Sudan University of Science and Technology

College of Petroleum Engineering & Technology

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Feasibility Study of Improved Oil Recovery through Water flooding In Sudanese Oil Field (Case Study)

دراسة إمكانية زيادة الانتاج عن طريق الغمر المائي لحقل سوداني

This dissertation is submitted as a partial requirement of B.Sc. degree (honor) in petroleum engineering

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الاستهلال

قال تعالى :

﴿ وَجَعَلْنَا مِنَ الْمَاءِ كُلَّ شَيْءٍ حَيٍّ أَفَلَا يُؤْمِنُونَ ﴾

صدق الله العظيم

Dedication

To our fathers and mothers, the source of encouragement and inspiration to us

throughout our life

To our supervisor **Eng. Satti Merghany Geily** for his guidance and support throughout this study

To **Eng. Husham Awadelsseid Ali** and **Eng. Mohanned Mahgoob Khairy** for their support and encouragement

To the spirit of **Dr. Mohammed Naeim**

To our brothers and sisters who stand with us, allow us to use their purpose when we

need it to complete this research.

For future generations that hold future of the oil industry in Sudan

To our dear friends who supported us

To anyone who taught us how to fight life

Finally, this thesis is dedicated to all those who believe in the richness of learning

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Thank to Allah before and after everything,

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Thanks to all our friends for encouragement in many moments

Abstract

Water flood is a mean of maintaining the reservoir pressure. It improves the sweep efficiency for oil and accordingly increases the recovery factor.

Aradaiba formation in Fula North suffering from reservoir pressure which indicates that the water flooding as pressure maintenance is more suitable recovery mechanism to improve the recovery factor from this field.

In this thesis selection of the suitable pilot area, converting of Eclipse model to CMG and then designing of waterflooding using the CMG and several scenarios has been done to select the optimum method to increase the oil recovery of Fula north field.

The results show that Water injection as 5- spot pattern (inverted) with injection rate of 1500 bbl in Fula North field sector model can increase the cumulative oil production from this area up to 6 million barrels.

المستخلص

تعتبر عملية الغمر المائي وسيلة للحفاظ على ضغط المكمن حيث تعمل على تحسين كفاءة الاكتساح للنفط وبالتالي زيادة معامل الاستخلاص (Recovery Factor). لذلك تعتبر هذه العملية الأكثر ملاءمة لزيادة معامل الاستخلاص في (Aradeiba Formation) في حقل (Fula North) نظراً لأنها تعاني من مشكلة الضغط.

في هذا البحث بعد اختيار المنطقة المناسبة تم تحويلها من(Eclipse model) إلى (CMG) ومن ثم تصميم عملية الغمر المائي باستخدام (CMG) وذلك بعدة محاولات (scenarios) من أجل اختيار أمثل طريقة لزيادة إنتاجية النفط في حقل (Fula North).

وتظهر النتائج أن حقن الماء بشبكة خماسية (عكسية) ((5- spot pattern(inverted) بمعدل حقن 1500 bbl يمكن أن يزيد من إنتاج النفط التراكمي (cumulative production) لهذه المنطقة إلى 7.3 مليون برميل.

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Nomenclature

API= Oil Density in American Petroleum Institute

ASP= Alkaline Surfactant Polymer

BBl= Barrel Oil

Bg= Gas Formation Volume Factor (bbl/scf)

Bo= Oil Formation Volume Factor (bbl/stb)

BWPD= Injection Rate

CMG= Computer Modeling Group

Ea= Areal Sweep Efficiency

Eclipse= Reservoir Simulator

Ed= Displacement Efficiency

EOR= Enhanced Oil Recovery

Eur= Estimated Ultimate Recovery (MMSTB) (%)

Ev= Vertical Efficiency

Ginj= Gas Injection

H= Net Thickness (Ft)

IMEX= Black Oil Model in CMG Software

Inj= Water Injection Pressure

Iw= Water Injection (Bbl/Day)

K= Absolute Pressure (md)

Kro= Relative Permeability of Oil (md)

Krw= Relative Permeability of Water (md)

LPG= Liquid Petroleum Gas

N= Initial Oil in Place (MMSTB)

Np= Cumulative Oil Produced (MMSTB)

OOIP= Original Oil in Place (MMSTB)

Pb= Bubble Point Pressure (psi)

RF= Recovery Factor

Sg= Gas Saturation (%)

So= Oil Saturation (%)

Sor= Residual Oil Saturation (%)

STB= Stock Tank Barrel

STOOIP= Stock Tank Original Oil In Place (MMSTB)

Swc= Connate Water Saturation (%)

V= Dykstra-Parsons Coefficient (bbl)

Vp = Pore Volume (bbl)

WAG= Water Alternating Gas (Psi)

Winj= Water Injection

WOR=Water Oil Ratio (bbl/stb)

Mo= Oil Viscosity (cp)

Chapter One

Introduction

1.1 Introduction:

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained.

1.1.1 Primary oil recovery

Describes the production of hydrocarbons under the natural driving mechanisms presents 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. 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.

1.1.2 Secondary oil recovery

Secondary oil recovery refers to the additional recovery that results from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also 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 the raise risk that the substantial capital investment required for a secondary recovery project may be wasted.

1.1.3 Tertiary (Enhanced) Oil Recovery

That additional recovery over and above what could be recovered by primary and 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 the irrespective economic limits. (Ahmed T 1946).

