).

When Oil reserves cannot be recovered by conventional methods approximately 60-70% and so enhanced oil recovery methods become increasingly important with respect to the limited worldwide resources of crude oil. The estimated worldwide production from enhanced oil recovery and heavy oil projects at the beginning of 1996 was approximately 2.2 million barrels per day (bpd) compared to 1.9 million bpd at the beginning of 1994 .This is approximately 3.6% of the world's oil production. Tertiary recovery is the additional recovery over and above what could be recovered by secondary recovery methods. Various methods of enhanced oil recovery (EOR) are essentially designed to recover oil, commonly described as residual oil, left in the reservoir after both primary and secondary recovery methods have been exploited to their respective economic limits. Enhanced oil recovery comprises mainly gas flooding methods, chemical methods, thermal methods and others.

Gas floods, including immiscible and miscible gas flooding processes. Chemical floods are identified by the specific chemical that is injected. The most commonly used are polymers, surfactants, and alkalis, but chemicals are often combined. Injection of materials that plug permeable channels may be required for injection profile control and to prevent or mitigate premature water or gas breakthrough Cross-linked or gelled polymers are pumped into injectors or producers for water shutoff or fluid diversion. The design of chemical injection-EOR projects can be more complicated than that of water flood projects. Down hole conditions are more severe than those for primary or secondary recovery production Well injectivity is complicated by chemicals in injected waters, so in addition to precautions used in water floods, chemical interactions, reduced injectivity, deleterious mixtures at producers, potential for accelerated corrosion, and possible well stimulations to cause reduced injectivity must be considered . EOR is more specific in concept and it can be considered as a subset of IOR. EOR implies the process of enhancing oil recovery by reducing oil saturation below the residual oil saturation “**Sor**” The target of EOR varies considerably by different types of hydrocarbons. EOR methods are implemented in order to improve oil displacement efficiency (microscopic and macroscopic displacement efficiency), There are a different factors must be taken into consideration during the design stage of an EOR process including: oil type, remaining oil in place, reservoir characteristics, and formation type, as well as oil saturation distribution and oil viscosity [1] .

1.2. Aim and Objectives

1.2.1. Aim

The aim of this project graduation is conducted to improve oil recovery or NPV from Sharyoof field-block-53 and determine the most appropriate development scenarios for future of the field using a polymer flooding.

1.2.2. Objective

To achieve the aim of the project, the following objectives are defined:

1. Studying the reservoir conditions of Sharyoof oil field and its petrophysical properties.
2. Determining the drive mechanism of Sharyoof oil field to better understanding the field behavior.
3. Review Wells production history and achieve an acceptable history-match for production and pressure.
4. Apply reservoir engineering concepts to design polymer flooding which compatible with Qishn Clastics formation properties.
5. Clarifying the polymer injection methodology in professional engineering way which will be workable to apply.
6. Utilizing ECLIPSE software to implement different scenarios of polymer injection into Qishn Clastics reservoir.
7. Selecting the best scenario that gives the highest displacement efficiency for polymer injection that will achieve the highest ultimate recovery.
8. Make recommendation, based on the study results, as to the best way to develop field.

1.3. Problem Statement

When petroleum reservoirs are depleted by natural drive mechanisms(primary recovery) due to decreasing reservoir pressure only a small fraction of the oil can be produced (30- 40%) original oil-in-place. Implementing a secondary recovery, waterflooding, would still not produce all the recoverable oil present in the reservoir. At the time of breakthrough the water cut level is high. The inefficiency of recovery is coupled by the fact that some regions in the reservoir, such as having low permeability sands, will not be swept by the injected water at all. The factor of high water mobility ratio results in poor volumetric sweep efficiency especially when reservoir rock is highly heterogeneous.

One of the methods to be looked into would be polymer flooding which augments waterflooding with greater recovery through the addition of polymer solution to enhance mobility ratio of the flood.

To date, no polymer flooding had been implemented in Yemen oil fields even though waterflooding is common. The field is now at the late stage of Water flooding with water-cut of more than 90% on most producing wells and due to the high water-cut (almost ends the secondary recovery); it is time to implement a suitable EOR process.

A simulation study of a polymer flooding process for sharyoof field Qishn sand will conduct in order to improve oil recovery and to understand the applicability of polymer injection in sharyoof field with take in consideration technical feasibility, and economic attractiveness.

1.4. Geology of Yemen

Republic of Yemen is an Arab country in Western Asia, occupying South Arabia, the southern end of the Arabian Peninsula. Yemen is the second-largest country in the peninsula, occupying 555000 km^2. The coastline stretches for about 2,200 km. It is bordered by Saudi Arabia to the north, the Red Sea to the west, the Gulf of Aden and Arabian Sea to the south, and Oman to the east-northeast. Yemen is in the Asia continent and the latitude and longitude for the country are 12° - 18° N, 42°- 53° E.

Yemen is covered with rocks whose ages date back to an era prior to the Cambrian era, about 3 billion years ago. Geologically speaking, Yemen composes part of the Arabian Shield within the larger framework of the Arabian-Nubian Shield. It has twelve onshore and offshore sedimentary basins have been identified in Yemen, categorized into three groups based on the geological era in which they originated: **Paleozoic, Mesozoic and Cenozoic.**(Hakimi M.H (2016)**.** (Fig.1)**.**

Paleozoic basins:

(1) Rub' Al-Khali (the southern flank of a much larger basin extending into Saudi Arabia).

(2) Sana'a.

(3) Suqatra (an island in the Gulf of Aden).

Mesozoic basins:

(1) Siham-Ad-Dali.

(2) Sab'atayn.

(3) Say'un-Masilah.

(4) Balhaf.

(5) Jiza‘‘-Qamar.

Cenozoic basins:

(1) Mukalla-Sayhut.

(2) Hawrah-Ahwar.

(3) Aden-Abyan.

(4) Tihamah.

Only Two, Sab’atayn and Say’un-Masilah basins, are well explored and produced hydrocarbon.

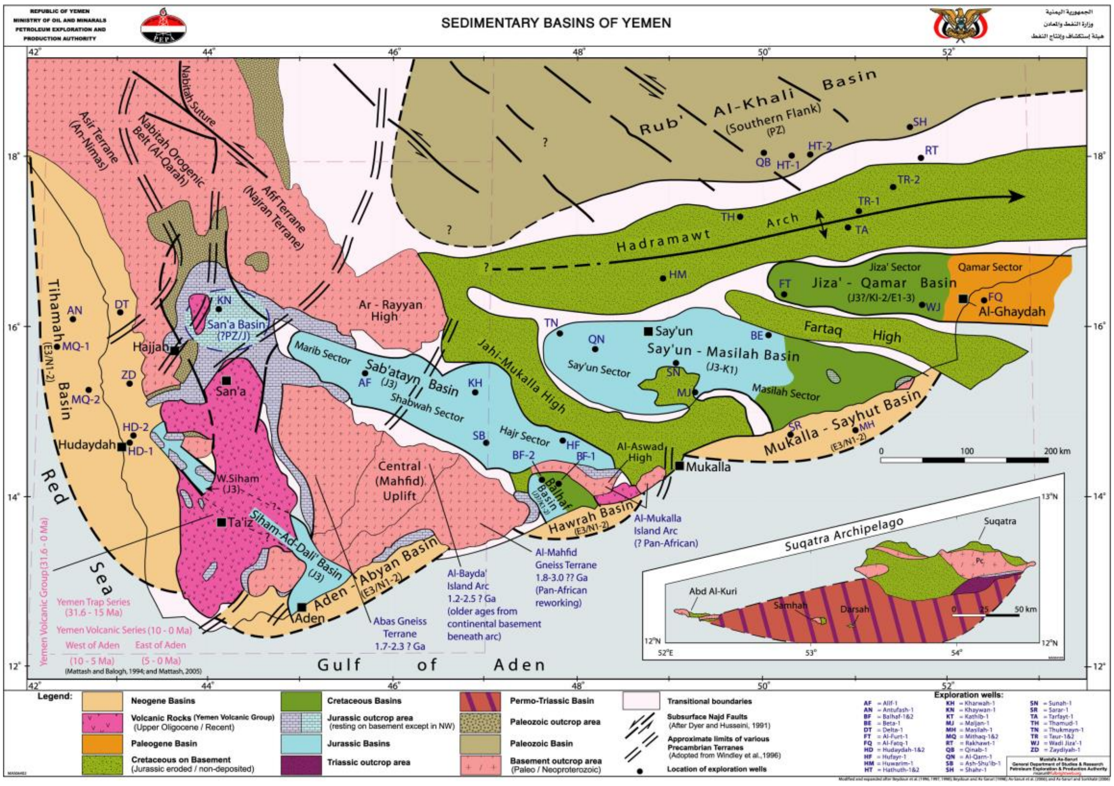

Figure 1.1 Sedimentary basins of Yemen and their classification according to the geologic era in which they formed. (Source : PEPA).

1.4.1. Stratigraphy of Yemen

The stratigraphic manners in which The Sedimentological characters of sedimentary rocks i.e. environment, sediment transport agencies and the nature of the syn to post depositional tectonic activities modify the stratigraphic order of deposition are significant in terms of their depositional environment, the thickness of the formations and primary structures. Since the tectonics related to stratigraphy are manifested in the distribution of sediments in Yemen, (Albaroot, M. et al., (2016)), as illustrated in the geological column (Fig.1.2).

1.3.1.1. Paleozoic Sediments

- Ghabar Group (Infra-Cambrian-Earliest Paleozoic):Sandstone limestone, silt, gypsum.
- Qinab Group (Infra Cambrian-Lowest Cambrian) : Volcano-sedimentary succession consisting of dolerite, sandstone, silty shale and tuff.
- Wajid Formation (Cambrian - Carboniferous): Quartz sandstone.

- Akbarah formation (Late Carboniferous-Permian): Tillite (pebbles & boulders of basement rocks), shales, mudstones, sandstones and siltstones.

1.3.1.2. Mesozoic Sediments:

- Kuhlan Formation (Lower-Middle Jurassic): Sandstones, thin claystone and siltstone interbeds.
- Amran Group (Middle Jurassic-Lower Cretaceous): Carbonate marl/shale with evaporitic succession.
- Tawilah Group (Cretaceous): Sandstone with siltstone, marl, and shale, often interbedded with sandstone and also forming distinct marl or shale intervals and with generally persistent limestone-marl clasts.
- Mahra Group (Cretaceous): Limestone, marl, and shale, often interbedded with sandstone.

1.3.1.3. Cenozoic Sediments:

- Hadramawt Group (Paleocene-Middle Eocene): Dolomite, shale, limestone with chalk and dolomite, marl, papery shale, bedded gypsum, and alternating sand stone and claystone.
- Majzir Formation (Paleocene-Lower Eocene): A shallow marine-littoral sandstone succession.
- Shihr Group (Oligocene-Pliocene): Conglomerate, sandstone, silt, lime tone and Gypsum.

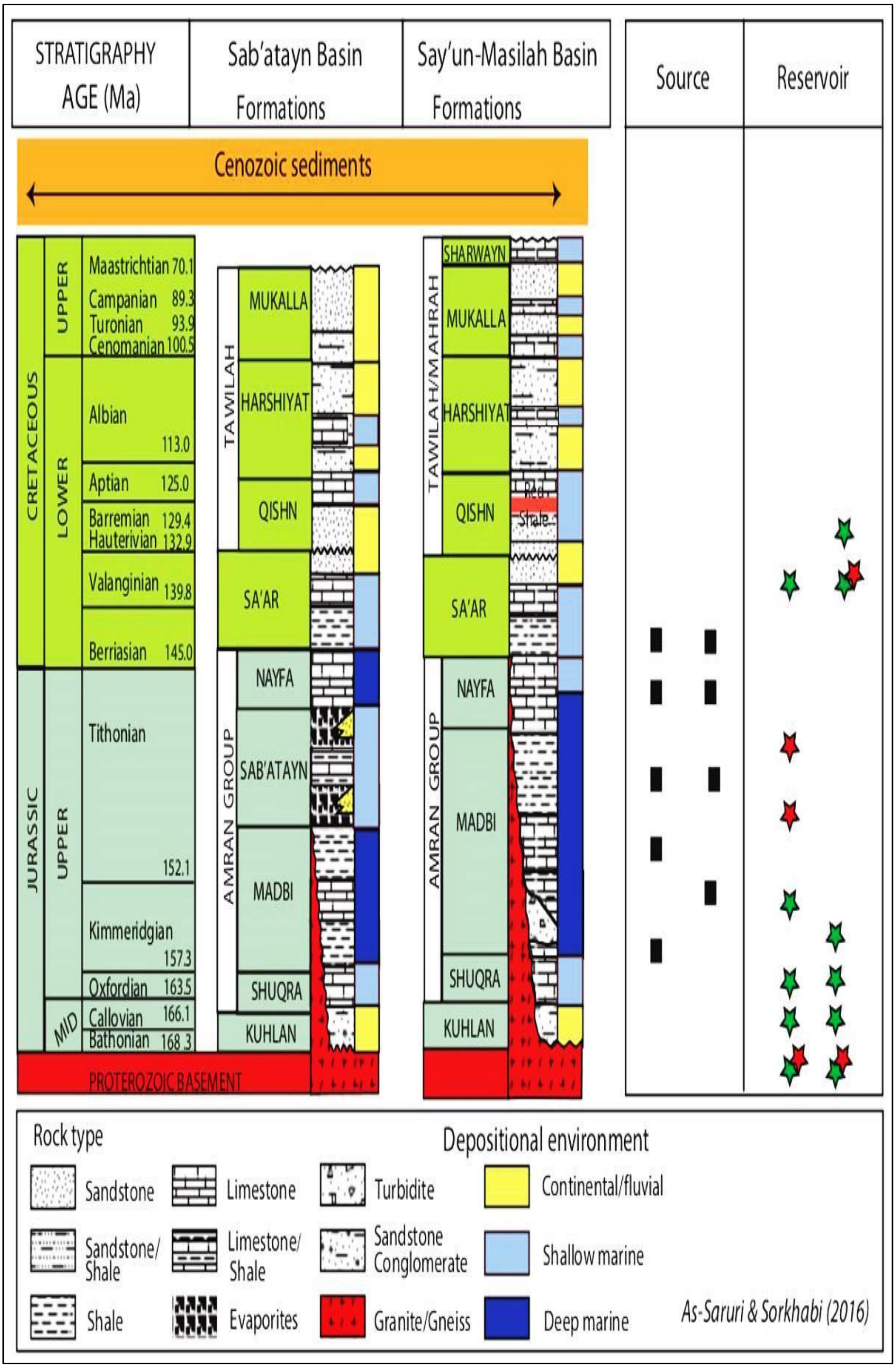

Figure 1.2 Stratigraphy and petroleum systems of Sab'atayn and Say'un-Masilah Basins. (Source: As-Saruri & Sorkhabi (2016).

1.3.1.4. Basement rocks

The basement rocks of Yemen are considered a part of the Arabian shield which can be divided into five terranes. Asir terrane, Abbas terrane, Al Bayda terrane, Al Mahfid terrane and Al Mukalla terrane. They arrange in manner that reflect the magnitude of tectonic process in time and space. Two of them represent island arcs which are abducted to continental crust, the Al Bayda terrane, and Al Mukalla terrane. The remaining three others from Archean to Proterozoic gneissic terranes, the Abbas terrane, Asir terrane and the Al Mahfid terrane. The Precambrian basement of Yemen covers a key location in the Pan-African orogeny of Gondwana.

1.4.2 Masila-Say'un Basin

Masila Basin is one of the most productive basins in Republic of Yemen. It is Mesozoic sedimentary basins of Yemen (Fig. 3), and was formed as a rift-basin linked to the Mesozoic breakup of Gondwanaland and the evolution of the Indian Ocean during the Jurassic and Cretaceous (Beydoun et al. 1998; Redfern and Jones 1995; Csato et al. 2001). Mesozoic and Cenozoic units are widely exposed in the sedimentary basins of Yemen. The stratigraphic section of the Masila Basin including studied Sharyoof oilfield in age from Precambrian to Tertiary. Basement complex rocks of Precambrian age underlie the Jurassic rocks at a sharp unconformity surface. They consist of granite, diorite, and metamorphic rocks. The Jurassic units comprise clastic, carbonate, and argillaceous sediments. The lower part of the Jurassic is composed of sandstone and limestone (Kohlan and Shuqra Formations). Here, the Kuhlan and Shuqra are regarded as a discrete pre-rift package (Eills et al. 1996). The Kuhlan Formation is predominantly clastic with local basement topography commonly providing the provenance of sediment. The Shuqra Formation conformably overlies the Kuhlan Formation with a gradational contact. This conformable relationship reflects the gradual transgression and a slight deepening of marine conditions. It conformably underlies the Madbi Formation. During the late Jurassic commencing in the Kimmeridgian, syn-rift sediments of the Madbi Formation were deposited. The lithofacies of this unit divided into two members. The lower member, Madbi limestone, and the upper member called Madbi shale. During latest Jurassic to early Cretaceous time, the rifting system of the Masila Basin continued but the subsidence became slower. It was accompanied by the accumulation of carbonates in shallow-marine shelf deposits (Naifa Formation). The Naifa Formation consists mainly of silty and dolomitic limestone and lime mudstone with wackestone. The Cretaceous units comprise the Saar, Qishn, Harshiyat, Fartaq, Mukalla, and Sharwayn formations (Mahara Group). The Saar Formation is conformably overlies the Naifa Formation and unconformably underlies the Qishn Formation. The Qishn Formation consists mainly of sandstones, with shale and minor carbonate interbeds, deposited in braided river channels, shoreface and shallow-marine settings as predominantly post-rift sediments. The Lower Cretaceous Qishn Formation in the Masila Basin has a variety of usage by the various operating oil companies and authors (e.g., Redfern and Jones 1995; Putnam et al.) interpreted the Qishn clastics as being age-equivalent of the Biyadh Sandstone of Saudi Arabia. They also identified a clear overall transgressive signature through the Qishn clastics and noted that the upper part of the formation typically consists of carbonates. A down-systems-tract facies change from coarse grained clastic deltas in the west to shale and limestone dominated successions farther east was recognized by Redfern and Jones (1995), Holden and Kerr (1997) and Brannan et al. (1999). The Qishn clastic underling the Qishn Carbonates, which comprises carbonate rocks with red shale beds at the base and represented the proven seal rock in the Masila Basin (Fig.1.3). The Qishn Carbonates sediments were deposited in deep water under alternating open and closed marine conditions.

1.5. Study of Area

1.5.1. Block (53)

Block (53) is located at northeastern portion of the Masila Basin, towards the east of Hadhramout Province, adjacent to three prolific Blocks which are, Block-14 (contains 16 producing fields) that operated by Nexen Petroleum Yemen Ltd (Dove, 2000). Block (32) (contains 2 producing fields) that operated by DNO from East side and Block (10) that operated by Total (Now PetroMasila) from west side. It was awarded to Dove in 1998 in relinquished acreage.

Block-53 holds three discoveries Sharyoof, Buyout and Hekma. The main reservoir in the block is Qishn sandstone and Basement. Now it is operated by PetroMasila.

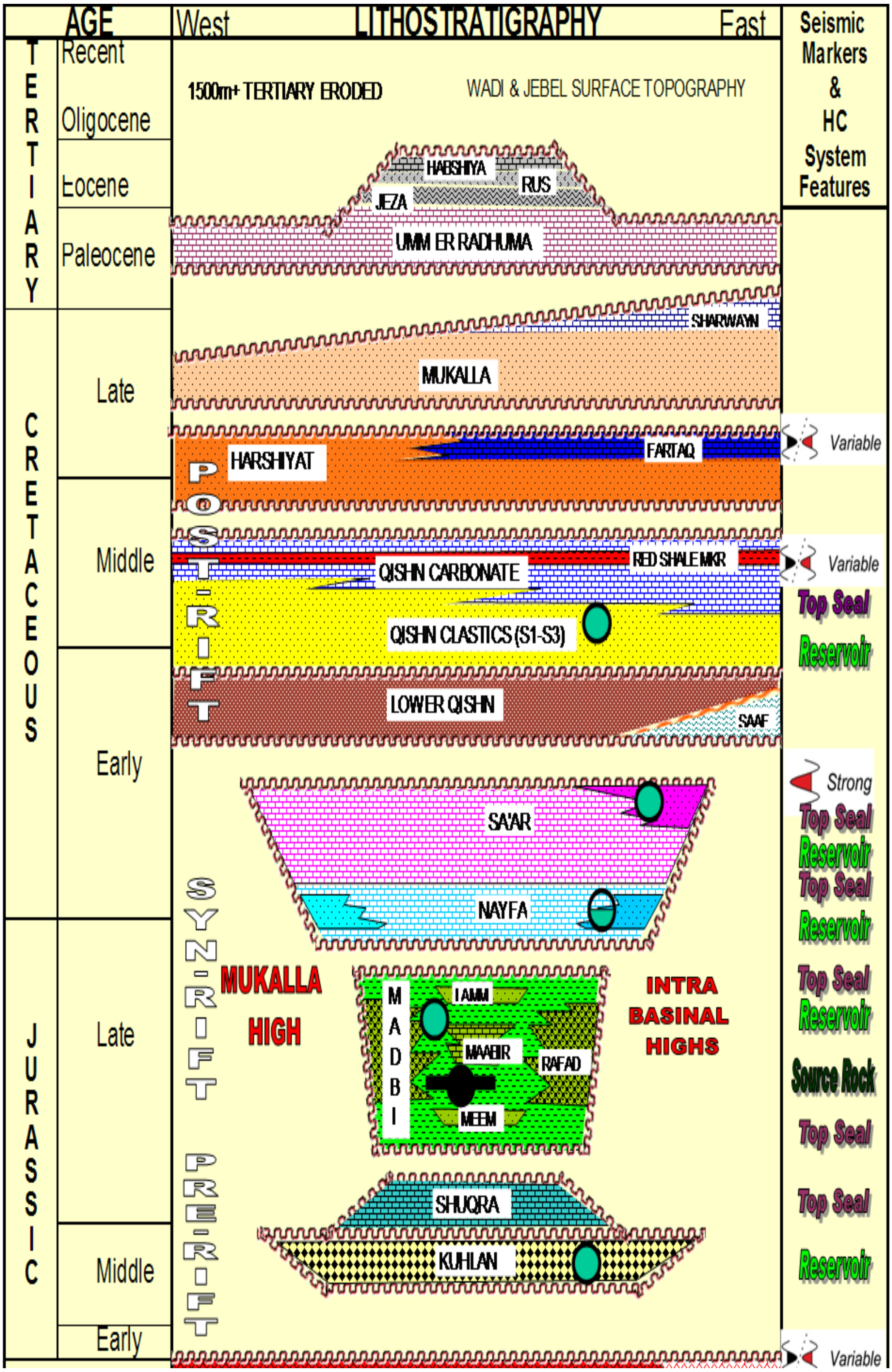

Figure 1.3 Masila Basin Stratigraphic Summary.

1.5.2. Sharyoof Oilfield

The Sharyoof oilfield is one of the most productive oilfields in the onshore of Block-53 in the Masila Basin, located in the N/W sector of the Masila Basin , 550 km east of Sana’a city, with area of 474 km2 (Fig.1.4). Sharyoof oilfield is also located between several successful producing oil fields: the Sunah oilfield to the southeast, the Kharir oilfield to the west, and the Tasour field to the east .Sharyoof filed was discovered by Dove Energy in June 2000 by Dove energy Company, Sharyoof-1 (TD 1765 m) and second well Sharyoof-2 (TD 1630 m) drilled which targeted the Cretaceous units. The field was put on development in December 2001. Water was first injected in 2004 and infill drilling has been continued since then. The field is now at the late Stage of Water injection (secondary recovery) with water-cut of more than 90% in most of the producing wells.

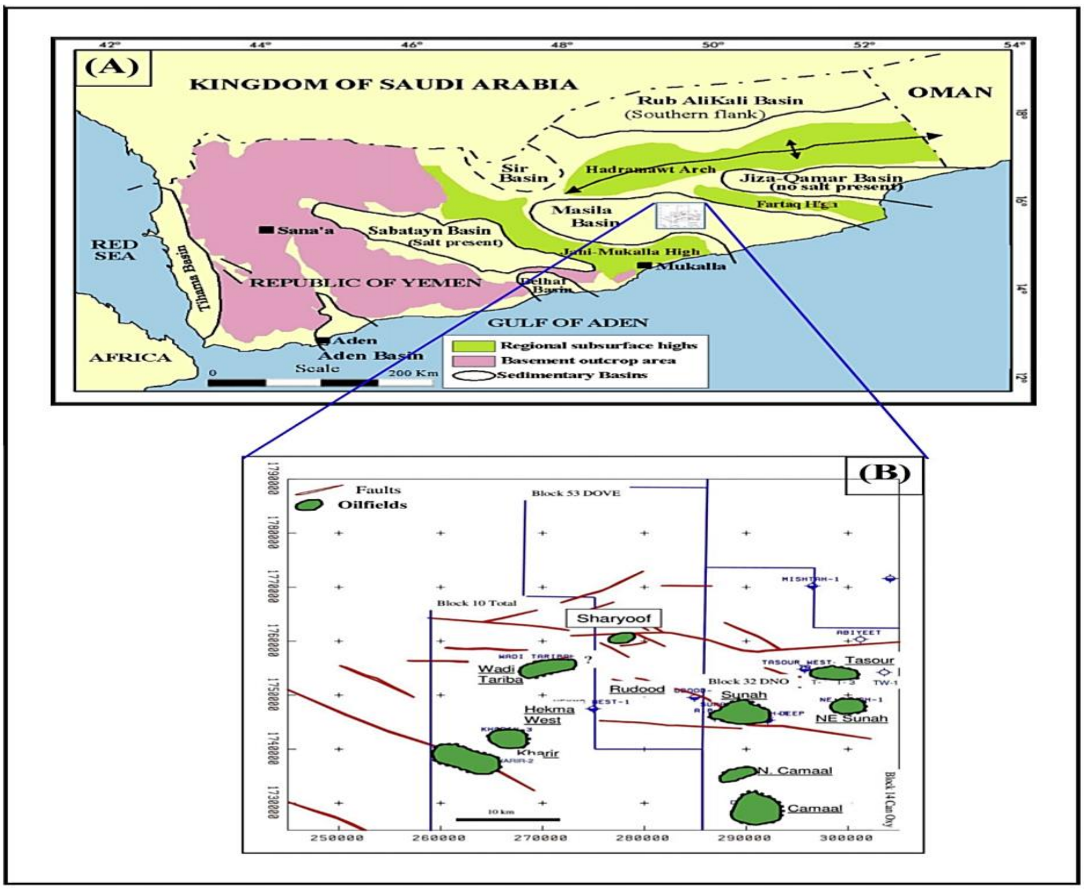

Figure 1.4 (A) Main sedimentary basins in Republic of Yemen (modified after Beydoun et al. [12]) and (B) location map of some Masila Basin’s Blocks including Sharyoof oilfield (Block 53), Hadramawt region of the Republic of Yemen

.

The structure types in the Sharyoof oilfield are characterized by horst, tilted fault blocks .These structures were formed during late Jurassicearly Cretaceous and developed during Oligocene–Middle Miocene time as a result of opening of the Red Sea and the Gulf of Aden during the Tertiary rifting tectonic event (Haitham and Nani 1990; Bott et al. 1992; Crossley et al. 1992; Huchon et al. 1991; Redfern and Jones 1995). The Sharyoof oilfield contains sedimentary rocks ranging from Jurassic to Tertiary in age, including Saar Formation (Fig.5).The early Cretaceous Qishn Formation Sandstone is an important hydrocarbon (oil) main reservoir in the Sharyoof oilfield.

Qishn sandstone reservoir is divided into three main units named S1, S2, and S3. S1 is main hydrocarbon-bearing unit which is further subdivided into three sub-units, i.e. S1A, S1B and S1C. S1A and S1C subunit attain the best hydrocarbon saturations and in same time S1A zone is the best petrophysical and reservoir quality properties and higher hydrocarbon content. The 100% water-bearing nature of the S1B subunit. The hydrocarbon content of S2 unit is lower than that of the S1A-and-S1C subunits as you can see in (Fig. 6).

Based on operating oil companies' unpublished data the productivity varies significantly within the Pre Cambrian/Archean grantic basement, lower Cretaceous Saar Formation carbonates, and middle Cretaceous Qishn Formation clastic deposits. The produced oil at Sharyoof oilfield is intermediate oil and has a specific gravity between 28 and 32 API. The source rock is Upper Jurassic Madbi Formation (Hakimi et al. 2010a), which began to generate oil began during Late Cretaceous (99–66 Ma), and reached a maximum during the Paleocene (<66 Ma) (Hakimi et al. 2010b). However, the lower Cretaceous Saar Formation carbonates are represents as secondary reservoir rocks in the Sharyoof oilfield (DNO Oil Company, 1999 personal communication).

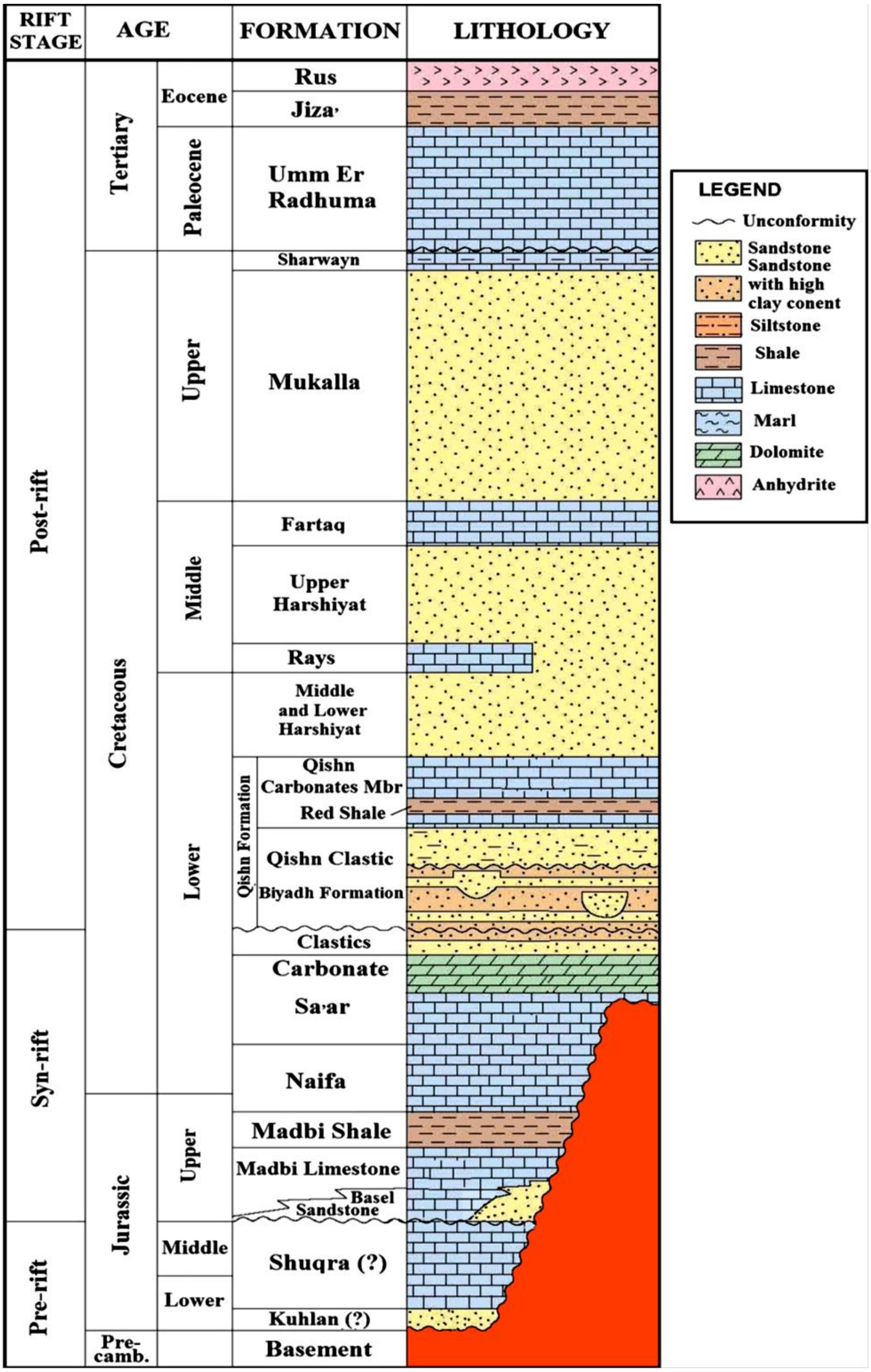

Figure 1.5 Stratigraphic column in the Masila Basin, including Sharyoof oilfield of the eastern Yemen.

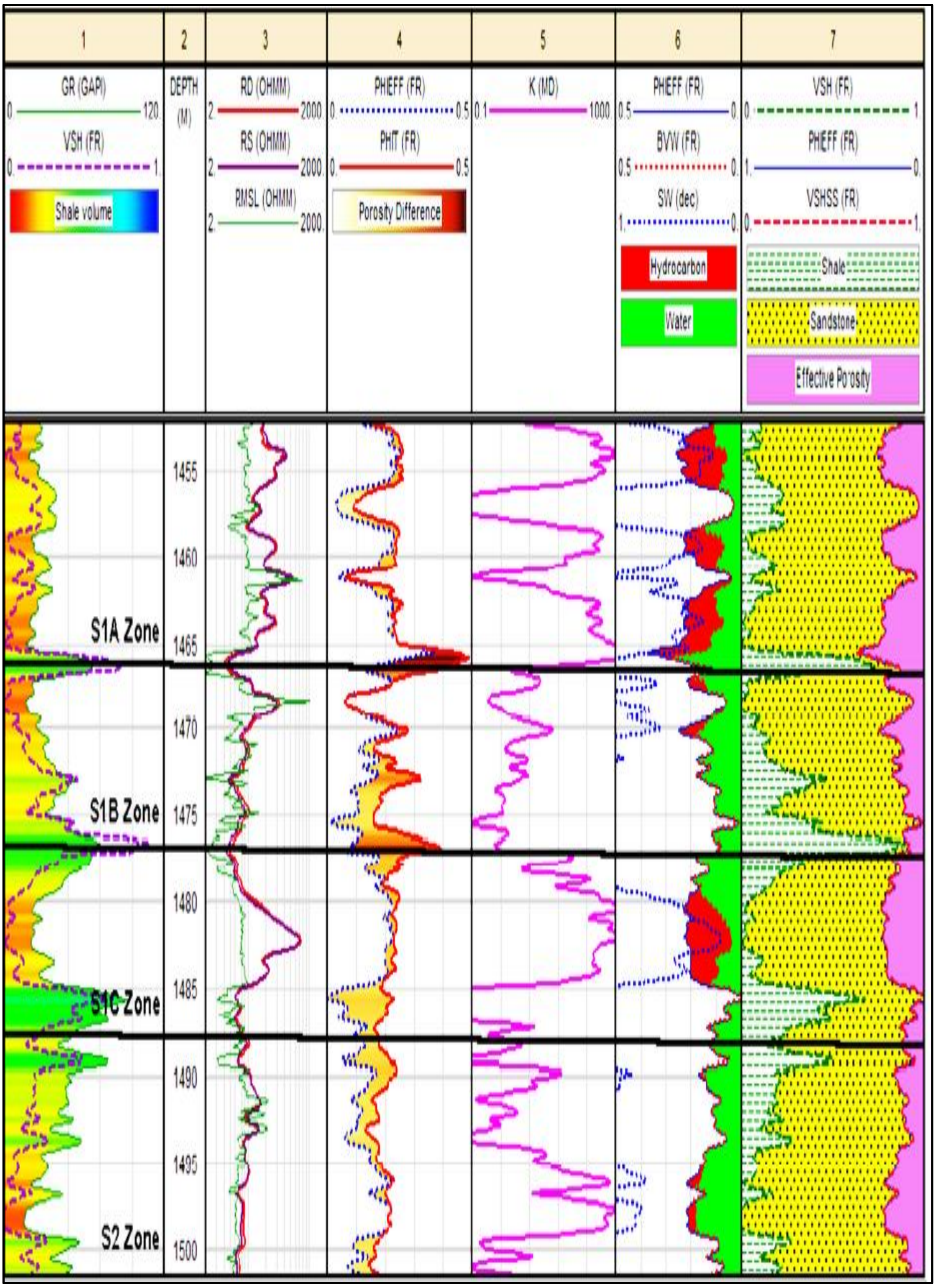

Figure 1.6 Log characteristics of gamma and resistivity logs used for lithological characterization of main units of Qishn sandstone reservoir.

