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جامعة السودان للعلوم والتكنولوجيا

A Study of Water Injection Application for increasing oil Recovery in South Annajma Oil Field-Sudan

دراسة تطبيق حقن الماء لزيادة الإستخلاص النفطي في حقل جنوب النجمة - السودان

A Thesis Submitted in Partial Fulfillment of requirements for the Degree of MSc in Petroleum Reservoir Engineering

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الإستهــلال

بِسْمِ اللَّهِ الرَّحْمَنِ الرَّحِيمِ

قـــال الله تعالى:

﴿ فَلَمَّا اسْتَيْأَسُوا مِنْهُ خَلَصُوا نَجِيًّا قَالَ كَبِيرُهُمْ أَلَمْ تَعْلَمُوا أَنَّ أَبَاكُمْ قَدْ أَخَذَ عَلَيْكُم مَّوْثِقًا مِّنَ اللَّهِ وَمِن قَبْلُ مَا فَرَّطتُمْ فِي يُوسُفَ فَلَنْ أَبْرَحَ الْأَرْضَ حَتَّىٰ يَأْذَنَ لِي أَبِي أَوْ يَحْكُمَ اللَّهُ لِي وَهُوَ خَيْرُ الْحَاكِمِينَ ﴾

صدق الله العظيـم

الآية ٨٠ سورة يوسف

Dedication

This thesis is dedicated to all my loving parents, family, teachers in all my previous and current educational levels, Colleagues, and my friends at Sudan University of Science and Technology who supported me during my work on this research. I warmly appreciate their support, encouragement, inspiration, and great help which made the completion of the research challenge is possible

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NOMENCLATURE

Symbols:

B_o	Oil Formation Volume Factor,
B	Formation Volume Factor
β	Momentum Transfer Coefficient
E_a	The Fraction Of The Floodable Pore Volume Area Swept By The Injected Water
E_v	The Fraction Of The Floodable Pore Volume In The Vertical Plane Swept By The Injected Water
Ed	Is Equal To The Fraction Of The Oil Saturation At The Start Of Water Injection Which Is Displaced By Water In That Portion Of The Reservoir Invaded By Water
E_D	Unit Displacement Efficiency.
H	Pressure Head
H	Net Thickness
K	Absolute Permeability
K_{rw}	Relative Permeability to Water
K_{ro}	Relative Permeability to Oil
K_r	Relative Permeability
M	Mobility Ratio.
μ_o	oil Viscosity
μ_w	Water Viscosity
N	The Oil in Place in the Floodable Pore Volume at the Start of Water Injection STB
∇P	Pressure Gradient
ρ	Density

P_{inj}	Water-Injection Pressure
Q	Flow Rate.
R_s	Gas-Oil Ratio
R_v	Oil-Gas Ratio.
(K_o)	Effective Permeability to Oil Measured at the Immobile Connate
@Swir	Water Saturation.
S_{oi}	Initial Oil Saturation.
S_{orw}	Residual Oil Saturation.
S_{wc}	Connate Water Saturation.
S_g	Free Gas Saturation at the Start of Water Injection.
S_o	Oil Saturation at the Start of Water Flooding.
S_w	Water Saturation
S_{or}(Sorw)	Residual Oil Saturation To Water Flooding,
S_{wc}	Connate Water Saturation
μ	Viscosity
Ø	Porosity
T	Time
Γ	Relative Gravity
T	Transmissibility
P	The Pressure,
V_p	Water Floodable Pore Volume, bbl.
V	Reservoir Stratification, (Dykstra-Parsons Coefficient,)
W_i	Water-Injection Rate
Z	Vertical Position.

Subscripts

O	Oil
W	Water
G	Gas

Abbreviation:

API	American Petroleum Institute
Bbl/D	Barrel Per Day
Cp	Centipoises
CO_2	Carbon Dioxide
EUR	Expected Ultimate Oil Recovery
EOR	Enhanced Oil Recovery.
EOR	Enhanced Oil Recovery.
H_2S	Hydrogen Sulfide
˚F	Fahrenheit
FOE	Field Oil Efficiency
FPR	Field Production Rate
FOPR	Field Oil Production Rate
MMSTB	Million Stock Tank Barrels
NP (MMSTB)	Cumulative Oil Production
O_2	Oxygen
OOIP	Original Oil in Place
Psia	Pounds per Square Inch Absolute
SPE	Society of Petroleum Engineers
C	Celsius
UR	Ultimate Recovery
Psi/Ft	The Pound per Square Inch Per Foot
VRR	Voidage Replacement Ratio

STB	Stock Tank Barrel.
STOIIP	Stock-Tank Oil Initially In Place
PR	Potential Recovery
RF	Recovery factor
UR	Ultimate Recovery
Psi/Ft	The Pound per Square Inch Per Foot
VRR	Voidage Replacement Ratio
STB	Stock Tank Barrel.

Abstract

Water flooding is the most widely used secondary recovery process in the world today. Along with the recent decades, water injection is still a promising technique for improving oil recovery.

The main objective of this work is to ascertain the optimal water injection arrangement to vertical water flooding at the South Annajma oil field using a reservoir simulation model (ECLIPSE) commercial software. This work came out with analyses of oil production rate, water cut, reservoir pressure drop, accumulated oil production, and recovery factor for the South Annajma reservoir as a heterogeneous model.

The result of this simulation work showed the effectiveness of eight years of water flooding in the enhancement of production performance.

However, South Annajma reservoir heterogeneity would introduce an uncertainty of geological model, which could bring a mismatch between the simulated case and a real case, the increase in oil recovery achieved throughout the model scenarios is 32%.

المستخلص

يعتبرالغمرالمـائي هـوالأكثر إسـتخدامًا كعمليـة إسـتخلاص ثانويـة فـي العـالم اليـوم .فـي العقـود الأخيرة,لاتزال هذه التقنية واعدة لتحسين إستخلاص النفط، ,الهدف من هذا البحث هو التأكد من الإعداد الأمثل للحقن بصورة رأسية وذلك بإستخدام برنامج المحاكاة المكمنية(ECLIPSE). ما تم هو إجراء تحليلات لمعدل إنتاج النفط ، ونسبة المياه المستخرجة ، وإنخفاض ضغط المكمن، وإنتاج النفط التراكمي ومعامل الإستخلاص لخزان حقل النجمة الجنوبي.

كما أظهرت نتيجة هذه المحاكاة أثر ثماني سنوات من غمرالمياه في تحسين أداء الإنتاج.

ومع ذلك، فإن عدم تجانس الخزان من ناحية جيولوجية من شأنه أن يؤدي إلى عدم التوافق بين وضع المحاكاة والحالة الحقيقية. الزيادة في كمية النفط المستخرج التي تحققت من خلال هذه الطريقة هي 32٪ مما يوضح بأن طريقة الغمر المائي لمكامن هذا الحقل تعتبر من الطرق الواعدة لزيادة الإستخلاص.

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INTRODUCTION

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INTRODUCTION

1.1 Introduction:

Water flooding is the most widely used fluid injection process in the world today. It has been recognized since 1880 that injecting water into an oil-bearing formation has the potential to improve oil recovery. However, water flooding did not experience field-wide application until the 1930s when several injection projects were initiated. (History of Petroleum Engineering, API, Dallas, Texas 1961) and it was not until the early 1950s that the current boom in water flooding began.

This concerns the use of water injection to increase the production from oil reservoirs, and the technologies that have been developed over the past 50+ years to evaluate, design, operate, and monitor such projects. The use of water to increase the oil production is known as "secondary recovery" and typically follows "primary production," which uses the reservoir’s natural energy (fluid and rock expansion, solution-gas drive, gravity drainage, and aquifer influx) to produce oil.

The principal reason for water flooding in an oil reservoir is to increase the oil-production rate and, therefore, the oil recovery. This is accomplished by injecting water to increase the reservoir pressure to its initial level and maintain it near that pressure. The water displaces oil from the pore spaces, but the efficiency of such displacement depends on many factors (e.g., oil viscosity and rock characteristics).

1.2 Problem Statements:

Bentiu formation in the South Annajma oil field suffers from a sharp decline in reservoir pressure, indicates that the water flooding as pressure maintenance is a suitable recovery mechanism to improve the recovery factor

1.3 The Research Objectives:

In this research, the possibility of using water injection as pressure maintenance is accompanied by the designing of optimum scenarios of injection rate by using the ECLIPSE reservoir simulator. The field has a static and dynamic model of Eclipse software.

The main objectives of this research are:

- Obtain the most updated model for the South Annajma field and validate its accuracy to the current field performance.
- Study how water injection effecting on maintaining the reservoir pressure in a small sandstone reservoir structure with good porosity and viscosity.
- Investigate if water flooding maintains a high oil production rate for a longer period and how it will affect oil recovery and reservoir life.
- Determine the optimum volume of total water to be injected and monitor the daily optimum injection pressure and rate, therefore to see how it will he pressure, in which it will be reflected on the oil rate (recovery factor).

1.4 Field Background:

South Annajma field area is about 60 sq. km wide within the Western escarpment, Fula Sub-basin of Block 17 in Star Oil Concession- Sudan, and it contributes the highest production potential in Block 17.

The South Annajma field was discovered in June 2011 and production began in December 2012.

The total STOIIP and recoverable resources (ultimate recovery (UR) +Potential recovery (PR)) are 304MMSTB and 86 MMSTB respectively.

Bentiu formation in the South Annajma field suffering from a sharp decrease in reservoir pressure, which indicates that the water flooding as pressure maintenance is a more suitable recovery mechanism to improve the recovery factor and maximize oil production from this field. Therefore, a feasibility study of water injection by using produced water will be performed through a technical support contract.

The production from the South Annajma Field is severely constrained due to a significant depletion of the reservoir pressure, about 1000 psi in some structure just in three years.

Annual Review of Petroleum Resources (ARP)

Annual Review of Petroleum Resources (ARPR), is an annual report that shall be submitted by Operators to the Responsible Authority not later than the end of February of each new calendar year.

Operators shall report all volumes until End of Field Life for each field/project and indicate the Economic Limit.

Any discovered hydrocarbon irrespective of its commerciality must be reported to The Authority according to the Agreement. Operators shall provide a Post-Drilling Notification report.

Table 1-1: (Block-17) Annual Review of Petroleum Resources

Status as of Mar.20l0	South Annajma
Formation	Bentiu
STOOIP (MMSTB)	74
EUR (MMSTB)	32.8
NP (MMSTB)	7.4
REMAING EUR(Reserve) (MMSTB)	25.5
EUR TO-DATE (%)	44.3
RF (%)	22.5
RF TO-DATE (%)	22.5

(ARPR).Year 2012

Water Flooding In South Annajma:

South Annajma field is a light oil with an API of 38 and viscosity of 23.99 cp @ 50 C the field since 2012 only 9275.117 MMbbl has been produced by cold production.

Currently, the recovery factor from the Star oil field is about 25 so they need to increase the recovery factor by using secondary recovery methods especially water flooding. Atypical core in south Annajma field might show a reservoir with good upper and lower permeability barriers and no water encroachment. The pay zone is approximately 16 to 22 feet thick with 11 to 15 percent porosity. Oil gravity is 38 API, and oil saturation is approximately 65 to 75percent. Studies have shown that fields with these characteristics are good water flooding prospects.

The oil fields in south Annajma reached peak primary production in 2014 and all-time low production in 2016. A sharp decline in primary production and low primary recovery is typical of solution gas drive reservoirs when natural gas is produced in an uncontrolled manner with the oil thereby dissipating the natural reservoir energy. It was estimated only 25 percent of the original oil in place had been recovered.

Implementing a water flooding would increase production in the field by injecting water into the formation through injection well and producing existing wells. This solution will be evaluated on three fundamental criteria: geology, cost, and required equipment.

The criteria of south Annajma Field that must be known is the geology. The formation of interest in the field is relatively shallow at 2100 m and the oil is 36API. Table 1details the geological criteria of the formation of interest.

Geological Characteristics of Reservoir:

First and foremost, the geology of the reservoir must be evaluated. Water floods will be successful under specific reservoir characteristics. The characteristics in the South Annajma field that must be evaluated are listed below:

Table 1-2: The Characteristics In South Annajma Field.

Average Depth to Base of Sand (ft)	**5970**
Average Reservoir Temperature (F)	**174.0**
Average Crude Oil Viscosity at Reservoir Conditions (cp)	**2.1640**
Pressure at 5905.5 ft (psia)	**2425**
Crude Gravity at 60 F (API)	**36**
Average Permeability (md)	**50-200**
Average Sand Thickness (ft)	**50**
Average Porosity (%)	**15 - 26**
Area (acres)	**627.65**
Initial Oil Saturation (%)	**20.8**
Formation Volume Factor (Res bbls/stb)	**1.2245**
Original Oil in Place (MMbbl)	**67**

The total injection rate, the number of the producers and the number of injectors, type of pattern, the total volume of water injected and the injection and production period of Bentiu formation should be stated clearly.

Water flooding is the targeted technique that cannot be successful unless a perfect design is done. Currently, the recovery factor of the South Annajma oil field is about 25, therefore the need for increased oil recovery is become more important by using water flooding techniques.

1.5 Methodology:

In this research selection of the suitable pilot area, the Eclipse model will be used for designing water flooding by using several scenarios which will be selected to choose which the optimum method that will increase the oil recovery of Bentiu formation.

1.6 Study Outlines:

in this project chapter one reviews the general introduction of the recovery mechanism and take the water flooding with definition, also discuss the objectives and the problem statements and introduce the field background of south Annajma, and view the methodology used in this project, chapter two will be related to the theoretical background and literature review of water flooding definition and some case studies around the world, the methodology and the data collection have been reviewed in chapter three also the eclipse model will be introduced and built, while chapter four results and discussion show the basic formation of South Annajma and discuss the result of the four scenarios which will be suggested in this model, chapter five view conclusion and recommendations.

CHAPTER 2

THEORITICAL BACKGROUND AND LITERATURE REVIEW

CHAPTER 2

Theoretical Background and Literature Review

2.1 Introduction:

Water injection is one of the most useful techniques for enhancing the production of oil from petroleum reservoirs. This is not only because of the low cost of water but also because of the characteristics of the water which help sweep the trapped oil efficiently. In this research, the main aim is to investigate how far this reservoir will produce oil with the support of water injection.

Therefore, an oil reservoir model will be developing using the software ECLIPSE for reservoir simulation to study and attempt to evaluate the water flooding parameters.

This model will be used to compare the production of oil and the reservoir pressure for many case studies where the water was not injected in the first case study, but later, it will be injected in the second case study and see results if the water which will be injected, how much the developed reservoir model can produce out of the original oil in the reservoir of. On the other hand, how the application of water injection in the second case study will support the average reservoir pressure, which may lead to increasing the production of the original oil in the reservoir.

Water flooding is a secondary method of oil recovery where water is injected into the reservoir to increase the pressure and thereby increasing oil production, (Binder et al., 1956). Water flooding was first practiced for pressure maintenance after primary depletion and has since become the most widely adopted OR technique (Morrow and Buckley, 2011). It is now commonly applied at the beginning of reservoir development, (Morrow and Buckley, 2011).

With water injection, the reservoir pressure is sustained and oil is pushed towards the production well. The oil-water front progresses toward the production well until the water breaks through into the production stream. With the increasing water production, the oil production rate diminishes, until the time when the recovery is no longer profitable and the production is brought to an end (Van Essen et al, 2006). Up to 35%.

Oil recovery could be achieved economically through water flooding (Van Essen et al, 2006). Figure1 depicts a typical vertical water flooding arrangement.

Water flooding is a process used to inject water into an oil-bearing reservoir for pressure maintenance as well as for displacing and producing incremental oil after (or sometimes before) the economic production limit has been reached, (Craig 1971).

Water flooding is the most widely used fluid injection process in the world today. It has been recognized since 1880 that injecting water into an oil-bearing formation has the potential to improve oil recovery. However, water flooding did not experience field-wide application until the 1930s when several injection projects were initiated. (History of Petroleum Engineering (API), Dallas, Texas (1961) and it was not until the early 1950s that the current boom in water flooding began.

Water flooding is one of the oldest methods employed to recover additional oil after primary methods of recovery which are no longer feasible. Water flooding began accidentally in Pithole, Pennsylvania by 1865. Water flooding became common in Pennsylvania in the 1880s.

The primary reasons why water flooding is the most successful and most widely used oil recovery process are (Craig F.F 1971):

- General availability of water
- Low cost relative to other injection fluids

- Ease of injecting water into a formation
- High efficiency with which water displaces oil

Water flooding is a process used to inject water into an oil-bearing reservoir for pressure maintenance as well as for displacing and producing incremental oil after (or sometimes before) the economic production limit has been reached, (Craig 1971).

Water flooding is the most widely used fluid injection process in the world today. It has been recognized since 1880 that injecting water into an oil-bearing formation has the potential to improve oil recovery. However, water flooding did not experience field wide application until the 1930s when several injection projects were initiated. (History of Petroleum Engineering, API, Dallas, Texas 1961) and it was not until the early 1950s that the current boom in water flooding began.