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

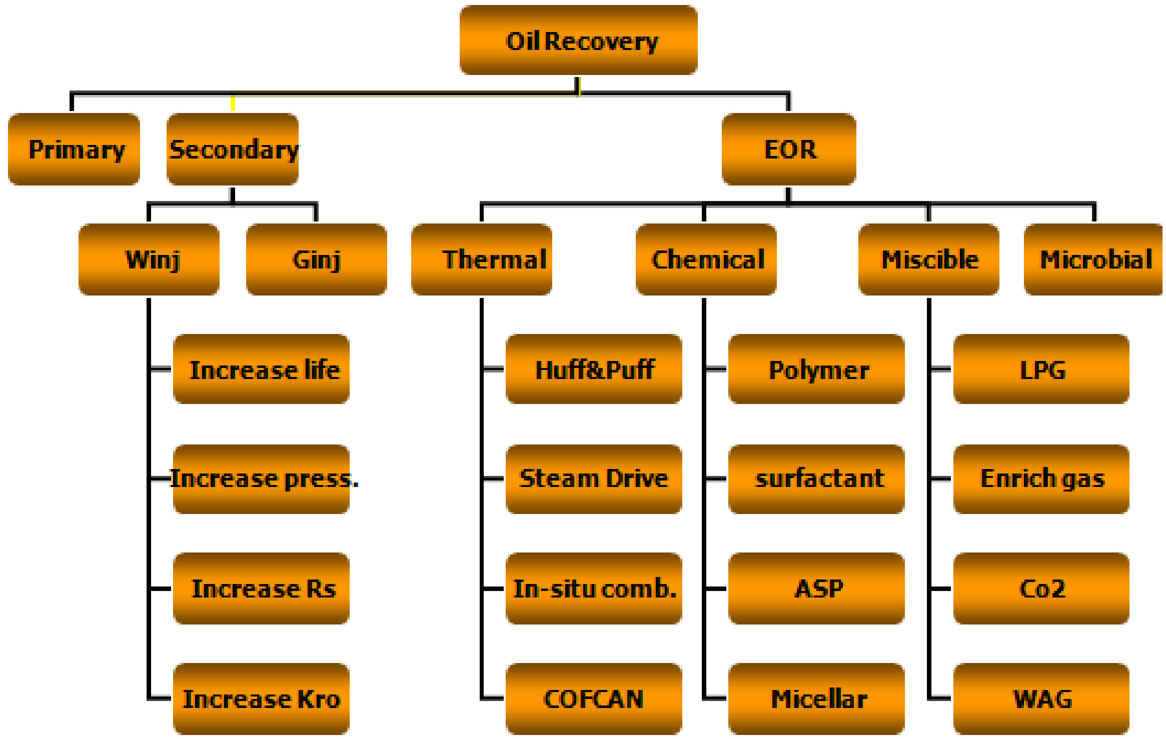

Figure (1.1): Describe Oil Recovery Mechanism

1.2 Waterflooding:

1.2.1 Introduction

Waterflooding 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).

Waterflooding 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, waterflooding 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 waterflooding began.

Waterflooding is responsible for a significant fraction of the oil currently produced in the United States. Many complex and sophisticated enhanced recovery processes have been developed through the years in an effort to recover the enormous oil reserves left behind by inefficient primary recovery mechanisms. Many of these processes have the potential to recover more oil than waterflooding in a particular reservoir. However, no process has been discovered which enjoys the widespread applicability of waterflooding.

The primary reasons why waterflooding 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

By discuss the reservoir engineering aspects of waterflooding. It is intended that the reader will gain a better understanding of the processes by which water displaces oil from a reservoir and in particular, will gain the ability to calculate the expected recovery performance of a waterflood project. While this discussion will be limited to the displacement of oil by water, the displacement processes and computational techniques presented have application to other oil recovery processes. (James, 1990).

1.2.2 Factors to Consider in waterflooding

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

- Reservoir geometry
- Fluid properties
- Reservoir depth
- Lithology and rock properties
- Fluid saturations
- Reservoir uniformity and pay continuity
- Primary reservoir driving mechanisms

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 and, if offshore, will influence the location and number of platforms required. The reservoir's geometry will essentially dictate the methods by which a reservoir can be produced 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 waterflooding.

The viscosity of the crude oil is considered the most important fluid property that affects the degree of success of a waterflooding project.

The oil viscosity has the important effect of determining the mobility ratio that, in turn, controls the sweep efficiency.

Reservoir Depth

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

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 deflocculating 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:

$$P \propto iw/hk \quad \ldots\ldots\ldots\ldots \text{(1.1)}$$

Where

pinj = water-injection pressure

iw = 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 waterflooding, 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).

1.2.3 Factors Controlling Waterflood Recovery

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

1) Oil-in-Place at the Start of Waterflooding ~ 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 waterflood performance or the interpretation of historical waterflood behavior can only be made if a reliable estimate of oil-in-place at the start of waterflooding is available.
2) Areal Sweep Efficiency ~ This is the fraction of 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.

Waterflood recovery can be computed at any time in the life of a waterflood project from the following general equation:

$$Np = N * Ea * Ev * Ed \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots (1.2)$$

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

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

- Oil saturation at the start of waterflooding. **So**
- Residual oil saturation to waterflooding, **Sor (Sorw)**
- Connate water saturation, **Swc**
- Free gas saturation at the start of water injection, **Sg**
- Water floodable pore volume**, Vp**, bbls (This takes into account the permeability or porosity net pay discriminator)
- Oil and water viscosity, **μo** and **μw**
- Effective permeability to oil measured at the immobile connate water saturation, **(ko) swir**
- Relative permeability to water and oil, **krw** and **kro**
- Reservoir stratification, (Dykstra-Parsons coefficient, **V**)
- Waterflood pattern (symmetrical or irregular)
- Pressure distribution between injector and producer
- Injection rate, BWPD
- Oil formation volume factor, **Bo**
- Economics

(James, 1990)

1.2.4 Waterflooding 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 waterflood. 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).

1.2.5 Optimum Time to Waterflood

The most common procedure for determining the optimum time to start waterflooding 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 for several assumed times and the net income for each case determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected.

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

- Reservoir oil viscosity. Water injection should be initiated when the reservoir pressure reaches its bubble-point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turns improves the sweeping efficiency.
- 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 initiation of injection is desirable.
- Productivity of producing wells. A 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 in order to develop the most favorable overall economics.

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

1.2.6 Selection of Flooding Patterns

One of the first steps in designing a waterflooding project is flood pattern selection. The objective is to select the proper pattern that will provide the injection fluid with the maximum possible contact with the crude oil system. This selection can be achieved by (1) converting existing production wells into injectors or (2) drilling 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).

1.2.7 Waterflood Design

The design of a waterflood 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 waterflood. If so, then more-detailed technical calculations are made. These include the full range of engineering and geoscience 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 preflood 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 wellbores. 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 waterflood progresses, there almost certainly will be modifications to the original designs and operating plans.

A number of waterflood 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 waterflooding
- Production wells
- Surface facilities for injection water
- Surface facilities for produced fluids

(Rose S.C 1989)

1.2.8 Waterflood Management

Effective waterflood management requires a multidisciplinary team approach that includes reservoir, drilling, and production engineers, as well as chemists, accounting, legal, and others. Guidelines for waterflood 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 requirement 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 waterflood 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.

Waterfloods require a 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.