CHAPTER-TWO

2. LITERATURE REVIEW

2.1. Oil Recovery Mechanisms

Recovery of hydrocarbons from an oil reservoir is commonly recognized to occur in several recovery stages. These are: Primary oil recovery, secondary oil recovery and tertiary (enhanced) oil recovery are terms that are traditionally used in describing hydrocarbons recovered according to the method of production. The three different oil recovery mechanisms are presented in (Fig. 2.1),[1].

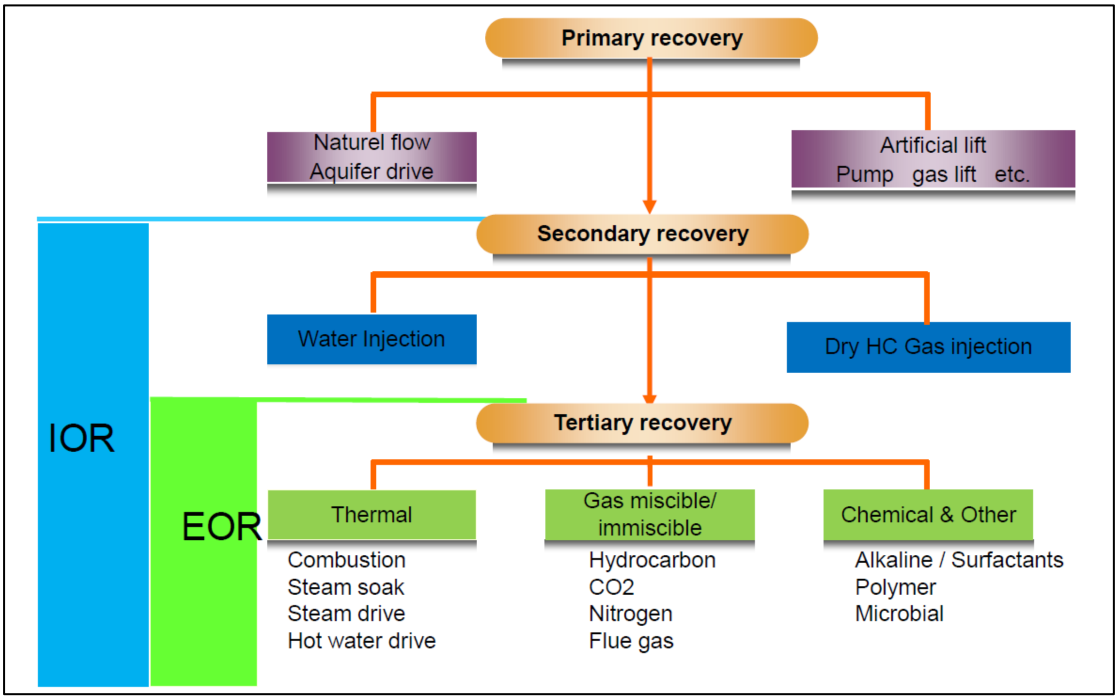

Figure 2.1

2.1.1. Primary Oil Recovery

It is necessary to have knowledge of the driving mechanisms that control the behavior of fluids within reservoirs. The overall performance of oil reservoirs is largely determined by the nature of the energy driving mechanism, available for moving the oil to the wellbore. 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.

Primary recovery describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery (0 to 30% of the reservoir original oil-in-place). The 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.

2.1.2. Secondary Recovery

Refers to the additional recovery resulting from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery follows the primary recovery but may be conducted concurrently with the primary recovery. Water flooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project it should be clearly proven that the natural recovery processes are insufficient; otherwise, there is a risk that the required substantial capital investment may be wasted. After primary recovery, 25 to 45% oil recovery can be obtained by the implementation secondary recovery.

2.1.3. Tertiary (Enhanced) Oil Recovery (EOR)

EOR is the additional recovery over and above what could be recovered by primary and secondary recovery methods. Secondary and tertiary recovery processes are those processes that stimulate oil recovery by external injection of fluids to increase the energy available in the reservoir following primary recovery. Oil recovery is about the efficient and cost-effective recovery of oil from subsurface reservoirs. The design of recovery methods to satisfy these objectives the responsibility of petroleum engineers. Petroleum engineers handle the analysis, design, and implementation of recovery projects, which include topics in reservoir, drilling, petrophysical, and production engineering.

Infill recovery

Is carried out when recovery from the previous three phases have been completed. It involves drilling cheap production holes between existing boreholes to ensure that the whole reservoir has been fully depleted of its oil. To determine the un-swept areas for the infill well locations, prediction simulation of the base case is run so as to identify the remaining oil saturated areas at the end of simulation period. Required number of infill wells is determined based on the identified oil saturation locations (Thang, et al., 2010).

Enhanced Oil Recovery

The terms enhanced oil recovery (EOR) and improved oil recoveries (IOR) have been used loosely and interchangeably at times. IOR is a general term that implies improving oil recovery by any means (e.g., operational strategies, such as infill drilling, horizontal wells, and improving vertical and areal sweep). EOR is more specific in concept and it can be considered as a subset of IOR. EOR comprises mainly gas injection methods, chemical methods, thermal methods and other methods. The optimal application of each type depends on reservoir temperature, pressure, depth, net pay, permeability, remaining oil and water saturation, porosity and fluid properties such as oil API gravity and viscosity. EOR implies the process of enhancing oil recovery by reducing oil saturation below the residual oil saturation "**Sor**" The target of EOR varies considerably by different types of hydrocarbons. (Fig.2.2). shows the fluid saturations and the target of EOR for typical light and heavy oil reservoirs and tar sand. For light oil reservoirs, EOR is usually Applicable after secondary recovery operations with an EOR target of approximately **45%** original oil in place (OOIP). Heavy oils and tar sands respond poorly to primary and secondary recovery methods, and the bulk of the production from these types of reservoirs come from EOR methods.

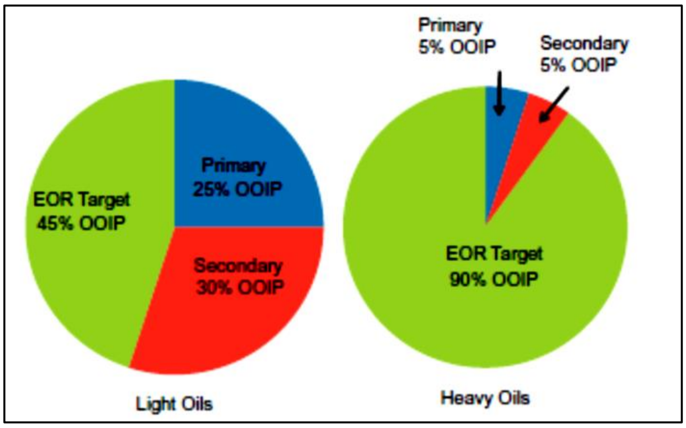

Figure 2.2 Target for different crude oil system.

EOR processes are implemented in order to improve the Total recovery efficiency of the oil which includes the microscopic and macroscopic displacement efficiency.

$$\mathbf{E_R = E_D * E_V}$$

E_R =Total recovery efficiency, **ED** = microscopic displacement efficiency (fraction), and EV = macroscopic or volumetric displacement efficiency (fraction).The efficiency of any EOR process is not measured by its technical feasibility and economics point of view, where there are some factors Controlling the economic implementation of the process mainly crude oil price and the cost of injection fluid .

2.1.3.1. Water Flooding

Water flooding is a process of injection of water into an oil reservoir to “push” additional oil out of the reservoir rock and into the wellbores of producing wells. Water flooding is a method of secondary recovery in which water is injected into the reservoir formation to displace residual oil.

The water from injection wells sweeps the displaced oil to adjacent production wells. The purpose of water flooding includes the maintenance of reservoir pressure and the displacement of hydrocarbons toward the wellbore as shown in (Fig.2.3).

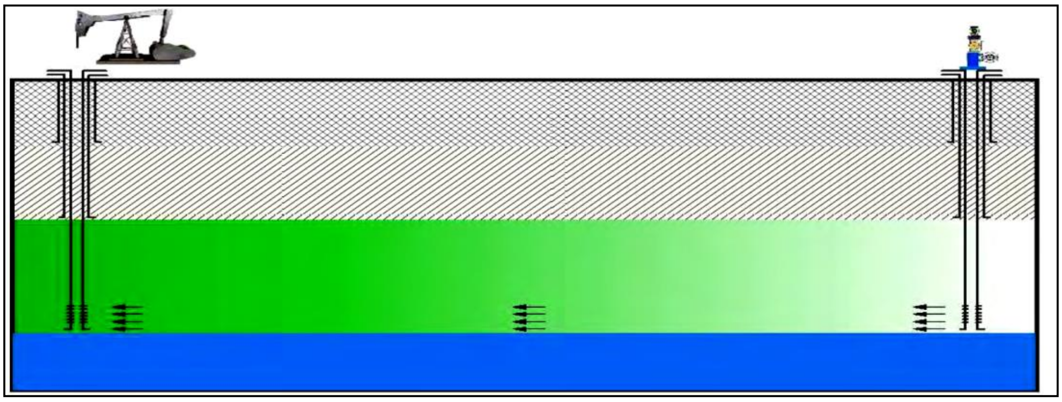

Figure 2.3 Water flooding scheme.

Absolute permeability, homogeneity in the pay zone and the mobility ratio of oil and water are critical to the sweep efficiency, however injection well location are also important. The injected fluid must be treated to avoid reservoir plugging, shale swelling, and corrosion of surface and downhole equipment.

The applications of Water flooding

- To support or maintain pressure of the reservoir
- To sweep or displace oil from the reservoir, and push it towards a wellbore.

Factors to Considered in Water Flooding

Factors to be considered when water flooding project for the purpose of enhancing oil recovery in the field are the following :

1) **Reservoir geometry:** the areal geometry of the reservoir will influence the location of wells.

2) **Fluid properties**: the viscosity of the crude oil is considered the most important fluid property that effects the degree of success of a water flooding project. The viscosity has important effect of determining the mobility ratio and in turns control the sweep efficiency.

3) **Reservoir depth**: reservoir depth has an important influence on both the technical and economic aspect of secondary or tertiary recovery. Maximum injection pressure will increase with depth, the cost of lifting oil from very deep wells will limit the maximum economic water oil ratio that can tolerated, thereby

reducing the ultimate recovery factor and increasing the total project operating cost.

4) **Lithology and rock properties**: porosity in some complex reservoir system only a small portion of the total porosity such as fracture porosity will have sufficient permeability to be effective in water injection operation; in this case the water injection program will have a minor impact on the matrix porosity.
5) **Fluid saturation**: high oil saturation is required in the begging of water flooding. High oil saturation will increase the oil mobility, in turns give higher recovery efficiency.
6) **Reservoir uniformity**: it refers to reservoirs that have homogenous petrophysical properties. The movement of the fluid through the reservoir will not be uniform if there is a large variation in such properties such as porosity, permeability and clay cement.
7) **Pay continuity**: it refers to a reservoir rocks with no isolated lenses. Isolated lenses may be depleted by single well completion but a flood mechanism requires that both the injector and producer be present in the lens.

Water Flooding Difficulties

The economics and success of deep water developments in most parts of the world is mostly hinged on the performance of water injectors. Producers whose high rates are solely dependent on these injectors present their own management risk but the maintenance of injectors relative to producers is a major challenge in the oil and gas industry as over time their injectivity may decline as a result of different factors such as: the injection water quality (main cause of impairments due to suspended solids), and the temperature difference between the injected water and the reservoir fluids leading to precipitation of solids and several other factors.

The injected water is either produced water, fresh water or sea water; each of these sources comes with a certain measure of impurities which are either organic or inorganic. Injected seawater contains suspended particulates (sand) and salts which settle out or precipitate in the formation when it is injected if not properly treated. However, even when the water is well treated at the surface, its quality may deteriorate as it travels down hole and this may be owing to corrosion which depends on the water pH or a gain in solids as it flows through piping. These suspended particles can over time settle and fill-up the wellbore, plug the completion screens and formation pores leading to severe permeability impairment, loss of injectivity, most of all inadequate voidage replacement and low hydrocarbon recovery.

In order to mitigate this issue in the oil and gas industry, different on-line filters are employed to remove solids of defined sizes that might cause injectivity problems and in most cases a down-hole filter assembly is installed to further separate transported solids before the water gets to the down-hole sand control completion. The finer the filtering, the more expensive and bulky the facilities required to implement it, especially in deepwater operations; hence, a balance has to be reached during water flood project planning between optimized reservoir performance and the economics of the required water treatment systems. For an optimized design of these filter systems, knowledge of the particle size distribution in the injected water is required and this can be used to carry out particle residence time analysis in the porous media to obtain an estimate of how long these particles stay in suspension in the formation before deposition. (Dambani .2013).

2.1.3.2. Polymer Flooding

Polymer is the material that plays an important role in the application of EOR technology, especially for hydrogel polymer. A typical polymer flood project involves mixing and injecting polymer over an extended period of time until about 1/3-1/2 of the reservoir pore volume has been injected. This polymer "slug" is then followed by continued long-term water flooding to drive the polymer slug and the oil bank in front of it toward the production wells. Polymer is injected continuously over a period of years to reach the desired pore volume. When water is injected into a reservoir, it seeks the path of least resistance (usually the layers of highest permeability) to the lower pressure region of the offset producing wells,[6].

"Polymer flooding is a tertiary recovery method by adding high-molecular-weight polyacrylamide into 'injected water, so as to increase the viscosity of fluid, improve volumetric sweep efficiency, and thereby further increase the oil recovery factors When oil is displaced by water, the oil/water mobility ratio is so high that the injected water fingers through the reservoirs. By injecting polymer solution into reservoirs, the oil/water mobility ratio can be much reduced, and the displacement front advances evenly to sweep a larger volume. The viscoelasticity of polymer solution can help displace oil remaining in micro pores that cannot be otherwise displaced by water flooding in areas with relatively poor physical properties and low permeability, there will still be a lot of residual oil left behind underground after using artificial water drive. Generally heterogeneous sandstone reservoir results in ultimate oil recovery of only about 30 percent According to theoretical predictions, the ultimate recovery of an oilfield can be increased to above 50 percent or more by using a polymer flooding solvent. The polymer flooding solvent acts to significantly drop the surface tension of the underground crude oil, thereby greatly increasing the displacement efficiency. This converts the original viscous well block of residual oil into moveable oil, in the stagnation zone of residual oil wells. The water content of the oil well declines and the capacity for production steadily rebounds; it’s a complex method with the potential for numerous factors to simultaneously affect the result. Many characteristics of the polymer flow in porous mediums are yet to be fully understood.

Polymer gel is also used to shut off high-permeability zones. In the process, the volumetric sweep is improved, and the oil is more effectively produced. Often, injectivity will be one of the critical factors. The polymer solution should therefore be a non-Newtonian and shear thinning fluid, that is, the viscosity decreases with increasing shear rate.

There is no general rule defining the quantity of polymer that should be injected into a reservoir. The number generally given, based on experience, is a minimum of 30% of the reservoir pore volume, with the following sequence:

Viscosity ramp- up at the beginning of the project to observe the reservoir response and possible pressure increases. Viscosity plateau with a minimum of 30% reservoir pore volume (the worldwide average is approximately 50% of pore volume injected). The larger the slug, the better the efficiency during polymer injection and after. The maximum efficiency will be reached after 1 PV injected. Viscosity ramp- down over the last 5% of pore volume injected, which serves to decrease the viscosity contrast between the polymer slug and the water chase. As previously indicated, the larger the volume of polymer injected expressed as reservoir pore volume, the higher the efficiency of the process. This is explained by looking at what is happening when the injection of polymer is switched back to water injection at the end of the process: if the polymer slug volume is too small, there is a high probability that the chase water will again finger through the polymer slug, thereby decreasing the efficiency of the whole process.

Polymer is designed to improve sweep efficiency by reducing the mobility ratio. The mobility ratio "**M**" is defined as the ratio of the displacing fluid mobility, **λ** displacing, to that of the displaced fluid, λ displaced. In traditional water flooding, the mobility ratio is defined mathematically as:

$$M = \frac{\lambda \text{ displacing}}{\lambda \text{ displaced}} = \frac{krw}{kro}\frac{\mu o}{\mu w}$$

A mobility ratio of approximately 1, or less, is considered favorable, which indicates that the injected fluid cannot travel faster than the displaced fluid. For example, when M=10, the ability of water to flow is 10 times greater than that of oil. Equation above indicates that M can be made more favorable by any of the following:

- decrease oil viscosity **μo**;
- increase the effective permeability to oil;
- decrease the effective permeability of water;
- increase the water viscosity**, μw**.

Little can be done to improve the flow characteristics of the oil in the reservoir, i.e., **μo** and **kro**, except by thermal recovery methods. However, a class of chemicals, i.e., polymers, which when added to water, even in low concentrations, increases its viscosity and decreases the effective permeability to water, resulting in a reduction in the mobility ratio. The need to control or reduce the mobility of water led, therefore, to the development of polymer flooding or polymer-augmented water flooding. Polymer flooding is viewed as an improved water flooding technique since it does not ordinarily recover residual oil that has been trapped in pore spaces and isolated by water. However, polymer flooding can produce additional oil over that obtained from water flooding by improving the sweep efficiency and increasing the volume of reservoir that is contacted. Dilute aqueous solutions of water-soluble polymers have the ability to reduce the mobility of water in a reservoir, thereby improving the efficiency of the flood.

Partially hydrolyzed polyacrylamides (**HPAM**) and xanthan gum (**XG**) polymers reduce the mobility of water by:

• Increasing the viscosity of the injected aqueous phase

• Reducing the permeability of the formation water.

Permeability Reduction Factors

This reduction in the water permeability is fairly permanent, while the permeability to oil remains relatively unchanged. The reduction in permeability is measured in laboratory core flood and results are expressed in two permeability reduction factors:

1) Residual resistance factor "Rrf" Residual resistance factor is a laboratory measured property that describes the reduction of water permeability after polymer flood. Polymer solutions continue to reduce the permeability of the aqueous phase even after the polymer solution has been displaced by brine. The ability of the polymer solution to reduce the permeability is measured in the laboratory and expressed in a property that is called the residual resistance factor.

This permeability reduction factor is defined as ratio of the mobility of the injected brine before and after the injection of the polymer solution, i.e.:

$$\mathbf{Rrf} = \frac{\lambda w \text{ (before polymer injection)}}{\lambda P \text{ (after polymer injection)}}$$

2) Resistance factor "Rf" The resistance factor "**Rf**" describes the reduction in water mobility and is defined as the ratio of the brine mobility to that of the polymer solution, with both mobilities measured under the same conditions, i.e.:

$$\mathbf{Rf} = \frac{\lambda w}{\lambda P} = \frac{kw/\mu w}{kP/\mu P}$$

Where:

$\boldsymbol{\lambda_w}$ = mobility of brine.

$\mathbf{k_w}$ = effective permeability to brine.

$\boldsymbol{\mu_w}$ = brine viscosity.

$\boldsymbol{\lambda_P}$ = mobility of polymer solution.

$\mathbf{k_P}$ = effective permeability to polymer solution.

$\boldsymbol{\mu_P}$ = polymer solution viscosity.

This permeability reduction is essentially caused by the retention of polymer molecules in the reservoir rock. This is a combination of adsorption and entrapment, and it is not entirely reversible. Thus, most of the polymer (and the benefits it provides) remains in the reservoir long after polymer injection is stopped and the field is returned to water injection. Adsorption is the irreversible retention of polymer molecules on the rock surface. The amount of polymer adsorbed on the rock surface depends on the type and size of the polymer molecules, polymer concentration, and rock surface properties. Even with a favorable mobility ratio, if the reservoir has some degree of heterogeneity, polymer injection can help to reduce the water mobility in the high- permeability layers supporting the displacement of oil from the low-permeability layers.

The limitations of polymer flooding include :

1) Nearly half of the remaining underground oil reserves will be left behind after polymer flooding. Current technology does not provide a method to deal with these remaining reserves.

2) After polymer flooding for a long time, (usually two to three years), the oil reservoir will have serious scaling (i.e. materials sticking to metal surfaces - one of the major problems in the development of oil and gas fields). This ultimately leads to a large number of oil and water wells that are no longer operational.

3) Thirdly, the complex requirements of the project make polymer flooding an expensive option and therefore difficult for small or medium enterprises to put into action.

Screening criteria for polymer application

Historically, it appears that sandstones were preferred over carbonates when considering polymer injection. For instance, when looking at the projects in the USA between 1971 and 1990, 320 pilot projects or field wide chemical floods have been identified in the literature among which 57 were conducted in carbonate reservoirs. This preference can probably be explained by the fact that anionic polymers present several advantages: they have a high viscosifying power, very high molecular weights, and are cheap to produce by opposition to synthetic cationic polymers which are expensive to produce, highly shear sensitive, and display lower molecular weights on average. For sandstone and clayey reservoirs, which are negatively charged, the injection of anionic macromolecules is obviously preferred to limit ionic interactions. Some unchanging parameters that must be considered before the implementation of polymer flooding are:

• **Water injectivity** : obviously, good water injectivity will ensure appropriate polymer injectivity.

• **Clays** : a high percentage of clays can be detrimental to polymer propagation (adsorption and retention).

• **Presence of aquifers** : to avoid dilution and chemical losses, injection should occur Outside of the aquifer zone.

Comparisons of the Sharyoof oilfield reservoir conditions with the PF SC developed by PetroChina and the National Petroleum Council (NPC) of USA are shown in

Propertise	PetroChina	US NPC	Sharyoof	Applicability
Lithology	Sandstone	Sandstone	Sandstone	Yes
Permeability (10^{-3} μm^{-3})	>20	>20	1000	Yes
Oil Saturation %	>35	-	30	Yes
Oil Specific Density	<0.95	-	0.87	Yes
Oil Vis. (mPa.s)	<100	<100	6	Yes
TDS (mg/l)	<10000	<1000000	<3000	Yes
Hardness (mg/l)	<70*	-	<200	Yes
Inj. Water	<1000	-	<2500	Yes
Reservoir Temp	<70	<93	35	Yes

Table 2.1. Comparison of Sharyoof reservoir conditions with the SC.

2.1.3.3 Polymer Types and Their Properties

Polymers can be categorized to many types which are commercially available for EOR as shown below:

- **Polysaccharides**
  - Xanthan gum.
  - Biopolymers.
- **Polyacrylamides**
  - Polyacrylic acid.
  - Polyacrylamide(PAM).
  - Hydrolyzed polyacrylamide (HPAM).
  - Co-polymers of the above.
- **Celluloses**
  - Hydroxyethylsellulose(HEC).
  - Carboxyethoxyhydroxyethylcellulose.
  - Carbonxymethylcellulose.
- **Others**
  - Glucan.
  - Dextran.
  - Polyethyleneoxide.

- **Polyacrylamides (HPAM)**

These polymers' monomeric unit is the acrylamide molecule the chemical structure of HPAM is shown below (Fig2.4). When used in polymer flooding, polyacrylamides have undergone partial hydrolysis, which causes anionic (negatively charged) carboxyl groups (-COO-) to be scattered along the backbone chain. For this reason these polymers are called partially hydrolysed polyacrylamides (HPAM). Typical degrees of hydrolysis are 30-35% of the acrylamides monomers; hence the HPAM molecule is negatively charged, which accounts for many of its physical properties. This degree of hydrolysis has been selected to optimize certain properties such as water solubility, viscosity, and retention. If hydrolysis is too small, the polymer will not be water-soluble. If it is too large, the polymer will be too sensitive to salinity and hardness. The viscosity-increasing feature of HAPM lies in its large molecular weight. This feature is accentuated by the anionic repulsion between polymer molecules and between segments in the same molecule. The repulsion causes the molecule in solution to elongate and snag on those similarly elongated an effect that accentuates the mobility reduction at higher concentrations.

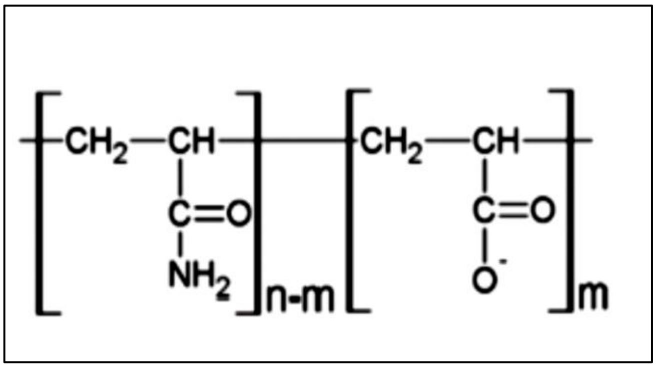

Figure 2.4 Chemical structure of HPAM**.**

If the brine salinity or hardness is high, this repulsion is greatly decreased through ionic shielding since the freely rotating carbon-carbon bonds allow the molecule to coil up. The shielding causes a corresponding decrease in the effectiveness of the polymer since snagging is greatly reduced. Almost all HPAM properties show a large sensitivity to salinity and hardness, which is an obstacle to use HPAM in many reservoirs; on the other hand, HPAM is inexpensive and relatively resistant to bacterial attack, and it exhibits permanent permeability reduction.

- **Polysaccharides**

This kind of polymer is formed from the polymerization of saccharide molecules, a bacterial fermentation process. This process leaves substantial debris in the polymer product that must be removed before the polymer is injected. The polymer is also susceptible to bacterial attack after it has been introduced into the reservoir. The disadvantages are also offset by the insensitivity of polysaccharide properties to brine salinity and hardness. The polysaccharide molecule is relatively non-ionic and, therefore, free of the ionic shielding effects of HPAM. Polysaccharides are more branched than HPAM, and the oxygen-ringed carbon bond does not rotate fully; hence the molecule increases brine viscosity by snagging and adding a more rigid structure to the solution. Polysaccharides do not exhibit permeability reduction.

Molecule weights of polysaccharides are generally around 2 million. HPAM is much cheaper than Polysaccharides so it was used in most of the polymer flooding projects. In this research HPAM is also adopted since the water brine salinity in oil Z106 is only 2434- 4566 mg/l.

- **Hydrophobically**

The design of hydrophobically associating polymers is based on the concept of association between hydrophobic groups that are incorporated in the backbone of the polymers. These hydrophobic groups could be randomly or block-like distributed, and coupled at one or both ends. When the polymer is dissolved in water, the hydrophobic groups associate forming micro-domains, which leads to increase in the hydrodynamic volume and accordingly yields an improved thickening capacity. (Fig2.5). shows the structure of a typical hydrophobically associating polymer.

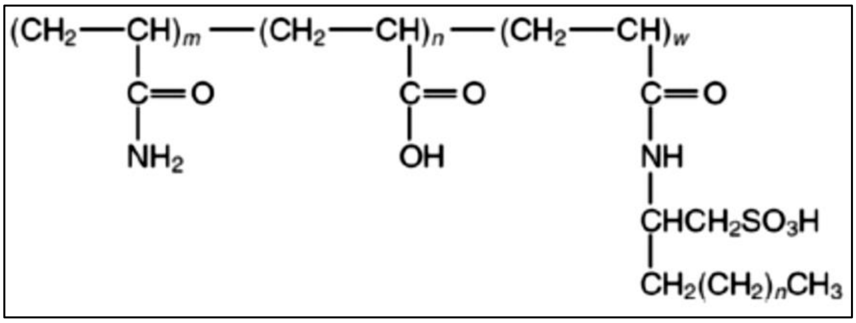

Figure 2.5 The structure of a typical hydrophobically.

- **Biopolymers**

In addition to the synthetic polymers, another kind of polymer frequently used is biopolymer, such as xanthan gum. Xanthan gum is a polymersaccharide which is produced by fermentation 10 Viscoelastic and Viscoplastic Materials of glucose or fructose by different bacteria. The chemical structure of xanthan gum as shown in (Fig.2.6). Illustrates the presence of two glucose units, two mannose units, and one glucuronic acid unit with a molar ratio of 2.8-2-2 [56]. X-ray diffraction studies proved that xanthan backbone has a helical structure where the side chains fold down along the helix. The average molecular weight of xanthan gum used in EOR processes is from 1–15 million.

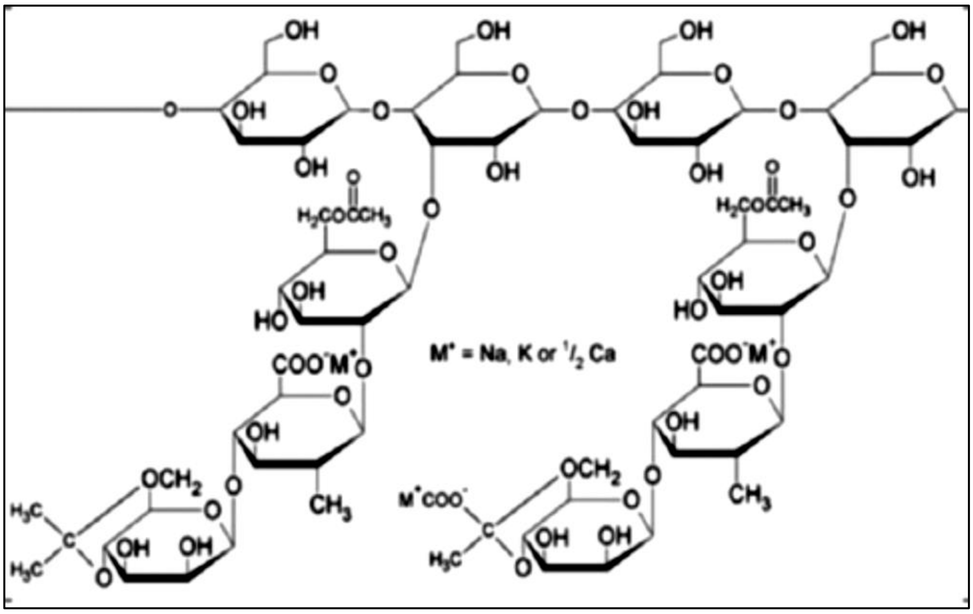

Figure 2.6 The structure of biopolymers.

2.2. Previous Study

2.2.1. Polymer Flooding in East China

DGXJ is a sandstone reservoir with temperature of 113 °C, salinity of 36235mg/L, and calcium and magnesium content of 1152mg/L and 30mg/L respectively. The reservoir is not only vertically multilayered and severe heterogeneous, but also witnesses water flowing channels, irregular and imperfect injecting- production well patterns, high recovery degree (43%) and high water cut (97%),[7].

Injection Process and Follow-Up Adjustment

From August, 2011 to August 2015, accumulated 0.08PV ($78.57*10^4 m^3$) was injected. During the process,it was discovered that on one hand, the advantage flow of the reservoir was stronger than previous understanding while on the other hand, due to the high temperature of reservoir, the performance of SMG and PSP could not achieve the expected result. Therefore, the proportion of preset/ middle conformance slug and main slug was adjusted from 1:9 to 4:6. Adjustment was also carried out in injection amount, slug size and concentration in light of various well responding's. For instance, some wells witnessed SMG upgraded from micrometer grade to sub-millimeter-grade while some others witnessed SMG concentration increasing to 0.5%. Multiple rounds of NPF injections were applied for unbalanced I/P well patterns to achieve middle water injection for energy recharge and for those wells partially finishing the injection amount of the preliminary scheme, extra NPF was injected to achieve complete effect of oil increase and water decrease.

Economic Results

According to real time oil price of each year(oil price after 2017 is predicted), by far (The end of 2016) the cumulative oil incremental was 89430.0 t and the total income was 43228.1 KUSD. When calculated on the basis of 30 USD/bbl as the oil price for all the years, the total income was 19719.3 KUSD while the total project investment was 15940.9 KUSD. The practical input to output ratio was 1:2.71, and the ratio of 1:1.24 could still be achieved even when the oil price dropped to 30 USD/bbl, demonstrating promising profits for the project.

It is predicted that by the year of 2020 when the project is expired, the cumulative oil incremental will be 135574.3 t and the total income will be 60697.8 KUSD. When calculated on the basis of the low oil price of 30 USD/bbl, the total income will be 29888.8 KUSD , the water flooding operating cost of oilfield DGXJ was 41.1 USD per barrel oil produced, while the EOR operating cost of it was 24.3 USD when calculated by far. It's predicted that when the project is expired by the year of 2020, the operation cost of EOR per barrel oil produced will be 16 USD. It is obvious that even the project is still undergoing, the cost has already been fully recovered andwith better profits. The cost of EOR per barrel oil produced will witness a large further decrease comparedto water flooding**.**

2.2.2. Polymer Flooding in Bohai Oil Fields

Reservoir Characteristics

With stable distribution and good connectivity, the reservoir is distributed in lower Dongying Group with a reversed sedimentary rhythmic feature. The buried depth is in the range of 1300~1600m and average thickness of pay zone is 61.5m. The whole oil-bearing formation is divided into 4 groups, which are subdivided into 14 layers. Lithologically, reservoir rocks are feldspathic quartz sand composed mainly of fine sands. The sand is unconsolidated and poorly cemented with porosity of 28~35% and average permeability of 2,600×10-3μm2. The original reservoir pressure is 14.28MPa and the reservior temperature is about 65°C,[8].

Pilot Area for Polymer Flooding

In order to improve the effectiveness of waterflooding, a numerical study of polymer flooding for the overall oilfield has been conducted, followed by a pilot test. The pilot area is located in the edge of the oilfield (Fig.2.7). It covers approximately 0.396km^2 and contains 1 injector (J**3**) and 5 corresponding producers (J**16**, A**2**, A**7**, A**12** and A**13**) with an average well spacing of 370m.

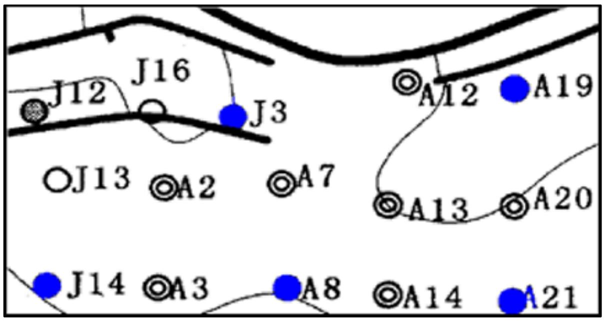

Figure 2.7 Location of wells in the pilot Area.

Viscosity - The major purpose of polymer flooding is to augment the viscosity of the injection water, resulting in the modification of poor water/oil mobility ratio. The viscosity of polymer solution is generally required to be greater than that of the crude oil. Some successful applications have been conducted with water/oil mobility ratios ranging from 0.1 to 42. The oil we deal with is the viscous oil with a viscosity of 70 mPa.s. It was hard to have a polymer solution with a viscosity in-situ over the viscosity of the crude oil.

Process of Polymer Injection

The concentrate polymer solution of 5,000 mg/L in the hydration tank is conveyed by the booster plunger pump and converged with the injected water so as to attain the dilute polymer solution of 1,750 mg/L in the static mixer, and then the dilute polymer solution passed through mesh filter is injected into the water input well, finally, it is injected into the pay zone after traversed the wire wrapped screen gravel packing zone.

Results of the Pilot Test

Realization of the goal for the pilot of polymer flooding Solubility and injectivity of the polymer under platform conditions - hydrophobically associating polymer could be resolved in water with the temperature and salinity above a lower limit. The actual visicosity of the polymer solution varied from 60 mPa·s to 100 mPa·s, indicating that the polymer powder dispersed and resolved in the solution to enhance the viscosity of the injected fluid in the limited time (2 hrs).

Incremental oil

Incremental oil production showed markedly in well J**16** (Fig.2.8). By the end of Feburary 2006, 23,000 m3 of accumulative crude oil has been produced in well J**16** with no natural decline was counted. The composite water cut of the well group reduced from 66% to about 50%. It was proved that polymer flooding would be feasible approach for production stimulation in SZ36-1 oilfield.