Water flooding is one of the oldest methods employed to recover additional oil after primary methods of recovery which are no longer feasible. Water flooding began accidentally in Pithole, Pennsylvania by 1865. Water flooding became common in Pennsylvania in the 1880s.

The water injection will be implemented in the South Annajma field. The performance may face the problem of high water cut from the producer. And water, oil ratio (WOR) needs to be optimized.

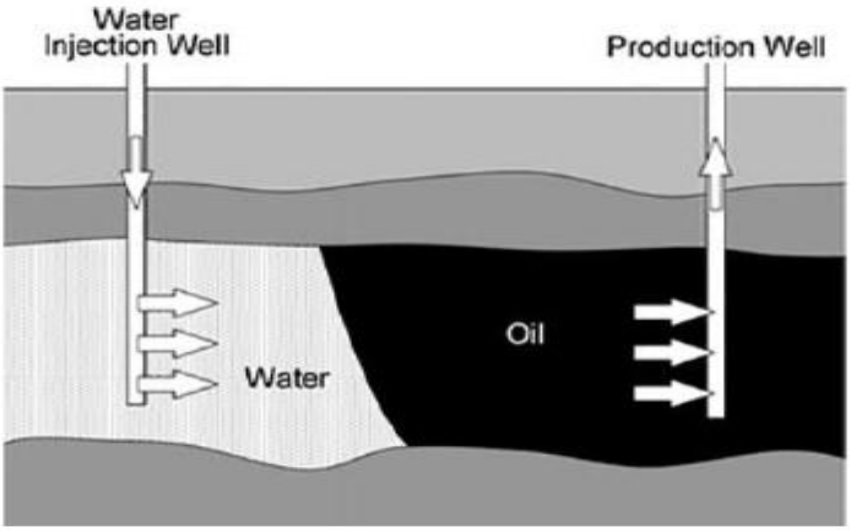

Figure 2-1: Typical Vertical Flooding Arrangements (Van Essen Et Al, 2006)

Water can be injected through a vertical well. Determining the optimal position and orientation of the wells has a potentially high economic impact, (Bangerth et al, 2006). Asheim studied the optimization of vertical well water flooding processes with fixed well locations, (Zandvliet et al, 2008). In this case, delay in water breakthrough improves the production rate. Also from literature, it has been shown that water breakthrough can be delayed by changing the position of the injection well profiles, (Brouwer et al, 2001).

2.2 Theory:

The principal reason for water flooding is to increase the oil production rate and improve oil recovery. This is achieved through Voidage Replacement Ratio (VRR) (the volume of the injected fluid/volume of the produced fluid) to support the reservoir pressure and sweep or displace oil from the reservoir towards the production well (SPE, 2014). The efficiency of such displacement depends on many factors like oil viscosity, density, and rock characteristics. Reservoir screening is necessary for the technical and economic success of water flooding.

Production is separated into three phases: primary, secondary and tertiary, (which is also known as Enhanced Oil Recovery (EOR)).

2.3 Oil Recovery

Oil production is separated into three phases: primary, secondary and tertiary, which is also known as Enhanced Oil Recovery (EOR).

a. Primary Recovery:

Primary oil recovery refers to the recovery of the oil by relying solely on the natural energy of the reservoir (Archer and Wall, 1986). It is limited to hydrocarbons that naturally rise to the surface or those that use artificial lift devices, such as pump jacks.

b. Secondary Recovery:

Secondary oil recovery is a technique used to augment the natural energy of the reservoir by artificially injecting fluid (gas or water) into the reservoir to force the oil to flow into the wellbore and to the surface (Speight, 2009). And the second stage of hydrocarbon production during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communicate with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore. The most common secondary recovery techniques are water flooding and gas injection. Normally, gas is injected into the gas cap and water is injected into the production zone to sweep the oil (physically) from the reservoir. A pressure–maintenance program can begin during the primary recovery stage. The secondary recovery stage reaches its limit when the injected fluid (water or gas) is produced in considerable amounts from the production wells and the production is no longer economical. This can bring the recovery of the OOIP from 40-55%, (Zargon, 2013).

Due to its capital-intensive nature, secondary recovery should only be employed when primary recovery is no longer economically viable to recover the oil, (Latil, 1980). The waterflood can also reduce the environmental impact by taking the water that is produced from within the reservoir (brine), and after simple treatment, using it for re-injection back into the wells, (Halliburton, 2013).

c. Tertiary Recovery:

Tertiary recovery or enhanced oil recovery is also referred to as a sophisticated recovery technique that is applied to increase or boost the flow of fluid within the reservoir. It involves the injection of fluid other than just conventional water and immiscible gas into the reservoir to effectively increase oil production.

Tertiary recovery is normally applied to recovering more of the residual oil remaining in the reservoir after both primary and secondary recoveries have reached their economic limit. The methods include: thermal, chemical, gas, and microbial (Speight, 2009).

Oil Recovery mechanisms consist of:

A- Primary oil recovery, there are six driving mechanisms:

1- Rock and liquid expansion

2- Solution gas drive

3- Gas cap drive

4- Water drive

5- Gravity drainage drive

6- Combination drive

B- Secondary oil recovery, which divided to:

1- Water injection

2- Immiscible gas injection

C- Tertiary enhanced oil recovery (EOR), contain of:

1- Thermal

2- Chemical

3- Miscible

4- Microbial

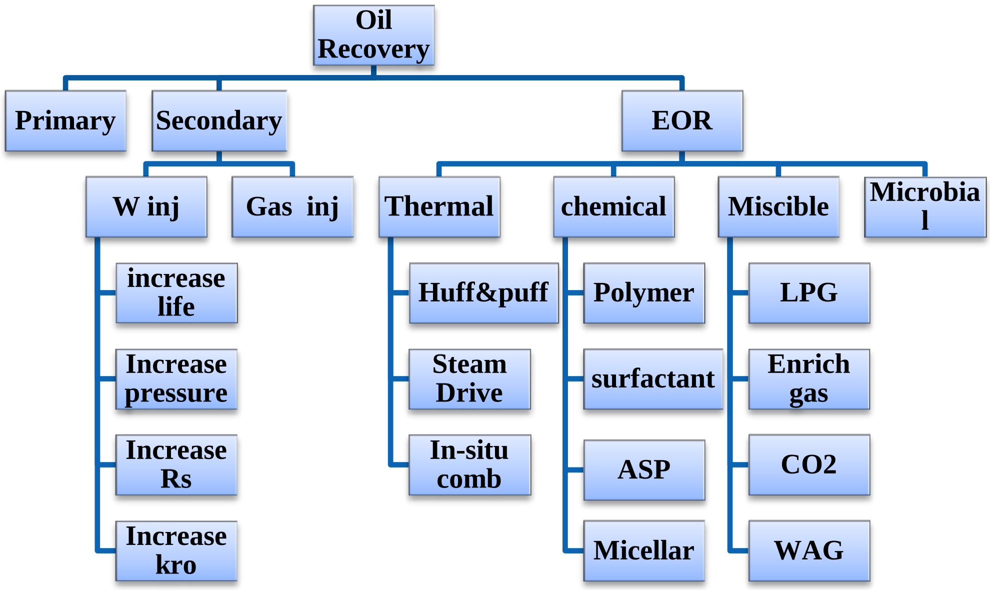

Figure 2-2: Description of Oil Recovery Mechanism

Data collection:

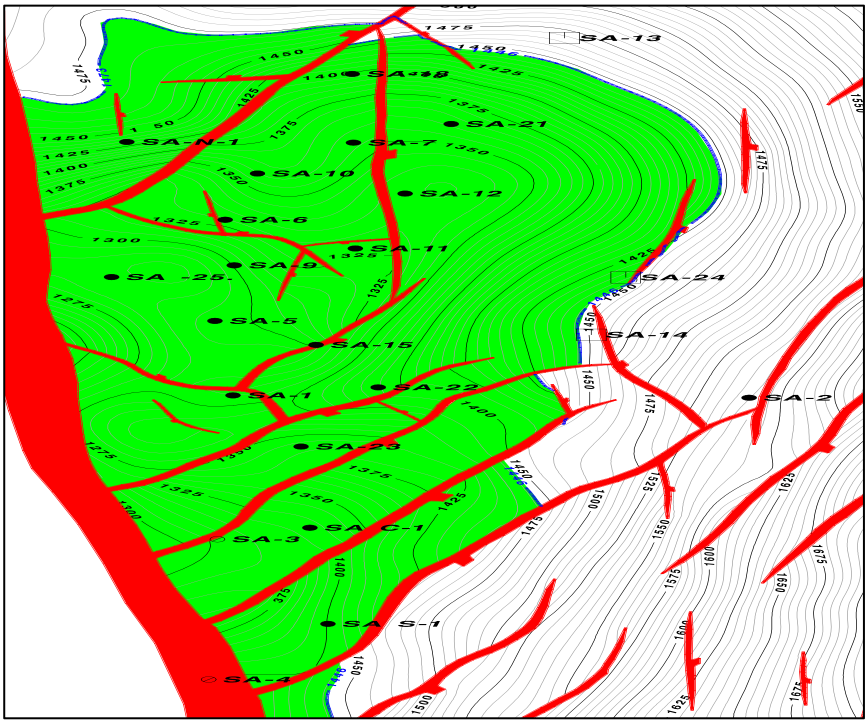

Figure 2-3: Star Oil field structure map

Table 2-1: The favorable geological factors for successful water floods.

Factors favorable for water flooding	
Oil saturation	> 40 %
Porosity	>20 %
Oil -zone thickness	> 15 ft
Permeability (average)	> 10 md
Reservoir depth	> 1000 ft
API gravity	20-60 API
viscosity	< 15000cp

Source: water flooding, Willhite.

- Reservoir rock properties Data:
  - Porosity, %
  - Permeability, md
  - Water saturation, %
- Reservoir condition Data:
  - Original Reservoir temperature, ˚F
  - Original Reservoir pressure, psia
  - Current Reservoir pressure, psia
- Reservoir fluid characteristics Data:
  - Oil gravity
  - Bubble point pressure, psia
  - Production and injection Data
  - Injector number
  - Producers number
  - Mobility ratio

During or immediately after the drilling of a well, core samples may be obtained and well logging operations are conducted to analyze the pay zone .

These initial tests provide the engineer with enough information to determine Specific information which is later used to evaluate the application of recovery methods.

The following physical data are essential for such an evaluation:

1. Permeability (a. effective b. absolute c. relative)
2. Porosity
3. Saturation
4. Wettability
5. Fluid viscosity
6. Original-oil-in-place
7. Recovery factor

Residual Oil Saturation:

Residual oil saturation and connate water saturation are very important numbers in water flooding. The connate water saturation is the lowest water saturation found in situ and determines how much oil is available initially, while the residual oil saturation indicates how much of the original oil in place (OOIP) will remain in the pores after sweeping the reservoir with injected water (SPE,2014). Equation (2-1)) represents the unit-displacement efficiency with the condition that the oil formation volume factor is the same at the start and the end of the water flooding (SPE, 2014):

$$E_D = 1 - \frac{S_{orw}}{S_{oi}} \tag{2-1}$$

$$S_{orw} = 1 - S_{wc} \tag{2-2}$$

Where:

E_D is the unit displacement efficiency.

S_{oi} is the initial oil saturation.

S_{orw} is the residual oil saturation.

S_{wc} is the connate water saturation.

Wettability:

The wettability of a reservoir rock can be defined as the tendency of a fluid to spread on, or to adhere to a solid surface in the presence of another immiscible fluid. In an oil- water system it is a measure of the preference the rock has for either oil or water. Changes in wettability influence the capillary pressure, irreducible water saturation, relative permeability and water flood behavior. Maximum oil production rate by water flooding is normally achieved at water-wet conditions shortly after water breakthrough.

Capillary Pressure:

Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids in porous media. Capillary pressure determines the amount of recoverable oil for water flooding applications through imbibition process for water wet reservoir.

Relative Permeability:

The Relative permeability is the ratio of the effective permeability to the absolute permeability of each phase.

It is expressed for a specific saturation of the phases as

$$K_{r,i} = \frac{K_i}{K} \qquad (2\text{-}3)$$

Where;

$K_{r,i}$ is the phase relative permeability

K is the total effective permeability

k_i is the phase effective permeability.

Relative permeability affects the unit displacement efficiency and how much of the OOIP will be recovered before the water flooding economic limit is reached.

When the interfacial tension between oil and gas phases decreases, the relative permeability values change (Al-Wahaibi et al., 2006), which influences the oil and gas recovery as well as the reservoir pressure. Figure 2 shows the plot of relative permeability curve used for the simulation.

Mobility:

Mobility, λ is described as the ratio between the endpoint effective permeability and the fluid viscosity, μ. It shows how easy the fluid is flowing through a porous medium. Mobility ratio, M, plays an important role during water flooding. It can be defined as the ratio between the mobility of the displacing fluid (water) and the displaced fluid (oil):

$$M = \frac{\lambda_{(displacing)}}{\lambda_{(displaced)}} = \frac{k_{r\ (displacing)} \cdot \mu_{(displaced)}}{K_{r\ (displaced)} \cdot \mu_{(displacing)}} \qquad (2\text{-}4)$$

Where;

M is the mobility ratio.

λ is the mobility.

k_r is the relative permeability

μ is the viscosity.

The subscripts displacing and displaced represent the displacing phase and the displaced phases respectively.

Mobility ratio is considered to be either favorable if the value of (M) is less than or equal to unity or unfavorable if the value is greater than unity (SPE, 2014). Favorable mobility ratio means that the displaced phase (oil) can move more quickly than the displacing phase (water) through the reservoir rock.

Computational Model:

Reservoir Simulation is a form of numerical modeling used to quantify and interpret physical phenomena with the ability to predict future performance. The process involves dividing the reservoir into several discrete units in three dimensions, and modeling the progression of reservoir and fluid properties through space and time in a series of discrete steps (Schlumberger, 2013). Equations (5-11) are solved for each cell and each time step which are a combination of the material balance equation and Darcy's law, (Schlumberger, 2008).

i. Darcy's law (without gravity term) is expressed as:

$$q = -\frac{k}{\mu}\nabla P \qquad (2\text{-}5)$$

Where;

q is the flux

k is the permeability

μ is the viscosity

∇P is the pressure gradient.

ii. Material Balance is expressed as

$$-\nabla . M = \frac{\partial}{\partial t}(\phi\rho) + Q \qquad (2\text{-}6)$$

Where;

M is the mobility ratio

∅ is the porosity

ρ is density

Q is volume flow rate.

Here, mass flux is considered as the sum of the accumulation and Injection/Production.

iii. Simulator Flow Equation (with gravity term) is given in equation (2-7).

$$\nabla.[\lambda(\nabla P - \gamma\nabla Z)] = \frac{\partial}{\partial t}\left(\frac{\phi}{\beta}\right) + \frac{Q}{\rho} \qquad (2\text{-}7)$$

$$\lambda = -\frac{K}{\mu\beta} \qquad (2\text{-}8)$$

Where;

M is mobility

t is time

β is momentum transfer coefficient

γ is relative gravity

Z is vertical position.

iv. Well Model is expressed as:

$$q_{p,j} = T_{wj}M_{p,j}(P_j - P_w - H_{wj} \qquad (2\text{-}9)$$

$$M_{o.j} = \frac{K_{o,j}}{B_{o.j.}\mu_{o,j}} + R_v\frac{K_{g,j}}{B_{g,j.}\mu_{g,j}} \qquad (2\text{-}10)$$

$$M_{g.j} = \frac{K_{g,j}}{B_{g,j.}\mu_{g,j}} + R_s\frac{K_{o,j}}{B_{o,j.}\mu_{o,j}} \qquad (2\text{-}11)$$

Where;

T is the transmissibility

P is the pressure,

H is the pressure head

B is the formation volume factor

R_s is the gas-oil ratio

R_v is the oil-gas ratio.

The subscripts p is phase, j is connection, w is well, o is oil and g is gas.

The above information is the basic data necessary for an evaluation of the potential for recovery . During the primary production phase, another reservoir characteristics are evaluated which include the following :

1. Homogeneity of reservoir - is the degree of consistency in a reservoir . The homogeneity can be approximately determined by analyzing well interference tests ‹production and pressure histories, core data and logs, and other petrographic and stratigraphic information .

2. Dip - is the average angle of inclination from the horizontal of the strata in a reservoir .

3. Diffusivity - is the determination of the rate at which a fluid will readjust in response to a pressure disturbance in the reservoir. (Productivity index=$Q/\Delta P$)

The best method for determining the feasibility of a full-scale water flooding operation is the pilot project. Especially useful in undeveloped areas, a pilot project is a mini-operation designed to assess the performance of the water flooding technique before large quantities of capital are committed to a full-scale project. The location of the wells is chosen to best represent the majority of the reservoir. The operating condition of the pilot wells must be closely monitored for an accurate evaluation of the project .