1.3 Field Background:

Fula North Field is located in the southern part of Fula sub-basin of Block 6 of Sudan.

It contributes the highest production potential in block 6. Several FDPs for Fula oilfield, There are three producing formation of Fula North field which are **Bentiu** and **Aradeiba** formation (Heavy oil) and **Abu Gabra** formation (Light oil). The details of OOIP (2P) in Fula North block for each formation in the following table:

Table (1.1): show the OOIP in (Aradeiba, Bentiu, Abu Gabra)

Formation	Aradeiba	Bentiu	Abu Gabra
OOIP (MMSTB)	302.95	69.69	55.3

Fula Field was put into production since November, 2003. The current production performance is showing in the below table.

As per production performance analysis of Fula North. Aradeiba formation is associated with weak edge water aquifer and need pressure support by water injection in order to maximize oil production and increase oil recovery. Therefore, a feasibility study of water injection by using produced water will be performed through technical support contract.

Table (1.2): production performance of (Aradeiba, Bentiu)

Status as of Mar.20l0	Fula North	Fula North
Pool	Aradeiba	Bentiu
STOOIP (MMSTB)	318.52	69.69
EUR (MMSTB)	86	19.2
NP (MMSTB)	43.8	2.36
REMAING EUR (MMSTB)	44	17
EUR TO-DATE (%)	49.8	12.3
RF (%)	27	27
RF TO-DATE (%)	13.74	3.38

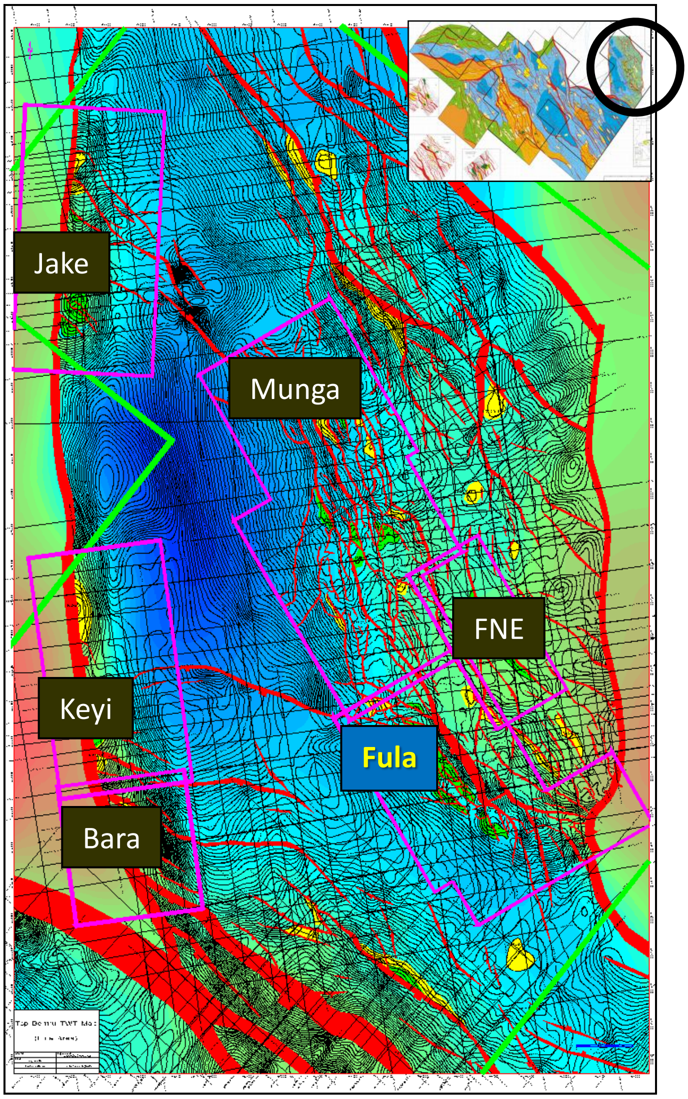

Figure (1.2): Fula oilfield overview

G.Fula oilfield is located in the Southern part of Fula sub-basin.

It covers an area of 625 km2. Fula North is the major structure with two main reservoirs: Aradeiba & Bentiu

Bentiu is strong-bottom water drive while Aradeiba is weak-edg water drive reservoir

As per Fula FFR, OOIP of Aradeiba-D is 76.85 MMSTB

1.4 Thesis Objectives:

In this research the possibility of using water injection as pressure maintenance for this field will be study and the designing and optimization for water injection rate and come up with optimum scenario and injection rate to;

- Maintain the pressure in the field
- Increase the oil recovery
- Increase the reservoir life
- Understand water flooding process and monitor its performance.
- Optimize the injection parameters (water injection rate, pressure and wells distribution.).

1.5 Problem Statement:

The waterflooding is the secondary recovery technique that cannot be successful unless a perfect design is done.

Aradeiba formation which suffering from reservoir pressure indicates that the water flooding as pressure maintenance is more suitable recovery mechanism to improve the recovery factor.

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 Aradeiba should be stated clearly.

1.6 Methodology:

Use a commercial simulator “CMG” to study the water flooding on an existing model and attempt to evaluate the water flooding parameters.

1.7 Study Outlines:

In this project chapter one reviews general introduction of the recovery mechanism and take the waterflooding with definition, Factors to be considered in waterflooding and factors controlling, optimum time, pattern, design and management, also introduce the Field Background of Fula North, discuss the Objectives & the Problem Statements & view the methodology used in this project, chapter two presents the Theoretical Background and Literature Review of water flooding definition and some of case studies around the world, the methodology and the data collection have been reviewed in chapter three also the model has been converted from Eclipse to CMG and built, in addition the sector area has been selected, while chapter four Results and Discussion show basic formation of Fula and discuss the result of the four scenarios which has been suggested in this model, chapter five view Conclusion and Recommendations.

Chapter Two

Theoretical Background and Literature Review

2.1 Introduction:

Waterflooding has come a long way since it was first tried 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 project waterflooding has climbed to a dominant role among fluid injection methods. It has a number of 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 possesses in the injection well.
4) It spreads well throughout oil-bearing formation.
5) Water is generally efficient in displacing oil.

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

2.2 Literature Review:

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

M. Terrado, et al, in (2006) illustrates how 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 waterflood management. (Terrado, 2006).

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

The second stage of hydrocarbon production was shown by Babak Aminshahidy, et al, in (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).