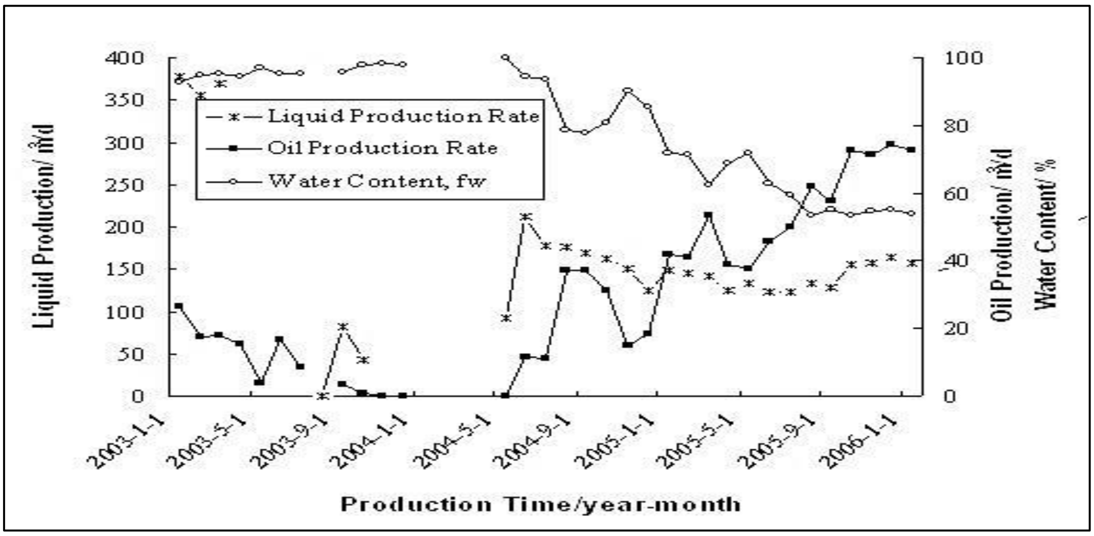

Figure 2.8 Incremental production of oil with polymer flooding in bohai field.

2.2.3. Polymer Injection Projects in Brazil

Reservoirs and Pilot Projects Areas

The selection of the reservoirs of Carmópolis (CP), was done using basic criteria defined in the literature., which was based on the average of these criteria extracted from two different sources. The first one is called "SELMET", which is a software developed by Petrobras for EOR screening purposes (15). The second source is IFP - Institut Français du Petrole (16), an entity that has been studying polymer injection for years and giving consultancy to Petrobras on field pilot projects.

Reservoir parameter

(CP) Have rock type sandstone and oil viscosity(cp) 50 , have API 22 , Oil saturation >50% ,Have Permeability (mD) is 100 , heterogeneity is high , Clay content is high.it can be seen that they fit all the criteria except for heterogeneity and clay content.

Polymer selection

Synthetic and natural polymers (biopolymer) were analyzed and, using a cost criterion, a partially hydrolyzed polyacrylamide (HPAN) was selected. the hydrolyze degree of the polymer based on the rock/fluid interaction parameters. For each reservoir, these two parameters should be defined through specific laboratory tests: solubility tests, rheological behavior, filterability tests, static These tests were realized to evaluate the compatibility of the polymeric solution with the reservoir rock and fluids and to determine the parameters of rock / fluids interaction (adsorption, resistance factor, residual resistance factor, inaccessible porous volume, etc.).

In (Fig.2.9) can observe the rheological behavior of the polymer solution in two conditions, a standard case using distilled water at 25°C, and other in the specific conditions of the candidate reservoir.

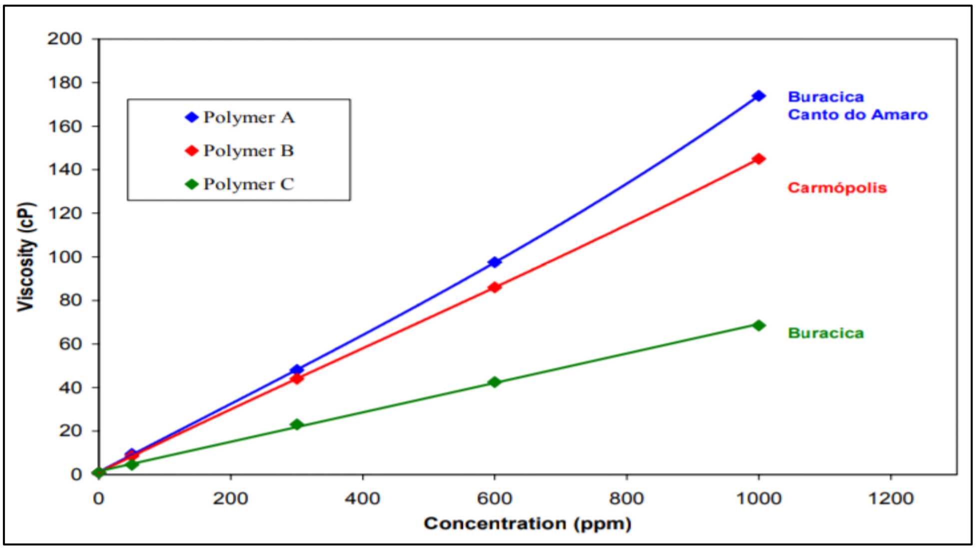

Figure 2.9 Rheological behavior of the polymer solution in two conditions, a standard case using distilled water at 25°C .

Result of the CP/SE pilot (Sept/1997 - Dec/2003)

The pilot of Carmópolis/SE was initially formed by four inverted nine-spot patterns. In order to obtain data from the pilot as fast as possible, four producers were drilled inside a given pattern , constituting a reduced pilot, , Two injectivity tests were carried out in these wells. The first with polymer and radioactive tracer, and the second with water and fluorescent tracer, just to check the polymer adsorption.

Injection and production data

In the polymer pilot of CP/SE a volume of approximately 0.1 PV was injected (Fig.2.10) which theoretically would have the largest chance of being influenced by the polymer injection. It can be seen that this well starts to respond approximately 3 years after the beginning of the injection, resulting in a cumulative increment of almost 2000 m³ in the oil production.

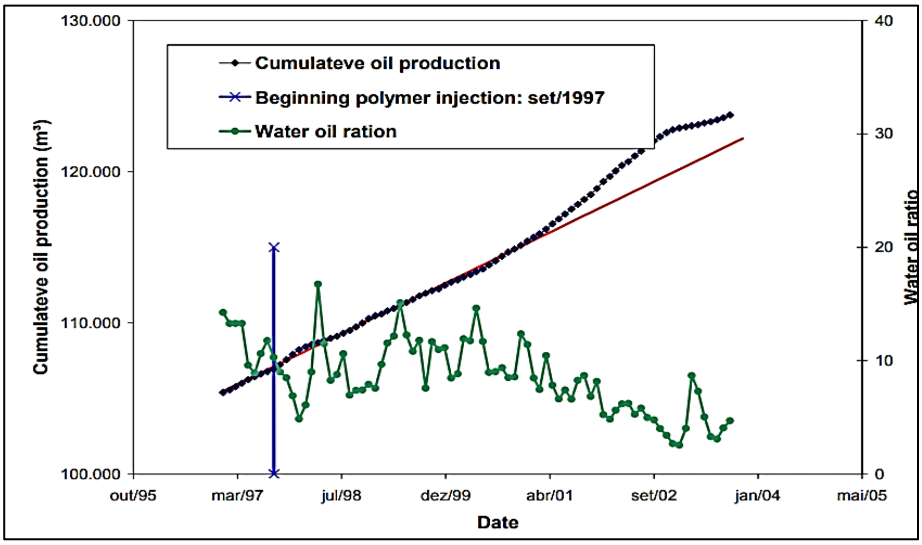

Figure 2.10 Production data of the central well of the four patterns in the CP/SE pilot.

2.3. General Description of Sharyoof Field, Block (53)

2.3.1. Regional Setting

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 Sharyoof oilfield is also located between several successful producing oil fields: the Sunah oilfield to the southeast, the Kharir oilfield to the west, and the Tasour oilfield to the east. The area is nearly flat with no topographic features and is located about 950 m above sea level. The exploration in Sharyoof field begun in 1999 while the production begun at 2001. Currently There are 30 wells have been drilled in the field, The first well here, Rudood-l, was drilled in 1999 by the DNO

Petroleum Company to a depth of about 2179 m. There followed wells Sharyoof-1 (TD **1765 m**) and Sharyoof-2 (TD **1630 m**) which targeted the Cretaceous units,[9].

Block 53 is operated by Dove Energy Ltd. The Sharyoof field production started in December 2001. The structure types in the Sharyoof oilfield are characterized by horst, tilted fault blocks. These structures were formed during late Jurassicearly Cretaceous and developed during Oligocene–Middle Miocene time as a result of opening of the Red Sea and the Gulf of Aden during the Tertiary rifting tectonic events. The produced oil at Sharyoof oilfield is intermediate oil and has a specific gravity between **28** and **32 API**

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2.3.2. Reservoir Geology

2.3.2.1. Upper Qishn Formation Clastics

Upper Qishn Formation Clastics are regionally widespread and have been encountered in all nearby wells. In the Block 53 area the Upper Qishn Formation Clastics have been subdivided into 3 units: the S1 (top), S2 (middle) and S3 (base).

The S1 is divided into three sub-units S1C, S1B and S1A (Putnam et al 1997). The upper S1A unit comprises good quality reservoir sand (Sharyoof-1 average porosity 18.4%, NTG 85%), which are between 8 to 15 meters thick in the Block 53 area. The underlying S1B comprises of non-reservoir, possibly sealing, carbonates and mudstones. The basal S1C comprises of poor quality reservoir sands and shales.

S1A sands provide the main reservoir in the region, including in the Tasour, Kharir, Sunah and Camaal Fields. It also tested oil in the Sharyoof-1 discovery well.

The best quality S1A sands are understood to have been deposited in a marine near-shore environment (e.g. sub-tidal shoals): sands pass eastwards into poor quality muddy offshore deposits and westwards into variable quality estuarine and fluvial deposits. Evidence from the presence of poorer quality S1A sands in Rudood-1 (14% average porosity) suggests there was a lateral facies shift to lagoonal and/or estuarine conditions.

The S2 and S3 sands form an estuarine and fluvial sand package, with a diffuse boundary between the two. The combined thickness varies between 40 and 80 meters in block 53, and is expected to be around 80 meters in the Sharyoof area. Net to gross ranges between 60 to 80% and porosity between 18 and 20% in the Sharyoof area.

2.3.2.2. Saar Formation Dolomites and Clastics

Saar Formation dolomites are several hundred meters thick in Tasour-1, thinning onto adjacent fault highs and also thinning to the west (56 metres in Rudood-1). Net to gross is likely to be near 100% in the Tasour area, but porosity is expected to be around 10%.

2.3.2.3. Basement Reservoirs

Fractured granitic basement is productive in the Sunah Field. Production is from swarms of open fractures that are propped open naturally by mineralisation, typically by fluorite. Closed fractures also contain oil and would act as a migration pathway between open fractures, but closed fractures are not likely to flow oil. Gross thickness is only limited by closure. Net to gross based on frequency of occurrence of open fractures, is around 20 to 30% in Sunah. Porosities range between 10 and 50%, with a most likely value of 20% (using a 10% porosity cut-off). Weathered basement is a few tens of metres thick in Sunah, with around 50% net to gross and 13% porosity. Kohlan sands are typically 5 metres or less in thickness, with 50 to 70% net to gross and 12% porosity.

2.3.3. Seal Potential

The seal for the Upper Qishn Formation Clastics is the overlying Qishn Formation Carbonate. The Sharyoof-1, Tasour-1, Rudood-1 and Hekma West-1 wells all penetrated in excess of 110 metres of micritic limestone with shaley interbeds, including the Red Shale. The throws on the faults associated with the Sharyoof structure do not exceed the likely Qishn Carbonate Formation thickness, and thus trap integrity is likely to be maintained. In the Tasour-1 well the S1 sand is underlain by limestone which could act as a base seal to the S1 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 the Tasour-1 well provided a top-seal,[10].

2.3.4. Source and Migration

The likely source for the Sharyoof structure 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-metre shale section was penetrated with an average total organic carbon content of approximately 5%. It showed good oil to source correlation with oil reservoired in Qishn Clastics formation. 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.

2.4. Petrophysics and Reservoir Fluid Properties

2.4.1. Petrophysical Characteristics from Core Analysis Studies

Petrophysical measurement in sharyoof field carried out on ten (10) core samples from Qishn sandstone reservoir rock were collected from one exploration well (Sharyoof-2) for conventional core analysis to carry out the petrophysical analysis (i.e., porosity and permeability). These core petrophysical results were also compared to those of the Qishn sandstone reservoir in the Sunah, Cammal, Haijah, Tawilah and Kharir oilfields ,which are close in location to the studied oilfield (Sharyoof oilfield) . In the Sharyoof-2 well, helium porosity of the Qishn sandstones is quiet good and ranges from **22%** to **27%** . Generally, horizontal permeability also obtained all over the Qishn sandstone reservoir is good with a wide range between **84.4** and **6318 mD** Table.2.2. However, the helium porosity and horizontal permeability values of the Early Cretaceous Qishn sandstone reservoir in this study are consistent with the results of the same reservoir rock in the boarded Sunah, Cammal, Tawilah, Haijah and Kharir oilfields as indicated from recent works by Hakimi Al Areeq et al. and King et al.

2.4.2. Petrophysical Characteristics from Well Logging

The petrophysics studies have been done by means of conventional well log analysis, also studies were used for the evaluation of the Saar Formation reservoir quality in terms of petrophysical parameters like shale volume, porosity, permeability, and fluid types and saturations.

Log-derived reservoir petrophysical properties									
Well name	Top depth (m)	Bottom depth (m)	Total thickness	Net pay thickness	Avg. Shale content (%)	Avg.Porosity (%)	Avg.Permeability (mD)	Avg. Water saturation (%)	Avg.Hydrocarbon saturation (%)
Sharyoof-1	1472.4	1621.95	149.6	78.1	5.5	20.6	384	28.3	71.7
Sharyoof-2	1455.7	1592.6	136.4	77.4	3.5	20.7	822	28.0	72.0
Sharyoof-4	1499.5	1632.3	132.8	56.5	3.5	20.0	455	29.7	70.3
Sharyoof-19	1482.8	1548.5	65.7	11.9	9.1	18.1	400	28.9	71.1
Sharyoof-18	1467	1528	61.0	16.4	3.1	17.7	48	40.6	59.4
Sharyoof-23	1504	1560	55.4	31.2	2.7	19.4	365	33.1	66.9
Average	-	-	100.2	45.3	4.1	19.4	413	31.4	68.6

Table 2.2 Summary of the petrophysical parameters for the Qishn clastic reservoir rocks in the studied wells from Sharyoof oilfield, Masila Basin.

2.4.2.1. Log-Derived Porosity And Permeability

In this study, porosity and permeability were calculated from conventional well log data (Fig.2.11). The Qishn clastic rocks have low shale contents, indicating that the porosity is filled with water or oil. The porosity values have been calculated using a combination of the density and neutron logs after applying various corrections. The neutron log measures the liquid filled porosity, whereas the density logs determine the overall density of a rock including the solid matrix and the fluid enclosed in the pore space. Based on log-derived porosity data for the Qishn clastic reservoir rock, the total and effective porosity values were calculated and shown similar values between them Table.2. This similarity of the total and effective porosities is generally attributed to the low shale volume content, since the effective porosity depends largely on the degree of connection between pores and depending on the total porosity and shale volume. The Qishn clastic reservoir rocks have relatively high total and effective porosity in the range from **17.3** to **20.7**. The porosity type in the Qishn clastic reservoir rocks is represented by the dominance of primary porosity and secondary porosity types. This secondary pore type may be attributed to the partially or completely dissolution of the presence significant amount of carbonate cements. The dissolution of the carbonate cements within the Early Cretaceous Qishn sandstone reservoir has been reported by Hakimi and Al Areeq et al.

On the other hand, the log-derived permeability is also calculated using a conventional method, i.e., Morris and Biggs. The calculated permeability values range between **0.001** and **7270 mD** . The log-derived permeability and porosity are positively correlated, with significant correlation (**R2 = 0.75**) between both of them. This good correlation between both permeability and porosity values indicates that the permeability decreases or increases as in the case of porosity. Therefore, the permeability is a strong association between porosity and the lithology components of the reservoir rocks. However, the log-derived permeability and porosity values are generally in agreement with measured permeability and porosity from core analysis.

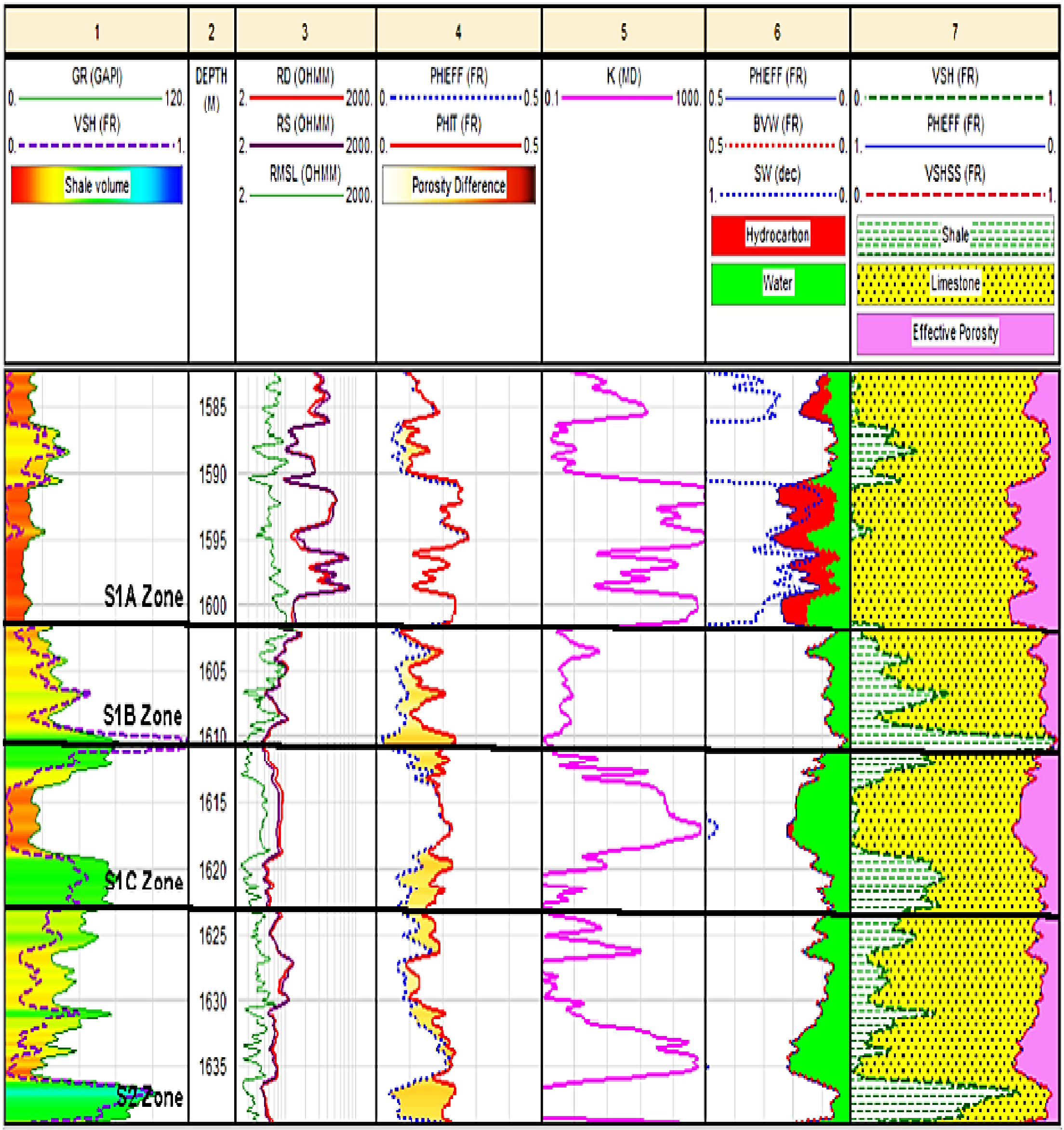

Figure 2.11 log analysis at Sharyoof oilfield.

2.4.3. Fluids In Reservoir Rocks

The fluid type and saturation in reservoir rocks can be estimated according to water saturation, effective porosity and shale content. This water saturation is the amount of pore volume in a rock that is occupied by formation water and is displayed as decimal fraction or as a percentage. The water saturation (***Sw***) has been computed with a shale correction using the Simandoux and Indonesian equations according to the sediment of the Qishn clastic rocks. On the other hand, the hydrocarbon saturation is the amount of pore volume in a reservoir rock that is occupied by hydrocarbons, and is usually determined by the difference between unity and water saturation ($S_h = 1 - Sw$). The hydrocarbon saturation can also be divided into fractions; movable hydrocarbon and residual hydrocarbon saturations. The residual hydrocarbon saturation is the difference between unity and the water saturation in the flushed zone ,($S_{hr} = 1 - Sxo$). The product of formation water saturation (***Sw***) and porosity represents the bulk volume of water; similarly, the bulk volume of oil is the hydrocarbon saturation multiplied by the porosity. The ‘‘movable” oil is the volume of oil which can be produced from a reservoir and can be evaluated using a ratio method:

$$(Sxo - Sw) * PHe = \text{movable hydrocarbons}$$

Where

Sxo is water saturation in the flushed zone.

Sw is the saturation in the uninvaded zone.

PHe is effective porosity.

The fluid saturations were computed for all the studied wells and showed that the hydrocarbon saturation is exceeding **70%**; with sufficient amounts of movable oil indicating the production is mainly oils.

2.4.4. Fluid Properties (Oil Properties)

PVT Data was obtained from wellhead samples taken during the sharyoof-1 and sharyoof-2 DSTs. A summary of the main oil properties from the sharyoof-1 DST and sharyoof-2 DST2 PVT analysis is given in the Table.2.3

Parameter	Sharyoof-1 sample	Sharyoof-2 sample
Oil Gravity	31.5 API	32.2 API
Reservoir Tem. @ Pi	146 F	139 F
Bubble point pressure	26-50 psig	50 psig
FVF @ Pi	1.033 rb/stb	1.078 rb/stb
Viscosity @ Pi	4.55 cp	4.975 cp
Oil compressibility @ Pi	5.9 x10^{-6} psi^{-1}	6.22 x 10^{-6} psi^{-1}
GOR	< 10 SCF/STB	-
Pressure@Pi	1468 psia	-

Table 2.3 summery of PVT analysis sharyoof-1 and sharyoof-2 from DST.

2.5. SIMULATION MODEL

Simulation is the only way to quantitatively describe the flow process of multi-phases in a heterogeneous reservoir; owing to the development of computer and computing techniques reservoir simulation has gained great progress in the past decades, from the simplest single phase model to multi-phase multi-component models, and got wide usage throughout the world. Many commercial software companies have provided their simulators, and thus have gained great commercial profits. Some research institutes or universities also have their own simulators aiming at theoretical research or education.

Though software's have been upgraded version by version so quickly, the theoretical basis of most of those software's still is multi-phase multi-component flow model or its simplified models. This chapter introduces the basic dynamics of fluids and mathematical model of fluid and polymer transport process in porous media.

2.5.1. Geological Model

Sharyoof Geological model was generated in Petrel. Static geological model is a Cartesian grid and gridded up into 311808 cells, distributed in three dimensions as (**I** = 111, **J** = 47, **K** = 57) grid blocks and 7 horizons with 57 layers and 5 zones , Table.2.4. Static model has 12 faults that exported to ECLIPSE model include file. The static model provide a more realistic estimate of oil-in-place in the Sharyoof Field, the well database, the structural model, integrate porosity and permeability maps and provide a static model to load into Eclipse.

Geological Horizon	Number of layers
S1AU	12
S1AL	12
S1B	10
S1CU	10
S1CL	1
S2	12

Table.2.4. Layers number of Geological Horizon.

Structural data and well data including formation tops for all wells Sharyoof-1 to -30 have been incorporated into the model. porosity and permeability maps were also included in the data set for all pay zones. Facies was distributed along the field layer by layer vertically and horizontally as well as Porosity distribution from logs and based on facies. The Permeability distribution was from core and reservoir engineering data and based on facies and ***Swi*** distribution Based on facies.

2.5.2. Well Database

All the well data used in the previous static model was used in the new model and updated with data from wells Sh-15 to -30. The formation top data and well settings for all the wells used in the model that located at different zones(S1A,S1C,S1B) as shown in Table.5.

Layer	**SIA**		**SIC**		
well	Trajectory	Depth	well	Trajectory	depth
Sh-**2**	Vertical	927 m	Sh-**9**	Vertical	923.07 m
Sh-**4**	Deviated	964.9 m	Sh-**28**	Deviated	935 m
Sh-**10**	Vertical	939.14 m	Sh-**3**	Deviated	902.74 m
Sh-**14**	Deviated	918.71 m			
Sh-**1**	Sidetracked	927 m			
Sh-**12**	Deviated	918.68 m			
Sh-**19**	Deviated	903.82 m			
Sh-**8**	Deviated	966.03 m			

Table 2.5 Summary of drilled wells of sharyoof field in SIA,SIC layers .

2.5.3. Data load

Well data comprising well header information, deviation files, and formation tops were imported well by well. All well deviations and wireline logs were loaded to the model as shown in the (Fig.2.12).

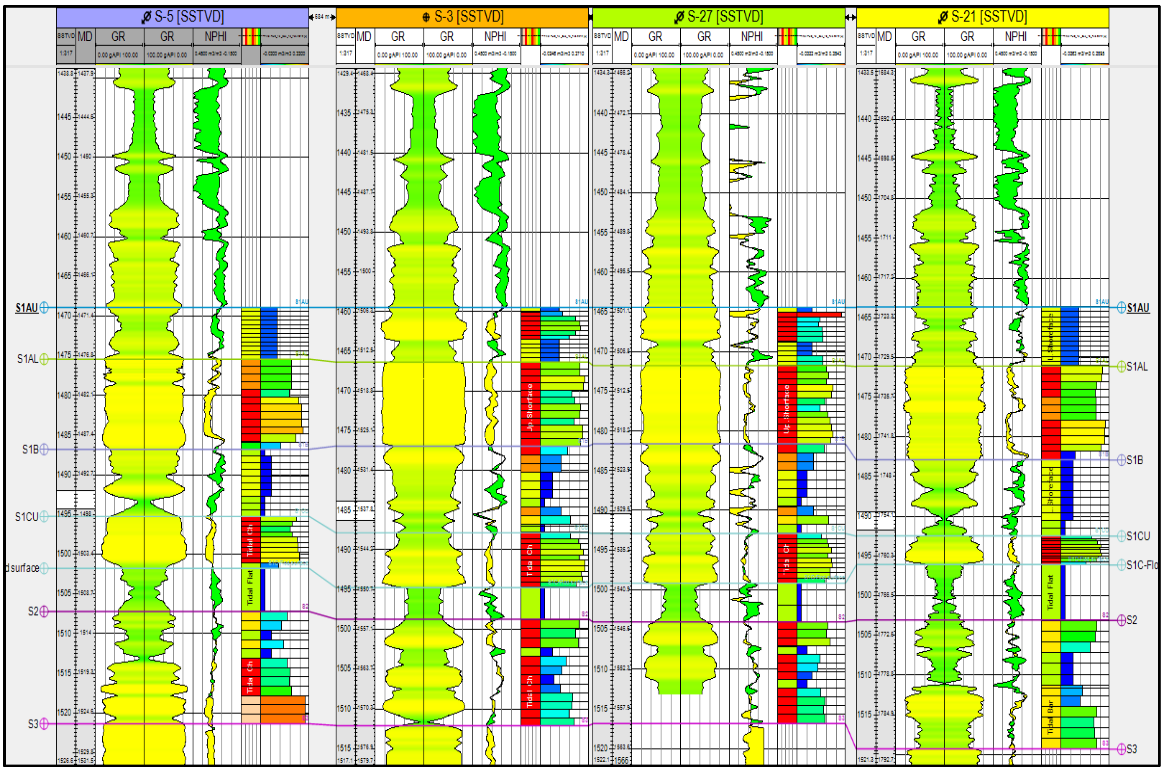

Figure 2.12 Gamma ray and neutron density logs for SH-5, SH-3, SH -27, SH -21 wells in sharyoof field.

2.5.4. Surfaces

A comprehensive re-mapping of the Sharyoof area, the basic four layer seismic grids were imported and then manipulated in Petrosys prior to importing into Petrel to smooth and remove anomalies which would cause problems during the creation of the sub-zones. The four layer grids, S1AU, S1AL, S1C and S2 were then imported into the model.

The S1AU horizon, located at the boundary with the overlying Qishn Carbonates, forms the upper bounding surface with the S3 forming the lower bounding surface. Once the grids are imported into Petrel it became clear that some manipulation of the surface would be required within Petrel as shown in Figures (13-a,b,c,d,e,f). Also the Surfaces S1B and S3 were created by using the make surface process.

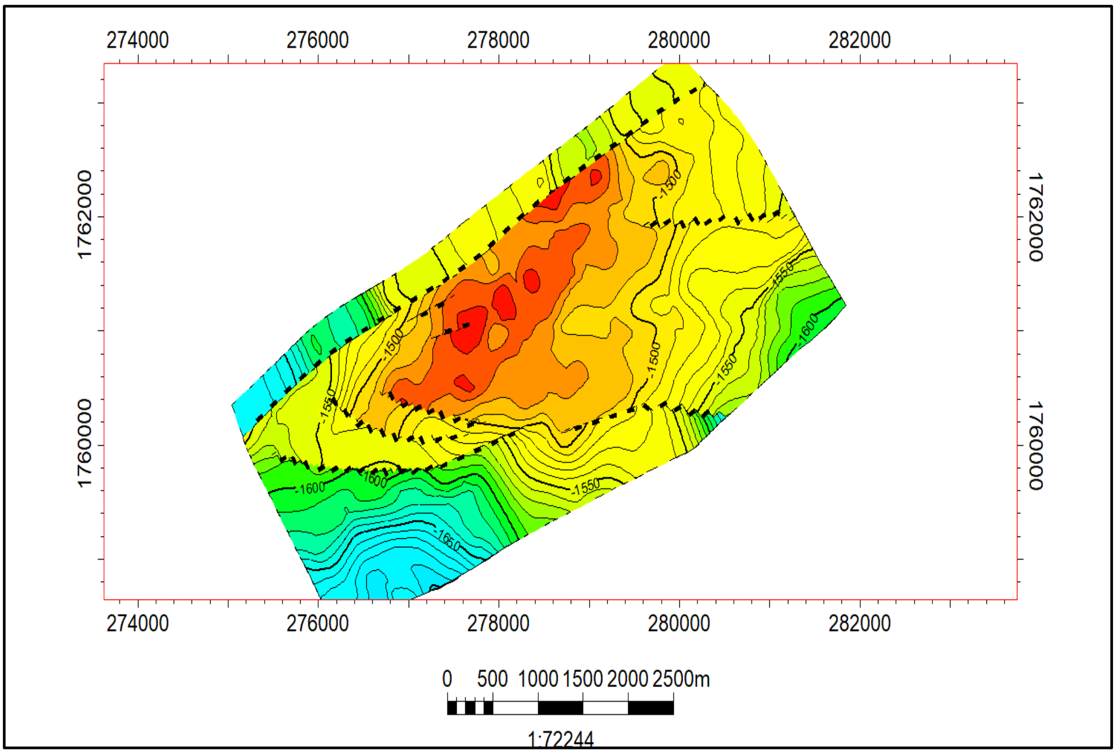

Figure.2.13-a S1AU depth map.

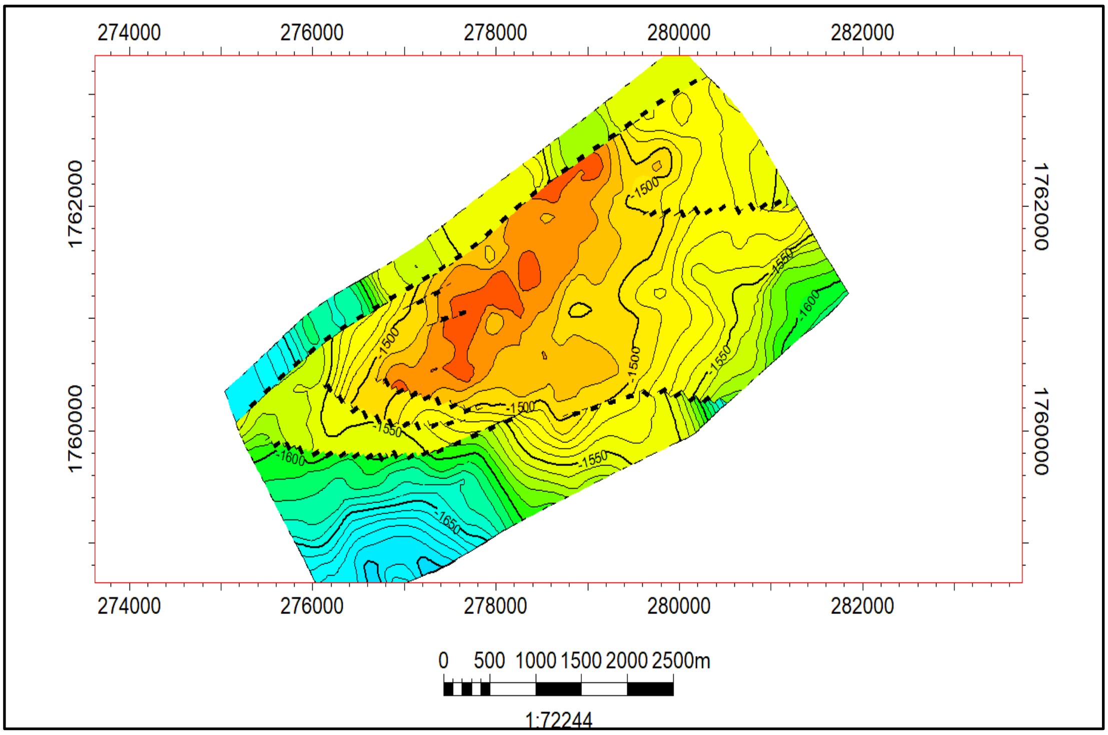

Figure.2.13-b S1AL depth map.

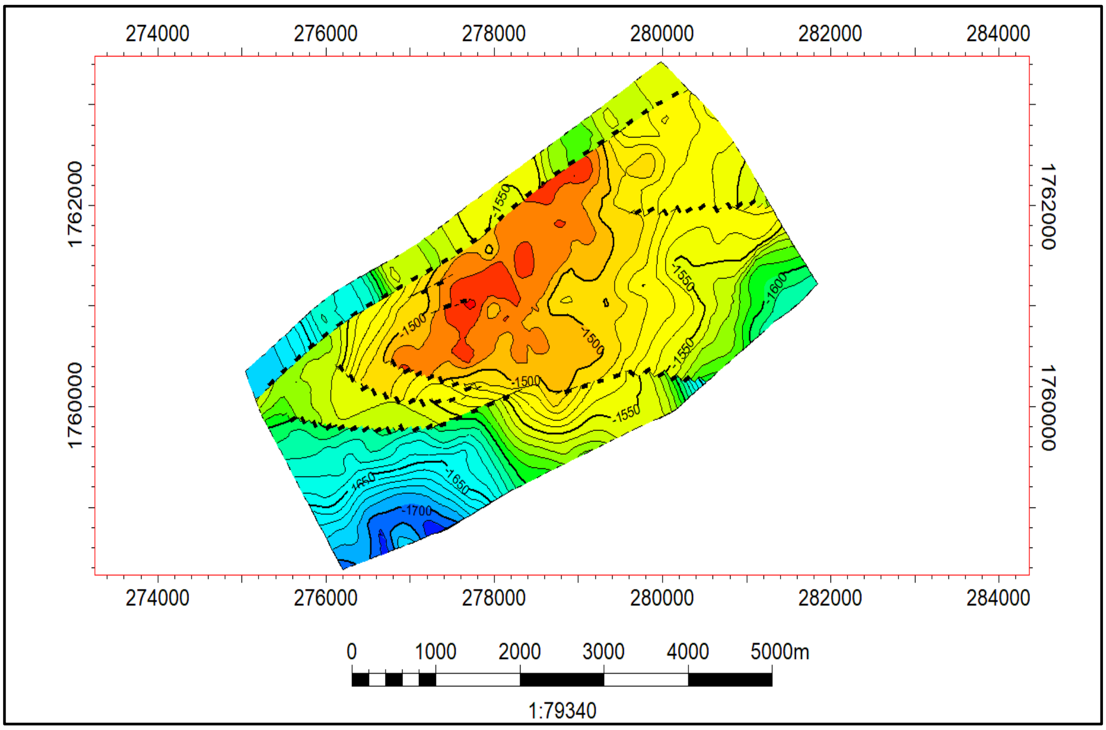

Figure.2.13-c S1B depth map.