The information derived from a pilot is used to better evaluate the following :

- Incremental oil recovery
- Optimum pattern configuration
- Saturation distributions
- Areal sweep efficiency
- Mobility

Production potential is a generally accepted minimum yield for the initiation of a water flood. Oil price, water availability, construction costs, drilling and/or workover costs, etc., will also affect the ultimate feasibility of the project .

The amount of oil displaces by water can be determined from relative permeability data and core testing. Typical sandstones can be flooded to a residual oil saturation of 10 - 40 percent. In sandstones, the residual oil saturation to water flooding is also governed by the interfacial tension at the oil-water phase boundary .

Absolute permeability and homogeneity in the pay zone and the mobility ratio of the oil and water are critical to sweep efficiency. However, injection well locations and completion methods are also important .

After deciding to initiate a water flood operation, the operator will choose a good pattern. The majority of water flood operations utilize the "five-spot" water flood configuration.

Five-spot water flood configuration

The five-spot pattern is the most commonly used flooding pattern resulting primarily from the regular well spacing required, or at least used, in most areas. Note that the drilling pattern required to have a five-spot is square, and the ratio of producers to injectors is unity .the five-spot is a highly conductive pattern since the shortest flow path is a straight line between the injectors and producers .also, the pattern gives good sweep behavior .the square drilling pattern which yields the five-spot is also flexible enough that other flood pattern can be generated simply by rearranging the position wells .example of other pattern are the skewed four-spot, nine-spot, and inverted nine-spot.

Once the optimal pattern has been determined, the operator must consider injection well completions, the quality, quantity, and availability of water, water treatment, injection equipment, storage facilities, operating pressures, and the mechanical condition and maintenance of the injection and production wells.

Injection wells can be drilled or converted from existing production wells. Converted wells should undergo a thorough testing program to ensure integrity.

Water position is a crucial consideration in any water flooding project. After securing its availability, the operator must design the treatment and water handling facilities. Injection water should be protected from the atmosphere and injected immediately after filtration.

Anaerobic Sulfate -based bacteria that must be eliminated are often found in producing waters. Knowledge of the injection and formation water is essential to avoid such precipitates as iron oxide, iron sulfide, calcium carbonate, calcium sulfate, and barium Sulfate. Sulfate precipitates are insoluble and are the most damaging.

Operators must also treat the injected fluids to avoid reservoir plugging, shale swelling, and corrosion of the surface and down-hole equipment's.

There are two types of injection systems; open and closed. In the open system, water is obtained from surface waters or fresh water wells. In the closed system, produced water is recycled and re-injected. The water may be treated chemically and by aeration and sedimentation processes before injection. Fluids used in the open system require more treatment than the closed system. The operation of an injection system requires a comprehensive operations and maintenance program. Regular inspections of the wells and the surface production facilities must be conducted. Water quality and corrosion control are particularly important.

Inspections of injection wells should include, but are not limited to:

Temperature, flow meter (for stress), and radioactive tracer surveys when casing, packer, and/or tubing leaks are suspected.

Annular pressure checks.

Wellhead pressure surveys to monitor injection pressure and formation plugging.

Caliper log to ensure tubing integrity.

Cost:

The cost of water flooding is relatively low compared to alternate secondary recovery methods. There are two main expenses when implementing a secondary recovery method; the first is the costs of expenses of surface equipment and maintenance of surface equipment which would be added to first-year expenses.

The second criterion that must be evaluated is the final cost of the project. An entire water flooding process is estimated to cost by Dollar per year. Smaller costs may be realized in the expenses of employees and troubleshooting malfunctions in the process.

Equipment:

The last criterion that must be evaluated is the use of equipment and machinery needed to implement the secondary recovery methods and would require importing a large amount of machinery to the field .

The primary goal of water flooding is to increase overall production by injecting water into a reservoir through injection wells and producing offset wells. The injection rates must be optimized to produce the highest production rates. Depending on the location, water must be imported or piped to the well sites .

According to the textbook Water flooding, the dominant mechanism of water flooding is immiscible displacement. This refers to the displacement of the oil by the injected water. The water and oil cannot mix. Therefore, the injected water pushes the remaining oil towards the production wells. Water flooding is the most used secondary recovery method around the world because of its effectiveness at a relatively low cost .

Water floods are implemented in reservoirs with a wide range of screening criteria .

They are generally used in lighter oil reservoirs because of their low resistance to flow .

Water flooding can be implemented successfully at any reservoir depth. The table below lists favorable geological factors for successful water floods.

2.4 The Factors Considered In Water Flooding:

Thomas, Mahoney, and winter (1989) pointed out that in determining the suitability of a candidate reservoir for water flooding, the following reservoir characteristics must be considered:

1. Reservoir geometry
2. Fluid properties
3. Reservoir depth
4. Lithology and rock properties
5. Fluid saturations

Each of these topics is discussed in detail in the following subsections.

- **Reservoir Geometry:**

The areal geometry of the reservoir will influence the location of wells. The reservoir’s geometry will essentially dictate the methods by which a reservoir can be produce through water-injection practices.

An analysis of reservoir geometry and past reservoir performance is often important when defining the presence and strength of a natural water drive and, thus, when defining the need to supplement the natural injection. If a water-drive reservoir is classified as an active water drive, injection may be unnecessary.

- **Fluid Properties:**

The physical properties of the reservoir fluids have pronounced effects on the suitability of a given reservoir for further development by water flooding.

The viscosity of the crude oil is considered the most important fluid property that affects the degree of success of a water flooding project.
The oil viscosity has the important effect of determining the mobility ratio that, in turn, controls the sweep efficiency.

- **Reservoir Depth:**

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

- **Lithology and Rock Properties:**

Thomas et al. (1989) pointed out that lithology has a profound influence on the efficiency of water injection in a particular reservoir. Reservoir lithology and rock properties that affect flood ability and success are:

• Porosity
• Permeability
• Clay content
• Net thickness

In some complex reservoir systems, only a small portion of the total porosity, such as fracture porosity, will have sufficient permeability to be effective in water-injection operations. In these cases, a water-injection program will have only a minor impact on the matrix porosity, which might be crystalline, granular, or vugular in nature.

Although evidence suggests that the clay minerals present in some sands may clog the pores by swelling and when water flooding is used, no exact data are available as to the extent to which this may occur.

Tight (low-permeability) reservoirs or reservoirs with thin net thickness possess water-injection problems in terms of the desired water injection rate or pressure. Note that the water-injection rate and pressure are roughly related by the following expression:

$$P_{inj} \propto iw/hk \qquad (2\text{-}12)$$

Where

P_{inj}= water-injection pressure

i_w= water-injection rate

h = net thickness

k = absolute permeability

The above relationship suggests that to deliver a desired daily injection rate of iw in a tight or thin reservoir, the required injection pressure might exceed the formation fracture pressure.

- **Fluid Saturations**

In determining the suitability of a reservoir for water flooding, a high oil saturation that provides a sufficient supply of recoverable oil is the primary criterion for successful flooding operations. Note that higher oil saturation at the beginning of flood operations increases the oil mobility that, in turn gives higher recovery efficiency. (Ahmed T 1946).

2.5 Factors Controlling Water Flood Recovery:

Oil recovery due to water flooding can be determined at any time in the life of a water flood project if the following four factors are known:

1. Oil-In-Place at the Start of Water Flooding:

The oil-in-place at the time of initial water injection is a function of the floodable pore volume and the oil saturation. Floodable pore volume is highly dependent on the selection and application of net pay discriminators such as permeability (and porosity) cutoffs. A successful flood requires that sufficient oil be present to form an oil bank as water moves through the formation. An accurate prediction of water flood performance or the interpretation of historical water flood behavior can only be made if a reliable estimate of oil-in-place at the start of water flooding is available.

2. Areal Sweep Efficiency:

This is the fraction of the reservoir area that the water will contact. It depends primarily upon the relative flow properties of oil and water, the injection-production well pattern used to flood the reservoir, pressure distribution between the injection and production wells and directional permeability.

3. Vertical Sweep Efficiency:

Vertical sweep refers to the fraction of a formation in the vertical plane which water will contact. This will depend primarily upon the degree of vertical stratification existing in the reservoir.

4. Displacement Sweep Efficiency:

This represents the fraction of oil which water will displace in that portion of the reservoir invaded by water.

Water flood recovery can be computed at any time in the life of a water flood project from the following general equation:

$$Np = N * Ea * Ev * Ed \qquad (2\text{-}13)$$

Where;

N = the oil in place in the floodable pore volume at the start of water injection, STB

Ea= the fraction of the floodable pore volume area swept by the injected water

Ev= the fraction of the floodable pore volume in the vertical plane swept by the injected water

Ed = is equal to the fraction of the oil saturation at the start of water injection which is displaced by water in that portion of the reservoir invaded by water.

Water flood recovery is dependent on a number of variables. The variables which usually have the greatest impact on water flood behavior are listed below:

- Oil saturation at the start of water flooding. $\mathbf{S_o}$
- Residual oil saturation to water flooding, $\mathbf{S_{or}}$ **(Sorw)**
- Connate water saturation, $\mathbf{S_{wc}}$
- Free gas saturation at the start of water injection, $\mathbf{S_g}$
- Water floodable pore volume**, Vp**, bbls (This takes into account the permeability, porosity and net pay)
- Oil and water viscosity, $\boldsymbol{\mu_o}$and$\boldsymbol{\mu_w}$
- Effective permeability to oil measured at the immobile connate water saturation, **($\mathbf{k_o}$)@swir**
- Relative permeability to water and oil, $\mathbf{k_{rw}}$ and $\mathbf{k_{ro}}$
- Reservoir stratification, (Dykstra-Parsons coefficient, **V**)
- Water flood pattern (symmetrical or irregular)
- Pressure distribution between injector and producer
- Injection rate, BWPD
- Oil formation volume factor, $\mathbf{B_o}$
- Economics

(James, 1990)

2.6 Water Flooding Versus Pressure Maintenance

Maximum combined primary and secondary oil recovery occurs when water flooding is initiated at or near the initial bubble point pressure. When water injection commences at a time in the life of a reservoir when the reservoir pressure is at a high level, the injection is frequently referred to as a pressure maintenance project. On the other hand, if water injection commences at a time when reservoir pressure has declined to a low level due to primary depletion, the injection process is usually referred to as a water flood. In both instances, the injected water displaces oil and is a dynamic displacement process. Nevertheless, there are important differences in the displacement process when water displaces oil at high reservoir pressures compared to the displacement process which occurs in depleted low pressure reservoirs. (James 1990).

2.7 Optimum Time to Water Flood

The most common procedure for determining the optimum time to start water flooding is to calculate:

- Anticipated oil recovery
- Fluid production rates
- Monetary investment
- Availability and quality of the water supply
- Costs of water treatment and pumping equipment
- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors

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

Cole (1969) lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

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

• Free gas saturation. (1) In water injection projects. It is desirable to have initial gas saturation, possibly as much as 10%. This will occur at a pressure that is below the bubble point pressure. (2) In gas injection projects. Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure is at or above bubble-point pressure.

• Cost of injection equipment. This is related to reservoir pressure, and at higher pressures, the cost of injection equipment increases. Therefore, a low reservoir pressure at the initiation of injection is desirable.

• Productivity of producing wells. High reservoir pressure is desirable to increase the productivity of producing wells, which prolongs the flowing period of the wells, decreases lifting costs, and may shorten the overall life of the project.

• Effect of delaying investment on the time value of money. A delayed investment in injection facilities is desirable from this standpoint.

• Overall life of the reservoir. Because operating expenses are an important part of total costs, the fluid injection process should be started as early as possible.

Some of these six factors act in opposition to others. Thus the actual pressure at which a fluid injection project should be initiated will require optimization of the various factors to develop the most favorable overall economics.

The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after the primary. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the displacing fluid. On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time, (Ahmed T 1946).

2.8 Selection of Flooding Patterns:

One of the first steps in designing a water flooding project is flood pattern selection. The objective is to select the proper pattern that will provide the injection fluid with the maximum possible contact with the crude oil system. This selection can be achieved by

1. Converting existing production wells into injectors or drill infill injection wells. When making the selection, the following factors must be considered:

- Reservoir heterogeneity and directional permeability
- Direction of formation fractures.
- Availability of the injection fluid (gas or water)
- Desired and anticipated flood life
- Maximum oil recovery
- Well spacing, productivity, and injectivity in general, the selection of a suitable flooding pattern for the reservoir depends on the number and location of existing wells. In some cases, producing wells can be converted to injection wells while in other cases it may be necessary or desirable to drill new injection wells. Essentially four types of well arrangements are used in fluid injection projects:
  - Irregular injection patterns

- Peripheral injection patterns
- Regular injection patterns
- Cristal and basal injection patterns

(Ahmed T 1946).

2.9 Water Flood Design

The design of a water flood has many phases. First, simple engineering evaluation techniques are used to determine whether the reservoir meets the minimum technical and economic criteria for a successful water flood. If so, then more-detailed technical calculations are made. These include the full range of engineering and geosciences studies.

The geologists must develop as complete an understanding as possible of the internal character of the pay intervals and of the continuity of non-pay intervals. This pre-flood understanding often is limited because the injector/producer wells connectivity has not been determined quantitatively. Interference testing can provide insight into connectivity when its cost is justifiable. Data gathered from smart wells can be particularly helpful in determining connectivity in high-cost environments where there is a limited number of well bores. Analogs also can prove useful. Otherwise, little definitive data will be available until after there has been significant fluid movement from the injectors toward the producers.

The engineer will make a number of reservoir calculations to determine the well spacing and pattern style that will be used in a particular flood. These choices are based on the available understanding of the reservoir geology, the proposed design of surface facilities (particularly water-injection volumes), and any potential limits on the numbers of injectors and producers. Such factors are interrelated in terms of capital and operating costs and oil-, water-, and gas-producing rates to define the overall economics of the project. In making these preliminary calculations, facility capacities need to be flexible because as the water flood progresses, there almost certainly will be modifications to the original designs and operating plans.

Some number of water flood design considerations will be discussed briefly. (Rose *et* al.) are entirely devoted to this topic.) The design aspects discussed below include:

- Injection/producer pattern layouts
- Injection-water sensitivity studies
- Injection wells, injectivity, and allocation approaches, including well fracturing
- Pilot water flooding
- Production wells
- Surface facilities for injection water
- Surface facilities for produced fluids

(Rose S.C 1989).

2.10 Water Flood Management:

Effective water flood management requires a multidisciplinary team approach that includes reservoir, drilling, and production engineers, as well as chemists, accounting, legal, and others. Guidelines for water flood management include information on water source and quality. During most of the flood life, an oil reservoir will require about 0.5-1.0 b/d of injection water for each 1 acre-ft of reservoir volume. The ultimate volume of water required for many floods is about 1.5-2 times the reservoir pore volume, (Thakur, 1991). The water injected should be inexpensive and free from bacteria, suspended solids, and oxygen. It should also be nonreactive with any clays in the reservoir and compatible with the reservoir rock and formation water as well as not being corrosive in the injection and production facilities. Injected water can include produced, surface, or subsurface water, (Rose, 1989). The injection rate required to support the desired production rate depends on inflow performance relationship considerations, well injection pressure and rate, rules of thumb, local experience, and availability of compatible water. Controllable parameters in a water flood are the injection and production rates. Economic success depends on the additional recovery obtained and the cost of the water, injection wells, and surface treatment facilities. Water floods require regular analysis of the produced water to detect injected water breakthrough by such means as a change in chlorides if the injected and produced water have different salinities. Other parameters to monitor are the presence of corrosive dissolved gases (CO_2, H_2S, O_2); minerals, bacterial growth; dissolved solids; suspended solids, concentration, and compositions; ion analysis; and PH. This data is gathered at the water source wells, water injection wells, and points in the injection system.

Water flooding has progressed significantly since it was first attempted in 1865, over one hundred years ago in the Pit Hole City area of Pennsylvania. Its first use was to maintain the reservoir pressure and thus allow wells to have a longer productive life than they would by pressure depletion. Since that first water flooding project has climbed to a dominant role among fluid injection methods. It has some things going for it:

1. Water is generally available.
2. It can be injected with relative ease because of the hydraulic head it possesses in the injection well.
3. It spreads well throughout the reservoir.
4. It spreads well throughout the oil-bearing formation.
5. Water is generally efficient in displacing oil.

Increased knowledge of water flooding has kept pace with its popularity. With today's technology, we can engineer water floods for popularity and improved oil recovery. (Craig, 1973).

2.11 Literature Review:

Extensive literature reviews were conducted to characterize the water flooding.

The first edition of The Reservoir Engineering Aspects of Water flooding was published in 1970 and written by Forrest F. Craig, Jr. At the time of publication, much of the theory of oil displaced by water had been developed and many laboratory studies completed; however, the ability to perform computer modeling of 3D fluid flow in reservoirs with complex geologic depositions was in its infancy. In addition, several of the earliest, large-scale field applications of pattern water flooding had begun, but long-term performance results were not yet known.