D.B. Bennion, et al, in (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 work overs, stimulation jobs and recompletions, or in many cases, the uncontrolled fracturing of wells by high bottomhole pressures resulting in poor water injection conformance and reduced overall sweep efficiency and recovery. (Bennion, 1998).

2.3 Water Injection Cases study:

Gordon and Owen, in (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).

In (2008), D.Beliveau, showed that the water flooding of viscous oil reservoirs can be an effective recovery process with typical EUR 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 reservoir 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 noted that to maximize water flood recovery in a viscous oil reservoir, 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).

The successful implementation of a reservoir surveillance and optimization plan was presented by B. Choudhuri, et al, in (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).

L.G. Schoeling, et al, in (1996) presented procedures to improve waterflooding through integrated reservoir management using two technologies have demonstrated positive 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).

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).

2.4 Water Injection Case study in Sudan:

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

Tewari, R. D, in (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 asset and improve the reserves and overall development strategy. Therefore, he highlighted that success and failure of water injection project depends 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).

In (2010) Bahuguna, A. found that the general outcome of the remedial jobs based on this approach was a considerable reduction in water production in both Munga-XX and USS-XX wells as well as oil production gain, making this a successful job in Munga field. (Bahuguna, 2010).

This project therefore focuses on designing of Water injection pilot and possibility of increasing oil recovery in Fula North field by the use of CMG Software and study different case in order to select optimum scenario for this field.

Chapter Three

Research Methodology

3.1 Introduction:

The water injection has been implemented in Fula North field since 2003 and performance is good but they face the problem of high water cut from producer and water oil ratio (WOR) need to be optimized.

The field has static and dynamic model by Eclipse software, so the first challenge for this research is to convert the model to CMG Software and we used Eclipse 100 converter to convert the black oil model IMEX which the black oil simulator in CMG software package.

3.2 Data collection:

- Fula Oil Field structure map
- Reservoir rock properties Data
  - Porosity, %
  - Permeability, md
  - Water saturation, %
- Reservoir condition Data
  - Original Reservoir temperature, ˚F
  - Original Reservoir pressure, psia
  - Reservoir pressure before implementing waterflooding, psia
  - Current Reservoir pressure, psia
- Reservoir fluid characteristics Data
  - Oil gravity
  - Bubble point pressure, psia
- Production & injection Data
  - Injectors number
  - Producer number
  - Mobility ratio

3.3 CMG content:

Several elements which are:

1) I/O control
2) Reservoir
3) Component
4) Rock & Fluid prosperities
5) Initial condition
6) Numerical
7) Geomechanic
8) Well & Recurrnet

3.4 Steps of building the Water Injection Modeling CMG:

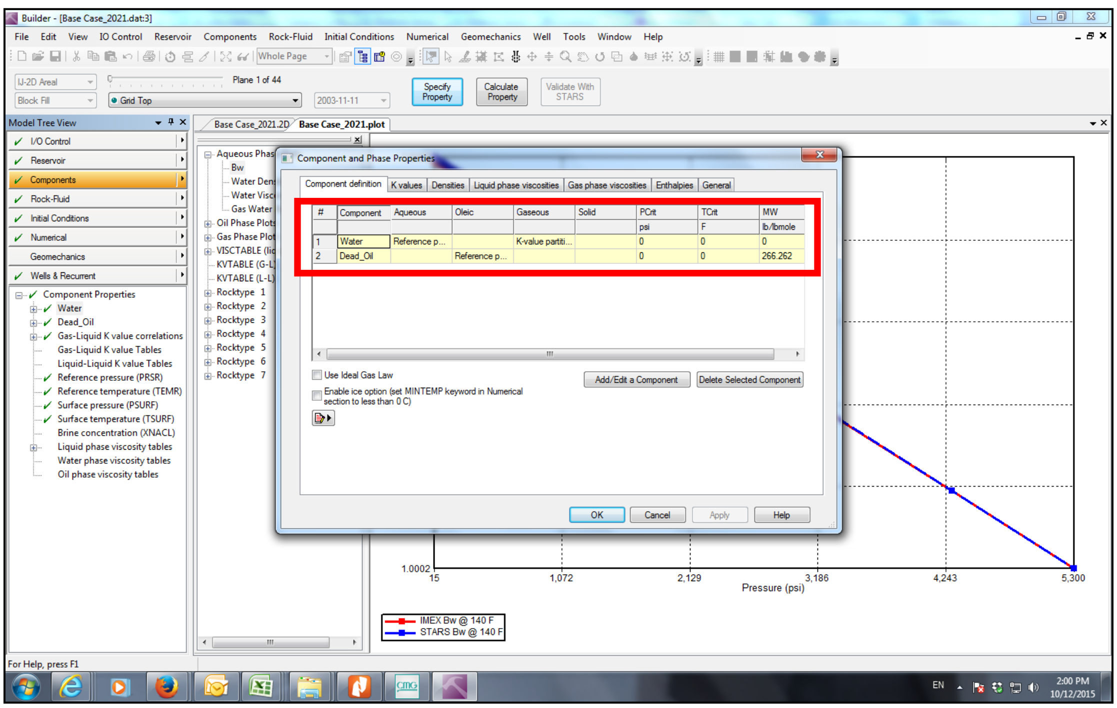

Figure (3.1): describe the insert of the component & phase properties - definition