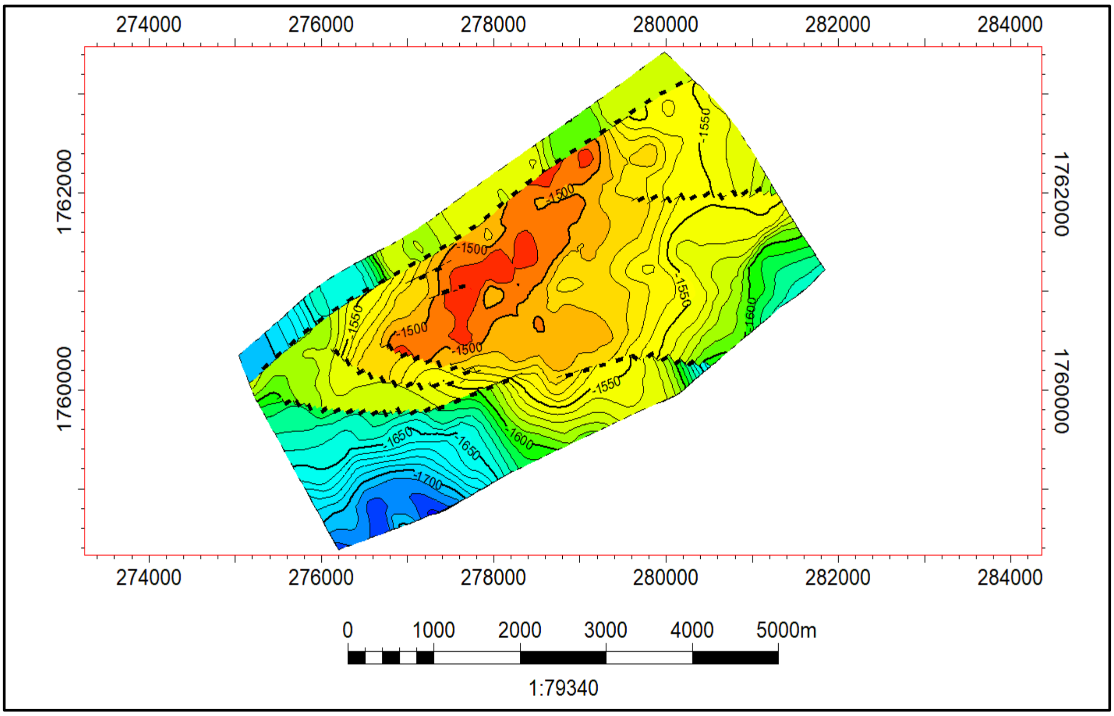

Figure.2.13-d S1C depth map.

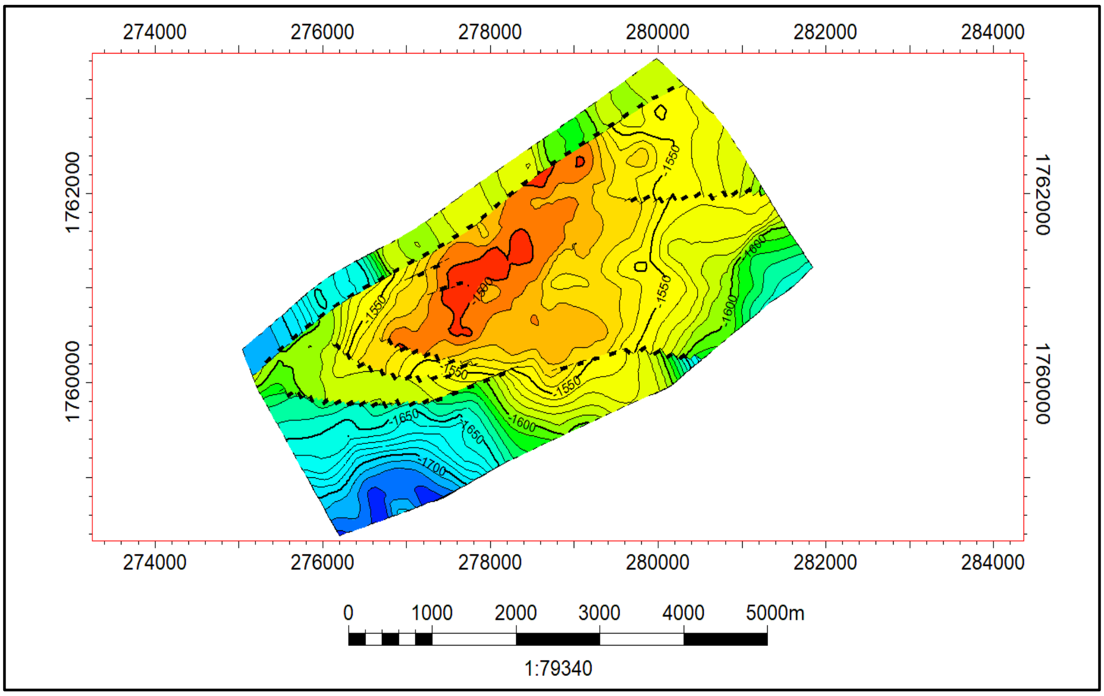

Figure 2.13-e S2 depth map.

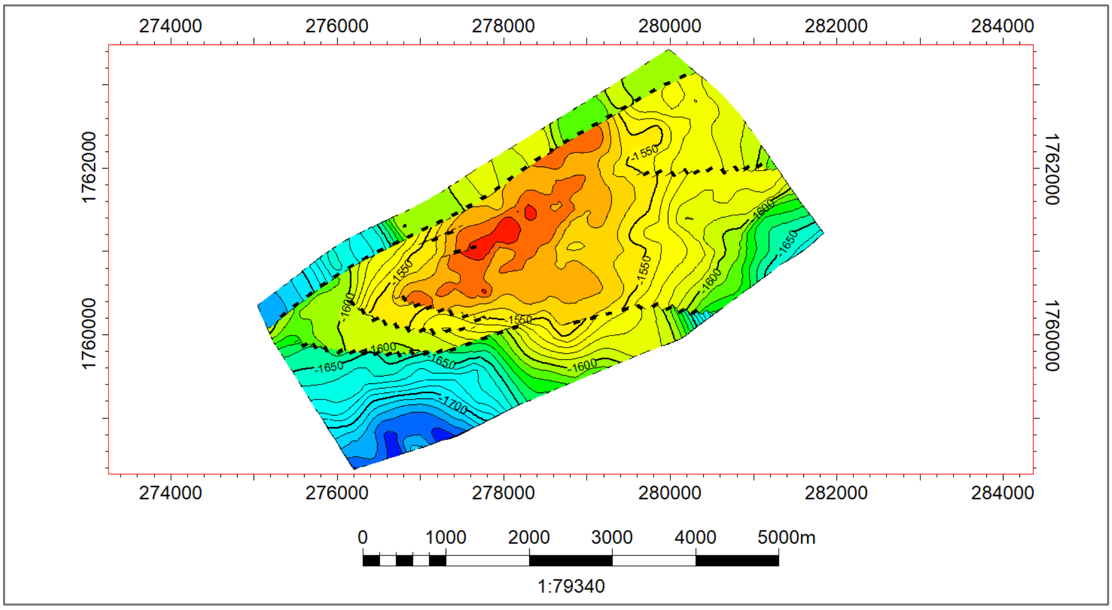

Figure 2.13-f S3 depth map.

Gridding and Layering Basic statistics for the model.

X Increment:	50m
Y Increment:	50m
Cells I x J x K:	141 x 97 x 23
Total 3D cells:	314571
Modelled layers:	23
Grid rotation angle:	27.9

2.5.5. Faulting

The model faults were exported from the Petrel model in the form of an Eclipse include file as shown in (fig.2.14). The Northern fault was considered to be sealing due to its high throw. The sealing nature of the remaining faults was used as a matching parameter.

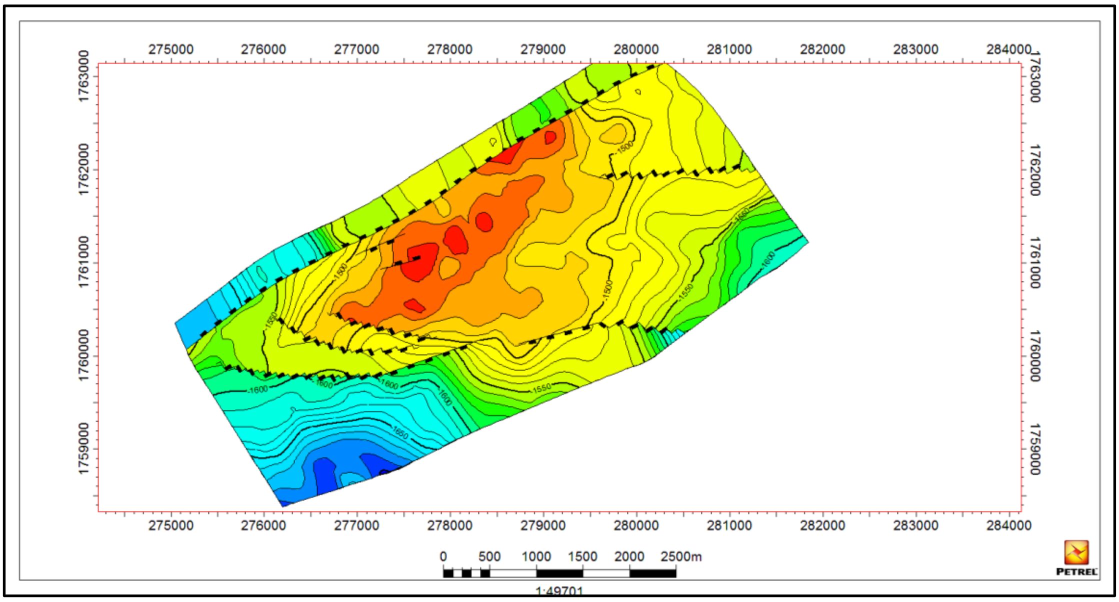

Figure 2.14 S1A map shows faults modeling of sharyoof field.

2.5.6. Fluid Properties

PVT data was obtained from the analysis of the wellhead samples taken during the Sh-1 and Sh-2 drill stem tests, the sample taken from layer S1AL in well Sh-1 is used in the simulation model. The main reason is that this sample has the lowest oil viscosity and allows a better pressure match to be achieved. An increase in the oil viscosity will result in a lower reservoir pressure and therefore, a greater oil in place oil would be required in order to match the observed reservoir pressure. Water viscosity is believed to be in the range of 0.47 to 0.65 cP. Although no measurement currently exists. A new water sample has been taken and is currently being analysed for viscosity determination.

The values used in the simulation models were chosen based on the history matching quality. Water viscosity has a strong influence on the reservoir pressure and sweep efficiency.(Fig2.15) explain the PVT data.

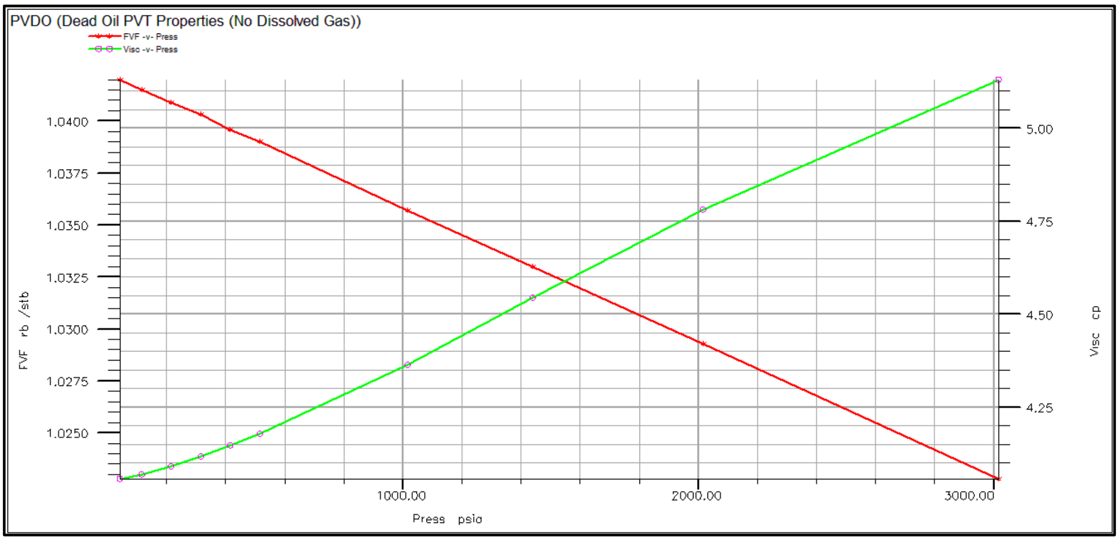

Figure 2.15. PVT data of sharyoof field.

2.5.7. Relative Permeability

One relative permeability table based on Sharyoof -2 SCAL data was entered into simulation model as (Fig.2.16). This analysis included wettability testing, clean-state relative permeability and restored-state relative permeability. After analysing and refining the lab measured relative permeabilities, the data from eight core plugs were selected to be used in the simulation model .

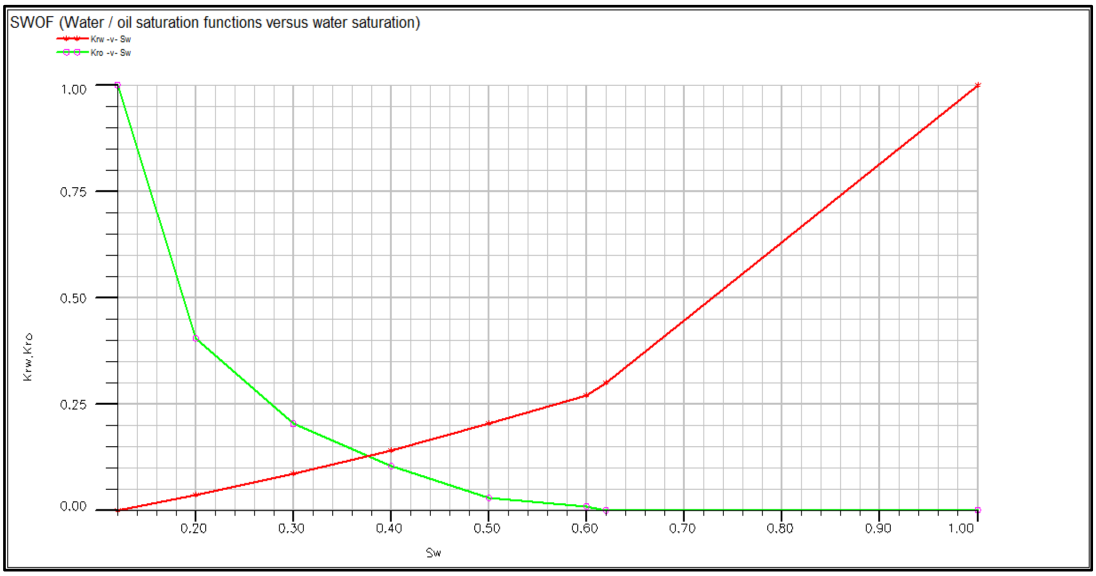

Figure 2.16 Chart explaining core studies of relative permeabilities to oil, water**.**

2.5.8. Oil Water Contact

The oil water contact information from the wells indicates a common OWC across the field in all layers of 1507 m bSRD (566 m bmsl) for S2 and S3 as listed below in (Fig.2.17). This value is also used for S1C layer except the Sh-8 block, which uses a shallower value to match the production test data.

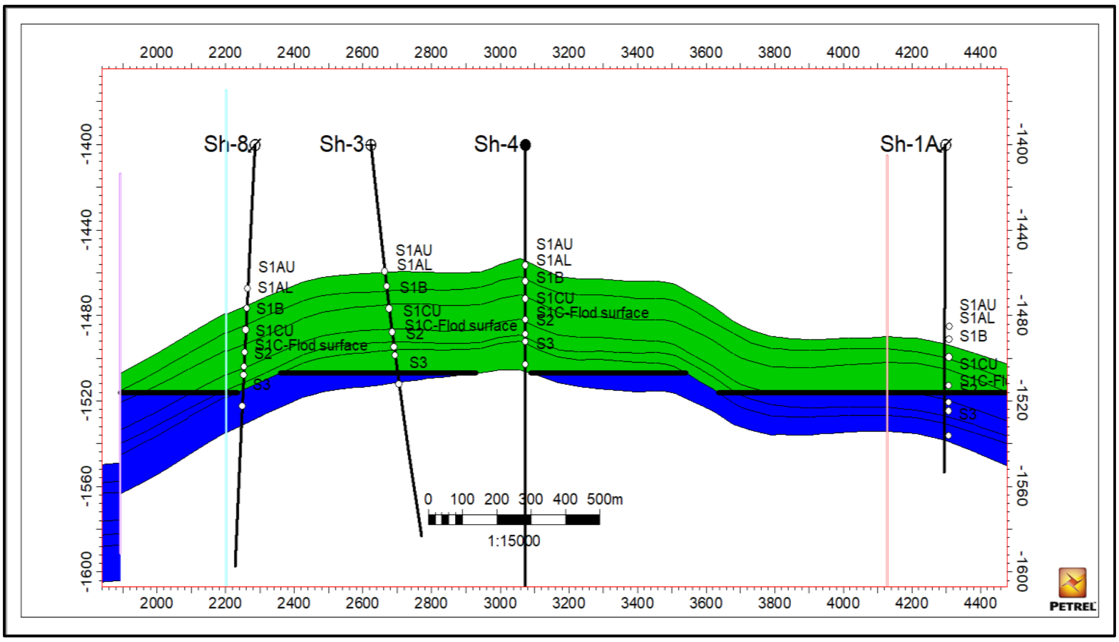

Figure 2.17 Cross section of (OWC) in sharyoof field.

2.5.9. Aquifer

The production wells appear to be observing pressure support from an aquifer, which extends outside the mapped area of the Sharyoof Field. The limited data available from surrounding wells suggests that significant aquifer volume exists. A Carter-Tracy aquifer was attached to the Eastern edge of the simulation grid. As the reservoir layers have different thickness and permeability it was decided to assign bigger aquifers to S1AL and S1C layers. The aquifer sizes were used as a pressure matching parameter.

2.5.10. History matching

Reservoir is a Geo-body buried underground as an objective reality; it's any existential Property should be unique, though some of them may change during exploitation of the reservoir (usually this variation can be neglected in reservoir simulation). Theoretically, if the correct data or functions, which describe the reservoir rock and fluids, were put into the simulation model, its solution would surely match the production history. But unfortunately such occasion will never happen. Since much of the physically measurable information used in the simulator is based on incomplete or inaccurate field measurements, any property data or functions about the reservoir are not absolutely certain, even we have made many efforts: many wells drilled, many logging data, many core analysis data, well production tests, seismic data, etc. We still know only a part about the reservoir, just as we can only see the tip of an iceberg. For a practical reservoir simulation, history matching can be achieved by manipulating two fundamental processes, which are controllable during history matching: the quantity and distribution of fluid within the system, and the movement of fluid within the system. These processes are manipulated by adjusting input data until a minimal difference remains between the production data and the simulator calculations at the same point in time. One must be noted that these two processes are not independent, but are related to each other. For example, for grid cell with lower permeability, usually its initial oil saturation should also be lower since the capillary pressure is controlled by pore structure, and permeability is also controlled by it. If permeability is lowered, the other data should also be altered correspondingly. As a result, history matching is correspondingly the most time consuming part of a reservoir simulation project.

2.5.10.1. Field match

Measured and calculated field rates are shown in Figures.(2.18.a,b,c,d), The overall match to field data is very good, although the 2002/03 period produces a little too much oil and too little water, and in 2005 the model gives too little oil and too much water .The calculated field rates for end of 2005 are 15300 BOPD and 133000 BWPD. This calculated oil rate compares well with the early Jan 2006 rate of 15300 BOPD .The measured produced water was at 115000 BWPD.

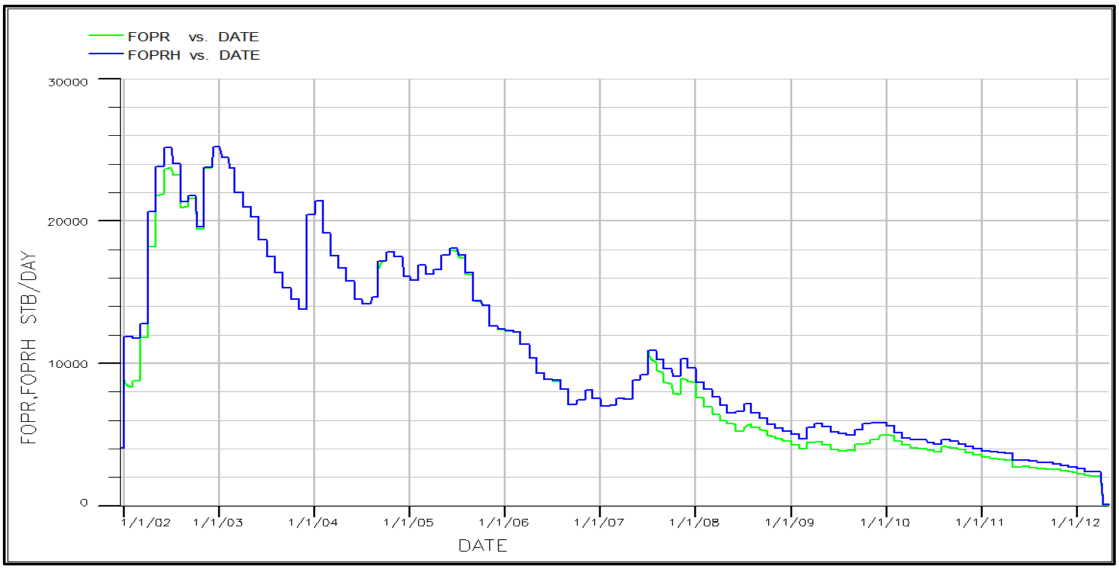

Figure 2.18.a Field oil production rate.

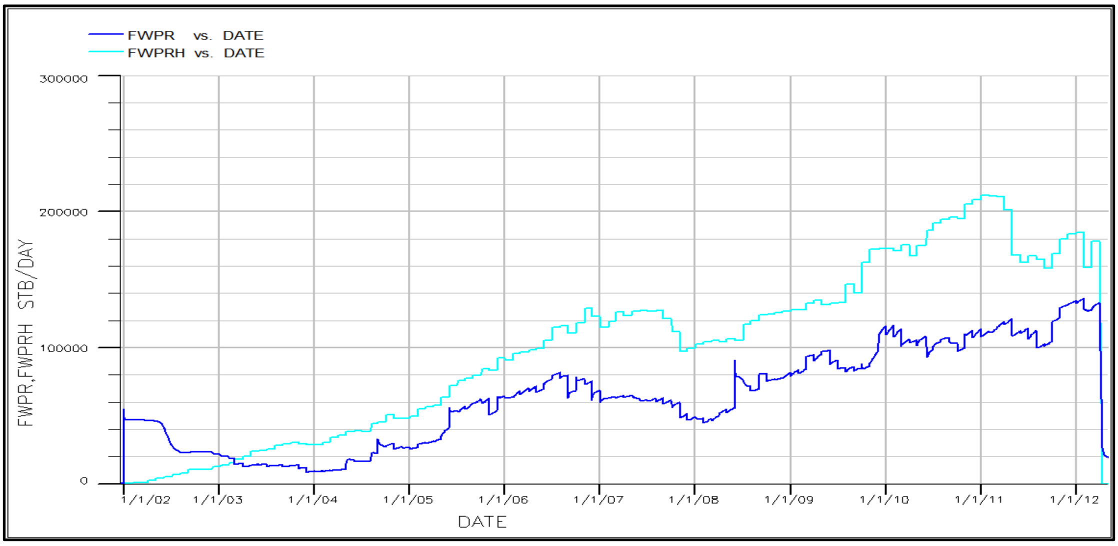

Figure 2.18.b Field water production rate.

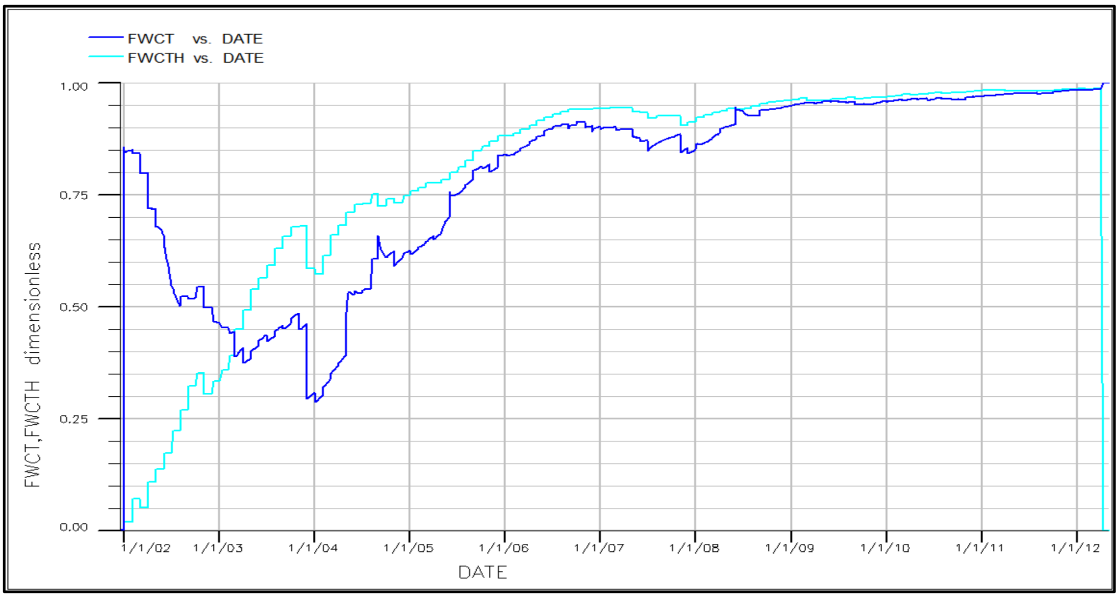

Figure 2.18.c Field water cut.

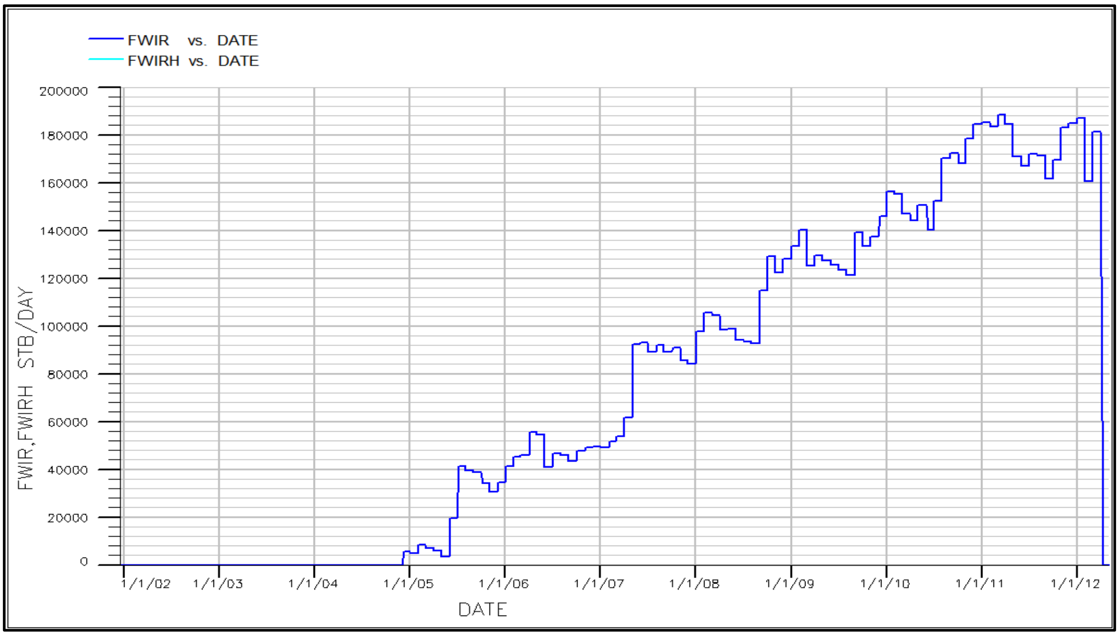

Figure 2.18.d Field injection water rate.

2.5.10.2. Result of Final History Match; Production Data.

The results of the final history match for each well on production data are listed below :

SH-1

The water production rate match on Sh-1 shows the model produces too little water although it does match the shape of the development . There are two issues in the model that may have caused this. Firstly, the model was initialized with a transition curve from well Sh-2 . this may be an over simplification and the area around Sh-1 may have a higher Swi . permeability and porosity in this area is poorer then in Sh-2 , and this may cause a longer transition zone then the one applied . as shown in (Fig2.19)

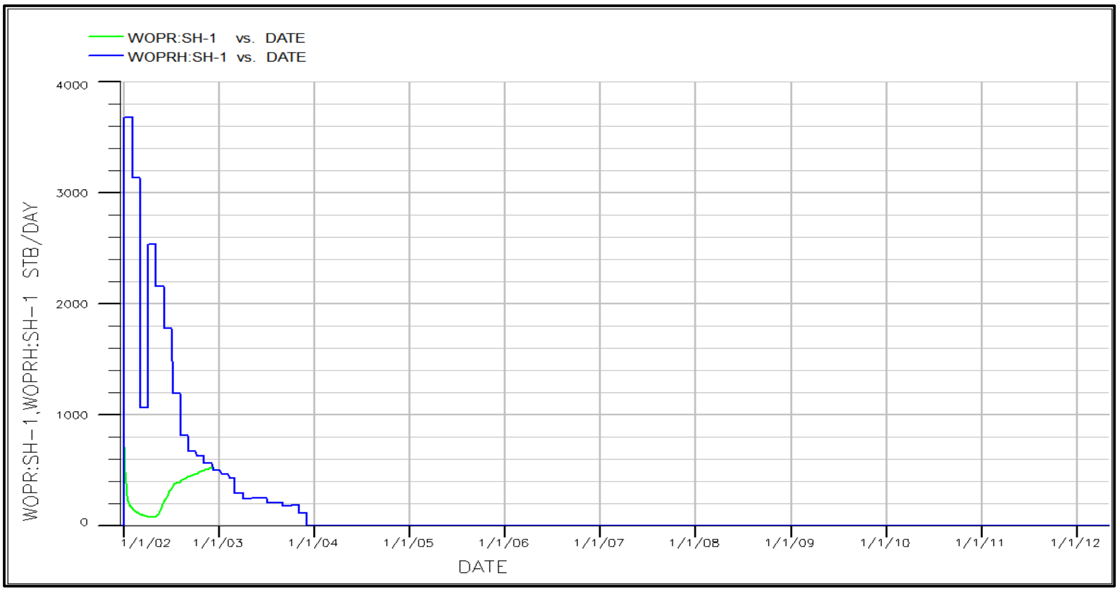

Figure 2.19 SH-1 well oil production rate.

SH-2

The well matched until mid-2005, after which the model produces too much water and too little oil. One possible cause of this may be that the structure south of Sh-**2** is actually 18.5 m higher than in the model as proved by well Sh-**19** this would allow Sh-**2** to sustain higher oil rate for a longer period. The increase the liquid rate in Q1 2004 , is attributed to the start of injection in Sh-**1** . As Sh-**1** continues injecting at higher rate during 2004 and 2005, the rates and pressures in Sh-**2** also trend higher. As shown in (Fig.2.20).

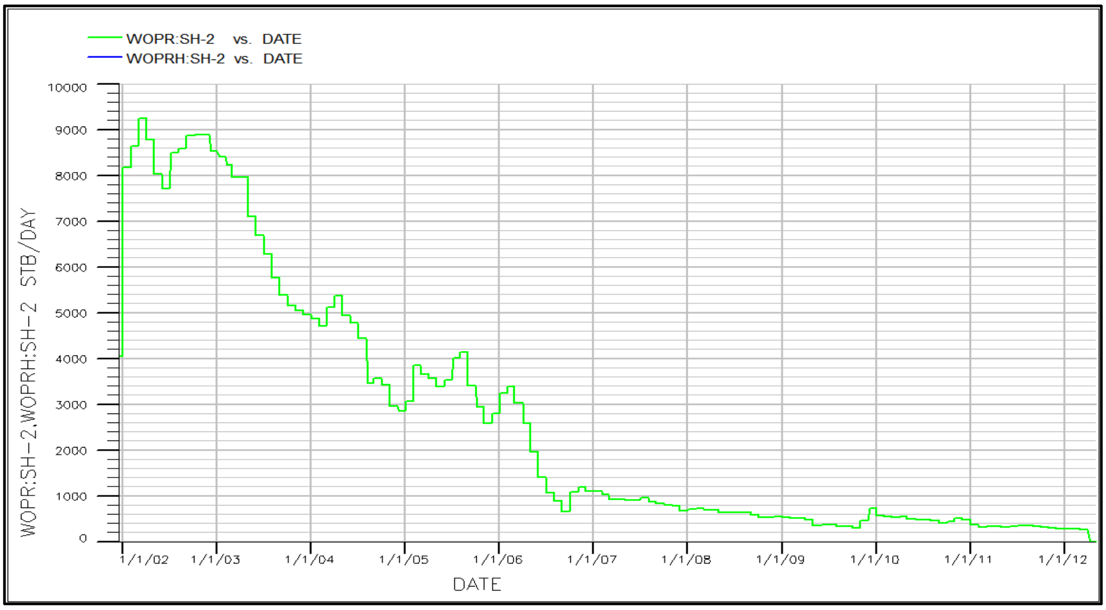

Figure 2.20 SH-2 well oil production rate.

SH-4

A good oil rate match on Sh-**4** was relatively achieved, but water match is too little as shown in (Fig.2.21)

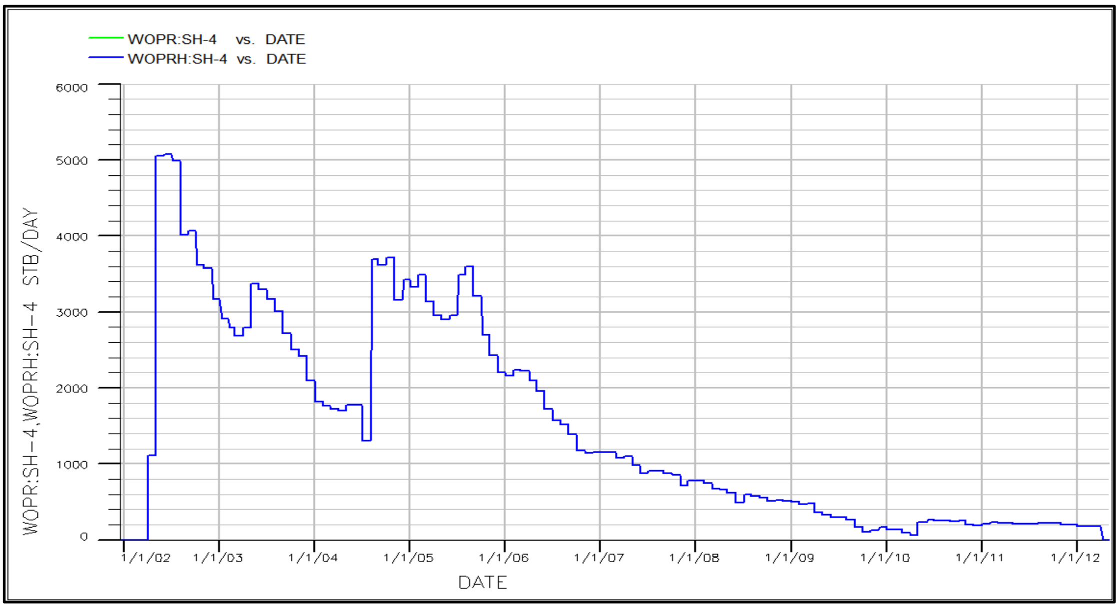

Figure 2.21 SH-4 well oil production rate.

SH-18 :

Well was a big disappointment when drilled and only produced for a few days be for being closed because of high water cuts. The model has matched history very well despite the now known structural error at this location Sh-**18** was 8M deep to prognosis. As shown in (Fig.2.22).