Craig, (1971) states that "many of the early water floods occurred accidentally either by casing leaks or by surface water entering the well bore and the introduction of this water was considered beneficial because it was thought to help maintain reservoir pressure thereby increasing oil production", (Craig, 1971).

In (1972) Schneider described the role of geological factors on the design and surveillance of water floods in the structurally complex reservoirs of the Ventura Field in California. Geologic factors strongly influenced injection profiles and the responses of the producing wells; the water flood was monitored to establish the dependence of injectivity and productivity on geologic factors. This continual geologic surveillance proved quite useful in determining the cause of injection anomalies and predicting their effect on the water flood, (Schneider, 1972).

Gordon and Owen, (1979) described the importance of a thorough well-organized reservoir surveillance effort in the West Yellow Creek Field. While this surveillance involved many activities, three programs, in particular, were identified as being critical to the success of the effort of pressure fall-off testing, computerized flood balancing, and produced water sampling, (Gordon, 1979).

L.G. Schoeling, et al, (1996) presented procedures to improve water flooding through integrated reservoir management using technologies that have demonstrated a positive impact on economics.

An air flotation unit has demonstrated that the poor water quality can be improved economically with reduced costs compared to previous operations, and permeability modification treatments plugged channels, and increased oil recovery. The case study applied in the Savonburg Field, a shallow reservoir located in southeastern Kansas.,(Schoeling,1996).

D.B. Bennion, et al, (1998) showed that the poor injection water quality is a prime factor in the reduction in injectivity in many water injection and disposal wells. These reductions in injectivity often result in costly workovers, stimulation jobs, and re-completions, or in many cases, the uncontrolled fracturing of wells by high bottom-hole pressures resulting in poor water injection conformance and reduced overall sweep efficiency and recovery, (Bennion, 1998)

The successful implementation of reservoir surveillance and optimization plan was presented by B. Choudhuri, et al, (2005) which could arrest production decline from the reservoir in the Haima West reservoir in a mature field in south Oman which showed severe production decline after initial encouraging results in re-development phase using horizontal injectors and horizontal producers, (Choudhuri, 2005).

M. Terrado, et al, (2006) illustrates how the practical application of surveillance and monitoring principles are keys to understanding reservoir performance and identifying opportunities that will improve ultimate oil recovery and practices on how to process valuable information and analyze data from different perspectives are presented in a methodical way on the following bases: field, block, pattern, and wells. The results indicated that the nominal decline rate improved and the change in the decline rate is primarily attributed to effective water flood management, (Terrado, 2006).

Tewari, R. D, (2007) discussed the application of diagnostic methods like Hall plot, Jordan plot, and other empirical relations using Pressure, injection, and production data for understanding and improving the injection process and illustrated the important ingredients which can add value to the asset and improve the reserves and overall development strategy. Therefore, he highlighted that the success and failure of a water injection project depend on why, when, where, what, how, and how much to inject, plus what will happen to the formation once the water injection starts. Case study applied in Aradeiba formation in Fula north field, (Tewari, 2007).

D.Beliveau(2008), showed that the water flooding of viscous oil reservoirs can be an effective recovery process with typical EUR) expected ultimate oil recovery of 20-40% STOIIP or even higher like in large Mangala, Aishwariya, and Bhagyam oilfields in India, if the appropriate operations are conducted. Simple water flood operations for viscous oil reservoirs should be the base process for improved oil recovery. To maximize water flood oil recovery in viscous oil reservoirs it is important to inject large volumes of water and then to handle large volumes of produced water along with the oil. Normally approximately 50% or more of the expected ultimate oil recovery is produced at very high water cuts; about 90% or even higher. Also note that to maximize water flood recovery in a viscous oil reservoir, the cumulative voidage replacement ratio should be close to unity. As in most conventional oil operations, recovery of viscous oil via water flooding will increase with reduced well spacing, (Beliveau, 2008).

Arne Graue, et al, (2012) studied the mixing of injected water and in-situ water during water floods and demonstrated that the mixing process is sensitive to the initial water saturation; the results illustrate differences between water flooded zone and a pre flooded zone. (Graue, 2012).

The second stage of hydrocarbon production was shown by Babak Aminshahidy, et al, (2013) during which an external fluid such as water or gas is injected into the reservoir through injection wells located in rock that has fluid communication with production wells. The purpose of secondary recovery is to maintain reservoir pressure and to displace hydrocarbons toward the wellbore, (Babak, 2013).

Water Injection Projects in Sudan:

1. Unity oil filed 2007
2. Greater Munga.2010
3. Greater Fula.
4. Jake south oil field
5. Keyi oil field.

This project, therefore, focuses on designing of Water injection pilot and the possibility of increasing oil recovery in the South Annajma field by the use of Eclipse Software and study different cases to select an optimum scenario for this field.

CHAPTER 3

RESEARCH METHODOLOGY

CHAPTER 3

Research Methodology

3.1 Introduction of Eclipse:

The ECLIPSE simulator covers the entire spectrum of reservoir simulation, including black oil, compositional, thermal finite volume reservoir, and streamline simulation. This enables you to simulate any type of reservoir, with any recovery method—from waterflooding to heavy oil recovery and chemical enhanced oil recovery (EOR)

Here the black oil model had been used for this simulation.

The Black Oil model is a relatively simpler numerical simulation model that handles how the fluids, that is, oil, water, and gas would behave at different pressure and temperature.

The black-oil equations are a set of partial differential equations that describe fluid flow in a petroleum reservoir, constituting the mathematical framework for a black-oil reservoir simulator.

The term *black-oil* refers to the fluid model, in which water is modeled explicitly together with two hydrocarbon components, one (pseudo) oil phase and one

(Pseudo) gas phase.

This is in contrast with a compositional formulation, in which each hydrocarbon component (arbitrary number) is handled separately

The equations of an extended black-oil model are:

$$\frac{\partial}{\partial t}\left[\phi\left(\frac{S_o}{B_w}+\frac{R_v S_g}{B_g}\right)\right]+\nabla.\left(\frac{1}{B_o}u_o+\frac{R_v}{B_g}u_g\right)=0$$

$$\frac{\partial}{\partial t}\left[\phi\left(\frac{S_w}{B_w}\right)\right]+\nabla.\left(\frac{1}{B_w}u_w\right)=0$$

$$\frac{\partial}{\partial t}\left[\phi\left(\frac{R_s S_o}{B_o}+\frac{S_g}{B_g}\right)\right]+\nabla.\left(\frac{R_s}{B_o}u_o+\frac{1}{B_g}u_g\right)=0$$

Where:

ϕ is a porosity of the porous medium,

S_w is a water saturation

S_o ,S_g are saturations of liquid (oil) and vapor (gas) phases in the reservoir

u_o ,u_w , u_g are Darcy velocities of the liquid phase, water phase and vapor phase in the reservoir. The oil and gas at the surface (standard conditions) could be produced from both liquid and vapor phases existing at high pressure and temperature of reservoir conditions. This is characterized by the following quantities:

B_o is an oil formation volume factor (ratio of some volume of reservoir liquid to the volume of oil at standard conditions obtained from the same volume of reservoir liquid),

B_w is a water formation volume factor (ratio of volume of water at reservoir conditions to volume of water at standard conditions),

B_g is a gas formation volume factor (ratio of some volume of reservoir vapor to the volume of gas at standard conditions obtained from the same volume of reservoir vapor),

R_S is a solution of gas in oil phase (ratio of volume of gas to the volume of oil at standard conditions obtained from some amount of liquid phase at reservoir conditions),

R_V is vaporized oil in gas phase (ratio of volume of oil to the volume of gas at standard conditions obtained from some amount of vapor phase at reservoir conditions).

The ECLIPSE industry-reference Black oil simulator offers the most complete and robust set of numerical solutions for fast and accurate prediction of dynamic behavior—for all types of reservoirs and degrees of complexity, structure, geology, fluids, and development schemes.

ECLIPSE is a fully implicit, three-phase, 3D, general purpose black-oil simulator that includes several advanced and unique features.

ECLIPSE Simulator determines Accurate of reserves, the number of wells needed, the best well pattern, the best perforation interval, the best injection rates, and the best time for injection, Confirm understanding of reservoir flow barriers to assessing whether untrained regions exist, quickly and cheaply assess various production scenarios, accurately model real geological structure and petrophysics, model a wide range of recovery techniques, where wells opened with the Reservoir, where they were closed, vertical flow performance, Economic limits to the producers and injectors, Wells Locations, Production and Injection Rates Production and Injection Control and Constrains and times at which the reports have resulted.

Also, it can estimate the size of separation facilities and when they may be needed, storage capacities and production rates from underground gas storage facilities, optimal means of meeting gas deliverability contracts, financial risk by economic analysis of best, worst, and most likely scenarios.

This simulator can predict the production performance and Assessment of the early gas or water breakthrough and investigate how to minimize it. It can be recognized by banks and funding organizations as supporting evidence for investment decisions.

3.2 Data Availability

To observe the effect of water flooding as a secondary oil recovery technique, a simple black oil reservoir model is used using the ECLIPSE simulator. The reservoir conditions are shown in Table 1, while Tables 2–4 describe The Reservoir characteristics in the South Annajma field, Initial conditions, and relative permeability curve (water-wetted), respectively. Figure 3.1 shows the reservoir model with one injector well and four producer wells.

Average porosity and permeability values are used to describe the model properties. One vertical injector well and four producer wells are initialized. Both wells are set to produce and inject at the same rate of 750 m3/day which is the average produced oil from the producers. The simulation was made to run from 1st Jan 2013 till 1st Jan 2015 (12 years). To simulate water flooding as a secondary oil recovery technique, the simulation ran at the time of production both commence to decline, which will be determined by which the highest recovery factor is. After running the above files on an ECLIPSE black oil simulator, the results will be analyzed and explained in detail. A base case scenario of initial water flooding is executed to give recovery of 7.5%.

Reservoir Conditions:

The reservoir is heterogeneous and consists of water- wetted rock. Although the reservoir fluid consists of live black oil, gas production was not considered for simplicity. The composition of oil components is assumed to be constant relative to pressure and time. The reservoir conditions are summarized in Table 4-1.

Table 3-1: The Reservoir Conditions

Status as of Mar.20l0	South Annajma
Formation	Bentiu
STOOIP (MMSTB)	74
EUR (MMSTB)	32.8
NP (MMSTB)	7.4
REMAING EUR(Reserve) (MMSTB)	25.5
EUR TO-DATE (%)	44.3
RF TO-DATE (%)	22.5

First and foremost, the geology of the reservoir must be evaluated. Water floods will be successful under specific reservoir characteristics. The characteristics the South Annajma field that must be evaluated are listed below:

Table 3-2: The Reservoir Characteristics in South Annajma Field

Parameter	Value	Unit
Component	Water ,oil and gas	-
wettability	Water-wetted	-
Rock compressibility		
Average Depth to Base of Sand	5970	ft
Average Reservoir Temperature	174.0	F
Average Crude Oil Viscosity at Reservoir Conditions (cp)	2.1640	cp
Pressure at 5905.5 ft	2425	psia
Crude Gravity at 60 F	36	(API)
Oil Density	0.8355	g/cm3
Gas Oil Ratio GOR	208	Scf/STB
Average Permeability	50-200	(md)
Average Sand Thickness	50	(ft)
Average Porosity	15 - 26	(%)
Area	627.65	(acres)
Initial Oil Saturation	20.8	(%)
Formation Volume Factor	1.2245	(Res bbls/stb)
Original Oil in Place	67	(MMbb)
Total simulation time		days
No of grids 37*68*343	862988	-

Initial Conditions:

Initially, the reservoir is assumed to be in hydrostatic equilibrium consisting of only oil. It is also desired to have the reservoir pressure above the bubble point to avoid gas production. Initial drawdown pressure of 400psi is also desired. Table 2 shows the initial conditions considered for the simulation.

Table 3-3: Initial Conditions

initial condition		Unit
Reservoir pressure	2400	psi
Bottom hole pressure	2000	psi
Bubble point pressure	940	psi
Oil saturation	0.496	%
Water saturation	0.23988	%
Gas saturation	0	%

Boundary Condition

- Highly faulted resulted in the compartmentalization of reservoir faults are either sealing or partially sealing at some areas.
- Pressure communication is established between compartments during production.
- Strong Aquifer behavior is noticed from the northern part of the structure lead to good pressure support while the southern area has less pressure support due to moderate effect in the middle of the structure.

Table 3-4.Relative Permeability Curve (Water-Wetted).

S_w	K_{rw}	K_{ro}
0.23988	0	1
0.289514	0.0011	0.752839
0.339148	0.0024	0.53075
0.388782	0.005	0.354911
0.438416	0.01	0.229107
0.48805	0.019	0.145416
0.537684	0.03	0.091896
0.587318	0.044	0.0575
0.636952	0.06	0.034237
0.686586	0.077	0.016573
0.73622	0.094	0

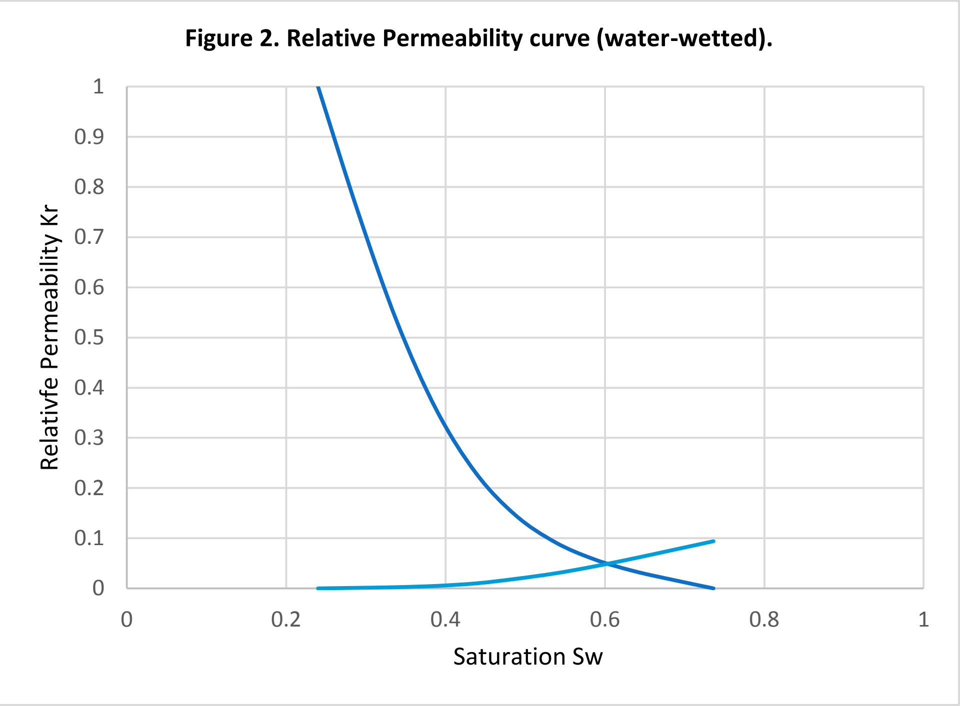

Figure 3-1: Relative Permeability Curve (Water-Wetted)

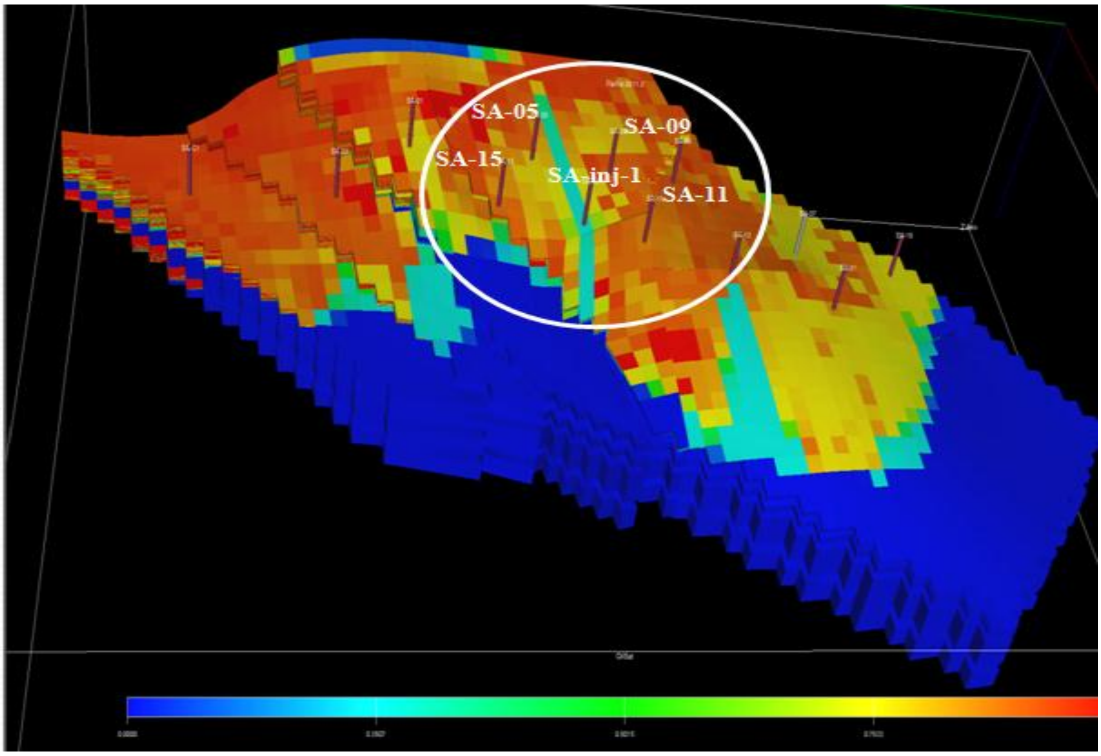

Figure 3-2: Location of Water Flooding Compartment

3.3 Procedure of the Work

- Collect the data (model of South Annajma -physical properties)
- Build the model Using ECLIPSE Software
- Running Model
- Analysis of the Result
- Determination of the best condition.
- Final Result

CHAPTER 4

SIMULATION MODEL

CHAPTER 4

Simulation Model

4.1 Simulation Model:

•No of grids 37*68*343 = 862988, with single porosity, the simulation begins from 1.1.2013 to 1.1.2024 as a prediction, running the simulation model in different scenarios.