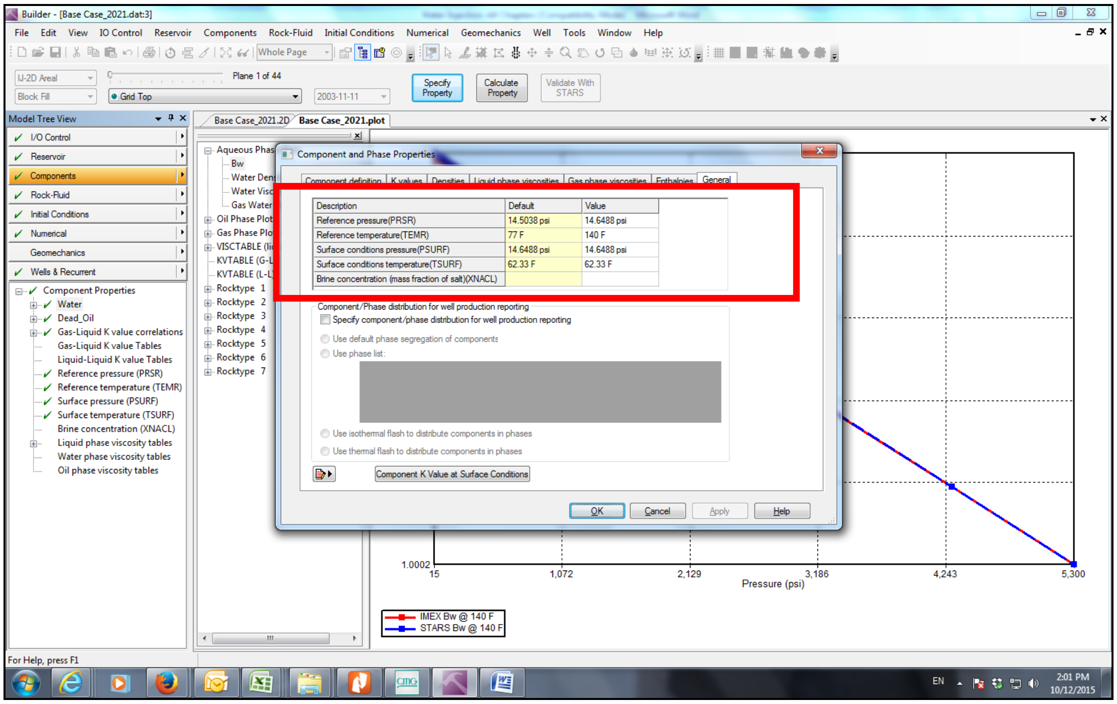

Figure (3.2): describe the insert of the component & phase properties - general

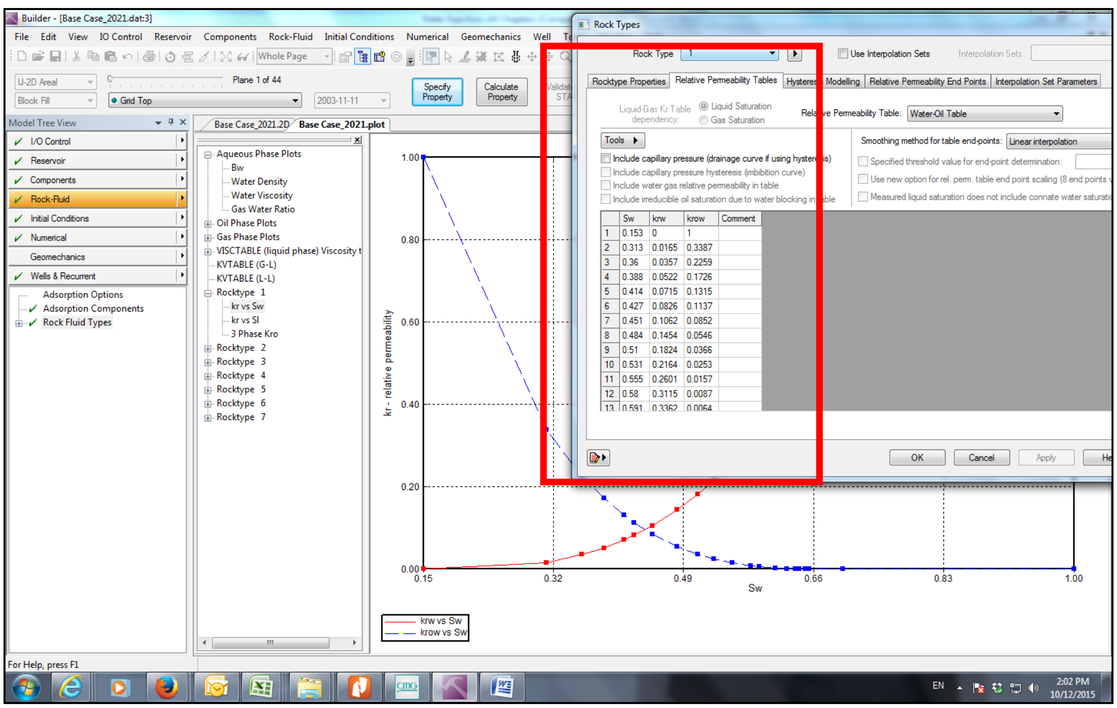

Figure (3.3): rock & fluid properties – showing the relative permeability table of rock type 2

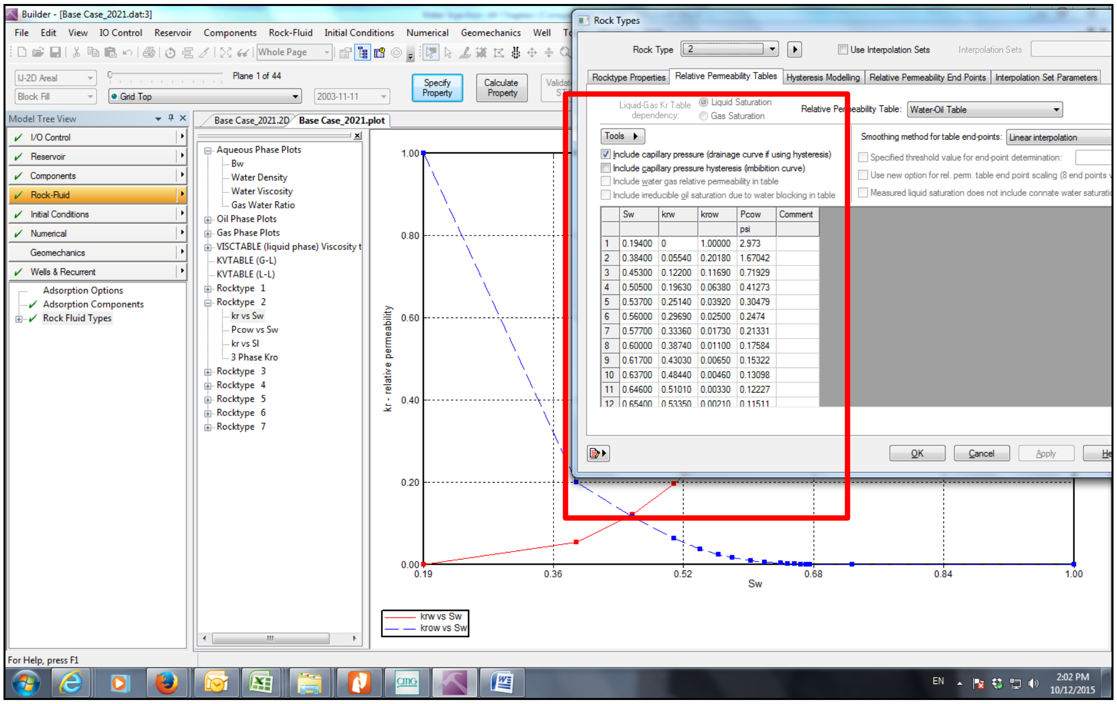

Figure (3.4): rock & fluid properties – showing the relative permeability table of rock type 1