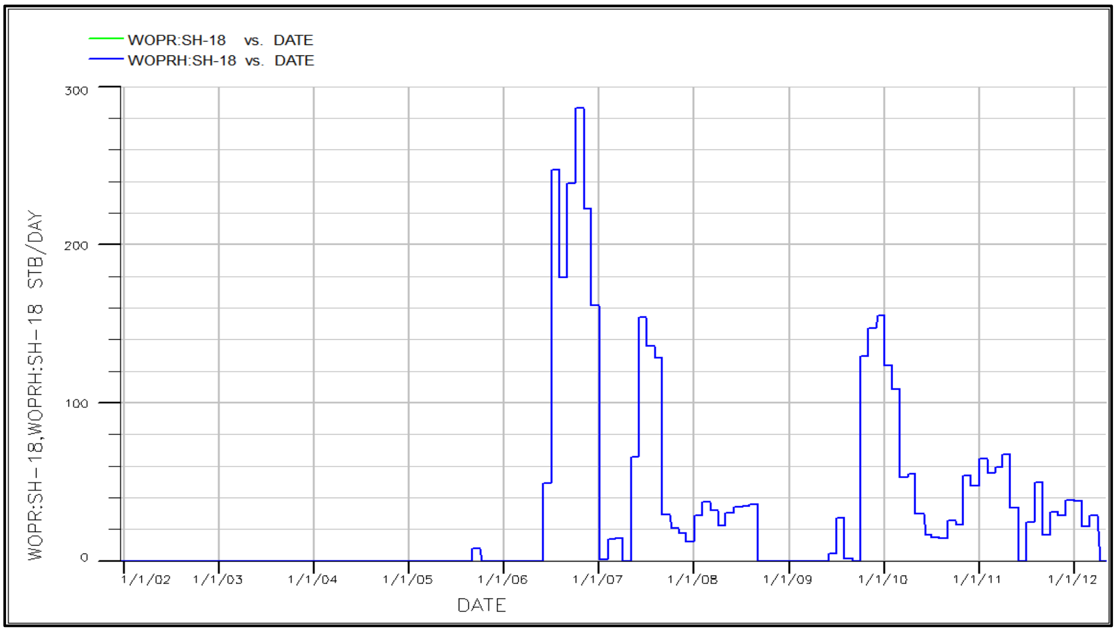

Figure 2.22 SH-18 well oil production rate.

2.6. Field Reserve and Oil in Place Estimation

Sharyoof field Oil and gas reserve estimates are a crucial part of economic analysis, Whether they are for a prospect assessment or an evaluation a field development project. Consequently this process repeated and revised through all stages of activity from exploratory through discovery, delineation and development of field, and ultimately to the final stage of enhanced oil recovery schemes.

At all stages ,the most accurate and realistic estimates are sought after ,however the confidence we place on our reserve determinations is only as good as the quality and reliability of the input data. Naturally , as more wells are drilled , more analytical data and production history obtained, there will be a corresponding increase in the degree of certainty of sharyoof field estimates .

In general there are a different methods for estimating reserve and oil in place such as volumetric calculation ,material balance equation MBE, and simulation . Which the later is the more accurate method for estimating oil and gas in place .
In our project we will show the oil in place of sharyoof field with simulation method from from both static and dynamic models as shown in Table2.6.

Simulator	Black Oil MMSTB	Dissolved Gas MSCF
Petrel	111.05	1110.50
Eclipse	109.01	1090.10

Table.2.6 Sharyoof oil and gas in place estimated from static and dynamic models.

2.7. Sharyoof field production and injection review

Dove Energy discovered, developed and produces from the Sharyoof Field with first oil achieved in December 2001 - an impressive 10 months from discovery to first oil. The principles of the design for the facility included technical simplicity, safety and environmental responsibility and have allowed production uptime of over 99.5%. The facility was originally designed to process 25,000 BOPD simultaneously with up to 60,000 BWPD handling capacity. Plant capacity has since been upgraded progressively in stages to increase total produced fluid capacity to over 200,000 BFPD. (Fig2.23) shows oil, gas, and water production rate from the beginning of field production until 2012.
The facility provides for oil and water separation vessels and storage tanks and includes water injection capacity enough to completely re-inject all produced water. Export oil is pumped through a dedicated pipeline to the gathering point at the Petromasila operated Masila (CPF). Sharyoof field now have 30 wells categorized as producers, injectors, and shut in wells in different layers are listed below in Table 2.7

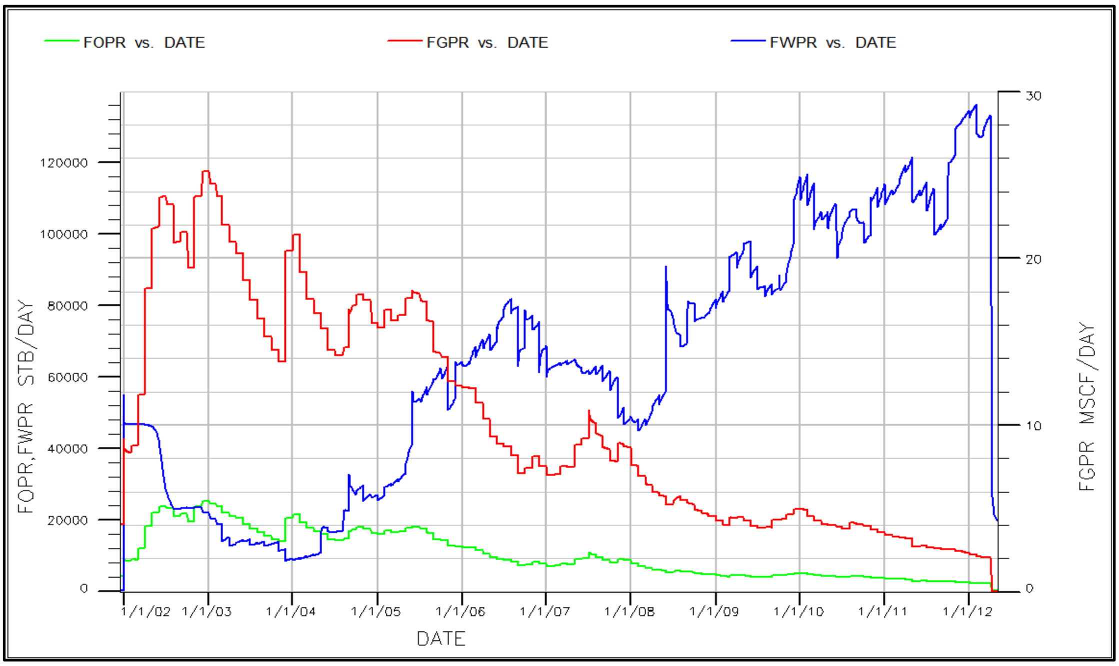

Figure 2.23 Sharyoof field oil, gas, and water daily production..

Layer	Producers	Injectors	Shut in
S1A	Sh-2 / Sh-4 / Sh-10 / Sh-14	Sh-1 / Sh-12 / Sh-19 / Sh-22	Sh-8
S1AU	Sh-6 / Sh-20 / Sh-23 / Sh-29	Sh-27	Sh-18
S1AL	Sh-11 / Sh-15	Sh-5 / Sh-25	Sh-21
S1C	Sh-9 / Sh-28	-	Sh-3
S2	Sh-24 / Sh-30	Sh-16 /Sh-7	Sh-13

Table 2.7 Summery of sharyoof field wells status at different layers.

Sharyoof oil field put on-stream in December 2001, and reached a peak production of 25,000 BPD in 2002 .In 2011 the average oil production reached to 3000 BPD from producing wells ,due to the higher water cut in some wells they converted into injectors .from (Table.8-a,b) and (Fig.2.23-a,b) show the cumulative oil production and cumulative water injection of sharyoof wells.

Well	Total prod MSTB	Well	Total prod MSTB
SH-2	10058.7	SH-23	1024.4
SH-3	4998.5	SH-24	498.7
SH-4	5544.4	SH-28	1125
SH-6	5192.2	SH-30	415.6
SH-9	3558.4	SH-1	648.02
SH-11	221.1	SH-5	1254.9
SH-13	1597.3	SH-8	104.4
SH-14	694.4	SH-16	2.05
SH-15	51.3	SH-21	62.8
SH-18	116.6	SH-27	5.33
SH-20	1213.5	SH-29	43.7

Table 2.8-a Cumulative oil production data of sharyoof production wells.

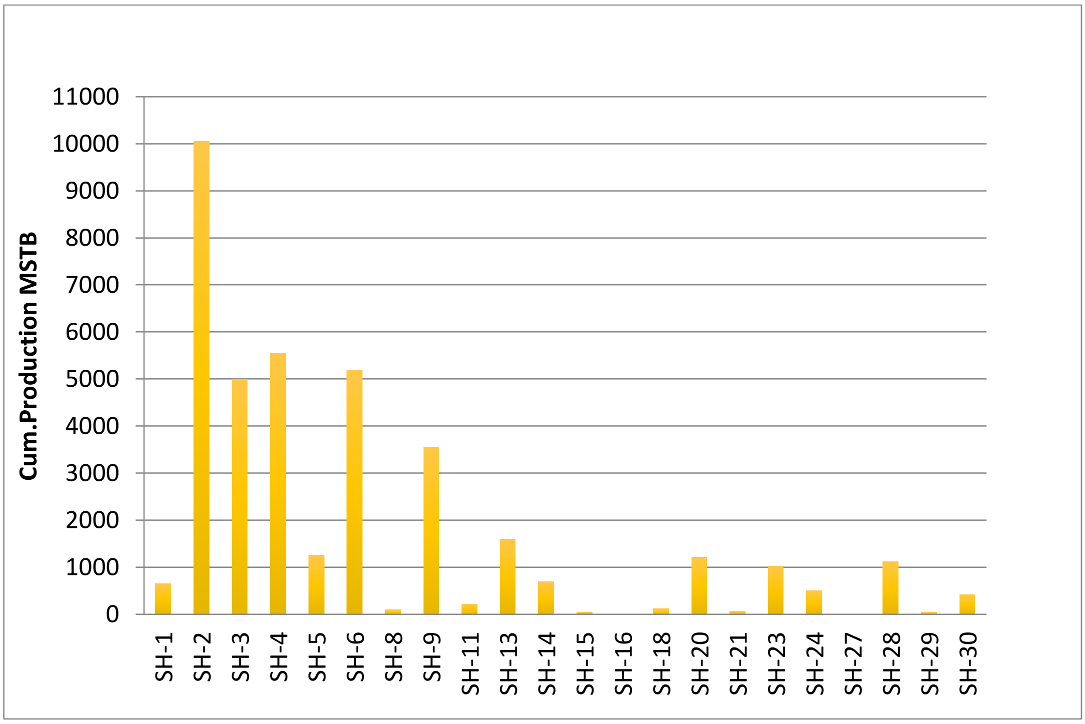

Figure 2.24-a Cumulative oil production of sharyoof wells .

Well	Total injected water MSTB
SH-10	18348.9
SH-12	22626
SH-19	44734
SH-25	26753
SH-1	46664.06
SH-16	6242.6
SH-21	12299.5
SH-27	20461.7
SH-5	54037.2
SH-8	15856
SH-29	1201576

Table 2.8-b Cumulative water injection of sharyoof injection wells.

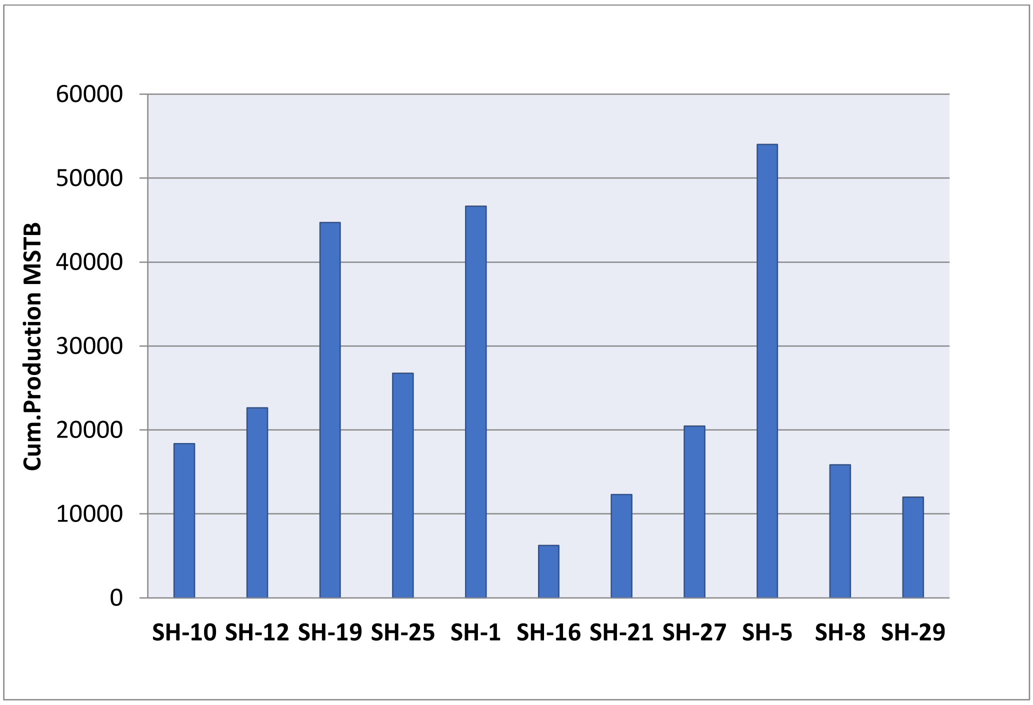

Figure 2.24-b Statistical representation of cumulative water injection of sharyoof wells.

CHAPTER-THREE

3.1 Introduction

Implementation of recovery technologies is essential to improve oil recovery. In order to reach the production and reserve goals of the project, this study is to asses and select the best scenario using polymer flooding which maximize oil recovery from Sharyoof field based on available data. Reservoir simulation study using ECLIPSE 100 was used to simulate the Sharyoof field to apply different scenarios of polymer flooding and compare them with waterflooding and each other's then select the best one.

3.2 Data Type Required

As shown in Table 3.1, Data that are required for our work are :

No	Data Require	No	Data Require
1	Static and Dynamic Model	6	Production Data
2	Reservoir fluid properties	7	Injection Data
3	Seismic Data	8	Completion Data
4	Geological Data	9	Rock properties
5	Well logging Data	10	Chemical Data

Table 3.1 Required data.

3.3 Software Description

ECLIPSE is one of the most popular reservoir simulators in the oil industry worldwide. Since of its multi-capabilities and its suitability for polymer flooding research it is selected as the simulator for this project**.**

ECLIPSE Office is used as simulation project manager for inputting data and displaying simulation results.

3.3.1 Polymer Flooding Model of ECLIPSE 100.

The simulator suite – ECLIPSE **-** consists of two separate simulators: ECLIPSE 100, specializing in black oil modeling, and ECLIPSE 300, specializing in compositional modeling. We introduce here only one special option of the ECLIPSE 100: **Polymer flood model**. All parameters and functions it needs are input through keywords,[11].

3.3.1.1 The Mathematical Model of Polymer Flood Option in ECLIPSE

The Polymer Flood option uses a fully implicit five -component model (oil/ water/ gas/ polymer/ brine) to allow the detailed mechanisms involved in polymer displacement process to be studied. The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases. The standard black- oil equations are therefore used to describe the hydrocarbon phases in the model. The equations are as follows:

For oil :

$$\frac{d}{dt}\left(\frac{VSo}{BrBo}\right) = \sum\left[\frac{Tkrw}{Bo\mu o}(\delta P_{\mathrm{o}} - \rho_{\mathrm{o}}\bar{g}\, Dz)\right] - Qo \tag{3-1}$$

For water:

$$\frac{d}{dt}\left(\frac{VSw}{BrBw}\right) = \sum\left[\frac{Tkrw}{Bw\mu w,effRkw}(\delta Pw - \rho w\bar{g}Dz)\right] - Qw \tag{3-2}$$

For polymer:

$$\frac{d}{dt}\left(\frac{VSwCp}{BrBw}\right) + \frac{d}{dt}\left(V\rho rCa\frac{1-\emptyset}{\emptyset}\right) = \sum\left[\frac{TkrwCp}{Bw\mu peffRkw}(\delta Pw - \rho w\bar{g}Dz)\right] + QwCpi$$

(3-3)

For brine:

$$\frac{d}{dt}\left(\frac{VSwCn}{BrBw}\right) = \sum\left[\frac{TkrwCn}{Bw\mu seffRkw}(\delta Pw - \rho w\bar{g}Dz)\right] + QwCni$$

(3-4)

$$\mathbf{S_w = S_w - S_{dpv}} \tag{3.5}$$

Where :

S_{dpv} denotes the dead pore space within each grid cell.

C_a denotes the adsorption isotherm which is a function of the local polymer solution concentration.

ρ_r denotes the mass density of the rock formation.

ϕ denotes the porosity.

ρ_w denotes the water density.

ρ_o denotes the oil density.

S denotes the sum over neighboring cells.

R_{kw} denotes the relative permeability reduction factor for the aqueous phase due to polymer retention.

C_p, C_n denote the local concentration of polymer and sodium chloride in the aqueous phase.

μ_{eff} denotes the effective viscosity of the water, polymer and salt components.

B denotes the formation volume factor of rock, oil and water.

N denotes the pore volume in the grid sell.

T Transmissibility.

D_z Depth difference.

The model makes the assumption that the density and formation volume factor of the aqueous phase are independent of the local polymer and sodium chloride concentrations. The polymer solution, reservoir brine and the injected water are represented in the model as miscible components of the aqueous phase, where the degree of mixing is specified through the viscosity terms in the conservation equations.

The principal effects of polymer and brine on the flow of the aqueous phase are represented by equations (3-1) to (3-5) above. The fluid viscosities ($\mu_{w,eff}$, $\mu_{p,eff}$, $\mu_{s,eff}$) are dependent on the local concentrations of salt and polymer in the solution. Polymer adsorption is represented by the additional mass accumulation term on the left hand side of the equation (3-3). The adsorption term requires the user to specify the adsorption isotherm ***Ca*** as a function of the local polymer concentration for each rock species. The effect of pore blocking and adsorption on the aqueous phase relative permeability is treated through the term R_{KW} requires the input of a residual resistance factor for each rock type.

The equations solved by the ECLIPSE polymer model are a discretized form of the differential equations (3-1)- (3-5). In order to avoid numerical stability problems which could be triggered by strong changes in the aqueous phase properties over a time step (resulting from large changes in the local polymer/sodium chloride concentrations) a fully implicit time discretization is used. The ECLIPSE polymer flood model is therefore free from this type of instability.

3.3.1.2 Treatment of Fluid Viscosities in ECLIPSE Polymer Flood Model

The viscosity terms used in the fluid flow equations contain the effects of a change in the viscosity of the aqueous phase due to the presence of polymer and salt in the solution. However, to incorporate the effects of physical dispersion at the leading edge of the slug and also the fingering effects at the rear edge of the slug, the fluid components are allocated effective viscosity values which are calculated by using the Todd-Longstaff technique.

To get the effective polymer viscosity, it is required to enter the viscosity of a fully mixed polymer solution as an increasing function of the polymer concentration in solution ($\mu_m(C_\rho)$). The viscosity of the solution at the maximum polymer concentration also needs to be specified and denotes the injected polymer concentration in solution (μ_g). The effective polymer viscosity is calculated as follows:

$$\mu_{\rho,\text{eff}} = \mu_m \ (C\rho)^{\omega} \ \mu_\rho^{(1-\omega)} \qquad (3\text{-}6)$$

Where:

ω is the Todd-Longstaff mixing parameter.

The mixing parameter is useful in modeling the degree of segregation between the water and the injected polymer solution. If $\omega = 1$, then the polymer solution and water are fully mixed in each block. If $\omega = 0$, the polymer solution is completely segregated from the water.

The partially mixed water viscosity is calculated in an analogous manner by using the fully mixed polymer viscosity and the pure water viscosity (μ_m),

$$\mu_{w,\text{eff}} = \mu_w^{(1-\omega)} \, \mu_m \, (C\rho)^{\omega} \tag{3-7}$$

In order to calculate the effective water viscosity to be inserted into (3-7), the total water equation is written as the sum of contributions from the polymer solution and the pure water. The following expression then gives the effective water viscosity to be inserted into (3-7):

$$\frac{1}{\mu_{w,eff}} = \frac{1-C}{\mu_{w,eff}} = \frac{C}{\mu_{P,eff}} \tag{3-8}$$

$$C = \frac{Cp}{Cp,\text{max}} \tag{3-9}$$

Where : ***C*** is the effective saturation for the injected polymer solution within the total aqueous phase in the cell.

If the salt-sensitive option is active, the above expressions are still suitable for the effective polymer and water viscosity terms. The injected salt concentration needs to be specified in order to evaluate the maximum polymer solution viscosity $\boldsymbol{\mu_\rho}$. The effective salt component viscosity to be used in (3-4) is set equal to the effective water viscosity.

3.3.1.3 Treatment of Polymer Adsorption

Adsorption is treated as an instantaneous effect in the model. The effect of polymer adsorption is to create a stripped water bank at the leading edge of the slug. Desorption effects may occur as the slug passes. The adsorption model can handle both stripping and desorption effects. The user specifies an adsorption isotherm, which tabulates the saturated rock adsorbed concentration versus the local polymer concentration in solution. There are currently two adsorption models, which can be selected. The first model ensures that each grid cell retraces the adsorption isotherm as the polymer concentration rises and falls in the cell. The second model assumes that the adsorbed polymer concentration on the rock may not decrease with time, and hence does not allow for any desorption. More complex models of the desorption process can be implemented if required.

3.3.1.4 Treatment of Permeability Reductions and Dead Pore Volume

The adsorption process causes a reduction in the permeability of the rock to the passage of the aqueous phase and is directly correlated with the adsorbed polymer concentration. In order to compute the reduction in rock permeability, the user is required to specify the residual resistance factor (RRF) for each rock type. The actual resistance factor can then be calculated:

$$\boldsymbol{R}_{kw} \;=\; 1.0 \;+ (\;RRF - 1.0)\frac{\boldsymbol{c}_a}{\boldsymbol{c}_{a,\max}} \qquad (3\text{-}10)$$

The value of the maximum adsorbed concentration, $\mathbf{C}_{\boldsymbol{a}\ ,\mathbf{max}}$, depends on the rock type and needs to be specified by the user. Alternative expressions for the resistance factor can also be implemented if required. The dead pore space is specified by the user for each rock type. It represents the amount of total pore space in each grid cell which is inaccessible to the polymer solution. The effect of the dead pore space within each cell is to cause the polymer solution to travel at a greater velocity than inactive tracers embedded in the water. The ECLIPSE model assumes that the dead pore space for each rock type does not exceed the corresponding irreducible water saturation.

3.3.1.5 Treatment of the Shear Thinning Effect

The shear thinning of polymer has the effect of reducing the polymer viscosity at higher flow rates. ECLIPSE assumes that shear rate is proportional to the flow velocity. This assumption is not valid in general, for example, a given flow in a low permeability rock will have to pass through smaller pore throats than the same flow in a high permeability rock, and consequently the shear rate will be higher in the low permeability rock. For a single reservoir, however, this assumption is probably reasonable. The flow velocity is calculated as:

$$\boldsymbol{\nu} \;=\; \mathrm{B_W} - \frac{Fw}{\emptyset A} \qquad (3\text{-}11)$$

Where:

$\mathbf{F}_w$ is the water flow rate in surface units.

$\mathbf{B}_w$ is the water formation volume factor.

ϕ is the average porosity of the two cells.

A is the flow area between two cells.

The reduction in the polymer viscosity is assumed to be reversible, and is given by:

$$\mu = \mu w[(\rho - 1)M - 1] \tag{3-12}$$

Where:

μ_m is the viscosity of water with no polymer present.

P is the viscosity multiplier assuming no shear effect (entered using the PLYVISC or PLYVISCS keywords).

M is the shear thinning multiplier supplied in the PLYSHEAR keyword.

The well inflows are treated in a manner analogous to the treatment of block to block flows. The viscosity of the polymer solution flowing into the well is calculated, assuming a velocity at a representative radius from the well. The representative radius is:

$$R_r = e^{\frac{ln(Rw)+ln(Rw)}{2}} \tag{3-13}$$

Where :

R_w well bore radius (taken from diameter input in COMPDAT).

R_a area equivalent radius of the grid block in which the well is completed.

In the present version of ECLIPSE, the radial inflow equation is not integrated over distance from the well to account for the local viscosity reduction due the local velocity.

3.3.2 ECLIPSE Office

ECLIPSE Office provides an interactive environment for the creation and modification of the simulation project, the submission and control of runs, the analysis of results and report generation. Data sets may be created by using a PEBI gridding module, correlations for PVT and SCAL data, keyword panels, or input from other pre-processors. It functions to manage the simulation process more efficiently and to display simulation result more systematically.

ECLIPSE Office consists of five managers: Case Manager, Data Manager, Run Manager, Result Viewer and Report Generator.

- **Case manager**

The Case Manager helps to capture the relationship between runs and graphically display them. Runs are shown as children to Cases from which they were derived by simply modifying some data.

- **Data manager**

The Data Manager provides user-friendly access to the keywords for all the simulators and to some basic features of FloGrid, Schedule, SCAL and PVTi. In this management module there is an Unstructured Gridder where a PEBI grid can be generated. It is allowed to quickly construct a grid from a series of contour maps, well positions and boundary.

- **Run manager**

The Run Manager offers an environment to launch, monitor and control simulation runs. Runs may be started locally or over the network on a server. Multiple realizations generated for well control options and multiple cases may be run simultaneously. With the Run Manager, it is possible to monitor the progress of runs on line plots and solution displays, and if they are not delivering the required results, the runs can be stopped.

- **Results Viewer**

The Results Viewer can display simulation results in both two and three dimensions. It can also be used to create and view solution displays and line plots of production data replacement for GRAF. Results from multiple runs can also be displayed simultaneously for comparative purposes and as an aid to quick decision-making.

- **Report Generator**

The Report Generator is used to create reports from the extraction of relevant information from the SUMMARY files or from the .PRT file, and to put them in a form required for the creation of written reports.

3.4. Steps of Study

3.4.1 Introduction

The oil reservoir has a large potential of oil that needed to recover most of the oil in the reservoir but the reservoir pressure is declining very rapidly. So, it is required to perform a water flooding project that enhances the reservoir pressure and in addition, can displace more oil towards the wells in order to get most of the oil in the reservoir. Before applying water flooding project it is required to build a prediction model in the reservoir simulation to ensure which type of pattern can get the maximum amount of oil in the reservoir and remaining only small amount of oil that can get it later by enhanced oil recovery techniques. Therefore, oil reservoir had built a static model to build the structural and property modeling, then a dynamic model is built with all parameters and reservoir characterization through reservoir production data, reservoir fluid properties and rock properties that make an accurate history matching for the oil and water. Now, this reservoir is ready for Water Flooding prediction design for the reservoir. There are different types of water flooding patterns that can be applied for oil reservoirs but not all pattern can be applied for the same reservoir due to the location of wells in the reservoir and the topography and geometry of reservoir is not able to put injectors in any location.

Sharyoof field initiated WF by dove energy with an average water-cut of about 54.3% based on history match. Due to the high water-cut on most producing wells, they initiated a screening process for the application of a suitable EOR process for the field in Dec.2004 with sh-12 injecting within the pay zone.

Our work was divided as the following:

1- Select the base case that will be compared with the other cases.
2- Water flooding cases.
3- Polymer flooding Cases.

3.4.2 Case Studies for The Water Flooding

3.4.2.1 Base Case

Based on the data from History Match, including the static model 2012 and history match results up to 1April 2012 were migrated into ECLIPSE simulator.

The case studies in our project have performance predictions from the end of historical data and terminated to the end of Dec.2025. Which are started with a base case having the same production and injection conditions Figure.(3.a,b,c). without any changes of wells completion as shown in Table.3.2.

Well	Type	Completion
Sh-**1**	injection	S1AU –S1C
Sh-**2**	Production	S1A
Sh-**3**	Production	S1A –S1C
Sh-**4**	Production	S1AU
Sh-**5**	Production	S1AL
Sh-**6**	Production	S1AU
Sh-**8**	Injection	S1AU
Sh-**9**	Production	S1CU
Sh-**10**	Injection	S1CU
Sh-**11**	Production	S1AL
Sh-**12**	Injection	S1AL - S1B
Sh-**13**	Production	S1CU
Sh-**14**	Production	S1A
Sh-**15**	Production	S1AL-S2
Sh-**16**	Injection	S1AU
Sh-**18**	Production	S1A
Sh-**19**	Injection	S1A –S1B
Sh-**20**	Production	S1AU
Sh-**21**	Injection	S1A
Sh-**23**	Production	S1CU
Sh-**24**	Production	S1CL –S2
Sh-**25**	Injection	S1A
Sh-**27**	Injection	S1AU
Sh-**28**	Production	S1CU
Sh-**29**	Injection	S1CL-S2
Sh-**30**	Production	S2

Table.3.2 Changes of well completion.

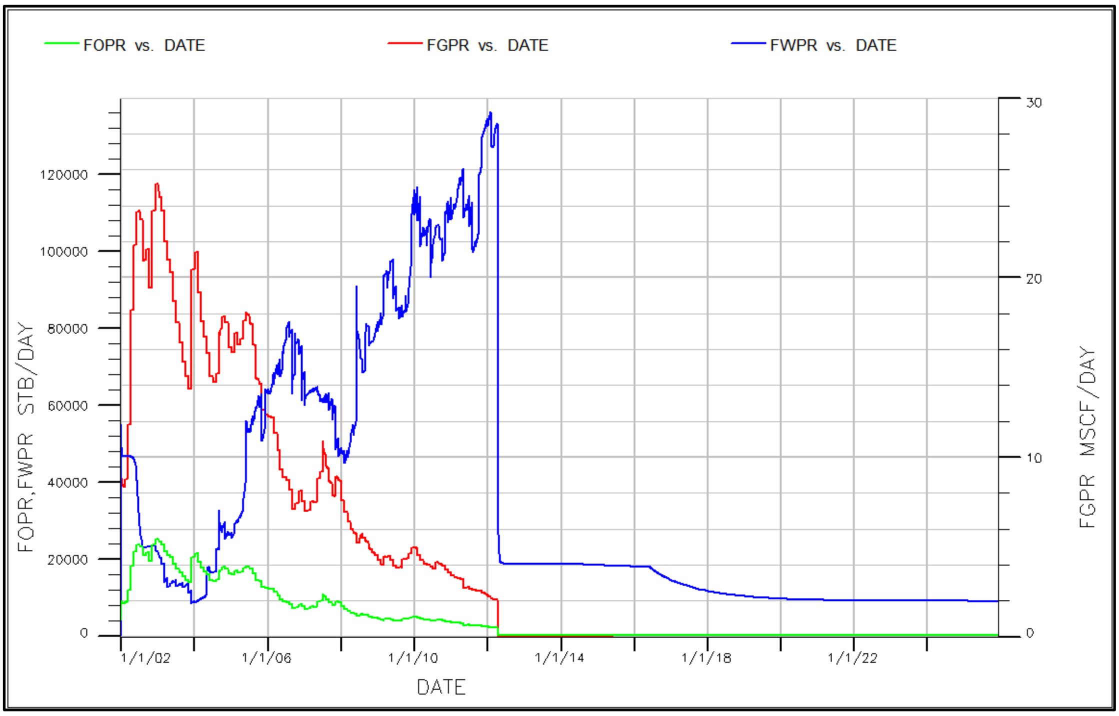

Figure.3.1 Field oil, gas and water production rates.

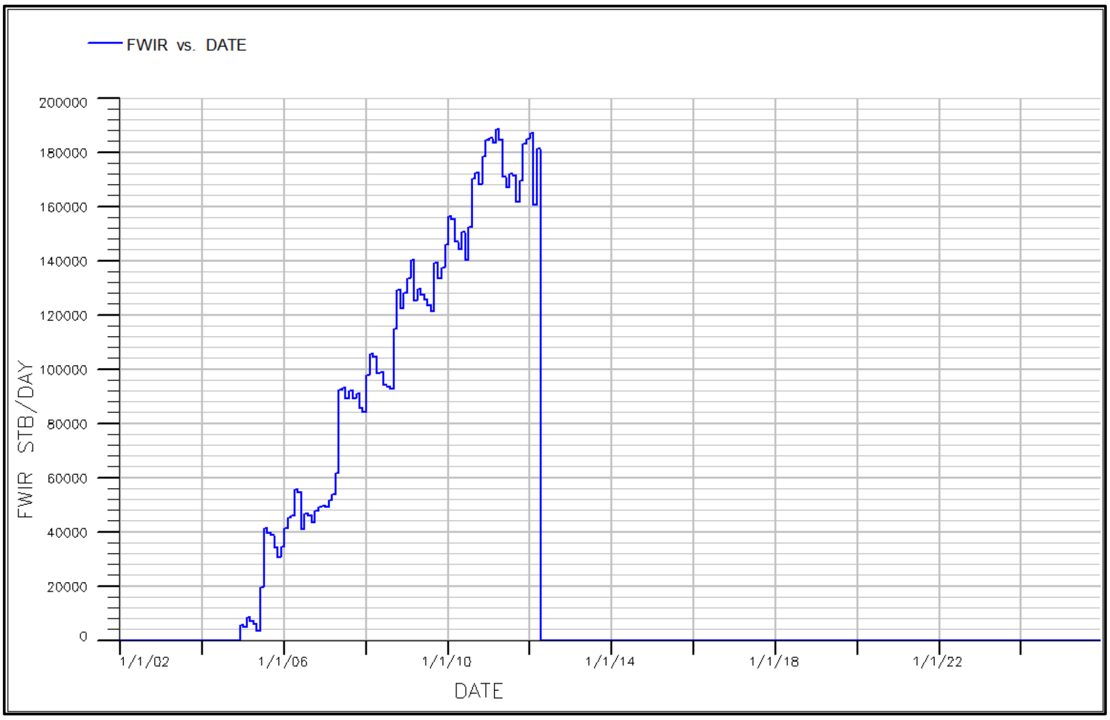

Figure.3.2 Field Water Injection Rate.

3.4.2.2 Water Flooding Cases

Since the main reserves in the Sharyoof field is located in two major zones, SIAL and SIAU, with estimated OOIP of 74532061 BBLS or 71.09 % of all the OOIP in the field, simulation efforts were focused in the lower (L) and upper (U) SIA zones in different patterns. Because some of the injection and production wells in the SIA zone were only perforated into parts of the vertical section, additional perforations were assume in the simulation study to cover the entire zone. Once the dynamic data are imported in ECLIPES the model needs the completion data in order to produce the well, therefore, casing for every well is imported and perforation intervals are also imported in order to detect the interval of production from each well. Therefor the injection wells is perforated in S1AL and S1AU separately, and production wells is perforated in S1AU and S1AL for all simulated injection patterns.

- **Simulated Water Flooding Patterns**

Flood pattern selection is the first steps in designing a waterflooding project. 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:

1- Converting existing production wells into injectors.

2- Drilling infill injection wells.

Based on surface or subsurface topology and/or the use of slant-hole drilling techniques In sharyoof oil field resulted the production and injection wells that are not uniformly located. In these situations, the region affected by the injection well could be different for every injection well. From historical data few production wells which didn’t reach the economic production level are converted into injectors so that also due to the faulting and localized variations in porosity and permeability in the field.

3.4.2.3 Synthetic Model of Polymer Flooding

The dimensional simulation were performed using ECLIPSE 100. The synthetic model is sectorized by 20*20*6 grid. The model has the same petrophysical properties of Sharyoof field, the permeability range is 100 mD and porosity range is between 0.18 to 0.21 Two active wells; a producer and injector, have been added to the model and they are located diagonally with respect to each other. Both wells are completed from the top to the bottom and they are set to be controlled by reservoir fluid volume rate (RESV), with a flow rate of 1000 BPD. The active phases in the reservoir model are oil and water.

3.4.2.4 Polymer Flooding Cases

- After water flooding simulation and due to the high water-cut on most producing wells, we initiated a screening process for the application of polymer flooding for the field in 1 May 2012, with the same wells parameters, completions and three injection patterns that are used in water flooding.
- Starting polymer injecting from the date of water flooding in the historical data, with two Simulation cases :
  1) Continuous polymer injection.
  2) Water alternative polymer injection.

3.5. Expected Outcomes from Water and Polymer Flooding

- The expected from water flooding is to improve oil recovery and maintain reservoir pressure.
- The results that we are expected from polymer flooding is to have a decreasing in water cut, with a better oil sweep efficiency.