•Simulation implement on the model with the next assumptions:

•One injection well has been drilled in the model.

•Simulations were carried out for 11 years by injecting water at a constant rate through a vertical well. Water was injected at the same depth as the production well. Also, the same lateral distance was maintained between the injections well and production wells.

•Different simulations were performed by varying injection rates from 750, 1125, and 1500 m3/day. A base case without water injection was considered for reference.

4.2 Results and Discussion:

In this simulation, analysis of the oil production rate, water cut, reservoir pressure, accumulated oil production, and recovery factor was made for the vertical water flooding. A base case without water injection was also considered as a reference.

4.3 History Matching:

History matching is the process of conditioning the geological or the static model to production data by adjusting a model of a reservoir until it closely reproduces the past behavior of a reservoir; this is a common practice in the oil and gas industry to have reasonable future predictions. It is traditionally performed by trial and error.

Once a reservoir simulation model has been constructed, the validity of the model is examined by using it to simulate the performance of a field under past operating conditions. This is usually done by specifying historical controlling rates, such as oil rate in an oil reservoir vs. time, and then making a comparison of the no specified performance such as gas/oil ratio (GOR), water/oil ratio (WOR), and reservoir pressure with measured data. or it is a process in which certain input parameters to the reservoir simulator such as porosity, permeability, thickness, saturation, depth of oil/water contact, connate water saturation, relative permeability, etc. are altered singly or collectively to obtain a match between simulator prediction values and observed historic data relating to flow rates of oil, gas, water, pressures, GOR (gas-oil ratio), WOR (water-oil ratio), and their variations as a function of time.

If there are significant differences between the calculated performance and the known performance of the well/reservoir system, then adjustments to the reservoir simulation model are made to reduce this difference.

The first step matching the reservoir pressure

- let the simulator produce the historical liquid volume, changes made to aquifer PI, volume, and fault transmissibilities then shift the controlling mood to oil rate and changes in:
- Relative permeability-end points
- Modify the K (multipliers ranged from (2-10) at different areas.

Figures 4-1 shows a history matching of south Annajma field pressure versus time to the historical performance and the calculated performance.

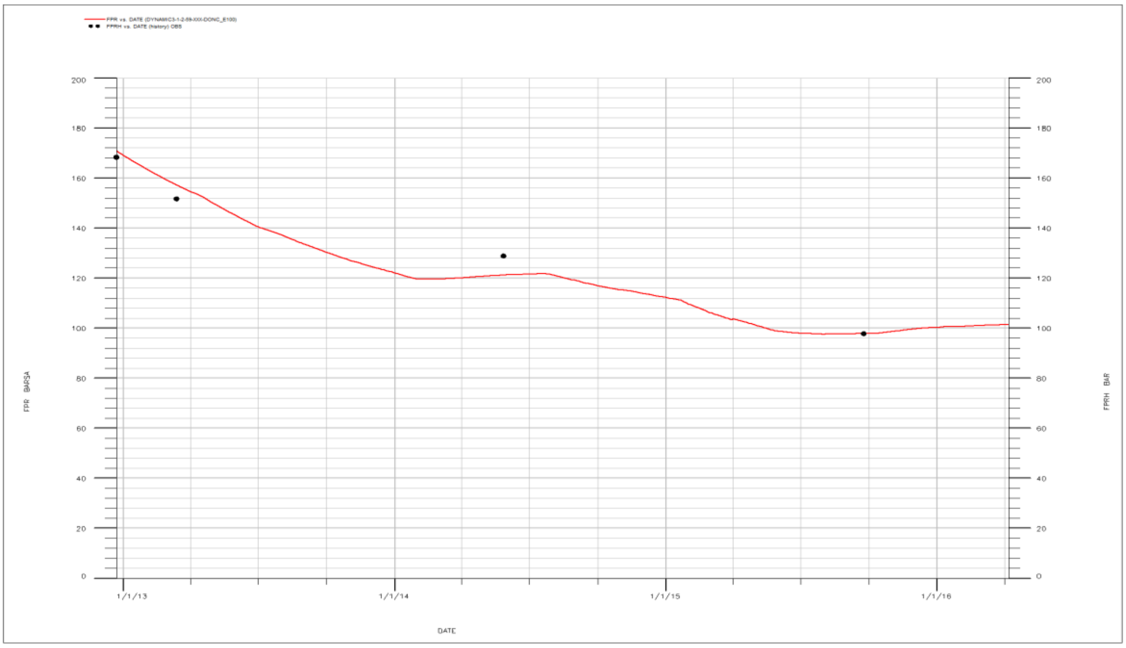

Figure 4-1: History Matching – Field pressure

Figures 4-2 shows a history matching of south Annajma field water cutversus time to the historical performance and the calculated performance.

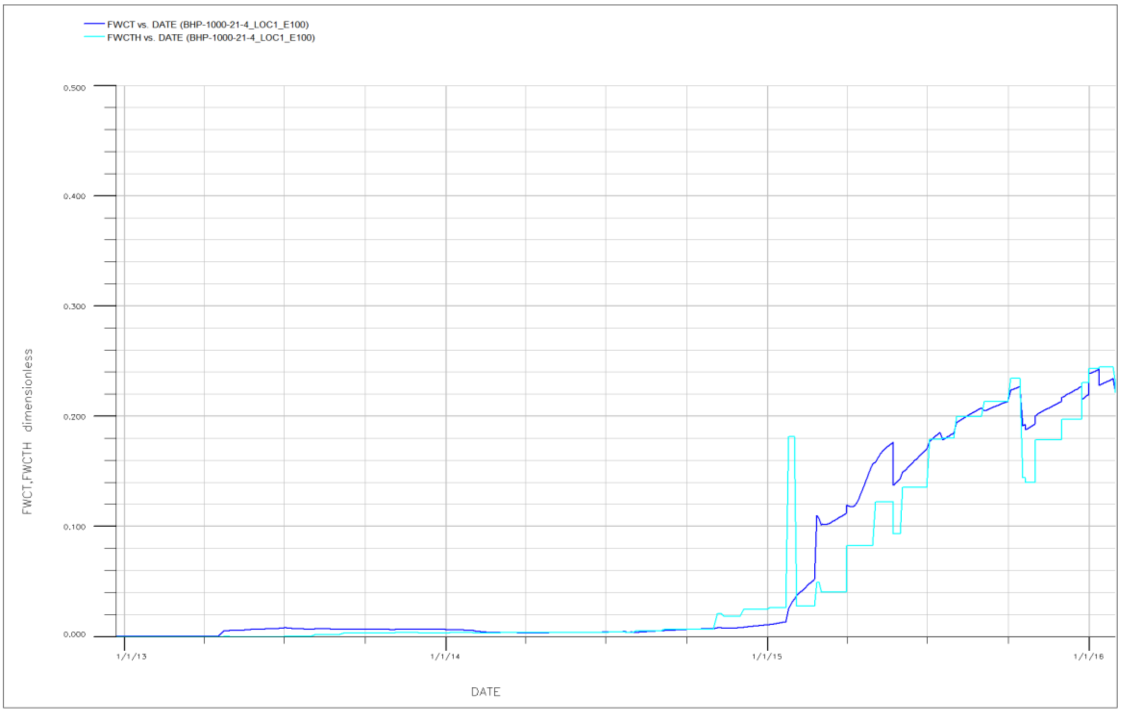

Figure 4-2: History Matching-Field Water cut

Figure 4-3 shows a History Matching of well pressure and water cut versus time to the historical performance and the calculated performance for the well SA-1.

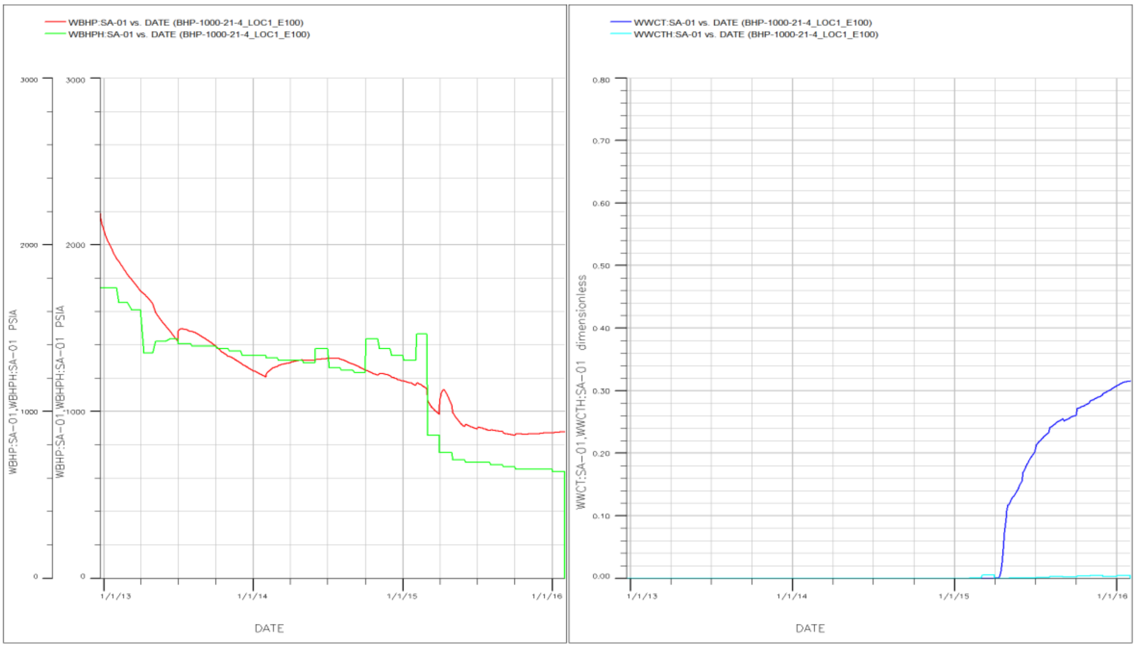

Figure 4-3: History Matching-SA-01

Figure 4-4 shows a History Matching of well pressure and water cut versus time to the historical performance and the calculated performance for the well SA-5.

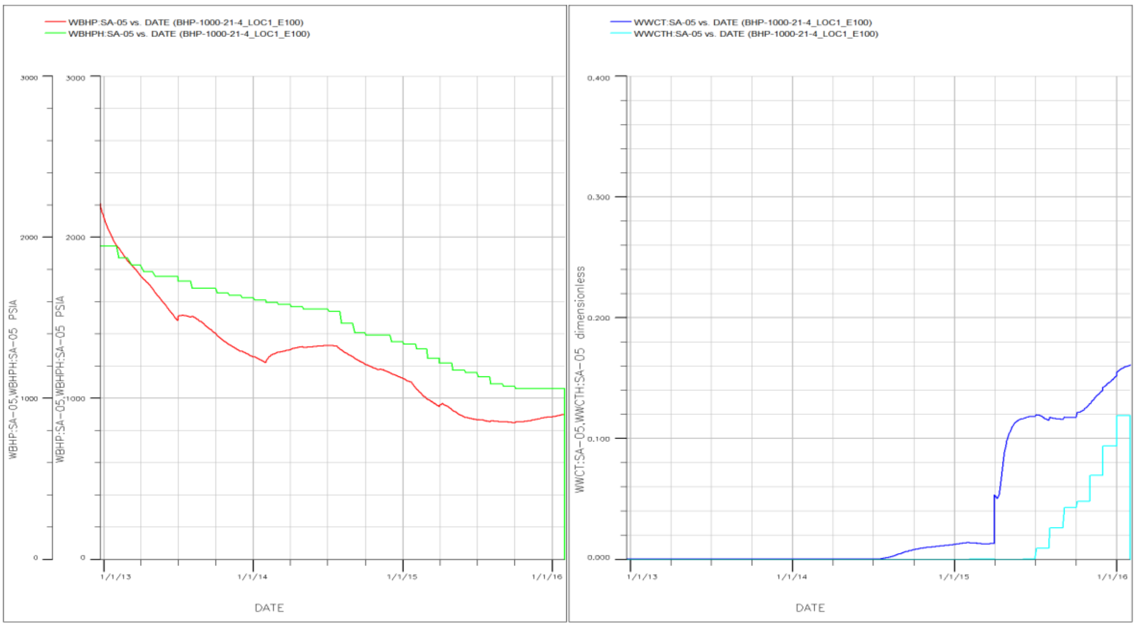

Figure 4-4: History Matching-SA-05

Figure 4-5 shows a History Matching of well pressure and water cut versus time to the historical performance and the calculated performance for the well SA-9.

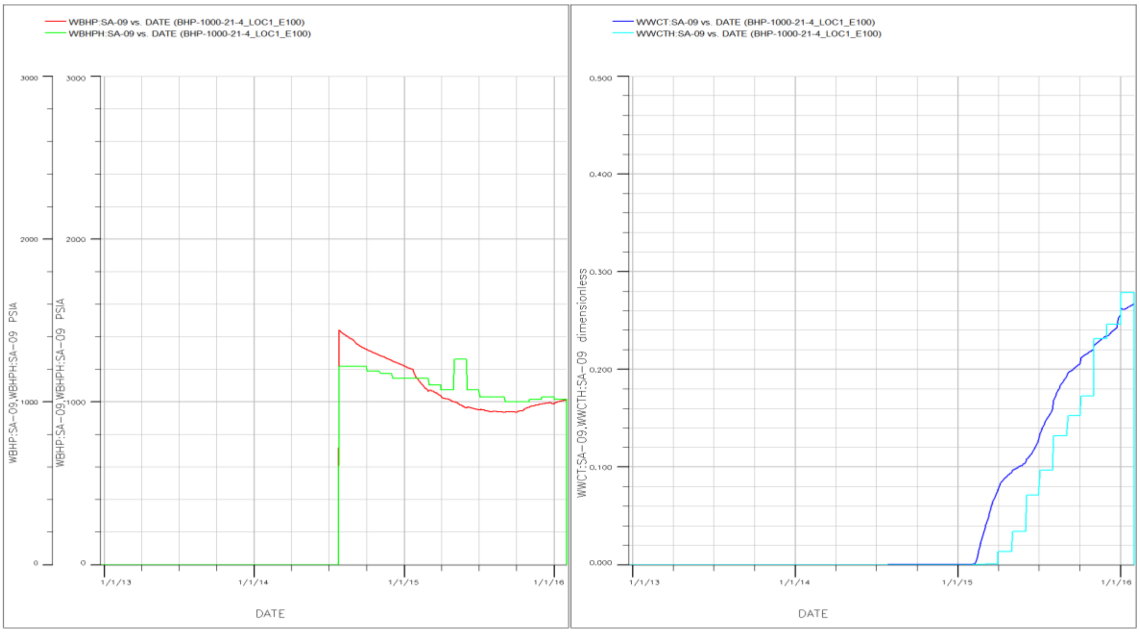

Figure 4-5: History Matching-SA-09

Figure 4-6 shows a History Matching of well pressure and water cut versus time to the historical performance and the calculated performance for the well SA-11.