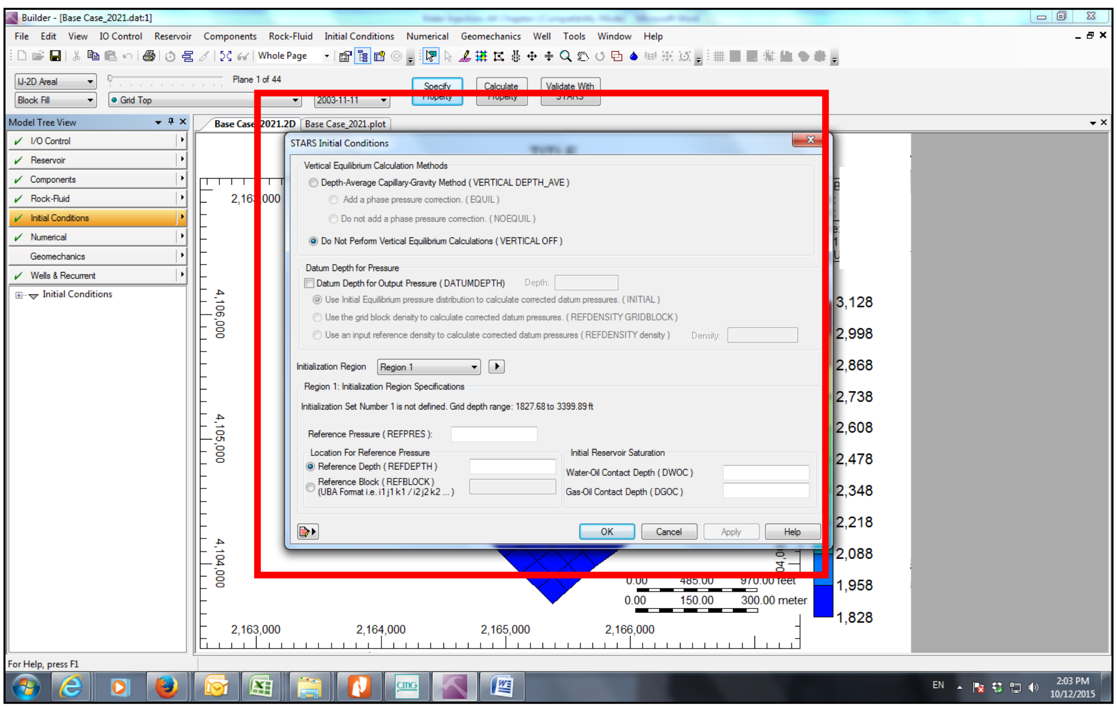

Figure (3.5): describing how to insert the initial condition

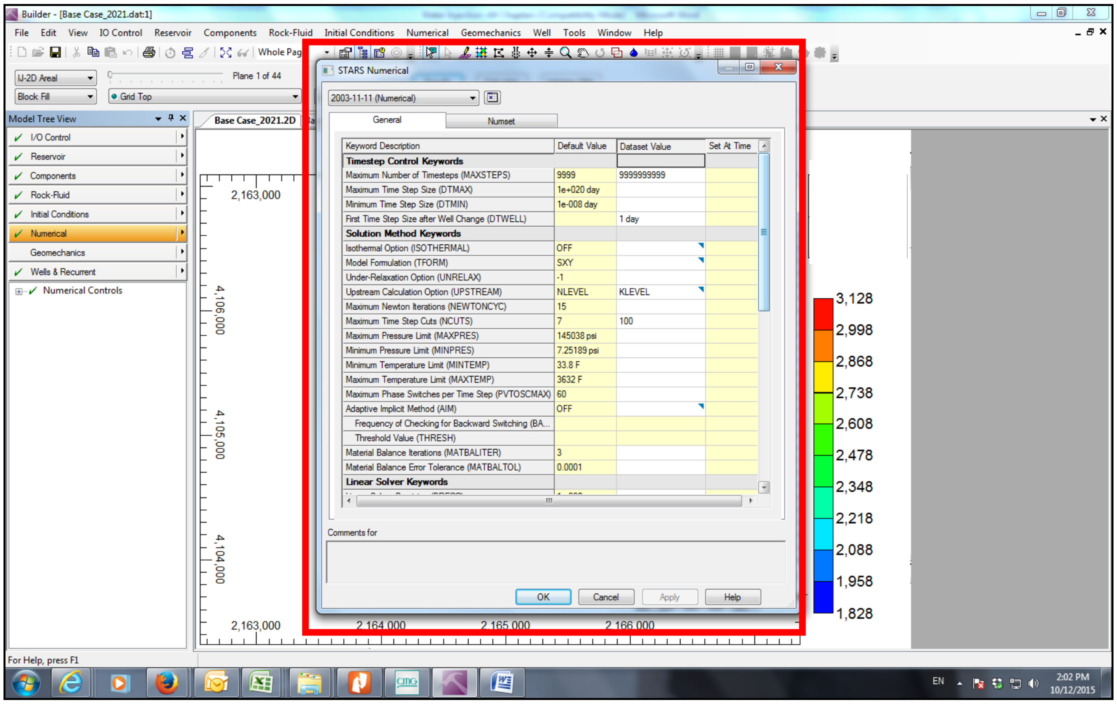

Figure (3.6): view the numerical – general option

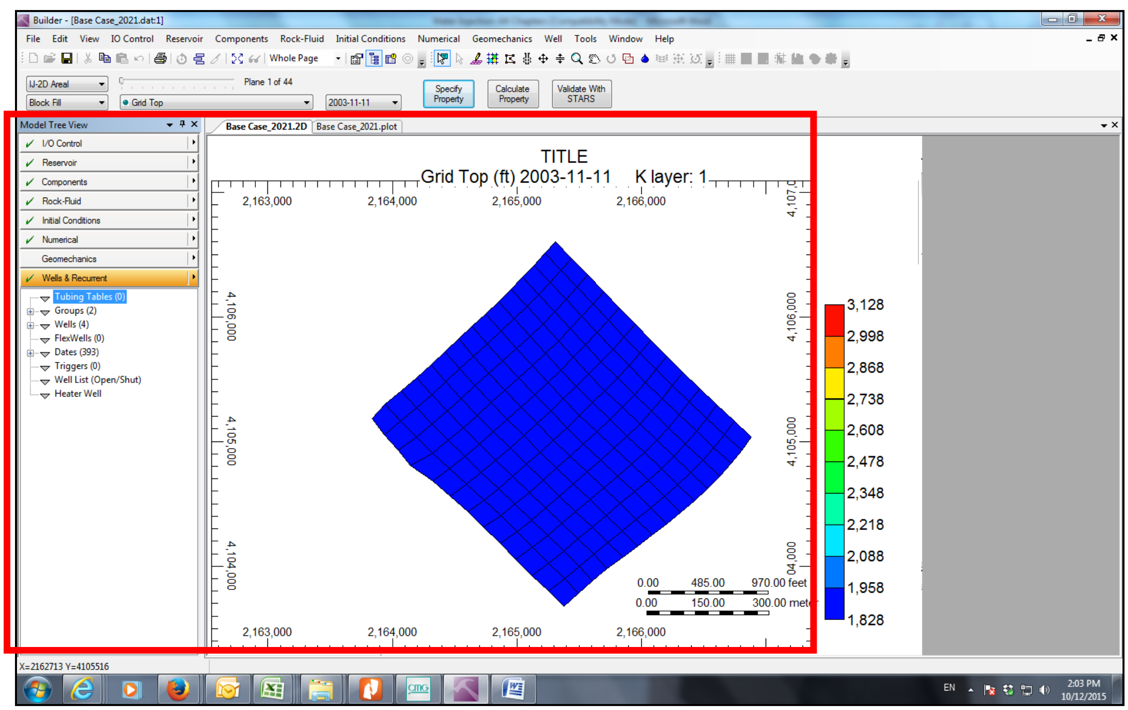