CHAPTER-FOURE

4.0 Result and Discussion

4.1 Introduction:

This chapter include analysis and evaluation of Sharyoof development results. The work in this study consists of two main components, Waterflooding and Polymer flooding development options. For the polymer studying, pilot-field tests and development options identification. In the waterflooding option, the effect of injection rate and well completion were conducted. However, for the polymer flooding process, the sensitivities were carried on the effect of different polymer concentration, polymer timing, and different well completions. A total of 82 simulation runs were prepared and run using the ECLIPSE 100 Simulator. The objective of this phase is to asses and select of the best development option that will maximize the oil recovery. All dependent variables that will affect the results of the study will be presented in each scenario.

4.2 Base case

The Base Case forecast represents a continuation of the current production and injection Strategy with existing wells from Dec 2004 to 1 Dec 2025. This was done in order to compare the Base Case with the rest of the other scenarios, (Fig.4.1).

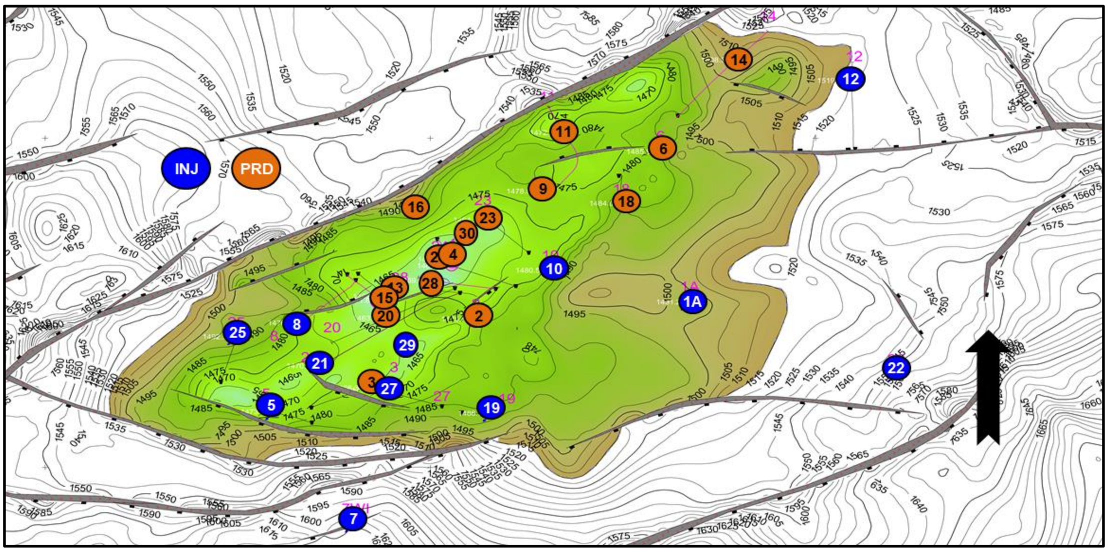

Figure.4.1 WF Injection and production wells distribution of base case.

The results of the base case is shown there is no significant increase of oil production ,having a lower sweep efficiency of the oil reserved of individual layers of sharyoof field about 0.35 of the Original in place as shown in (Fig.4.2)with an increase of field water cut about 0.95 as shown in (Fig.4.3).

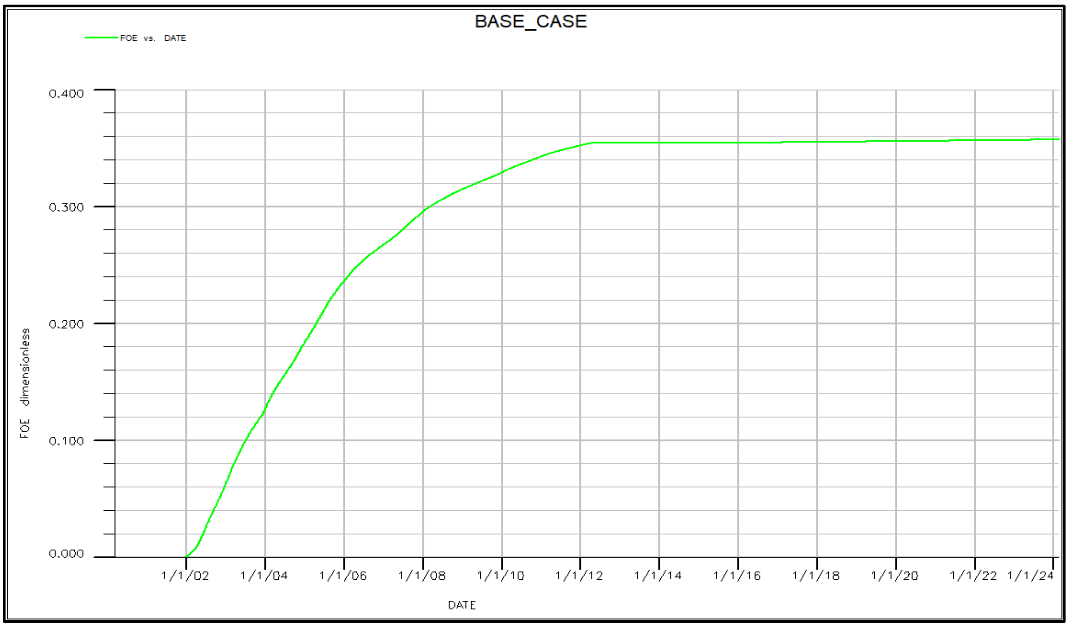

Figure.4.2 Field Oil efficiency.

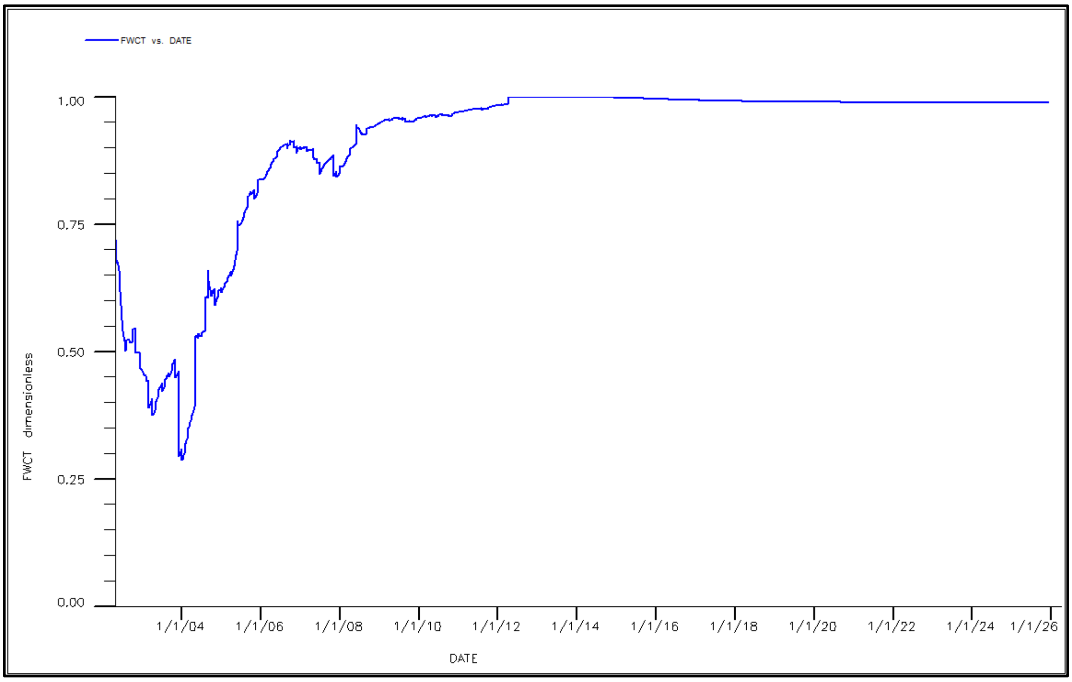

Figure.4.3 Field water cut .

4.3 Water Flooding Scenarios

WF simulation runs are based on two sensitivity cases are listed below:

4.3.1 Well completion sensitivity cases

This sensitivity cases is carried out for separating water flooding into separated intervals of the pay zone S1A including S1AL, S1AU,and combination of both intervals to distinguish between the responses of that two layers from water flooding process with operating all the injection and production wells .since the S1AL layer has more oil saturation than the upper layer S1AU .so that we implanted three scenarios worked on the basis of re-completing the injection wells in S1AU,S1AL separately and production wells in the overall pay zone for the three scenarios , since the injection wells having the same injection rate control.

1- First scenario operated all the producing and injection wells with re-perforation in the overall pay zone Including S1AU and S1AL.

2- Second scenario include re-perforating S1AL for the injection wells.

3- Third scenario include re-perforating S1AU for the injection wells.

The observation from the three completion sensitivity cases resulted with best choice for effective water flooding process by injecting water through S1AL(Second scenario) which gives better cumulative oil production than the other two scenarios about 4,194,129 STB as shown in (Fig.4.4),instead of all them shows a significant increase in displacement efficiency would be 3.69% .

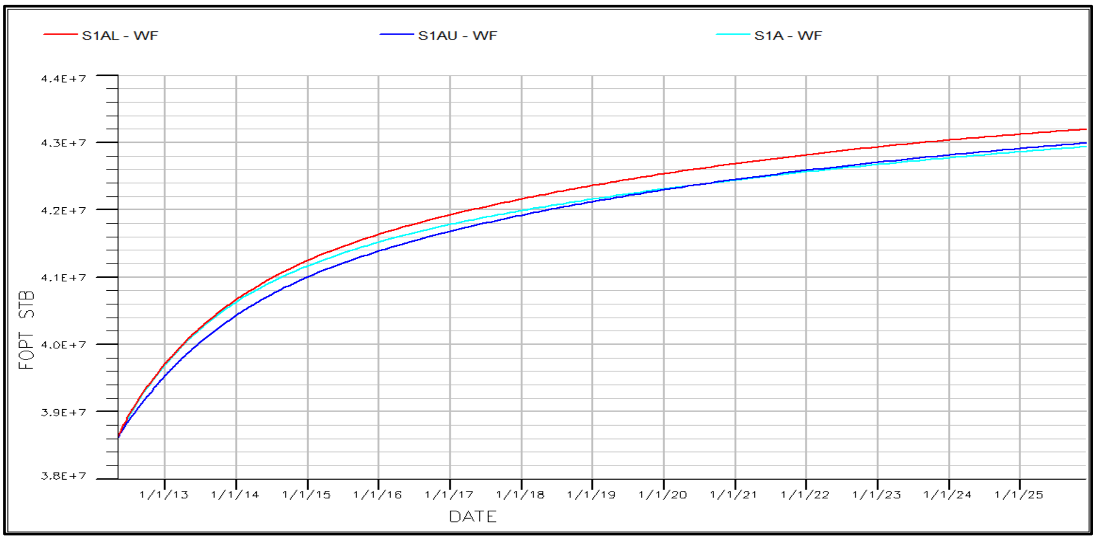

Figure.4.4 Cumulative oil production from combined and separated SIA layers.

4.3.2 Injection rate sensitivity cases

Injection rate control sensitivity cases were implemented in different field water injection rates according to the distances between injection wells and production wells, and the injection history of injection wells in sharyoof field dynamic model. According to the saturation distribution in Sharyoof oil reservoir, three WF patterns were proposed:

I-Pattern-1, as shown in (Fig.4.5), is to start the WF from the northeast section of the field from 1/may/2012. This option includes four water injection wells; SH-**8**, SH-**19**, SH -**21**, SH-**29**, and twelve production wells: SH-**2**, SH-**4**, SH-**9**, SH-**11**, SH-**13**, SH-**15**, SH-**18**, SH-**20**, SH-**23**, SH-**24**, SH-**28**, SH-**30**.

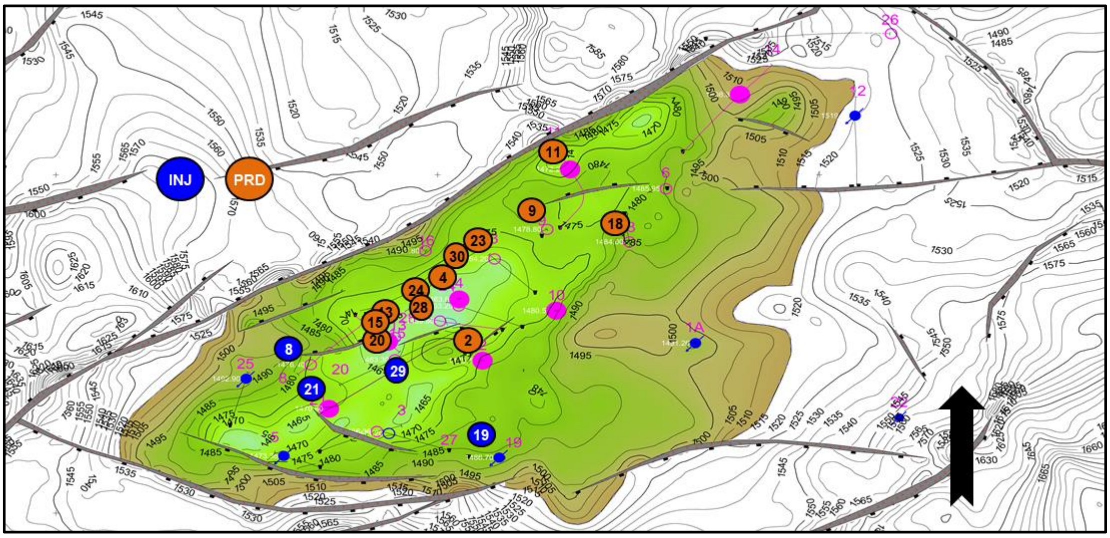

Figure.4.5 WF Injection and production wells distribution of Pattern-1.

Many **WF** simulation runs were conducted in **Pattern-1** for advancing oil displacement efficiency form **SIA** layer by re-completion of SH-**13**, SH-**23**, SH-**24**, SH-**28** and SH-30 into **S1A**, and SH-8 and SH-29 into **SIAL**, with different injection rates (Fig.4.6), shows the best two cases , **case-1**[FWIR = 155000 STB/D], and **case-2**[FWIR=83000 STB/D] ,shows the effect of water injection rate on cumulative oil production ,observing increasing the cumulative oil production of case-1 by 16,188 STB compared to **case-2** which have lower injection rate. On the other hand the average field water cut would be more than the lower injection rate case about 99.3%.

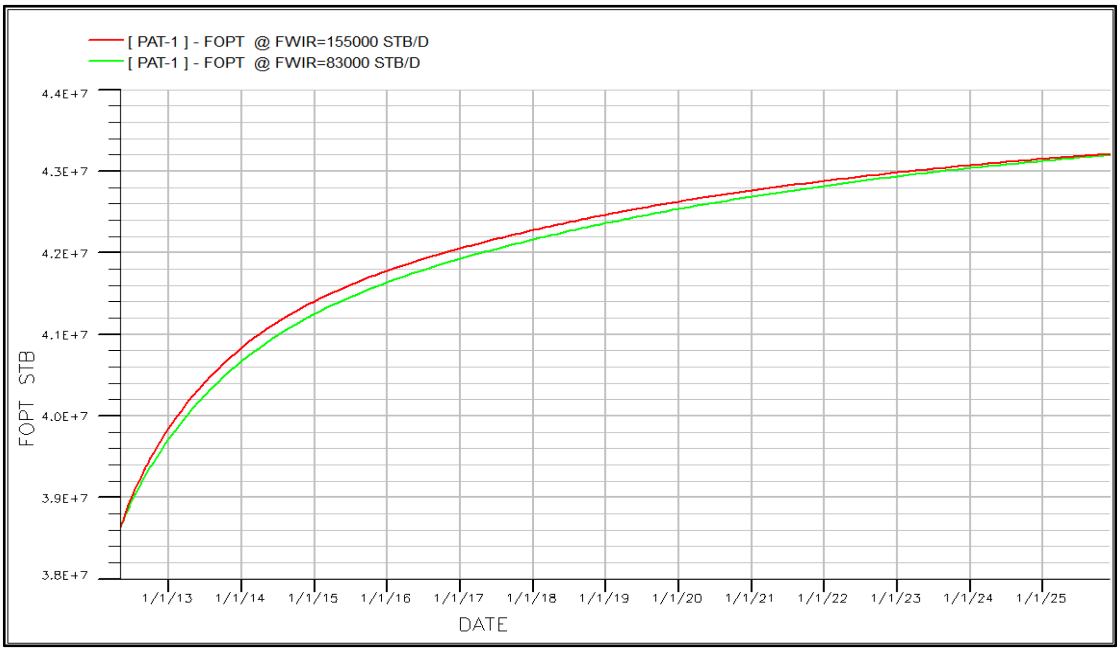

Figure.4.6 field Oil Production total of WF cases in pattern-1.

II-Pattern-2, as shown in (Fig.4.7), is to start the **WF** from the east section of the field from 1/may/2012. This option includes four water injection wells; SH-**1**, SH-**10**, SH -**19**, SH-**29**, and thirteen production wells : SH-**2**, SH-**4**, SH-**6**, SH-**9**, SH-**11**, SH-**13**, SH-**15**, SH-**18**, SH-**20**, SH-**23**, SH-**24**, SH-**28**, SH-**30**, with re-compilation of injection and production wells into S1AL and entire S1A respectively .

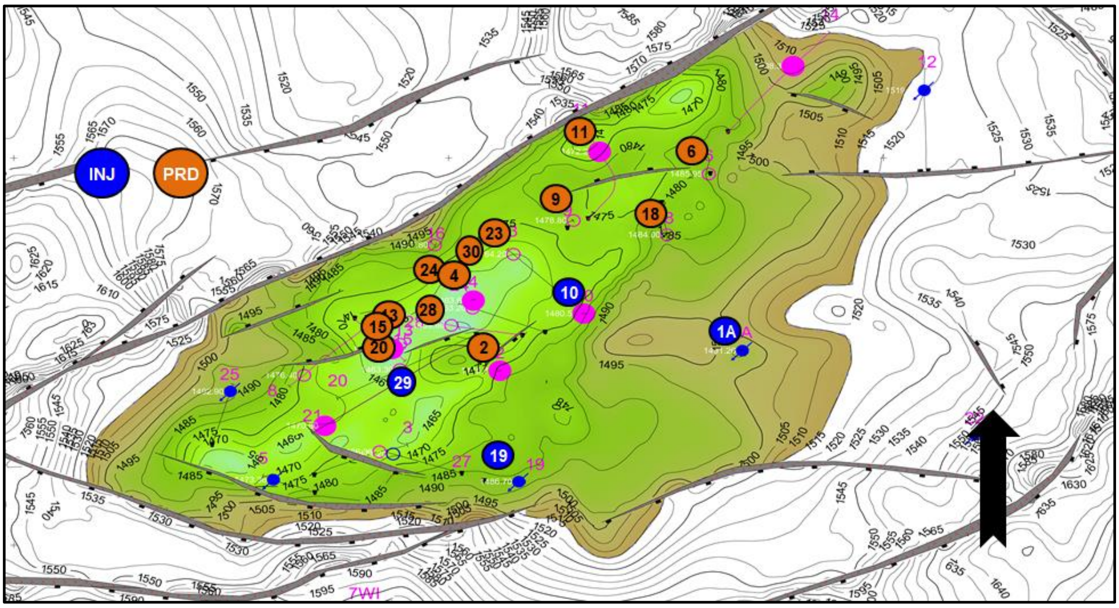

Figure.4.7 WF Injection and production wells distribution of Pattern-2.

The same approach of WF used in **pattern-1** is used in **pattern-2** by applying two different field water injection rates ,which shows similar response in field water cut and higher cumulative oil production in **case-3**-[FWIR=170000 STB/D] compared to **case-4**-[FWIR=148000 STB/D] by 285,716 STB, as shown in (Fig.4.8).

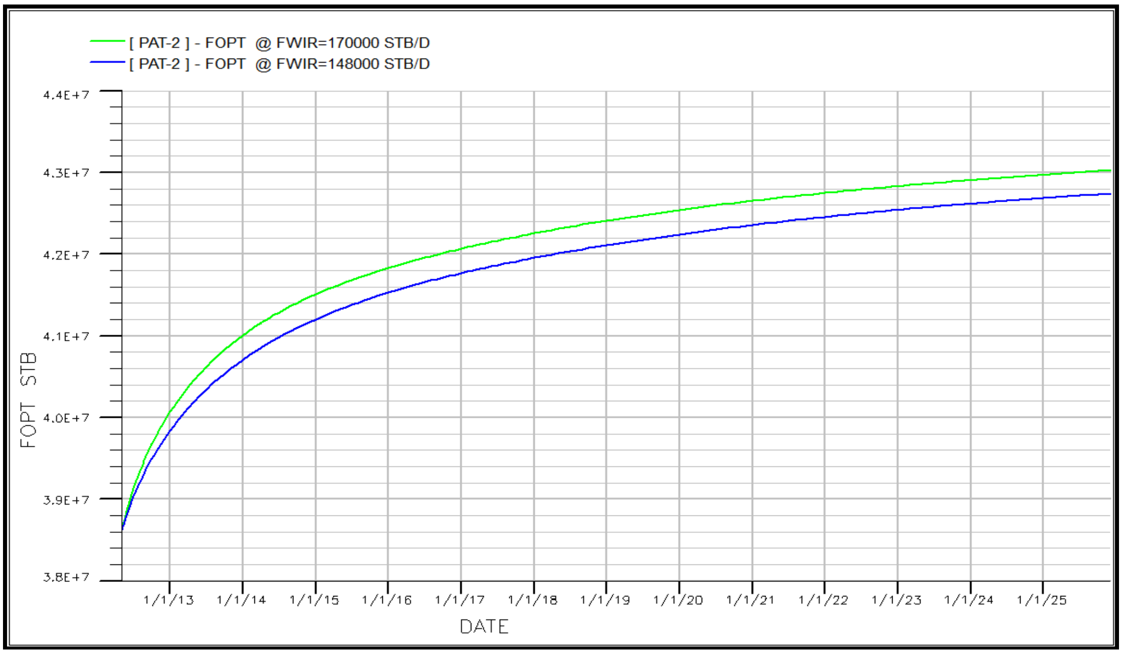

Figure.4.8 field Oil Production total of WF cases in pattern-2 .

II-Pattern-3, as shown in (Fig.4.9), is to start the **WF** from the middle section of the field from 1 may 2012. This option includes four water injection wells; SH-**6**, SH-**10**, SH **-16**, SH-**18**, and eight production wells : SH-**2**, SH-**4**, SH-**9**, SH-**11**, SH-**23**, SH-**24**, SH-**28**, SH-**30**. With converting the producing wells SH-**6**, SH **-16**, SH-**18** into injectors to cover large area of the field.

In this pattern three production wells converted into water injectors, which shows higher water cut in the late stage of their production history in the field, WF scenarios in this pattern have a lower field water injection rate compared to the two previous patterns due to the lower distance between production wells and to avoid rapid increase of water cut during water flooding process.

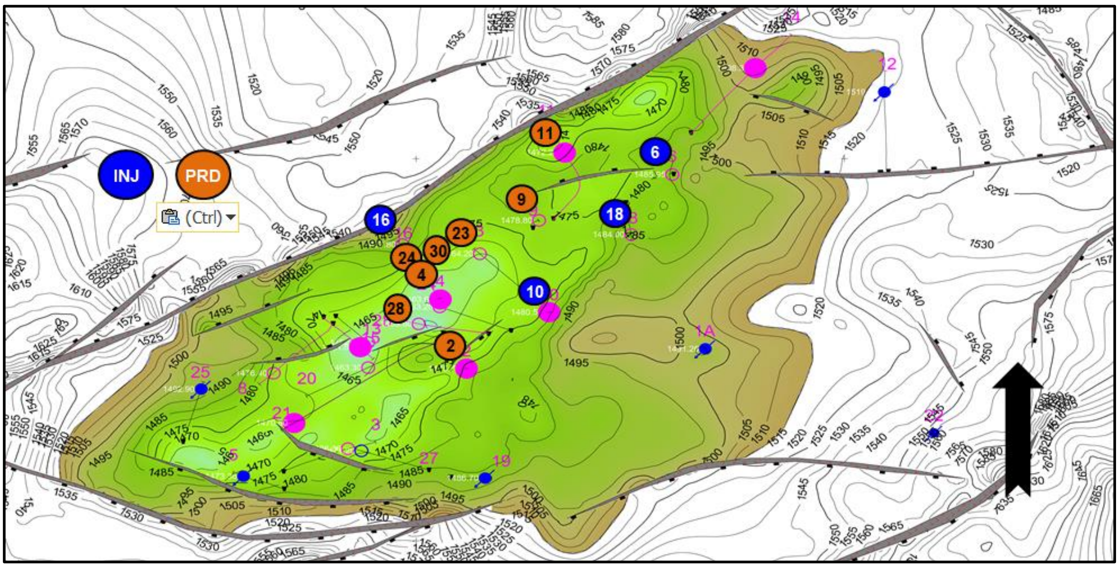

Figure.4.9 WF Injection and production wells distribution of Pattern-3.

Instead of the lower injectivity approach that used in **case-5**-[FWIR=60000 STB/D] and **case-6**-[FWIR=39000 STB/D] in pattern-3, it is observed case-6 has higher cumulative oil production of lower injection rate increased by 95,124 STB compared to the case-5 of higher injection rate as shown in (Fig.4.10), which resulted in rapid increase of water cut started from the beginning of WF as shown in (Fig.4.11).

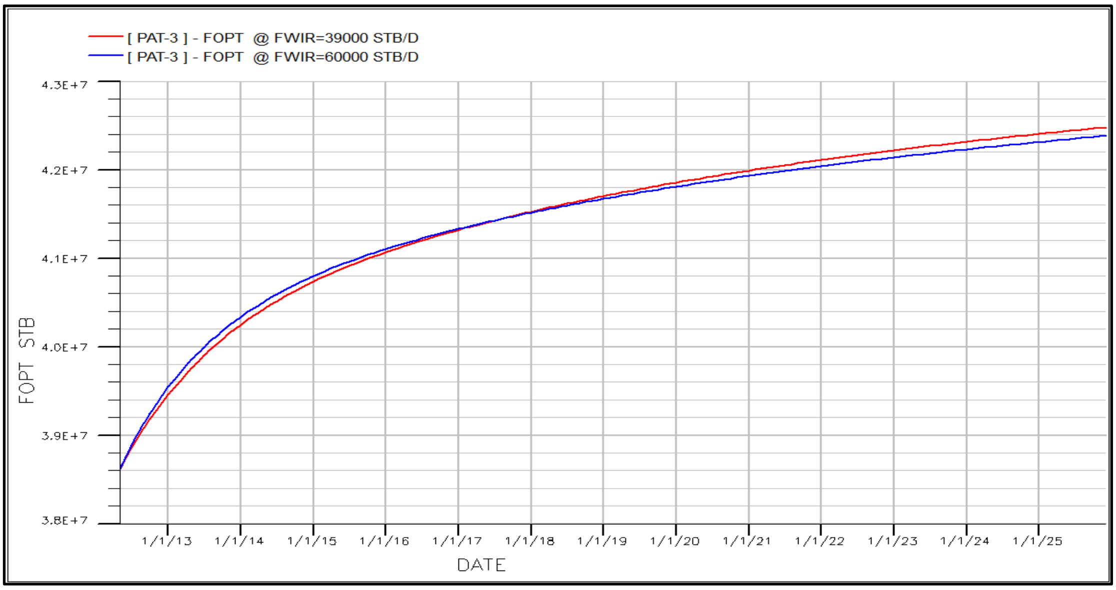

Figure.4.10 field Oil Production total of WF cases in pattern-3.

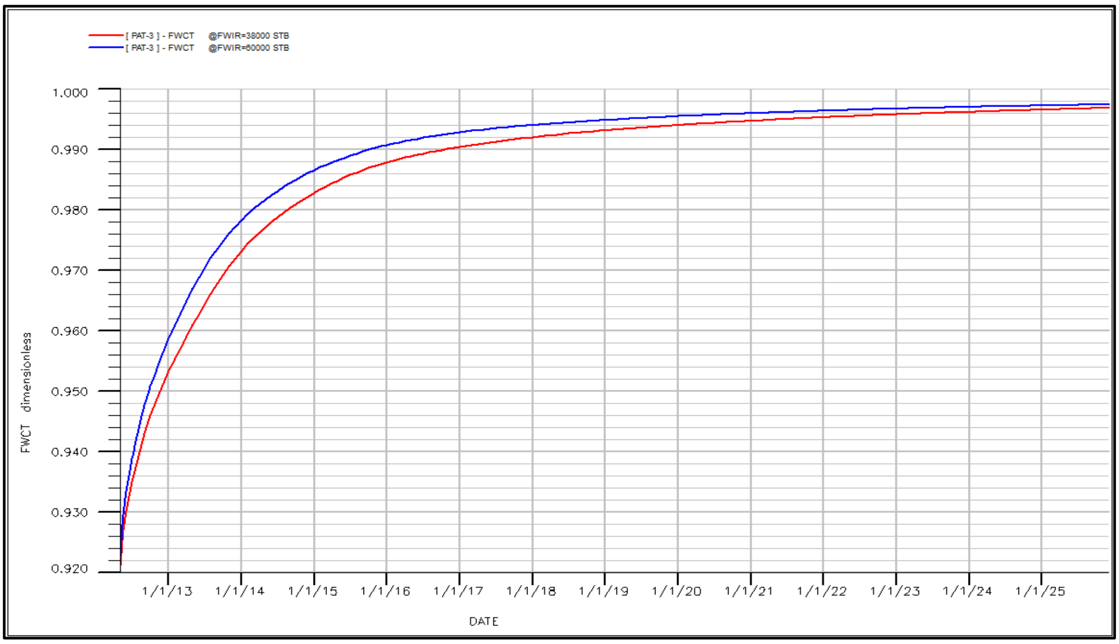

Figure.4.11 Field water cut of WF cases in pattern-3.

Statistical representation for WF scenarios for three patterns to compare between their cumulative oil production related to the total water injection rate as shown in (Fig.4.12) .

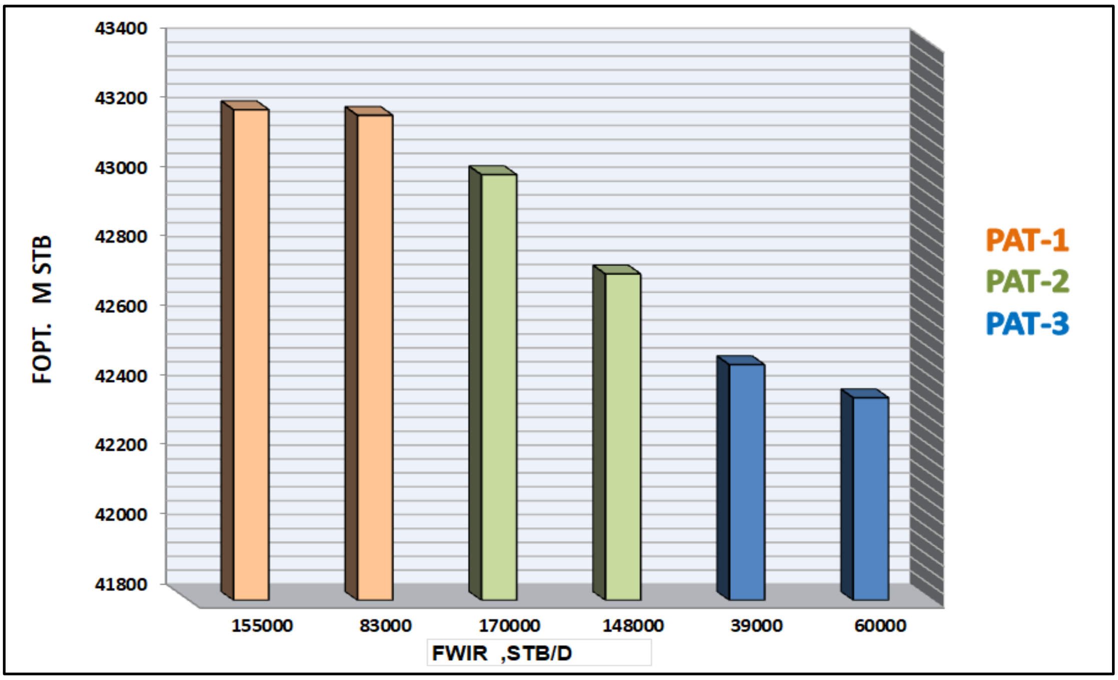

Figure4.12 Statistical representation of field water injection rate with cumulative oil production of WF cases.

4.3.3 WF recovery efficiency

According to what has been found in the previous water flooding cases the maximum oil recovery was achieved at an injection rate 155000 STB/D (the optimum WF case of pattern-1) with 3.871% difference from the base case as shown in (Fig.4.13)

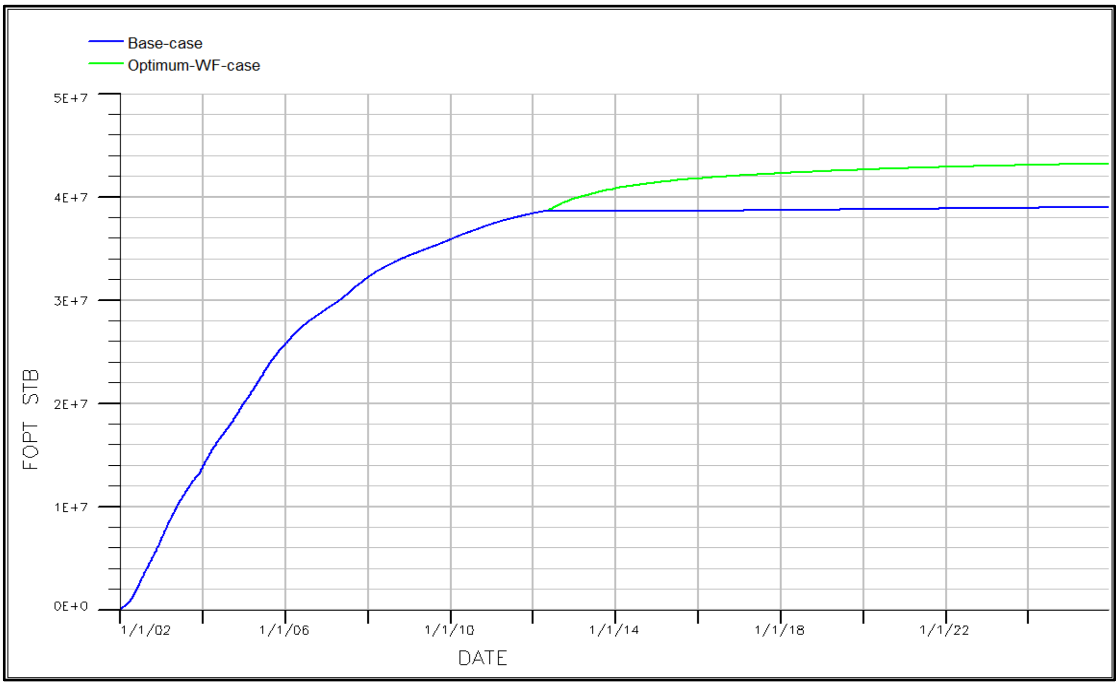

Figure.4.13 Field Oil Production total of base case and optimum WF case.

4.4 Polymer flooding scenarios:

4.4.1 Synthetic Model of polymer flooding

The Synthetic model was built to simulate the flooding process in this study the new Cartesian model contains **20x20x6** grid blocks. Having the same rock and fluid properties of sharyoof field with a porosity of 0.20. The base case model has two phases: oil and water. Two wells have been included in the Synthetic model, one production and one injection well where the production well located at I=20, J=20 grid block while the injection well is located in **I**=1, **J**=1 grid block, (Fig.4.14).Simulation lasted 10 years. Different cases have been simulated by injecting polymer Continuously and alternative slugs followed by water.