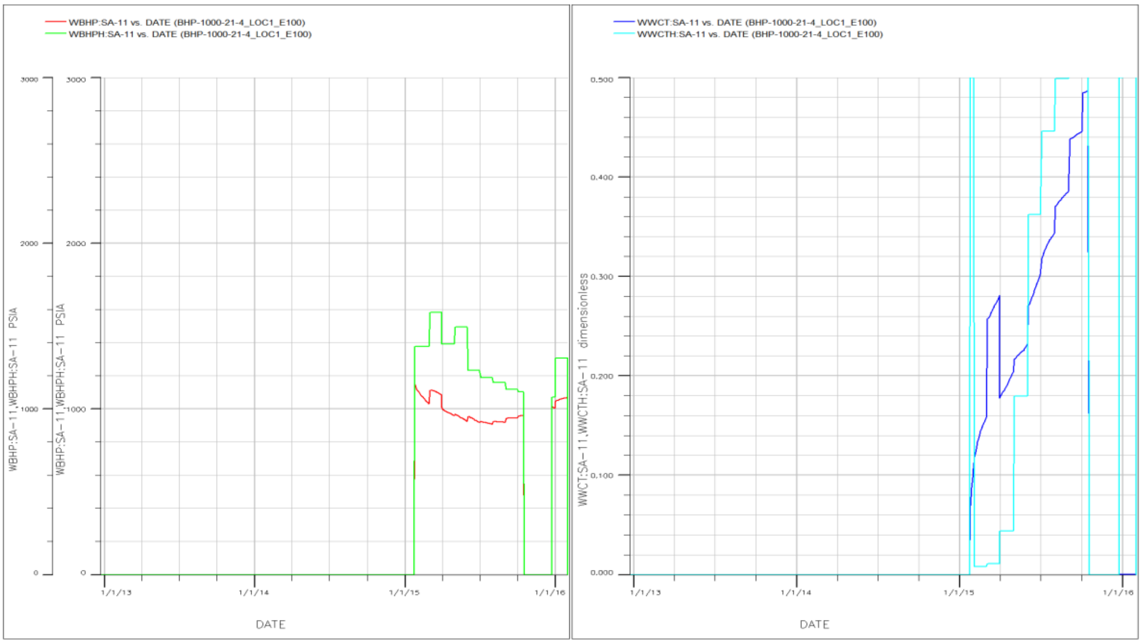

Figure 4-6: History Matching-SA-11

Figure 4-7 shows a History Matching of well pressure and water cut versus time to the historical performance and the calculated performance for the well SA-12.

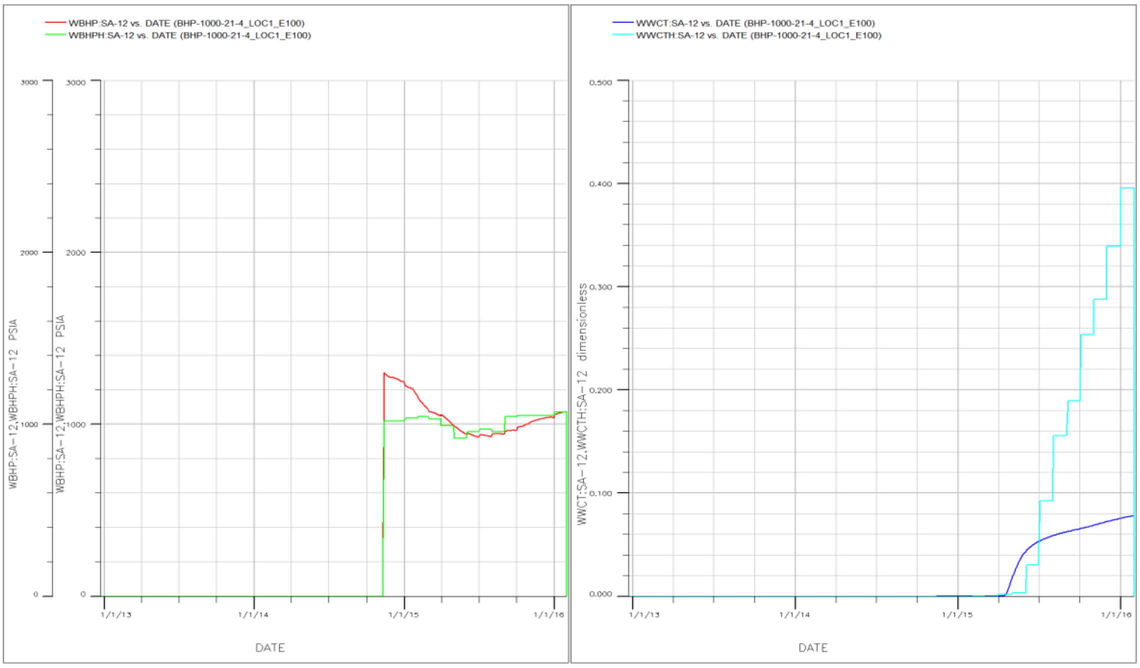

Figure 4-7: History Matching-SA-12

Figure 4-8 shows a History Matching of well pressure and water cut versus time to the historical performance and the calculated performance for the well SA-15.

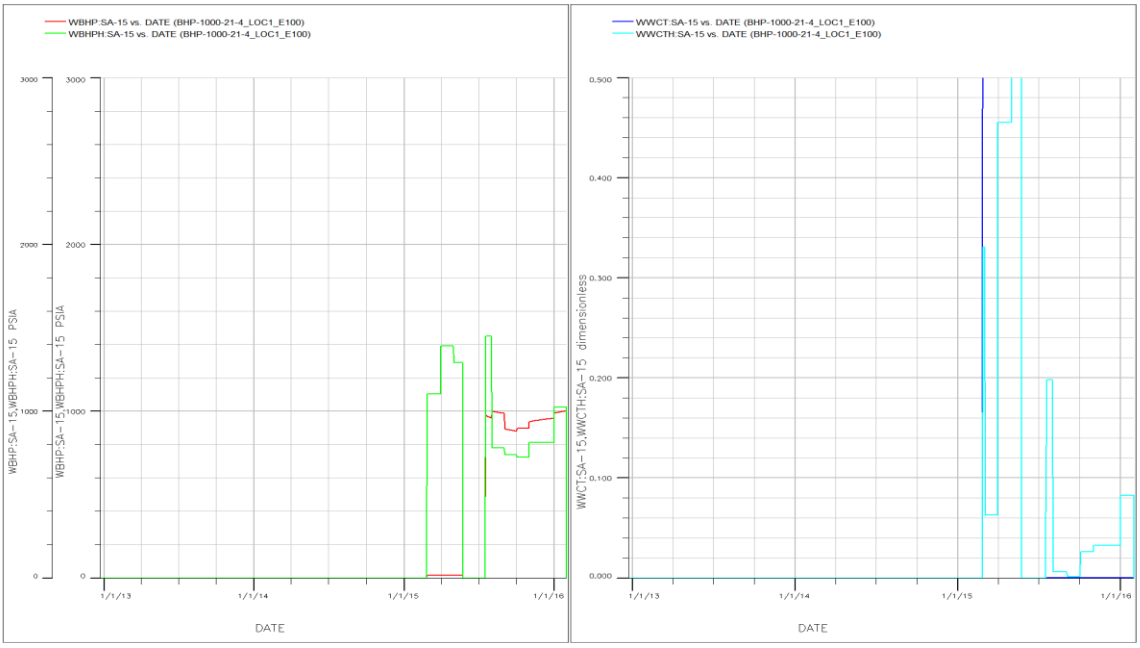

Figure 4-8: History Matching-SA-15

4.4 Injection Criteria:

Selection of the optimum injection date depended on the period in which field production starting to decline and the highest recovery factor results. (Mid 2015 or mid-2016). The injection rate scenario was chosen by the summation of production from targeted wells.

Well	Oil production STB/day	Distance from injection well m
SA-05	341	250
SA-09	197	225
SA-11	180	200
SA-15	32	280
Total	750	

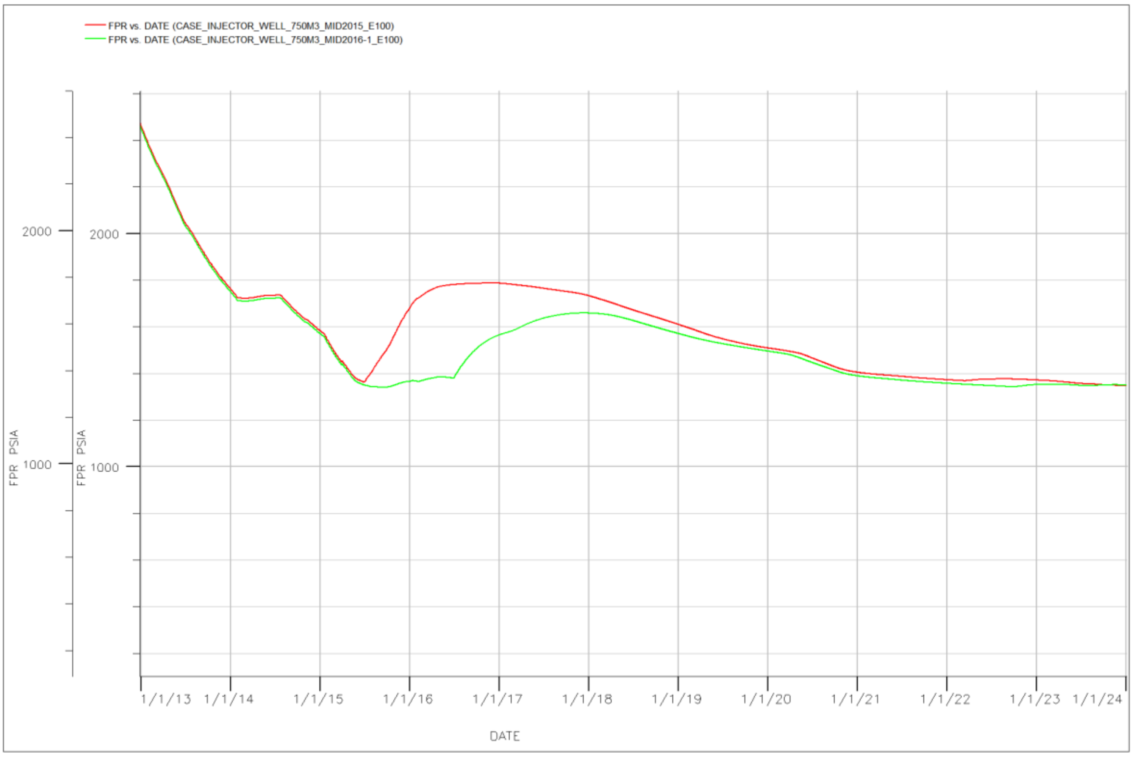

Figure 4-9: Reservoir Pressure at Injection Rate 750 M3/Day

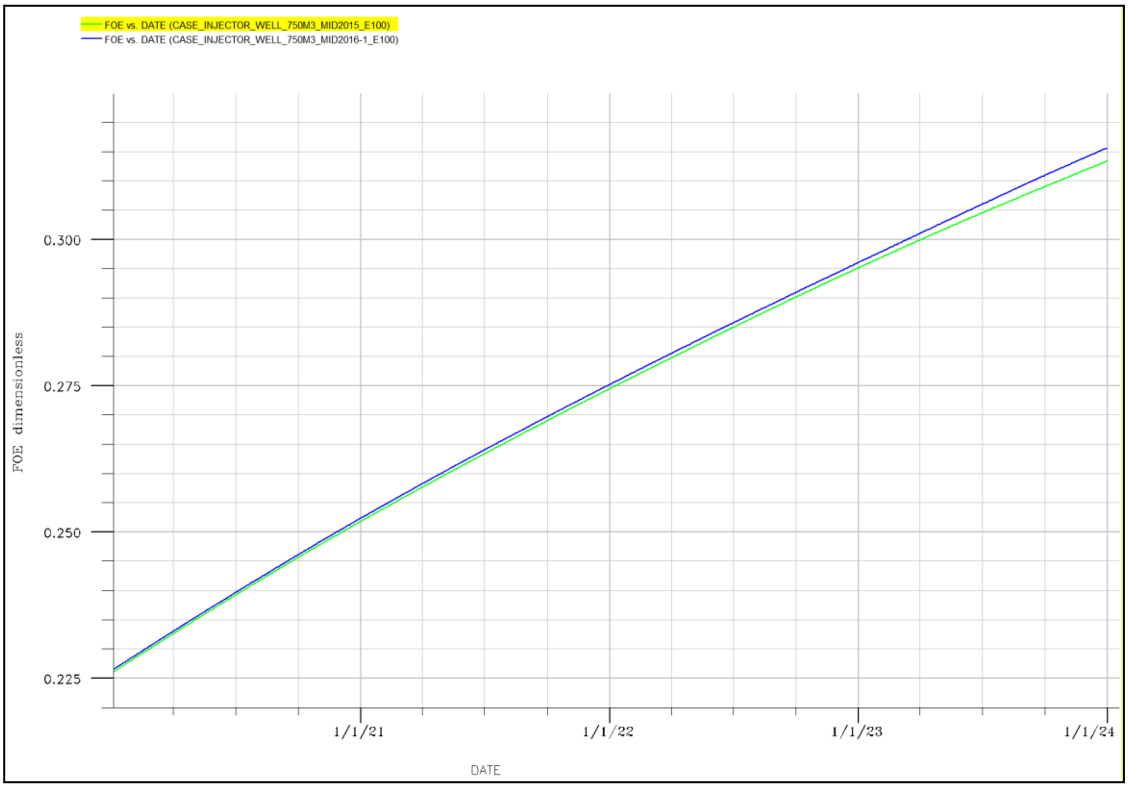

Figure 4-10: Recovery Factor at Injection Rate 750 M3/Day

4.5 Production Rate Trend:

The plot 4-11 shows that vertical water flooding maintains a higher oil production rate for a longer period until the water breaks through. After that, the oil production rate drops more for all cases. This may be attributed to rapid water production in all cases.

The production rate for the base case is very low compared to the cases with water flooding. This coincides with the water flooding which improves the oil production rate (Morrow and Buckley, 2011).

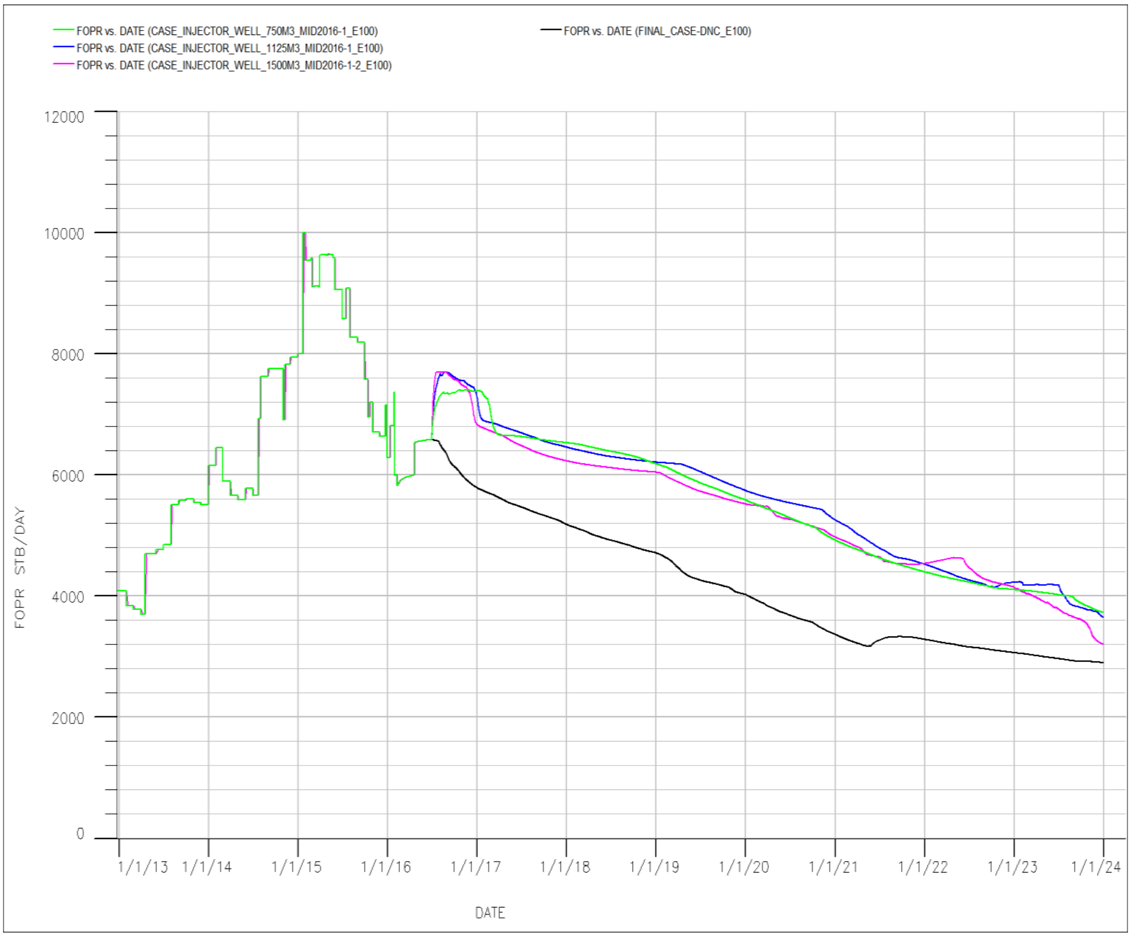

Figure 4-11: Plot of Oil Production Rate against Time

4.6 Reservoir Pressure Trend:

The figure 4-12 shows the reservoir pressure against time for vertical water injection, the highest pressure for all cases was before the year 2018 and then began to drop gradually until it reached the values that can be said, is stable.