Figure (3.7): wells & recurrent – grid top of base case 2D

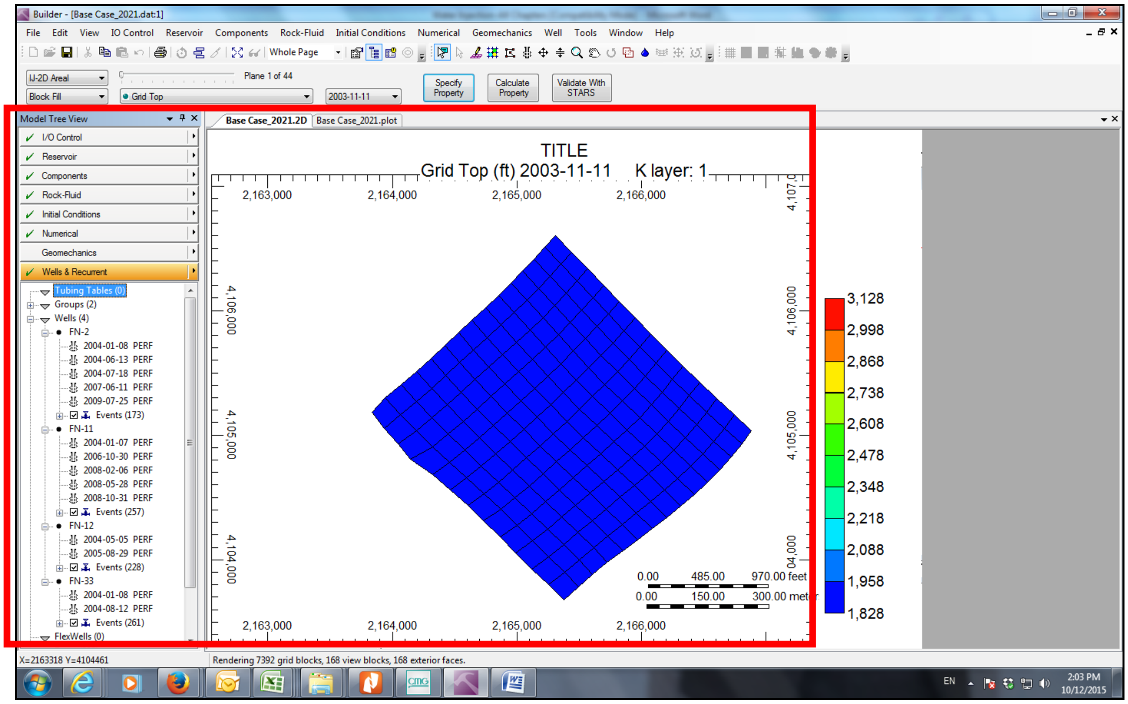

Figure (3.8): wells & recurrent with wells perforations date

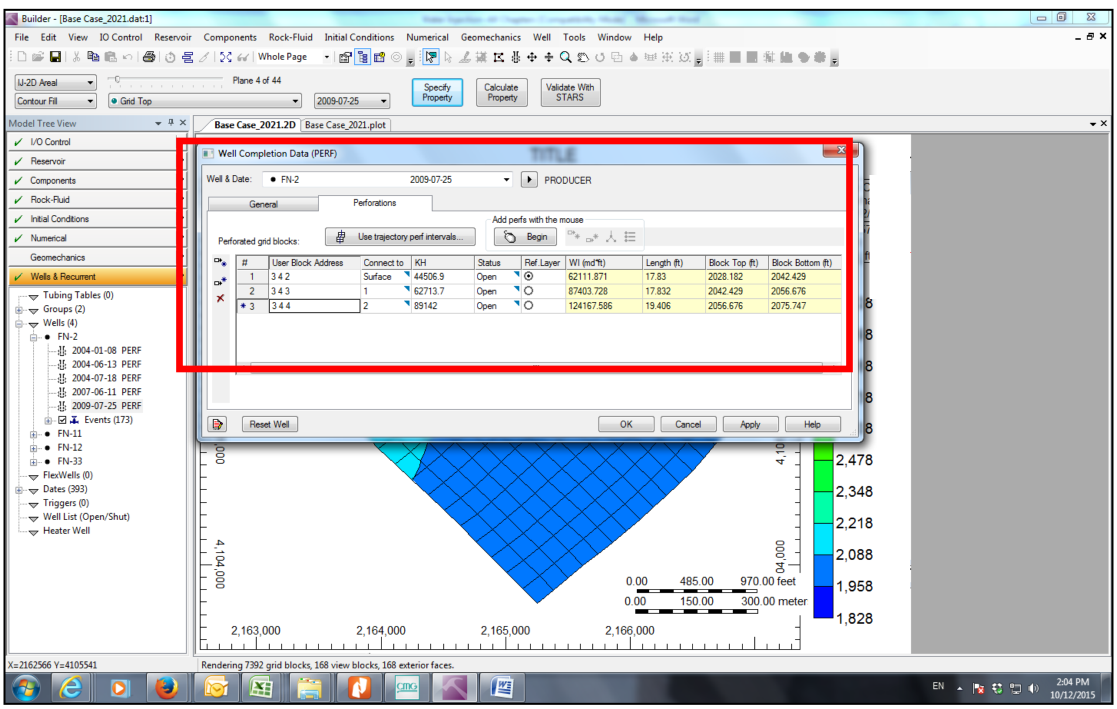

Figure (3.9): wells & recurrent – change the perforation depth for (FN-2)