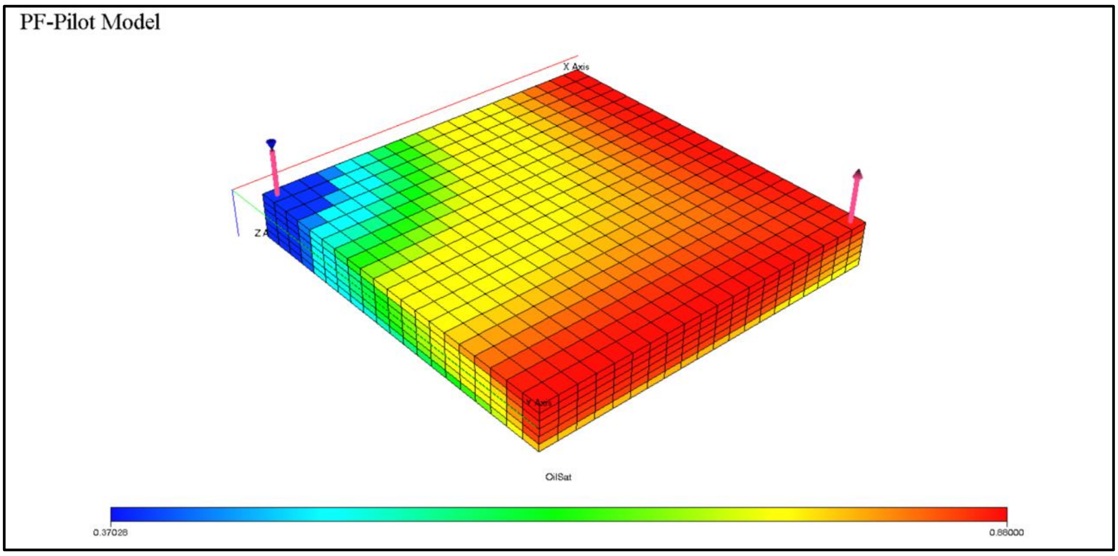

Figure.4.14 Synthetic model.

Several simulation cases for polymer flooding are conducted using synthetic model to understand the applicability of polymer flooding to the rest of the reserve of S1A layer in sharyoof field using different polymer slug sizes with different concentration are injected in the pilot model to measure the incremental oil recovery, decrease of water cut and understand the injectivity characteristics of polymer flooding process.

In order to analyze the effect of the polymer concentration, the simulation model has been run for different concentrations. Since the viscosity depends on the polymer concentration and the oil recovery is influenced by the viscosity it is important to carefully examine the polymer concentration effect. From sharyoof field polymer flooding lab test study done by Dove Energy, Ltd provided by the ranges of polymer slug sizes and concentrations (Fig.4.15).

Dove energy tested Different total slug sizes with different concentrations to obtain the more efficient slug sizes with a certain concentrations, they found the more efficient slug size is 0.5 PV with concentration of 1200 mg/l.

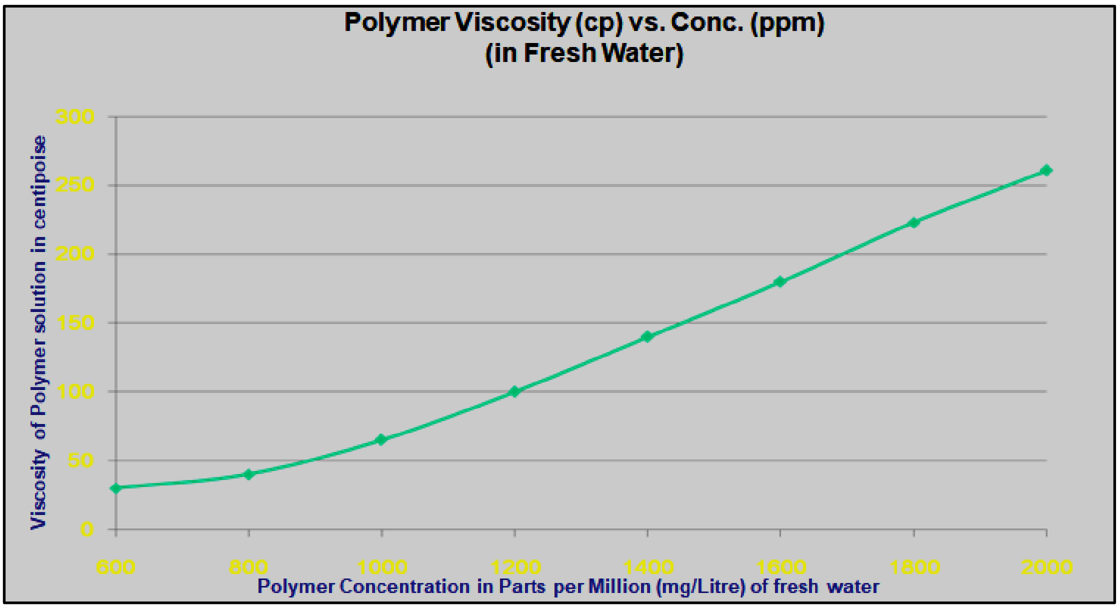

Figure.4.15 Polymer Viscosity vs Polymer Concentration.

In our project we conducted a detailed study by using Eclipse 100 simulator through dividing the total slug size 0.5 PV into separated slug sizes 0.1 PV ,0.2 PV , 0.3 PV with the rang of concentrations from 800 mg/l to 1600 mg/l. to measure the compatibility between the slug sizes with their concentrations ,and to study their relation to the displacement efficiency . In the pilot model the polymer was injected based on two sensitivity cases:

1- Continuous Injection Sensitivity.

2- Water Alternative Polymer (WAP) Sensitivity.

4.4.1.1 Continuous injection sensitivity

Each polymer slug size of 0.1PV, 0.2PV, 0.3PV injected continuously with all the concentrations of 800 mg/l, 1000 mg/l, 1200 mg/l, 1400 mg/l, 1600 mg/l to observe displacement efficiency as shown in (Fig.4.16, a,b,c).

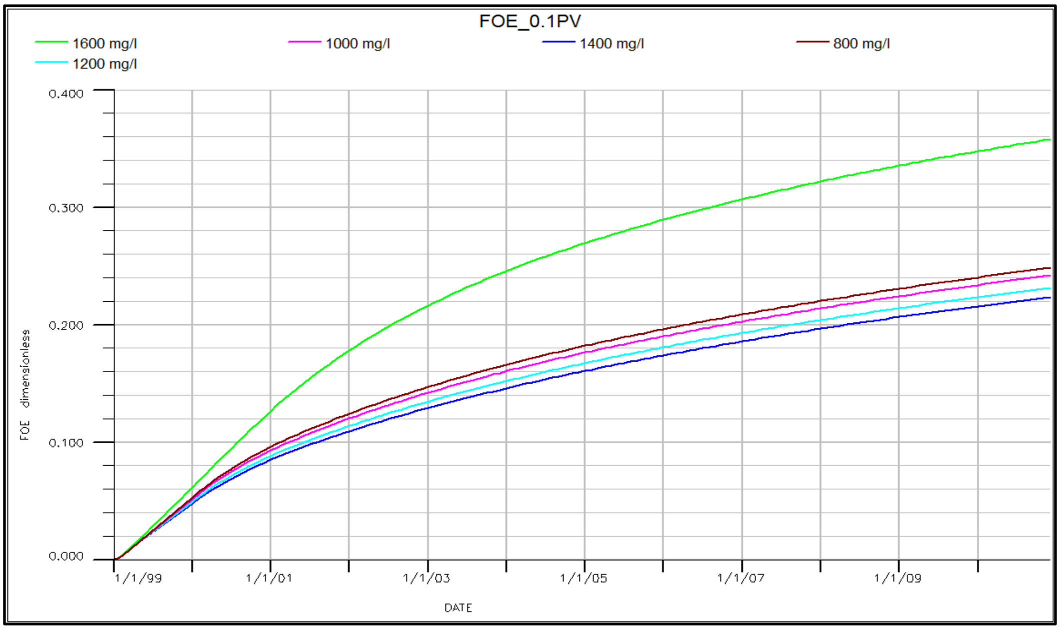

Figure.4.16-a Field oil efficiency of 0.1 PV slug size.

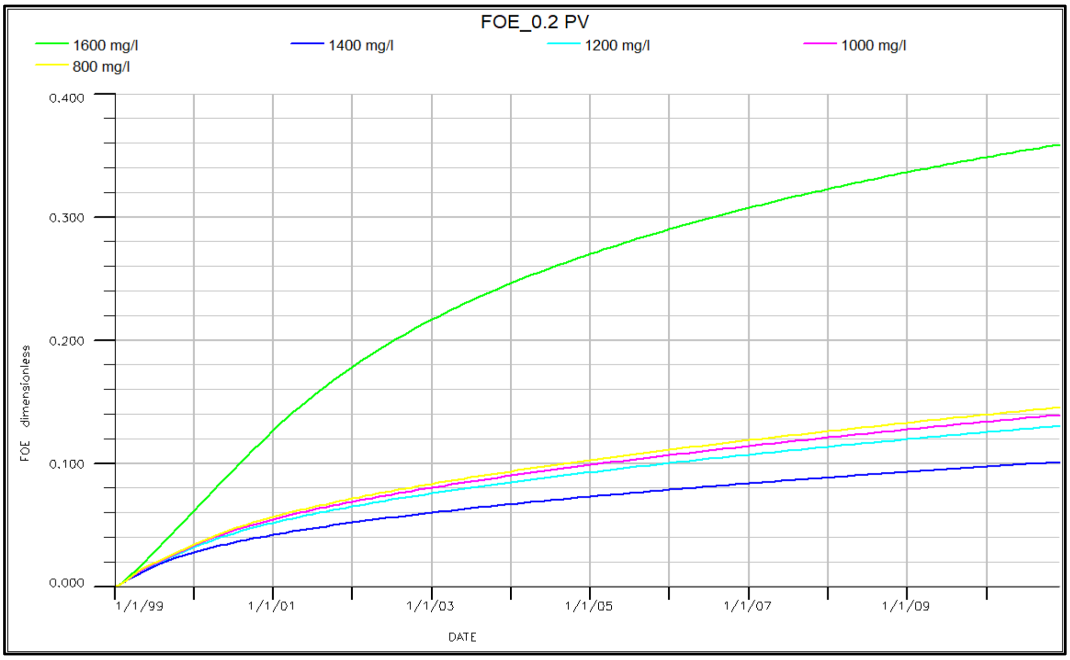

Figure.4.16-b Field oil efficiency of 0.2 PV slug size.

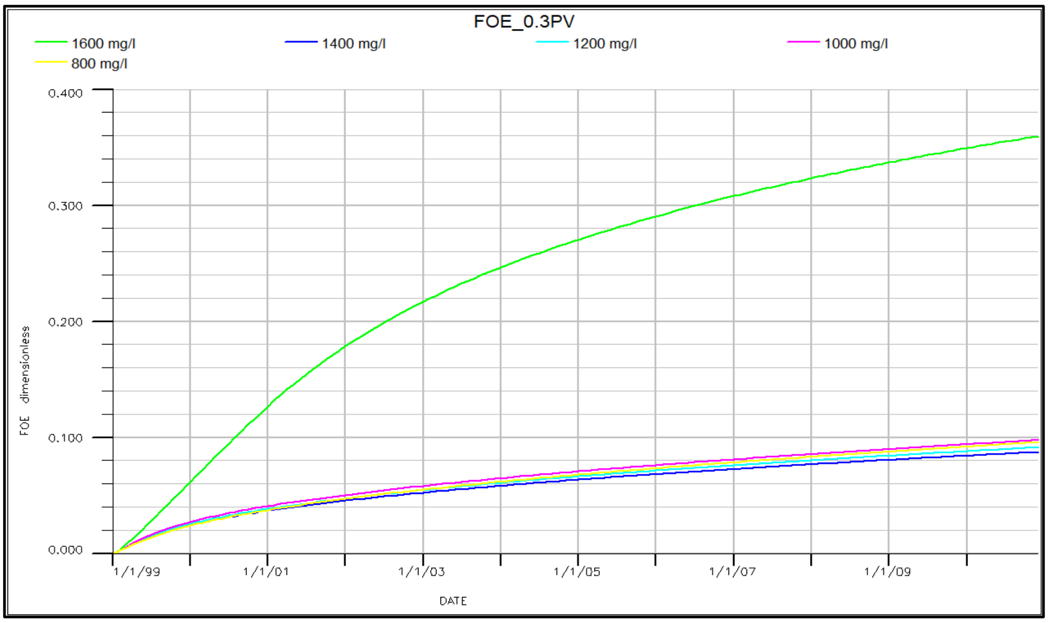

Figure.4.16-c Field oil efficiency of 0.3 PV slug size.

According to the previous scenarios it is observed that the concentration 1600 mg/l with the three slug sizes have higher displacement efficiency, however it tends to be adsorbed by the rock more than the lower concentrations, in the same time the slug sizes with 1000 mg/l, 800 mg/l concentrations shows a better displacement efficiency comparing to the other concentrations with low adsorption to the rock surface. As shown in (Fig.4.17).

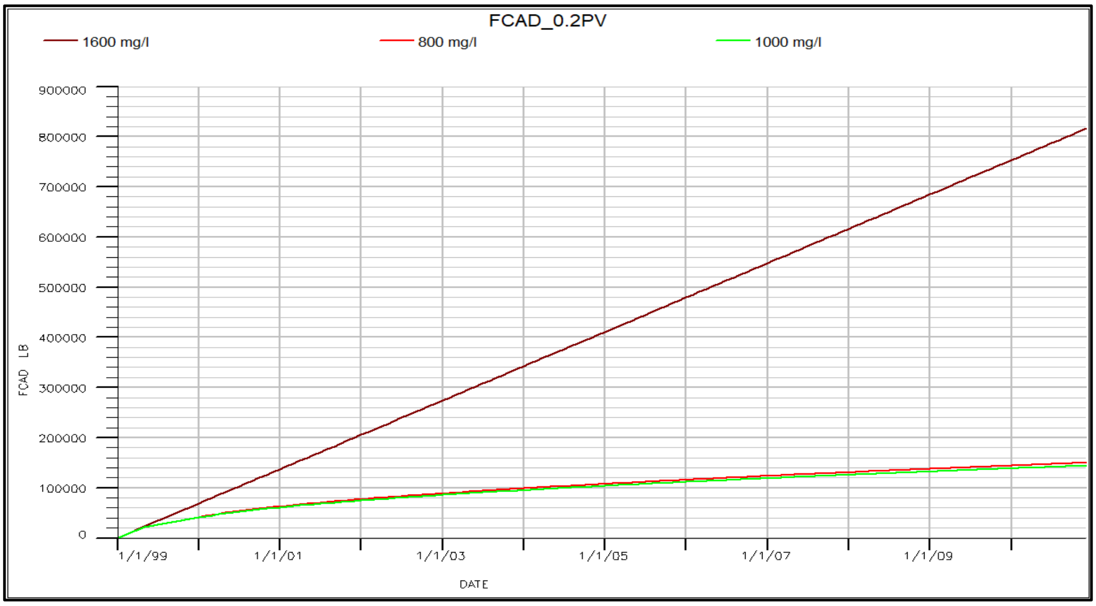

Figure.4.17 Field polymer adsorption.

4.4.1.2 Water Alternative Polymer (WAP) Sensitivity

In this sensitivity cases polymer solutions injected as a multi-slug process with different concentrations by using the optimal slug sizes and concentrations along 365 days followed by 730 days of injected water, with total injection rate 1000 STB/D along the entire period of simulation model .

Different displacement efficiency of five injection cases in this pilot model shown in (Fig.4.18), which are listed below :

- Case-1: 1600 mg/l, 0.1 PV +1000 mg/l, 0.1 PV +800 mg/l, 0.3 PV.
- Case-2: 1600 mg/l, 0.1 PV +1000 mg/l, 0.2 PV +800 mg/l, 0.2 PV.
- Case-3: 1600 mg/l, 0.2 PV +1000 mg/l, 0.2 PV +800 mg/l, 0.1 PV.
- Case-4: 1600 mg/l, 0.2 PV +1000 mg/l, 0.1 PV +800 mg/l, 0.2 PV.
- Case-5: 1600 mg/l, 0.3 PV +1000 mg/l, 0.1 PV +800 mg/l, 0.1 PV.

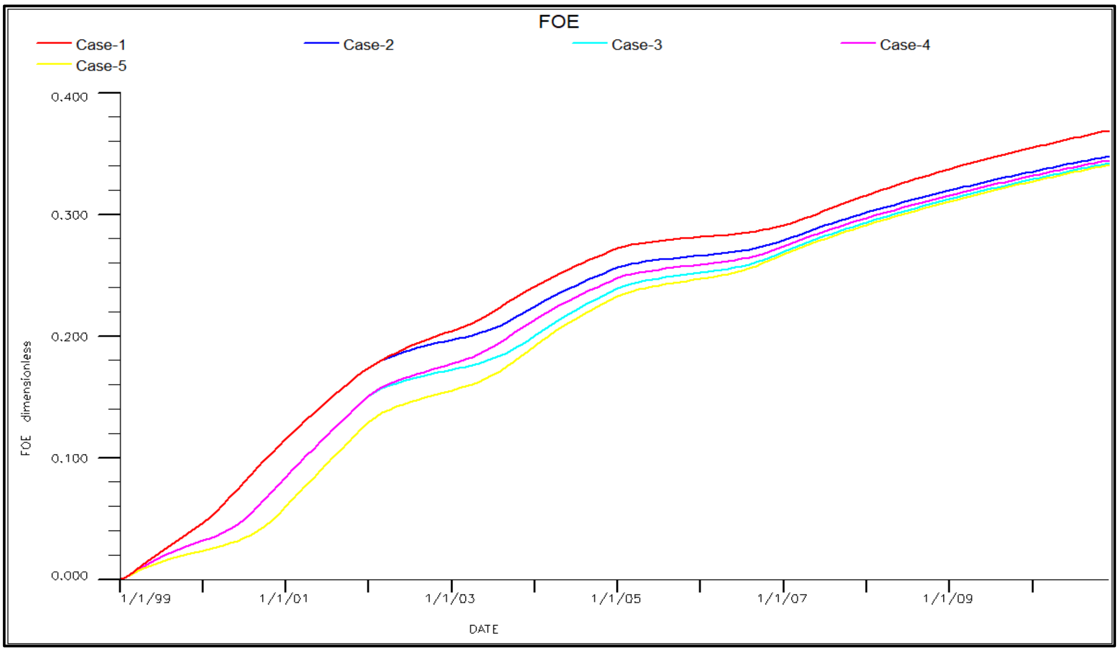

Figure.4.18 Field oil efficiency.

According to the previous cases it is observed the optimum case for polymer flooding that gives high displacement efficiency is case-1 with successive slugs of 0.1 PV-0.1PV-0.3PV that has higher recovery efficiency by 3.34 % comparing to water flooding recovery efficiency as shown in (Fig.4.19).

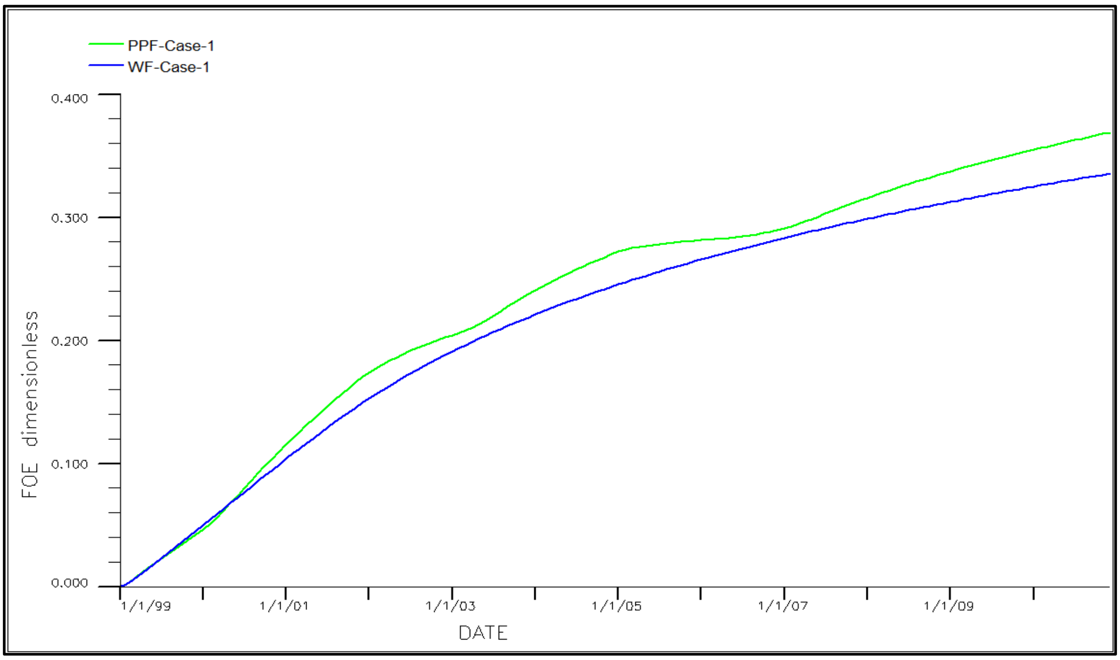

Figure.4.19 Field oil efficiency.

The positive results of the synthetic model polymer flooding gives an indicator to apply the polymer study for the Sharyoof field simulation model. Though, it may not give desirable results in the real model, since the synthetic model was assumed simple and homogenous and did not take into account any complexity and heterogeneity.

4.4.2 Polymer Flooding Cases

4.4.2.1 Description of Polymer Flooding Process

During polymer flooding, water mobility is obviously lowered; as a result, at the front of polymer slug an oil bank is accumulated. With time going, polymer slug flows towards producing wells, before which, the oil bank flows to producing wells earlier, and the oil production rate gradually increases to peak value. Shortly after that the polymer concentration peak value is also reached, then the oil production rate decreases more quickly to the lowest value.

4.4.2.2 PF Simulation Parameters

All PF simulation parameters were based on laboratory experimental results. The following tables show these input parameters:

Aqueous phase flowing velocity, (ft/d)	Factor used in the simulator
0	1.00
4725	0.45
82204.724	0.10
401811.02	0.05

Table 4.1 Polymer Shear Thinning Data.

Polymer conc. (lb/stb)	Fm (Viscosity modifier)
0	1.00
0.21033591	12.60
0.28044788	18.72
0.35055984	25.44
0.42067181	35.16
0.49078378	45.48
0.56089575	57.6
0.63100772	71.4
0.70111969	89.88

Table.4.2 Polymer Solution Viscosity Function.

Polymer conc. (lb/stb)	Polymer adsorption (lb/lb)
0	0
0.70111969	0.0015
2.80447880	0.0025

Table.4.3 Polymer Adsorption Functions.

Parameter	Value
Inaccessible pore volume (fraction)	0.09
Residual resistance factor (ratio)	5.0
Adsorption index	2.0
Maximum polymer adsorption (lb/lb)	0.002844

Table.4.5 Polymer rock properties.

4.4.2.3 The proposed WF patterns

The polymer flooding patterns are the same patterns that used in WF scenarios taking into account the simulation parameters, are listed below:

A-Injection Pressure control BHP: for the minimal impact on the possibility in fracturing the injection wells, injection pressures were limited to two cases; 1500 psi and 2000 psi in the simulation studies.

B-Polymer Slug Design and concentrations: polymer solutions may be injected by two years for each single slug with constant concentration or as a multi-slug process with different concentrations followed by two years of injected water alternatively, as we observed from polymer flooding synthetic model results we summarized the optimal slug sizes and consternations that gives the best displacement efficiency with a lower adsorption tendencies to the rock surfaces .summarized as :

- Continues injection cases :
    - 0.1 PV: 1600 mg/l - 1000 mg/l - 800 mg/l.
    - 0.1 PV: 1000 mg/l.
    - 0.1 PV: 800 mg/l.
- Water Alternative Polymer (WAP) cases :
    - Case-1: 1600 mg/l, 0.1 PV +1000 mg/l, 0.1 PV +800 mg/l, 0.3 PV.
    - Case-2: 1600 mg/l, 0.1 PV +1000 mg/l, 0.2 PV +800 mg/l, 0.2 PV.
    - Case-3: 1600 mg/l, 0.2 PV +1000 mg/l, 0.2 PV +800 mg/l, 0.1 PV.

4.4.2.4 PF Sensitivity cases

I-Pattern-1

- **Continuous injection sensitivity** cases for pattern-1 (Fig.4.20), conducted by applying two scenarios with variable concentrations, having the same bottom hole injection pressure 2000 psi from 1/May/2012, which resulted different cumulative oil production as shown in (Fig.4.21) .

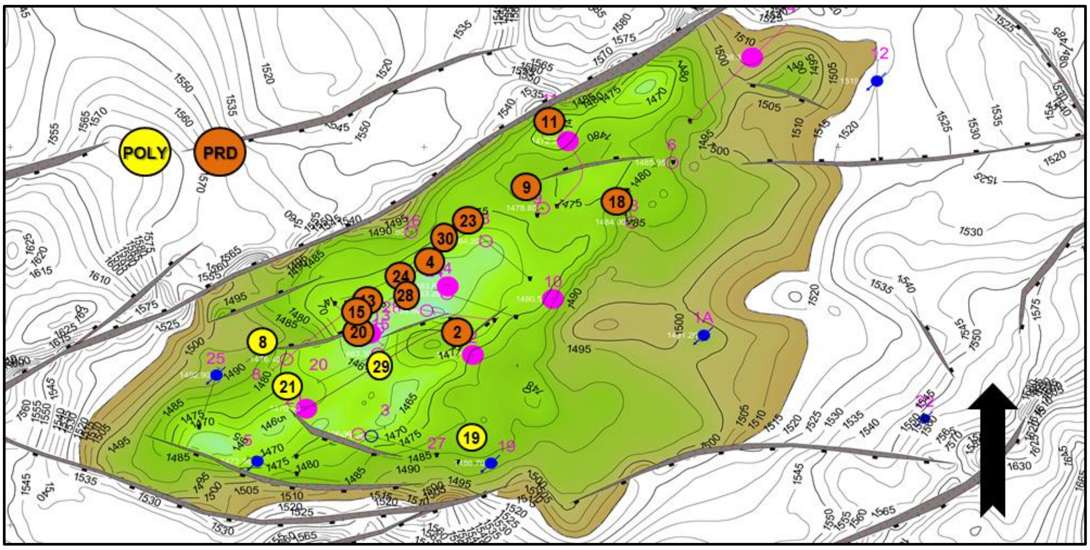

Figure.4.20 PF Injection and production wells distribution of Pattern-1.

According to the results of the two scenarios the case-[0.1 PV : 1600 mg/l - 1000 mg/l - 800 mg/l.], gives higher cumulative oil production by 59,672 STB Comparing to the case-[0.1 PV : 800 mg/l],that’s indicate continuous PF of multi-stage concentrations gives a better production performance with higher average water cut than injecting single polymer concentration .

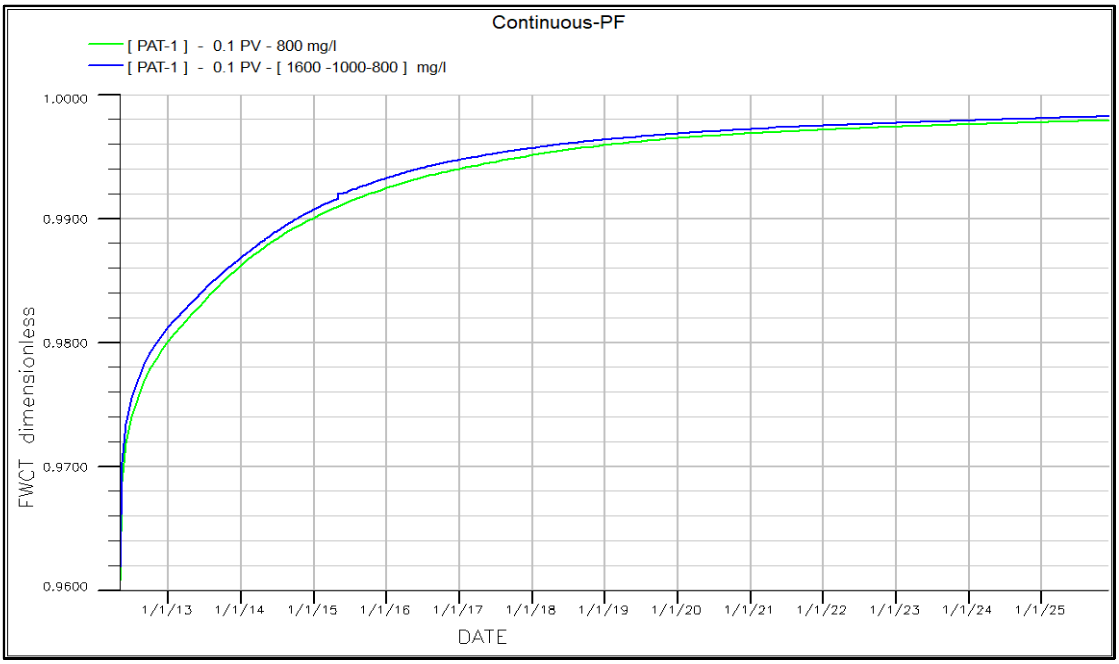

Figure.4.21 Field Oil Production total of continuous –PF cases in pattern-1.

- **Water Alternative Polymer (WAP)** cases for pattern-1, conducted by applying three scenarios with variable slug sizes with the same concentrations of [1600-1000-800] mg/l, having the same bottom hole injection pressure of 1500 psi from 1/May/2012, which resulted with little different cumulative oil production as shown in (Fig.4.22).

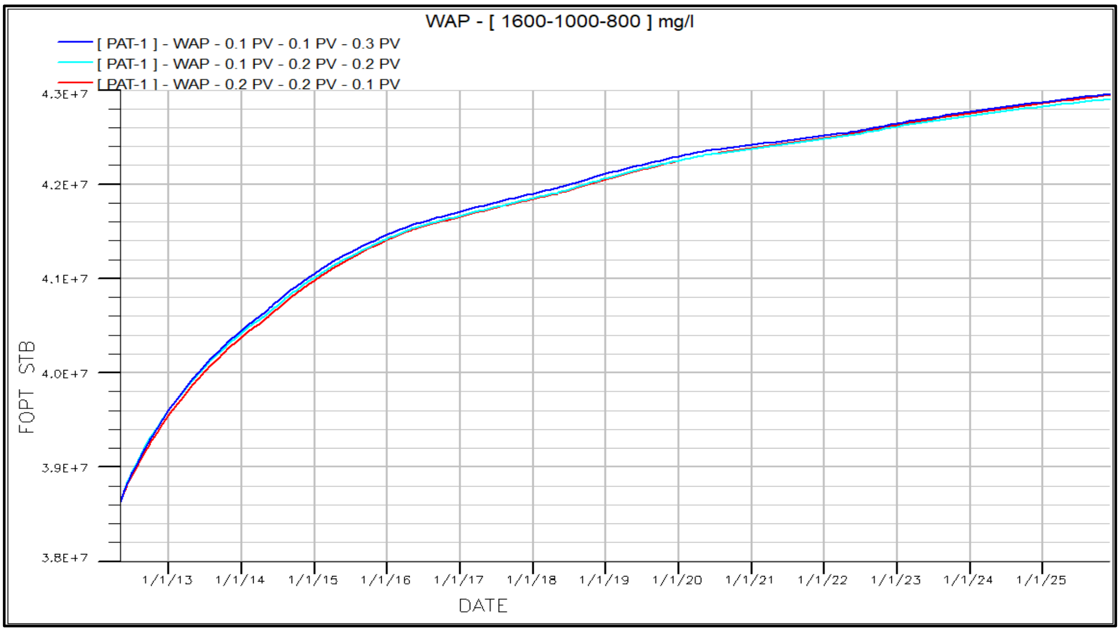

Figure.4.22 Field Oil Production total of WAP-PF cases in pattern-1.

The three WAP cases from the above figure the shows a little differences in cumulative oil production performance with an appreciable variation in their field water cut as shown in (Fig.4.23).

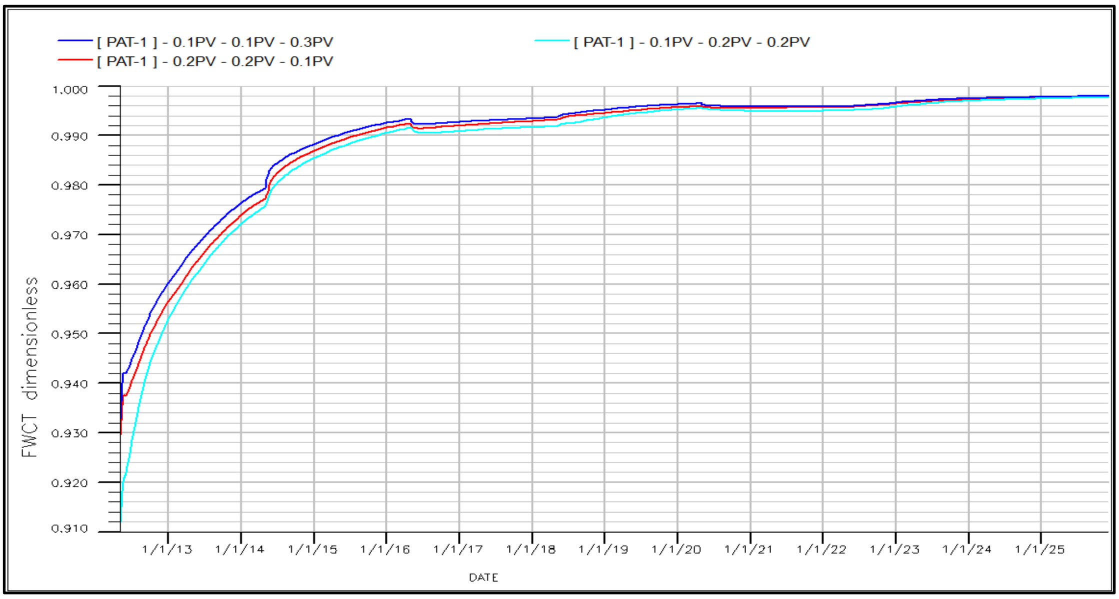

Figure.4.23 Field water cut of WAP –PF cases in pattern-1.

The observation from the sensitivity cases of PF in pattern-1 that is the alternative water polymer WAP approach have more oil displacement efficiency than continues PF of multi-stage concentrations, (Fig.4.24), with lower cumulative injected polymer in the reservoir as shown in (Fig.4.25).

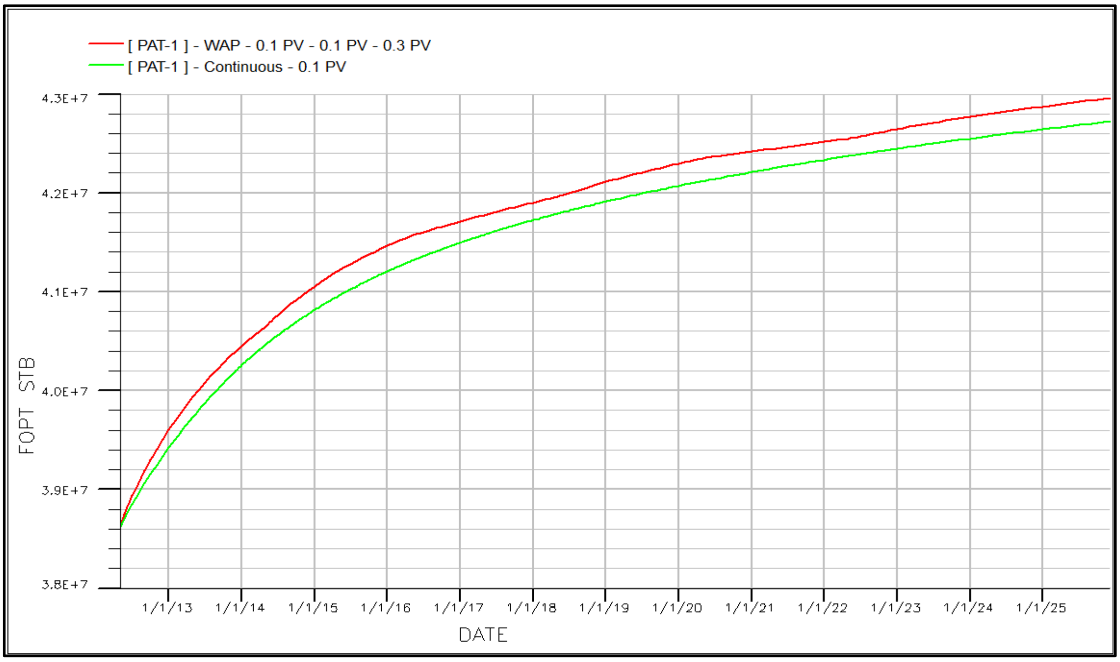

Figure.4.24 Field Oil Production total of optimal Continuous and WAP-PF cases in pattern-1.