In the starting of water injection the values of pressure are following:

1360 psia for the DNC Do Nothing Case

1660 psia for injection rate 750 m3/day

1960 psia for injection rate 1125 m3/day

2260 psia for injection rate 1500 m3/day

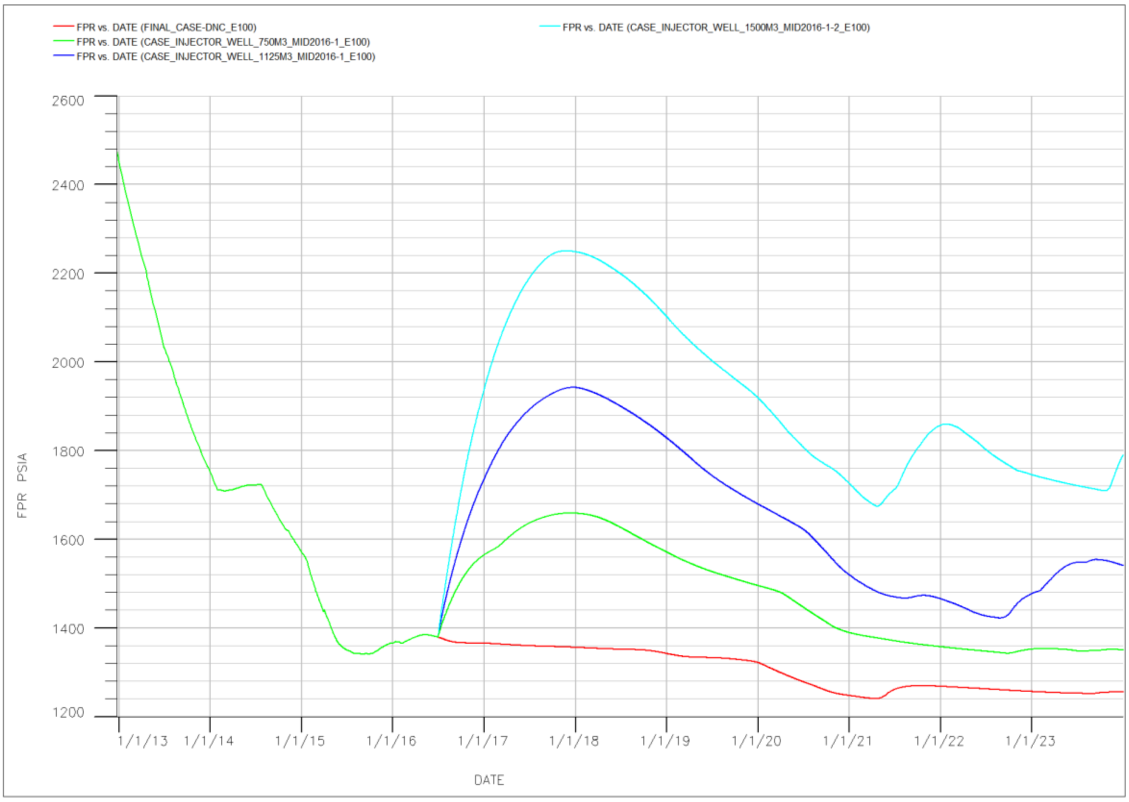

Figure 4-12: Plot of Reservoir Pressure against Time

4.7 Water Cut Trend:

The water cut trend is shown in figure 4-13. At the starting of water injection, the water cut was about 26 % in the year mid-2016 and it was gradually increasing up to the year 2024, the time which we decided to stop the water injection.

Below are the values of water cut at that time (year 2024):

70% for the DNC Do Nothing Case

73% for injection rate 750 m3/day

76 % for injection rate 1125 m3/day

78% for injection rate 1500 m3/day

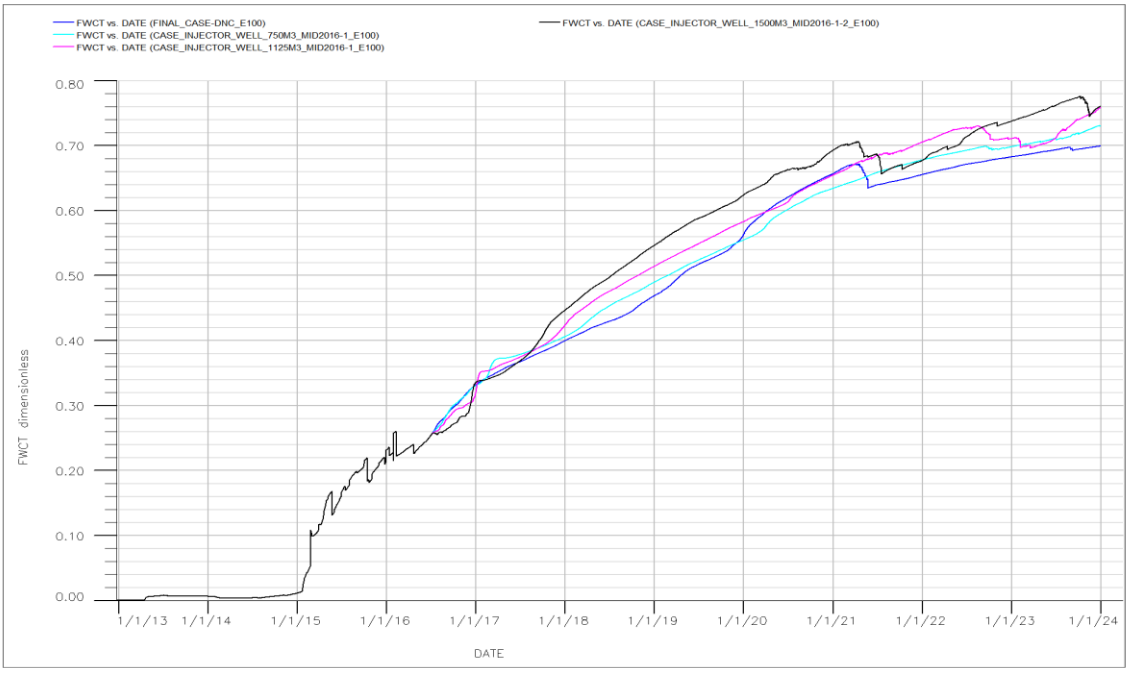

Figure 4-13: Plot of Water Cut against Time

4.8 Accumulated Oil Production:

The figure 4-14 shows the accumulated oil production trend. The plot shows that the accumulated oil production is increasing gradually with all injection rats and the maximum oil production is in the injection rat 1125,750 and 1500 STB/day respectively.

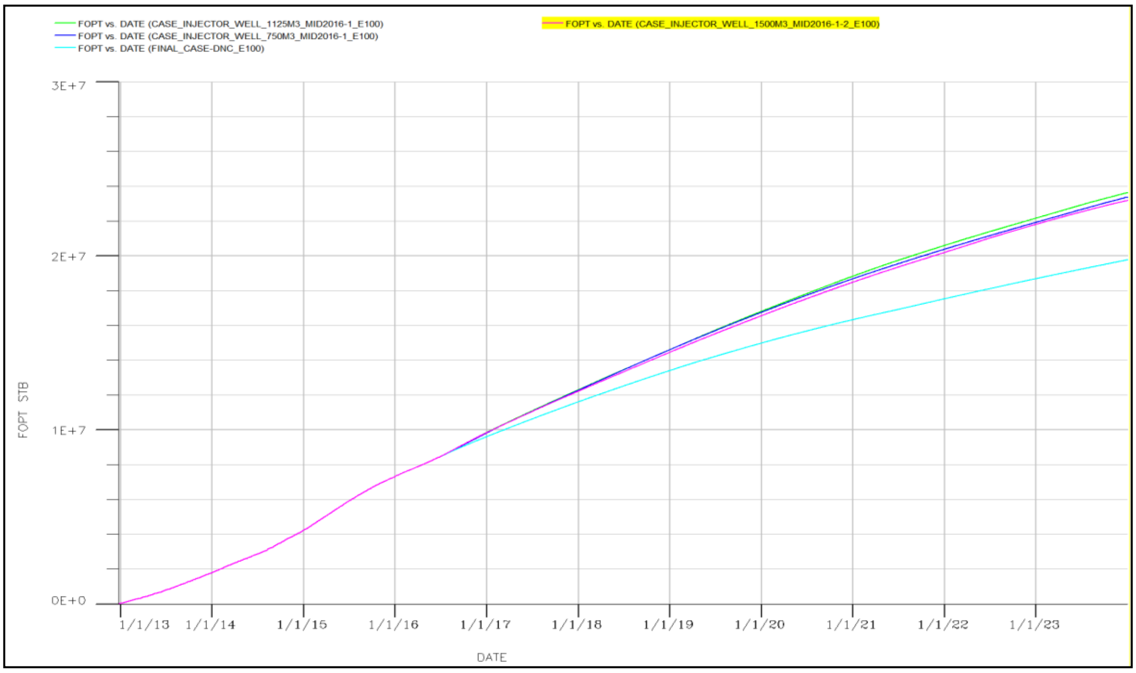

Figure 4-14: Accumulated Oil Production against Time

4.9 Recovery Factor:

The plot of the recovery factor against time shown in figure 4-15, there is a considerable increase in recovery factor at the year 1.1.2024 (0.265) and increases with injection rates1500, 750, and 1125 m3/day to 0.3125, 0.315, and 0.320 respectively. From This plot, we conclude that the injection rate of 1125m3/day is the optimum one.

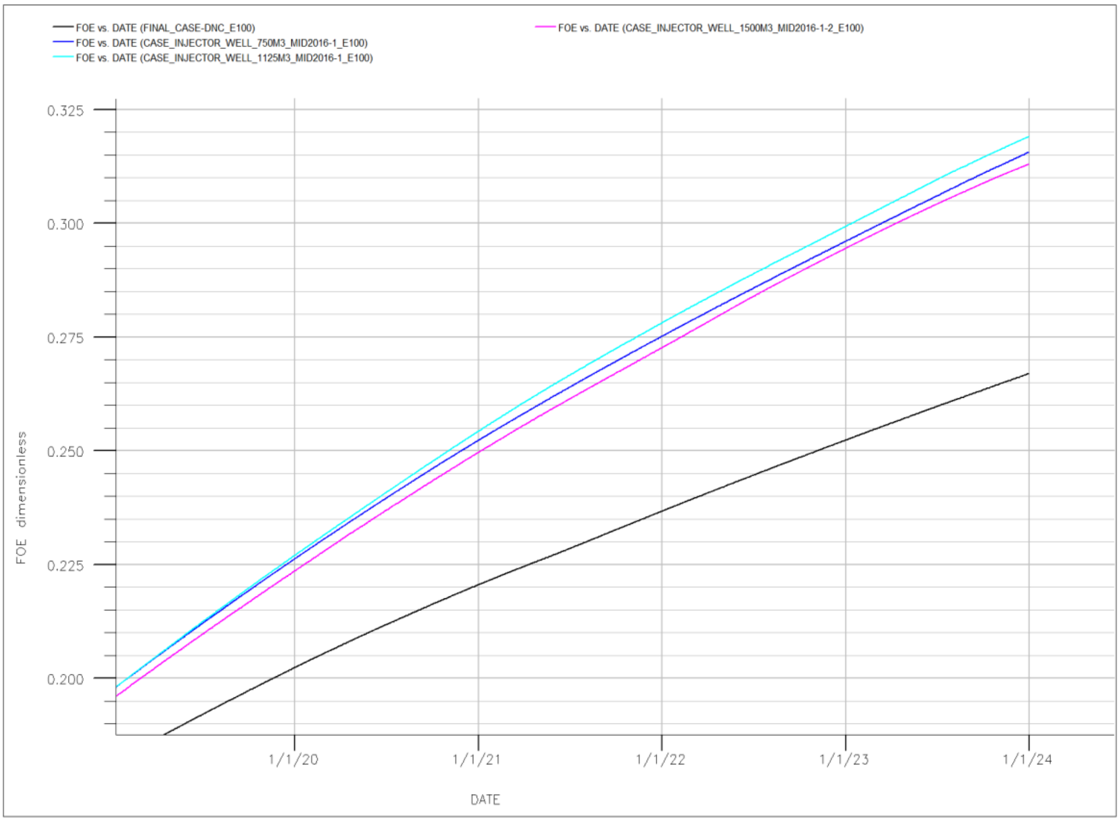

Figure 4-15 : Plot Of Recovery Factor Against Time.

4.10 Oil-Water saturation and Front Progression:

The case of water injection is used to illustrate how water displaces oil and sweeps oil towards the production wells. The above figure 4-16 shows the oil saturation distribution at the beginning of water injection

The oil-water front progression after 7.5 years is shown figure 4-17. From the plot, it can be seen that the oil saturation reduced due to more sweep by water injection.

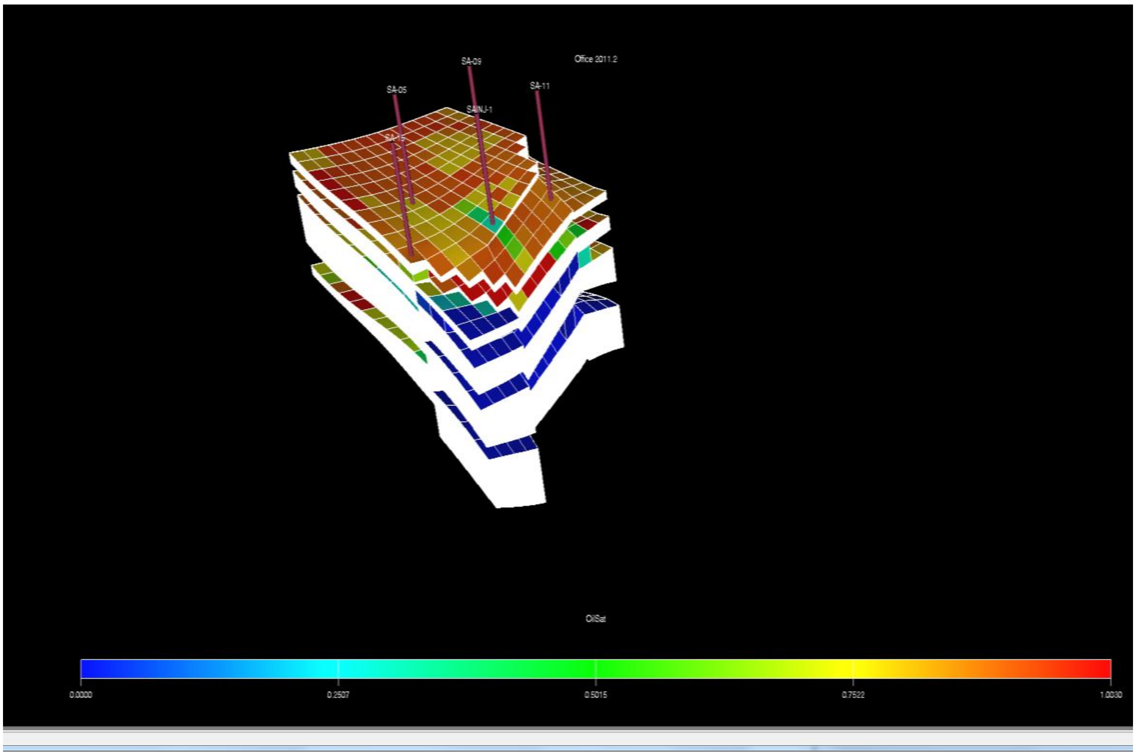

Figure 4-16: Oil-Water Saturation at the Beginning of Injection

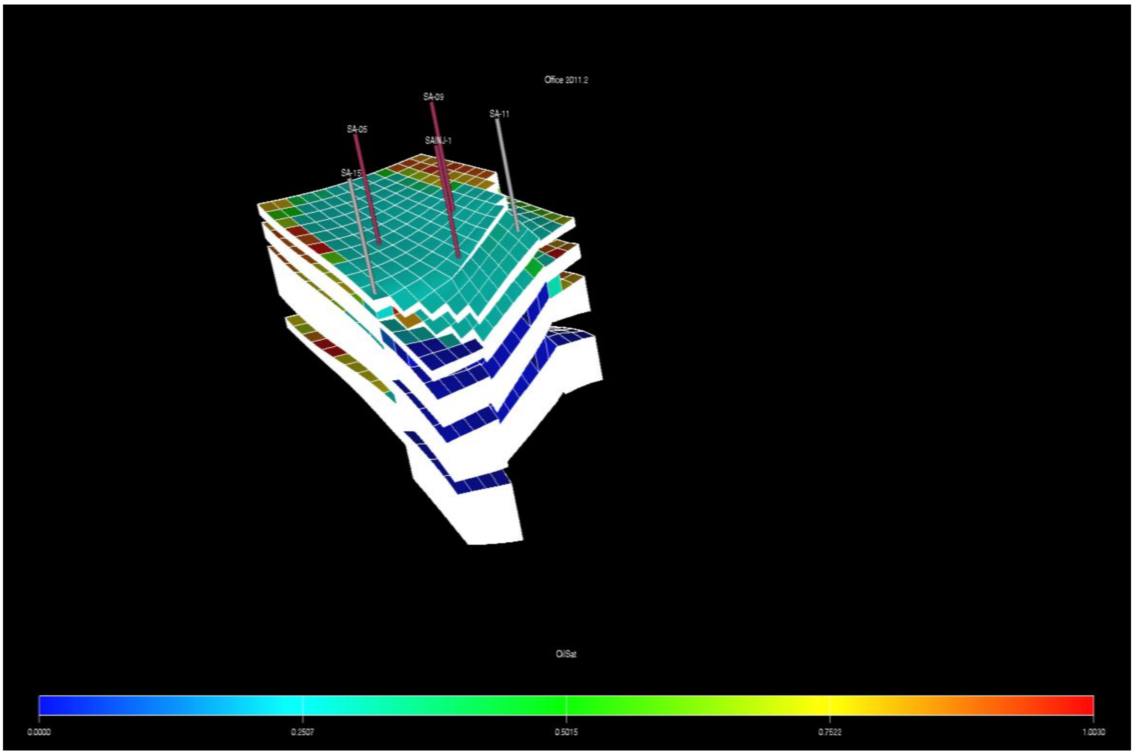

Figure 4-17: Oil-Water Front Progression after 7.5 Years

4.11 Produced oil from the south Annajma wells at the optimum injection rate (1125m3/day)

Figure 4-18 shows the produced oil from the well SA-01before injection and at the optimum injection rate (1125m3/day)