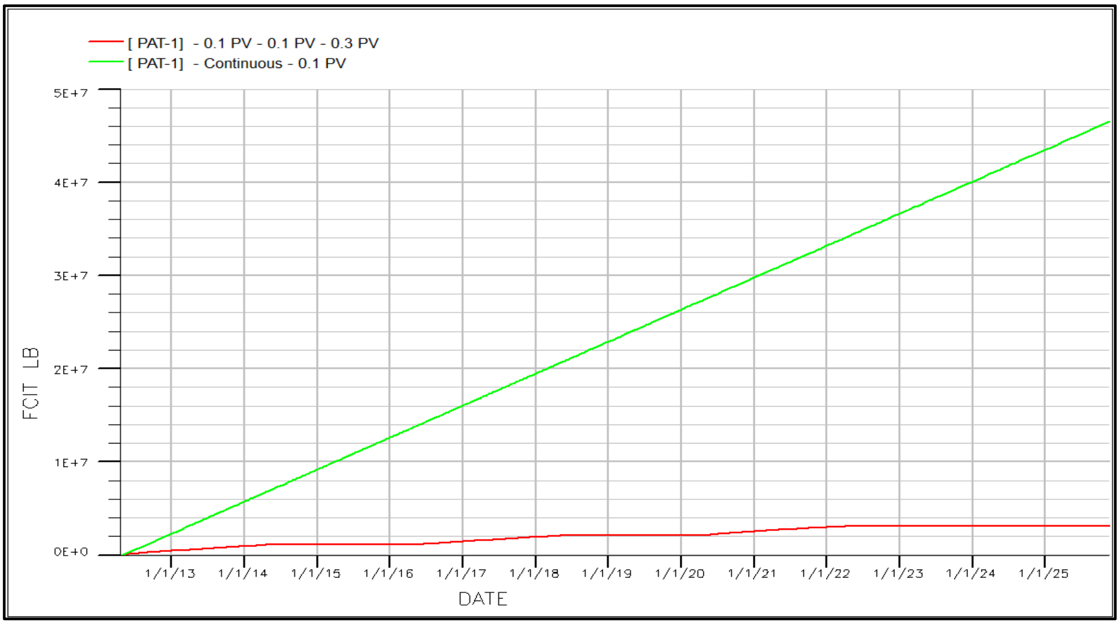

Figure.4.25 Field polymer injection total of optimal Continuous and WAP-PF cases in pattern-1.

II-Pattern-2

- **Continuous injection and Water Alternative Polymer (WAP)** sensitivity cases for pattern-2 (Fig.4.26), conducted by applying the optimum scenario for each sensitivity case , having the same bottom hole injection pressure 2000 psi and similar polymer concentrations from 1/May/2012, which resulted different cumulative oil production as shown in (Fig.4.27).

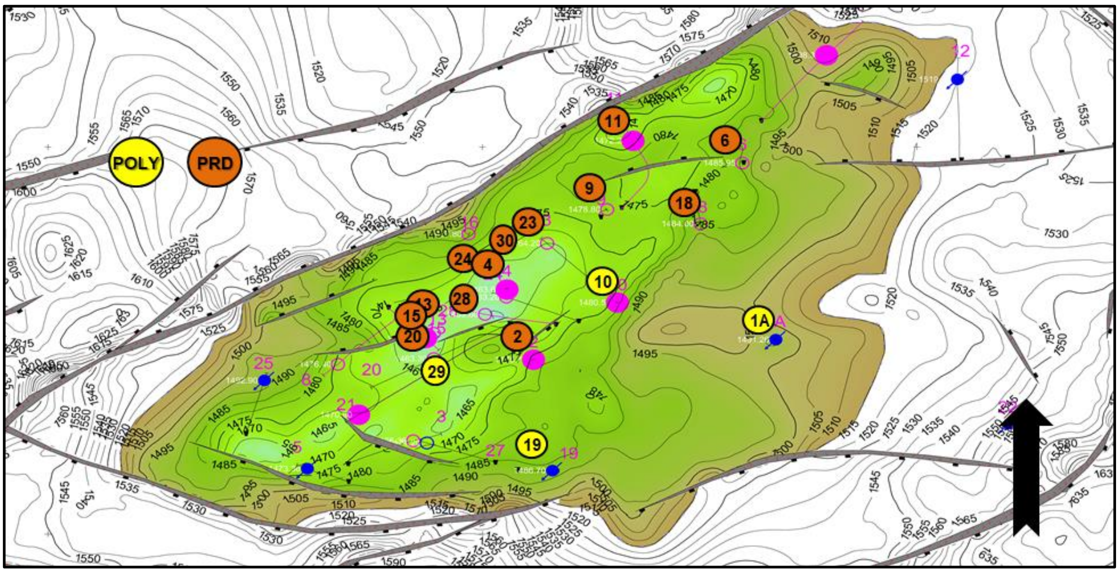

Figure 4.26 PF Injection and production wells distribution of Pattern-2.

The incremental of cumulative oil production of the WAP case about 296,528 STB comparing to the continuous PF case, with a significant decrease of water cut in the early stage of PF at the first injected polymer slug of the highest concentration followed by a rapid increase of water cut reached to the stable curve of continuous PF water cut line, (Fig.4.28),the latter two polymer slugs shows little effect on reducing water cut compared to the first one.

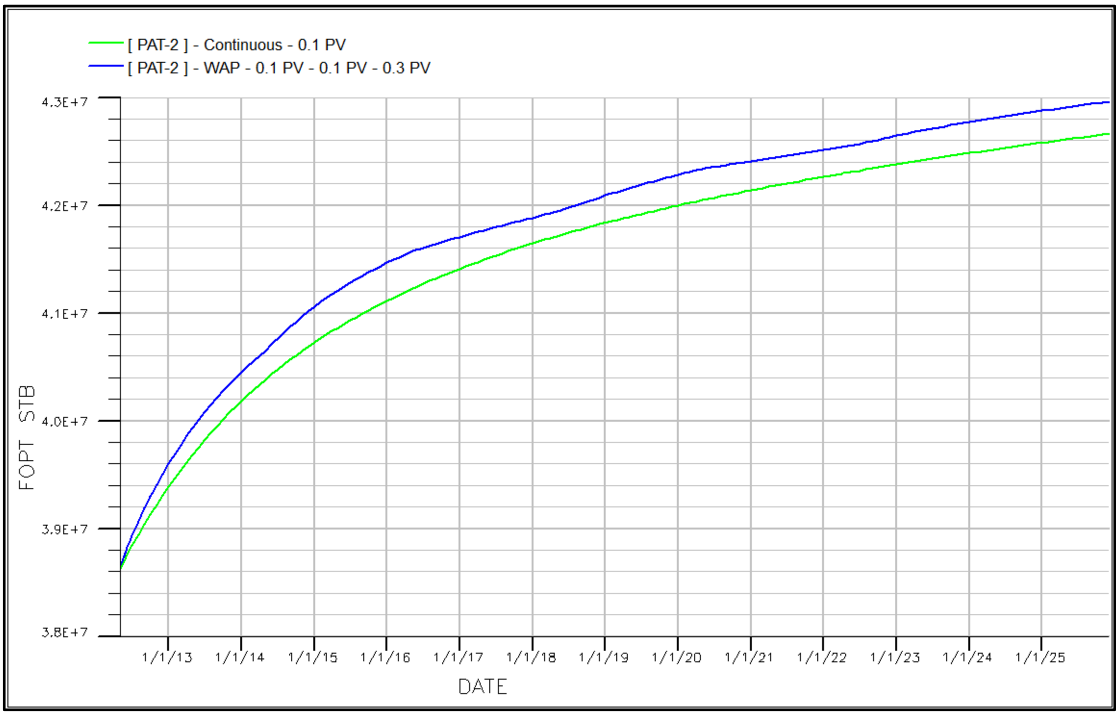

Figure 4.27 Field Oil Production total of optimal Continuous and WAP-PF cases in pattern-2.

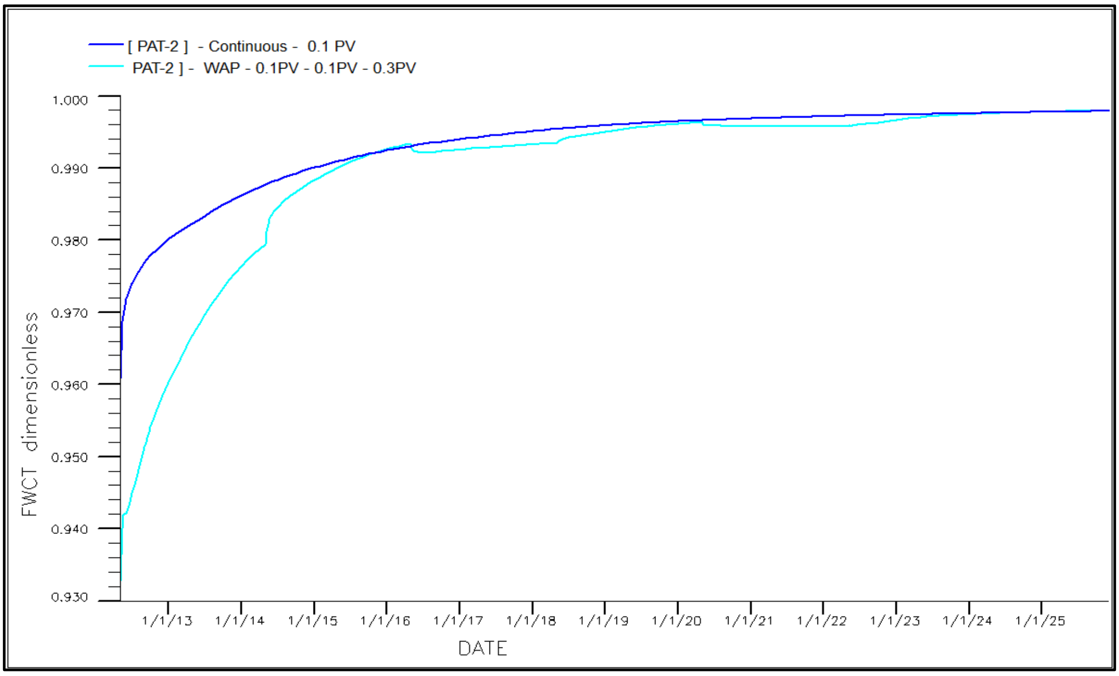

Figure 4.28 Field water cut of optimal Continuous and WAP-PF cases in pattern-2.

III-Pattern-3

- **Continuous injection and Water Alternative Polymer (WAP)** sensitivity cases for pattern-3 (Fig.4.29), conducted by applying the optimum scenario for each sensitivity case from 1/May/2012, having the same bottom hole injection pressure1500 psi and similar polymer concentrations .

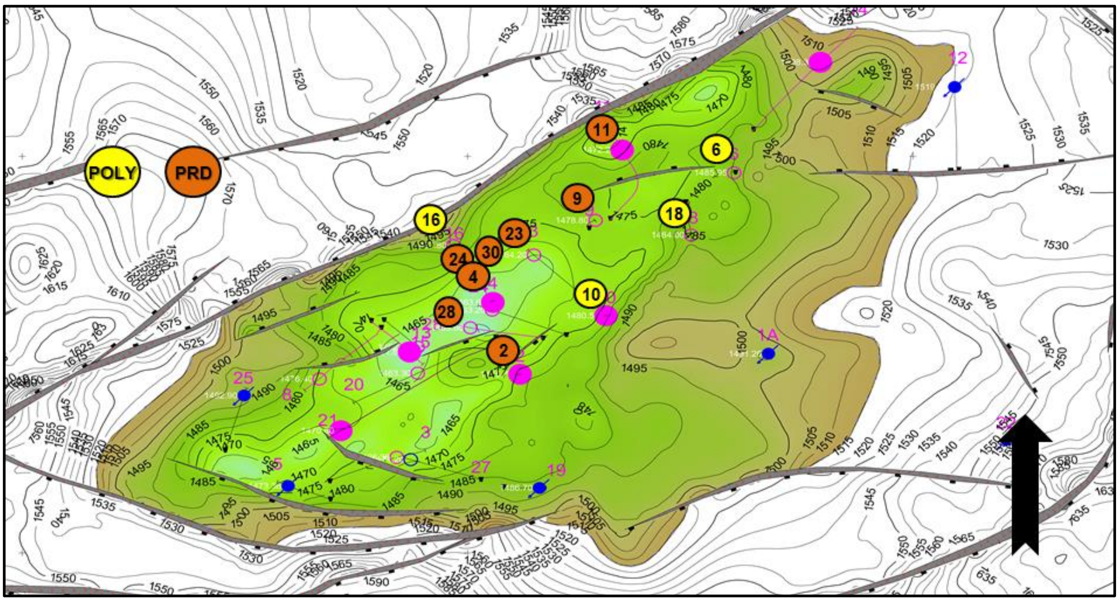

Figure 4.29 PF Injection and production wells distribution of Pattern-3.

which resulted different cumulative oil production as shown in (Fig.4.30). From the pattern observation the continuous PF case shows different performance in from previous patterns which shows increase by 77,780 STB than the WAP case with stable increase in field water cut as shown in (Fig.4.31).

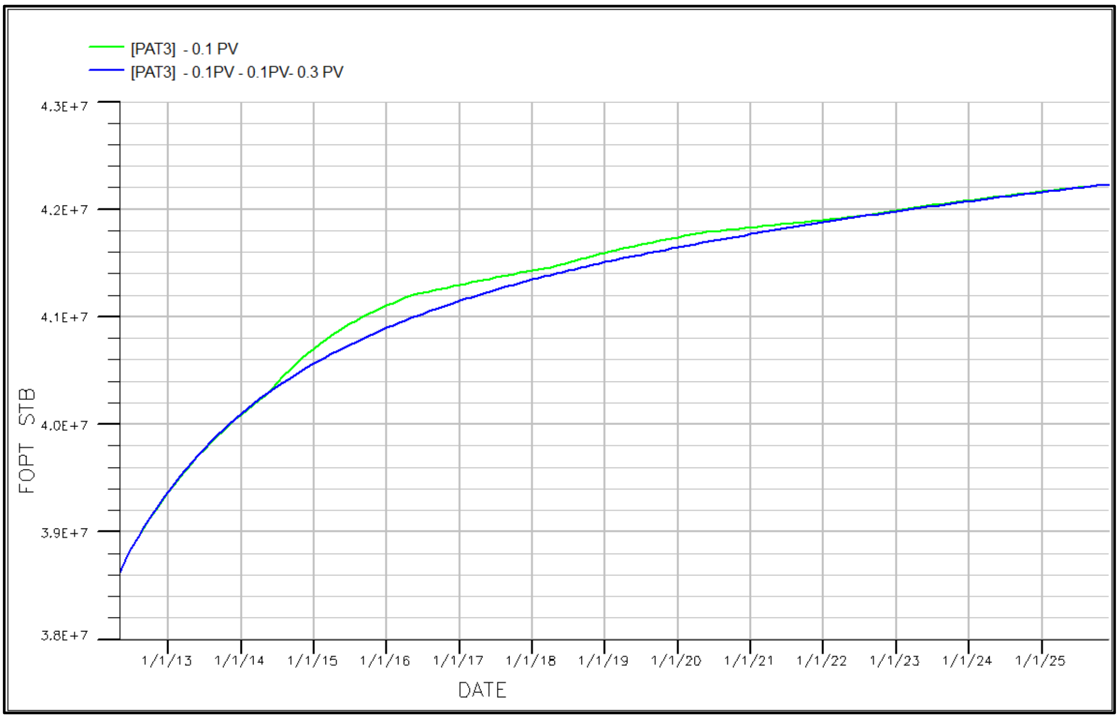

Figure 4.30 Field Oil Production total of optimal Continuous and WAP-PF cases in pattern-3.

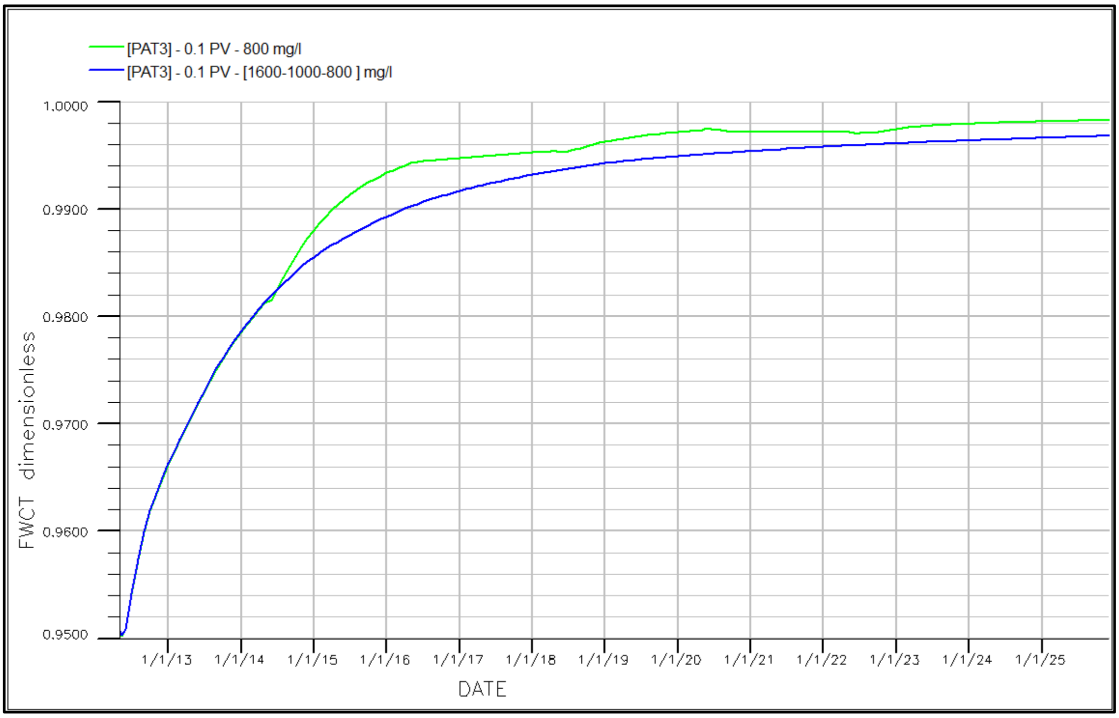

Figure 4.31 Field water cut of optimal Continuous and WAP-PF cases in pattern-3.

4.4.3. PF Recovery Efficiency

According to what has been found in polymer flooding sensitivity scenarios , the maximum oil recovery was achieved 3.637% compared to the base case as shown in (Fig4.32).

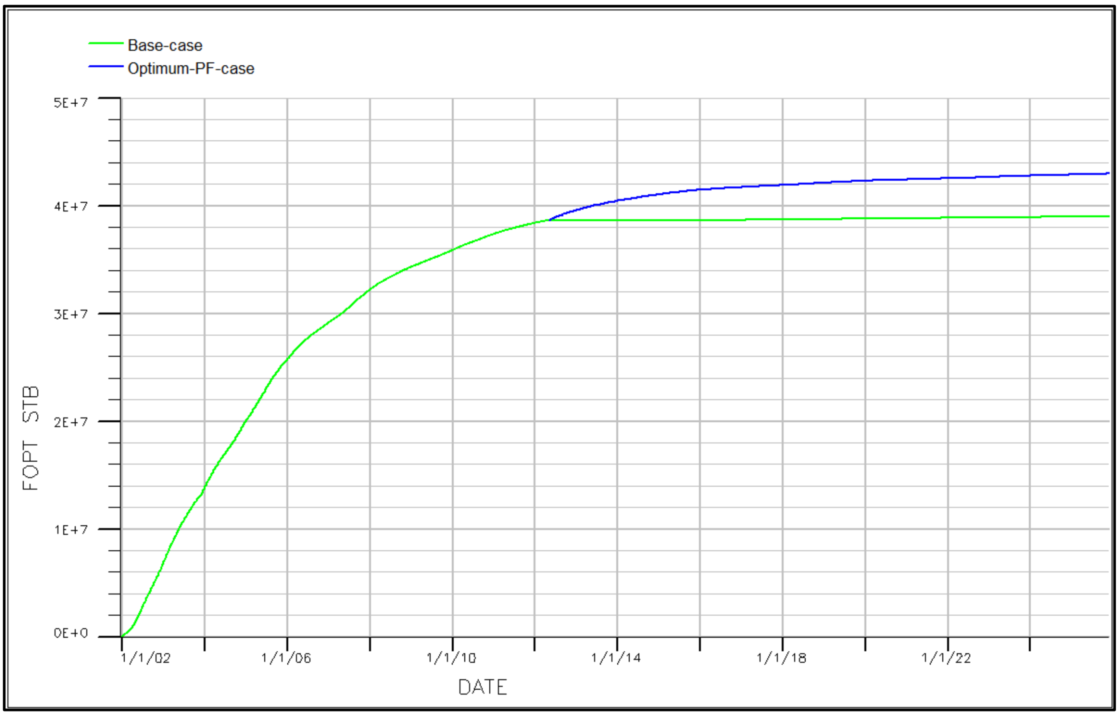

Figure 4.32 Field Oil Production total of base case and optimum PF case.

4.4.4. A comparison between water flooding and polymer flooding

An expected results were encountered when comparing PF and WF performance recovery efficiencies as shown in (Fig4.33). the theoretical explanation of this results returns to that the polymer flooding came late 1/May/2012, However, WF process started earlier in the reservoir in 1/Dec/2004; causing very high reservoir water cut F_w about 98%, then the PF process would be inefficient for enhancing residual oil displacement. PF would be more attractive if it using at earlier stages of water flooding process through improving areal and vertical sweep efficiency as discussing in the case below (PF at Starting of Water Flooding Date (Dec.2004).

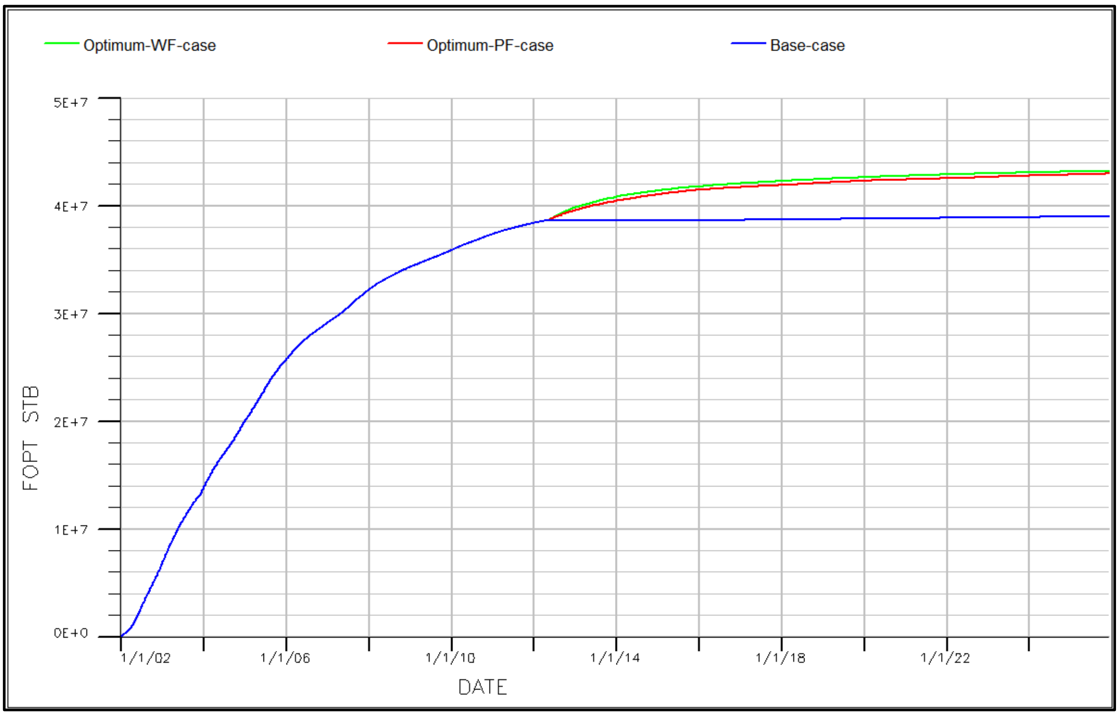

Figure 4.33 Field Oil Production total of optimum PF and WF cases with the base case.

4.4.5. PF at Starting of Water Flooding Date (Dec.2004)

In case the PF start at the early stage of water flooding process, two simulation cases were conducted in sharyoof field as the following:

1. **1-** Case –1 PF started in Dec. 2004 using the same wells of water flooding (SH-**10**, SH-**19**, SH-**21**, SH-**29).**
2. **2-** Case-2 PF started in the same time of water flooding in the base case using the same wells of WF.

Both cases run with water alternative polymer WAP and the sensitivity cases having the same slug design and concentration that used in the previous PF cases as discussed above, as shown in (Fig.4.34), the two cases resulted better displacement efficiency compared to the previous cases of the PF that shows bad results (Figure 4.35).

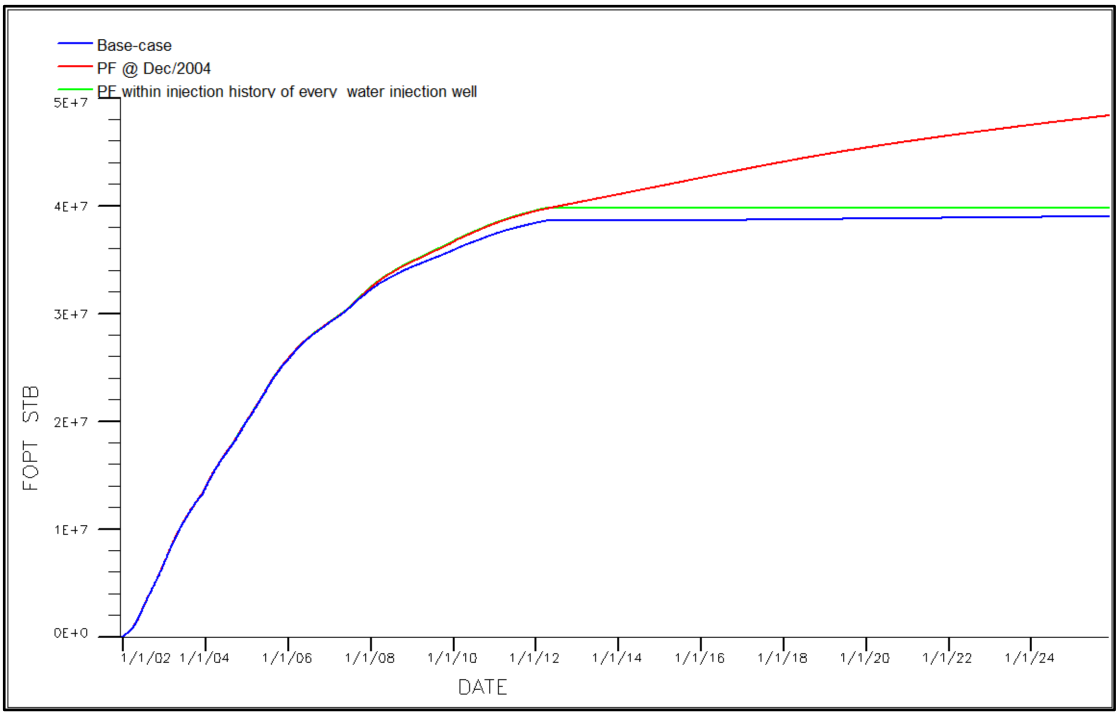

Figure.4.34 Field Oil Production total.

The results Reveal, that the earlier operated PF in the reservoir; the better displacement efficiency and higher cumulative oil production with lower field water cut as presented in, (Fig.4.36).

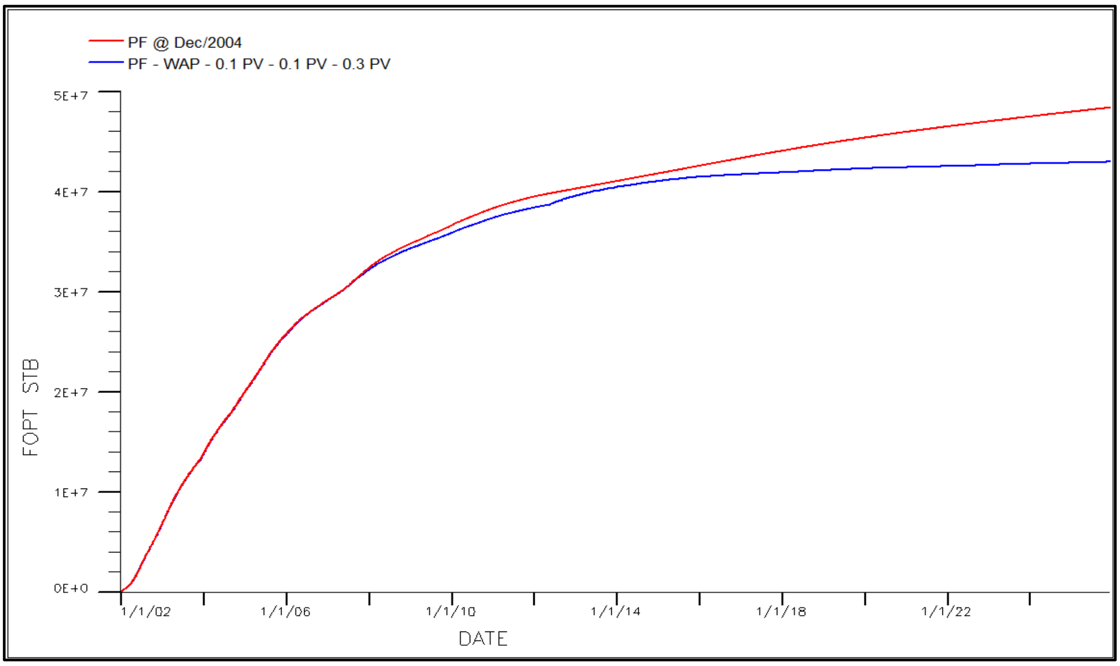

Figure.4.35 Field Oil Production total.

All PF cases applied in our project summarized to make compression between cumulative oil production (FOPT), displacement efficiency (FOE),field water cut (FWCT) and field polymer injection total (FCIT) ,Table 4.6.

<table>
<tr><th></th><th colspan="5">PAT-1</th></tr>
<tr><th>PF</th><th colspan="2">Continuous</th><th colspan="3">WAP</th></tr>
<tr><td>Case-</td><td>0.1PV [1600-1000-800] mg/l</td><td>0.1PV-800 mg/l</td><td>0.1PV-1600
0.1PV-1000
0.3PV-800
(mg/l)</td><td>0.2PV-1600
0.2PV-1000
0.1PV-800
(mg/l)</td><td>0.1PV-1600
0.2PV-1000
0.2PV-800
(mg/l)</td></tr>
<tr><td>FOPT (STB)</td><td>42721496</td><td>42661824</td><td>42960948</td><td>42946572</td><td>42958352</td></tr>
<tr><td>FOE</td><td>0.3919</td><td>0.3914</td><td>0.3941</td><td>0.3940</td><td>0.3941</td></tr>
<tr><td>avg. FWCT</td><td>98.86%</td><td>99.41%</td><td>98.68%</td><td>98.53%</td><td>98.67%</td></tr>
<tr><td>FCIT (Ib)</td><td>46642800</td><td>36222600</td><td>4335246</td><td>2895941.5</td><td>4264766</td></tr>
<tr><td colspan="6"></td></tr>
<tr><th></th><th colspan="2">PAT-2</th><th colspan="3">PAT-3</th></tr>
<tr><th>PF</th><th>Continuous</th><th>WAP</th><th colspan="2">Continuous</th><th>WAP</th></tr>
<tr><td>Case-</td><td>0.1PV [1600-1000-800] mg/l</td><td>0.1PV-1600
0.1PV-1000
0.3PV-800 mg/l</td><td colspan="2">0.1PV [1600-1000-800] mg/l</td><td>0.1PV-1600
0.1PV-1000
0.3PV-800 mg/l</td></tr>
<tr><td>FOPT (STB)</td><td>42638264</td><td>42934792</td><td colspan="2">39215988</td><td>39212292</td></tr>
<tr><td>FOE</td><td>0.3907</td><td>0.3939</td><td colspan="2">0.3597</td><td>0.3597</td></tr>
<tr><td>avg. FWCT</td><td>98.86%</td><td>98.57%</td><td colspan="2">99.18%</td><td>98.97%</td></tr>
<tr><td>FCIT (Ib)</td><td>44658000</td><td>3107912.8</td><td colspan="2">310465.72</td><td>291602.97</td></tr>
<tr><td colspan="6"></td></tr>
<tr><th>Base case</th><th colspan="2">PF started in Dec. 2004 using WF wells</th><th colspan="3">PF started in the same time of WF</th></tr>
<tr><th>PF</th><th colspan="2">WAP</th><th colspan="3">WAP</th></tr>
<tr><td>Case-</td><td colspan="2">0.1PV-1600
0.1PV-1000
0.3PV-800 mg/l</td><td colspan="3">0.1PV-1600
0.1PV-1000
0.3PV-800 mg/l</td></tr>
<tr><td>FOPT (STB)</td><td colspan="2">48365528</td><td colspan="3">39771096</td></tr>
<tr><td>FOE</td><td colspan="2">0.4436</td><td colspan="3">0.3648</td></tr>
<tr><td>avg. FWCT</td><td colspan="2">87.03%</td><td colspan="3">77.76%</td></tr>
<tr><td>FCIT (Ib)</td><td colspan="2">34472539</td><td colspan="3">28727116</td></tr>
</table>

Table.4.6. Summary of PF cases.

CHAPTER-FIVE

5. CONCLUSION AND RECOMMENDATIONS

5.1. Conclusion:

1- To achieve optimum production performance, oil production rate should be increased or at least be kept stabile. Since sharyoof oil field have reached high water cut stage, enhanced oil recovery (EOR) method should be gradually adopted for practice .

2- Sharyoof field has been developed with water flooding since Dec.2004 . Because of the unfavorable oil-water mobility ratio and reservoir heterogeneity, comprehensive water cut reached more than 98% at the end of historical data of Sharyoof field dynamic model; the permeability heterogeneity and faulting lead to extremely poor water flooding efficiency. In order to enhance the oil recovery, chemical EOR method are needed. Considering all practical situations for this reservoir and the present technique level, polymer-flooding method is selected as an EOR method with numerical simulation.

3- Polymer flooding, polymer transport process must be simulated which having the main property of polymer solution of its capability of enlarging water viscosity, through which, controlling the mobility of water phase and improving the sweep efficiency, During polymer flooding simulation, inaccessible pore volume, polymer shear thinning effect, polymer adsorption, and relative reduction factors have been taken into account for simulation model.
All simulations have been done with black oil model with polymer option in ECLIPSE

4- Comprehensively using geological data, geophysical data , production data, injection data and completion data, to re-understand the reservoir performance with WF and PF scenarios.

5- Because of the high mobility ratio and permeability heterogeneity in sharyoof field, simulation results have shown that with water flooding the oil recovery for reservoir can reach 3.871% most of the oil has been produced at high water cut stage, and the oil recovering velocity is very low.

6- For polymer flooding, polymer adsorption, polymer concentration and polymer slug size have great effects on its efficiency. With lower polymer adsorption, polymer flooding will be more efficient. This effect will be diminished with polymer slug size increasing. With a same polymer slug size, the higher the concentration of polymer solution is, the higher enhanced oil recovery polymer flooding has. But in order to keep a high enough injection rate of polymer solution and avoid fracturing reservoir rock, only a reasonable polymer concentration can be applied.

7- Based on the simulation runs and production performance of the polymer flooding in pattern-1, we can get conclusions from the PF cases; The water alternative polymer WAP injection of multi-slug process with different concentrations conditions has a strong relationship with the polymer injection parameters and permeability. The adsorption also increases as the polymer molecular weights and concentrations increase. The polymer adsorption-induced permeability reduction and the measured oil/water relative permeability relationships are affected significantly by concentration.

5.2 Recommendation

It is recommended that further encouragement be provided to extend project study of PF in sharyoof field :

- The effect of sharyoof field water salinity and it's chemical properties on polymer viscosity with different concentration.
- Prediction performance of PF with new injection and production wells in pattern-3,since it's the most oil saturated region.
- Studying the effect of PF on the reservoir pressure performance.
- Comprehensive economical study for PF project application in sharyoof field .

5.3 Limitations

1-The difficulties for getting the data required for applying this study.

2-The long time required for running the predicted simulation cases; that's hindering applying more sensitivity cases for PF study.

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