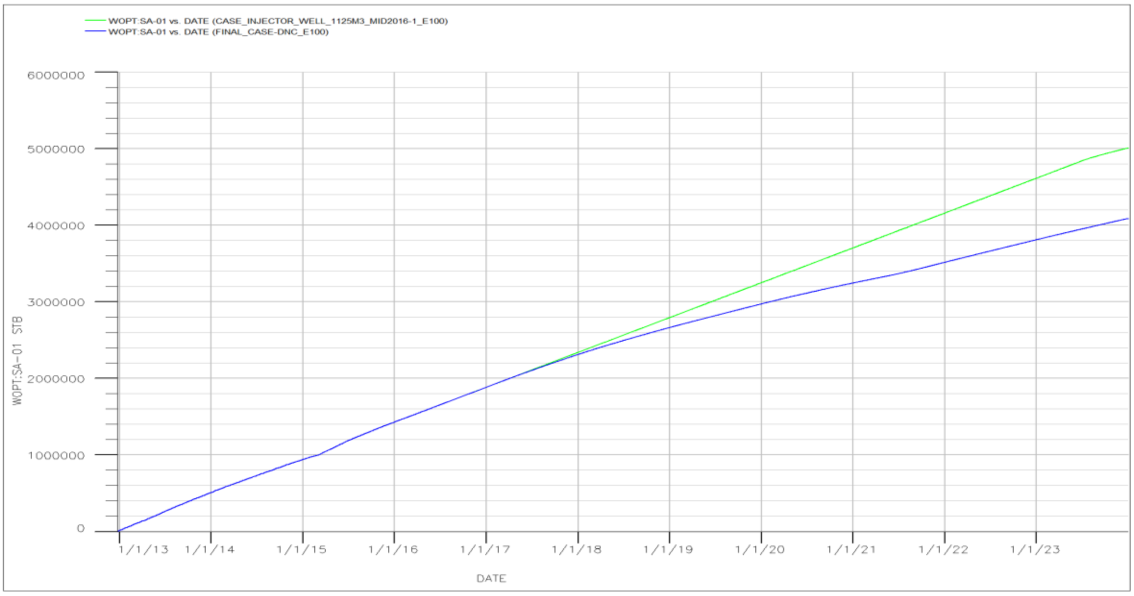

Figure 4-18: Produced Oil from the Well SA-01before Injection and At Injection Rate 1125 M³/Day

Figure 4-19 shows the produced oil from the well SA-05 before injection and at the optimum injection rate (1125m3/day)

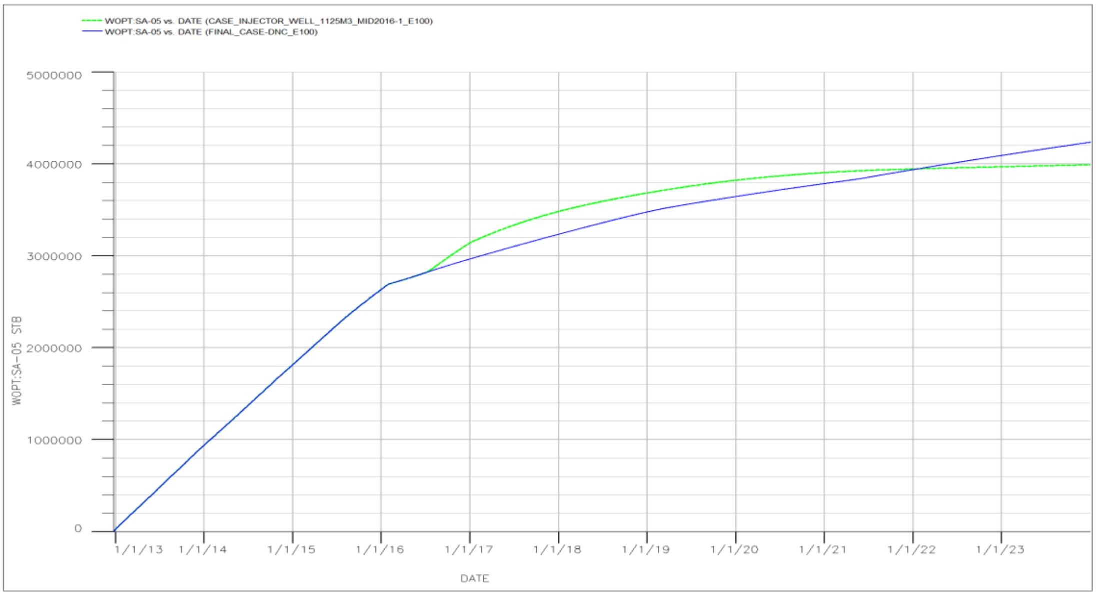

Figure 4-19: Produced Oil from the Well SA-05 before Injection and At Injection Rate 1125 M³/Day

Figure 4-20 shows the produced oil from the well SA-09 before injection and at the optimum injection rate (1125 m3/day)

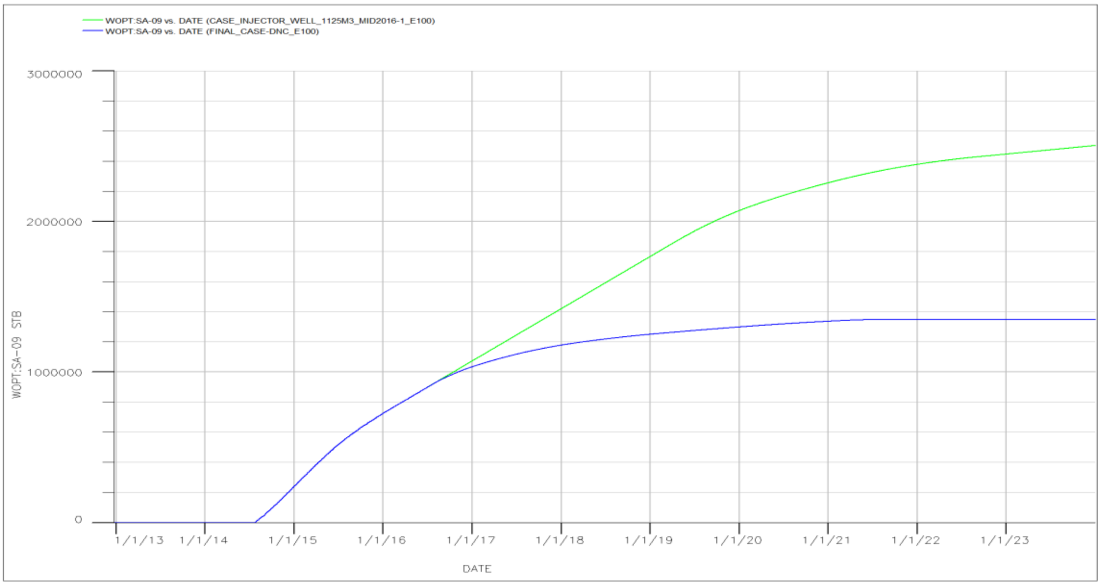

Figure 4-20: Produced Oil from the Well SA-09 before Injection and At Injection Rate 1125 M^3/Day

Figure 4-21 shows the produced oil from the well SA-11before injection and at the optimum injection rate (1125 m3/day)

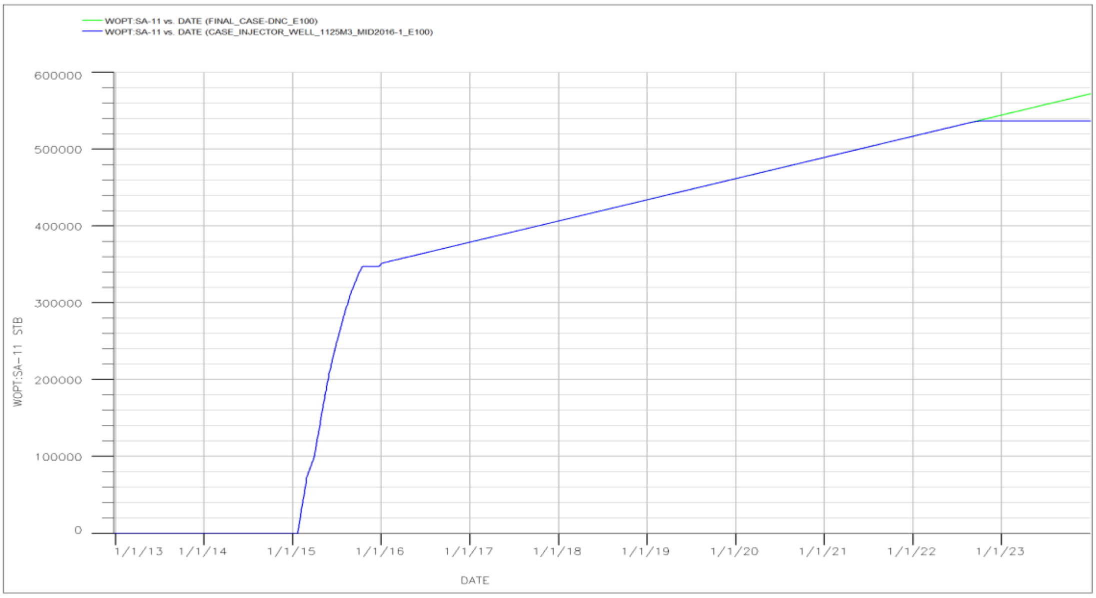

Figure 4- 21: Produced Oil from the Well SA-11 before Injection and At Injection Rate 1125 M^3/Day

Figure 4-22 shows the produced oil from the well SA-12 before injection and at the optimum injection rate (1125 m3/day)

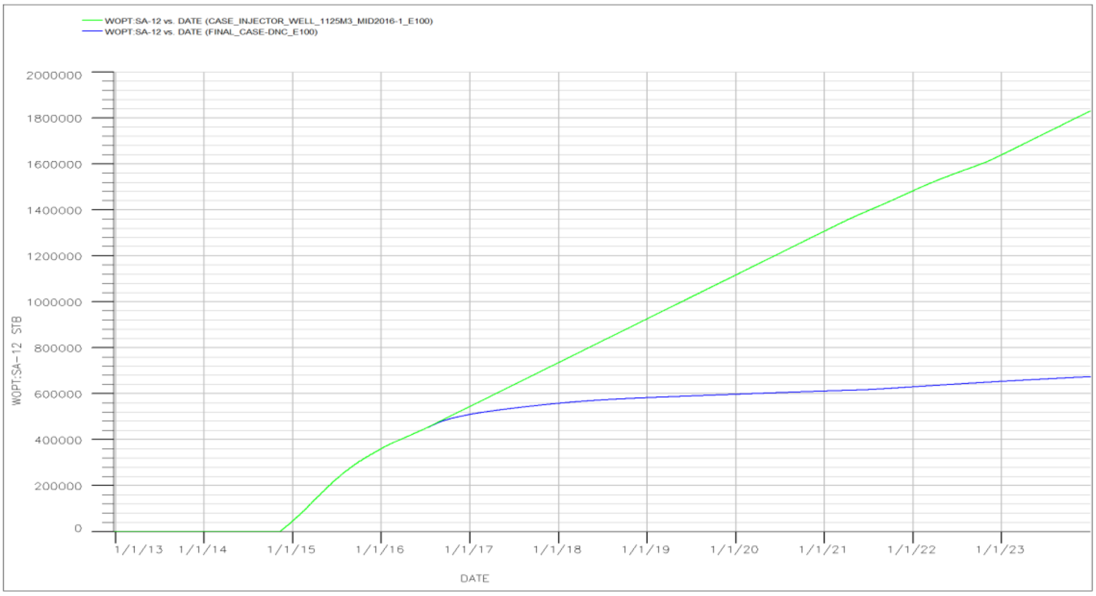

Figure 4-22: Produced Oil from the Well SA-12 before Injection and At Injection Rate 1125 M^3/Day

Figure 4-23 shows the produced oil from the well SA-15 before injection and at the optimum injection rate (1125m3/day)

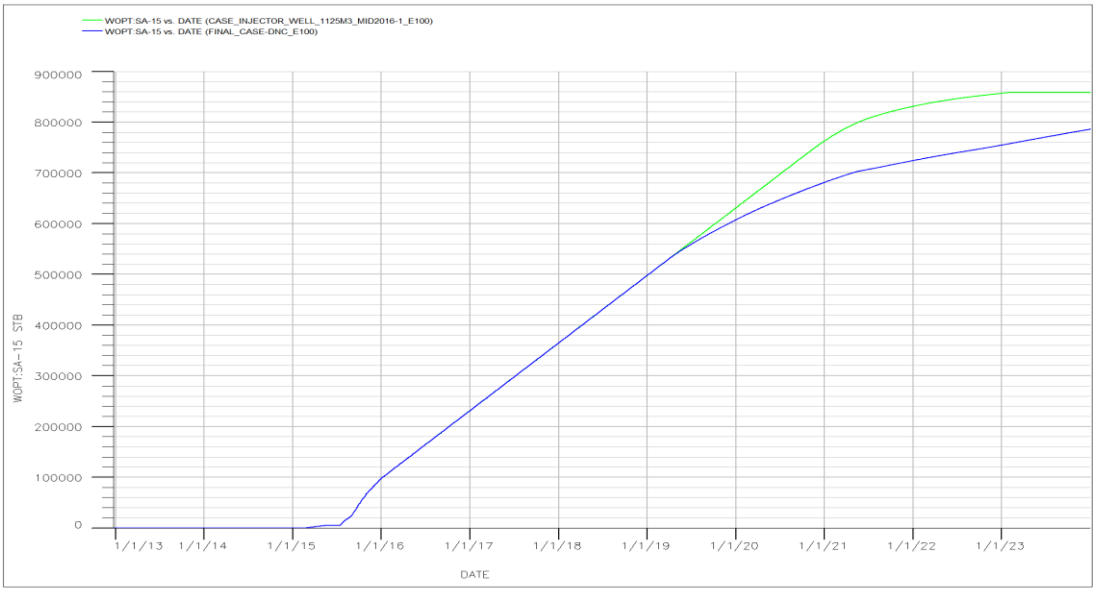

Figure 4-23: Produced Oil from the Well SA-15 before Injection and At Injection Rate 1125 M^3/Day

CHAPTER 5

CONCLUSIONS AND RECOMMENDATION

CHAPTER 5

Conclusions and Recommendation

5.1 Conclusions:

- In all cases, the result shows that oil production with water injection is a feasible recovery method compared to the base case.
- With these results, it would be preferred to apply water flooding to maximize the oil recovery in depleted reservoirs rather than using the primary method. The results also show that water flooding maintains a higher oil production rate for a longer period until water breakthrough. It is also observed that water breakthrough is increased gently in all studied cases.
- There are unseal faults between some compartments as a result of the considerable impact of wells SA-1, SA-12 (locates in different compartments from the area under study), at the optimum injection rate (1125 m3/day).
- The oil production drop in the case (1500 m3/day) is the highest of all cases. Is mainly due early water breakthrough at all wells comparing to other scenarios. Water breakthroughs will lead to less oil recovery due to rapid water production.

5.2 Recommendations:

- Based on the research results and the assessment of the geological criteria, water flooding for the South Annajma oil field is the best option and highly recommended.
- Because of high complicated geological structures in this field and to avoid the effect of uncertainty, more studies of the geological model are needed.
- With the implementation of an inflow control device to reduce water production, oil recovery would be optimal and more effective.

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