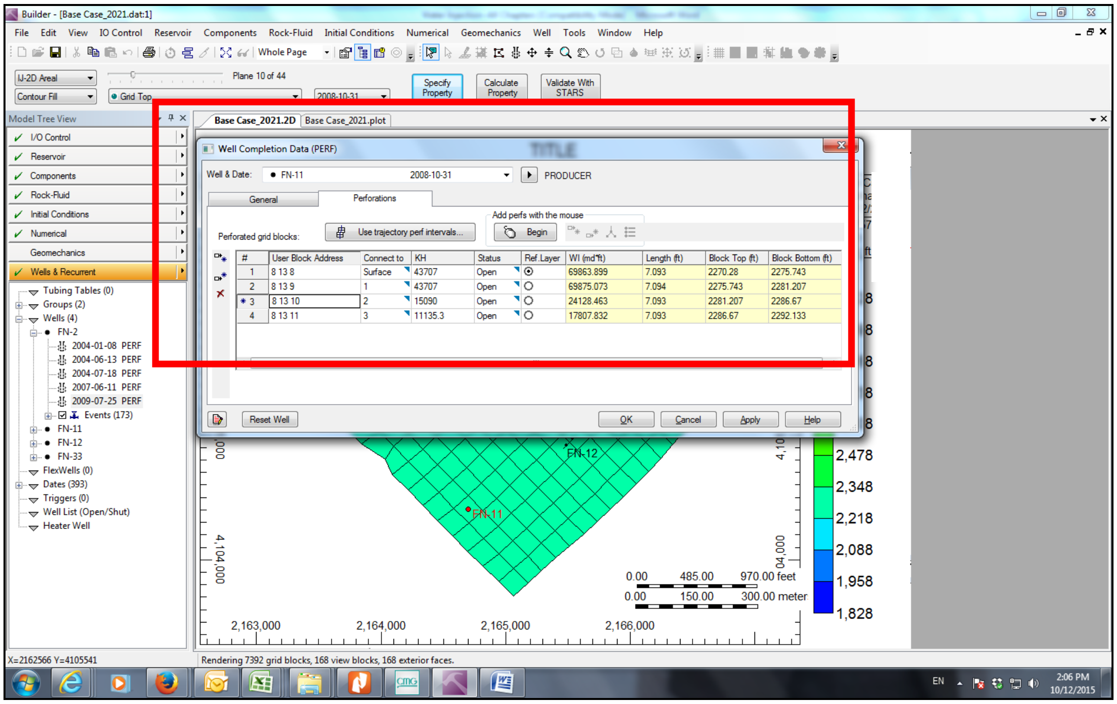

Figure (3.10): wells & recurrent – change the perforation depth for (FN-11)

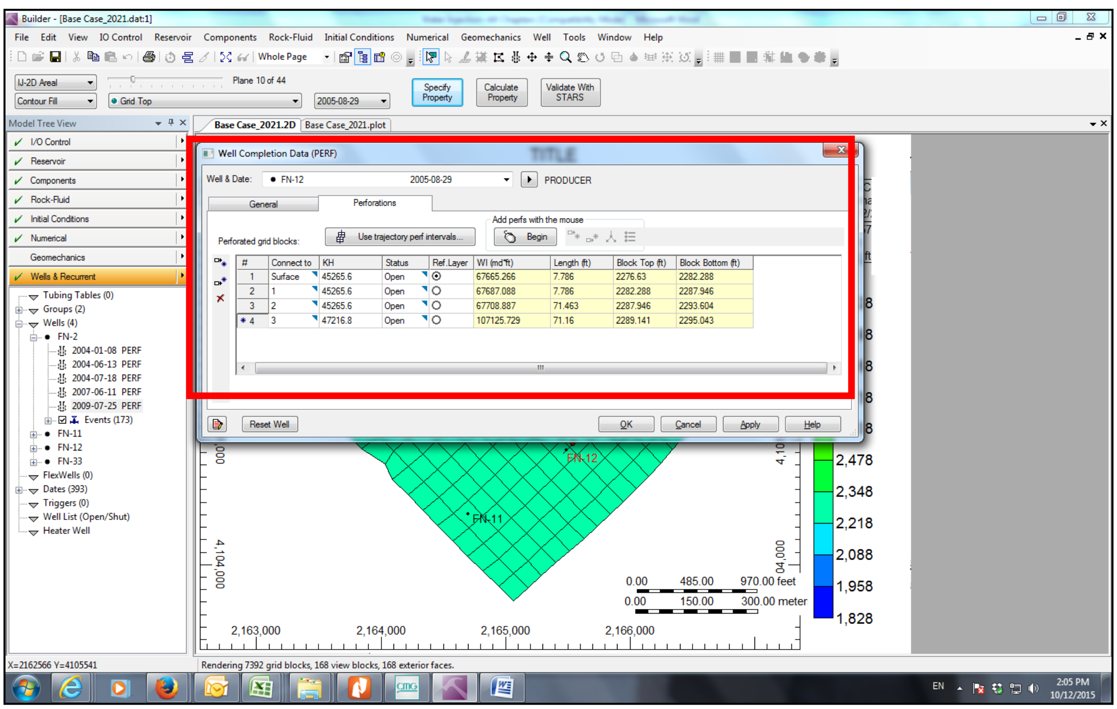

Figure (3.11): wells & recurrent – change the perforation depth for (FN-12)

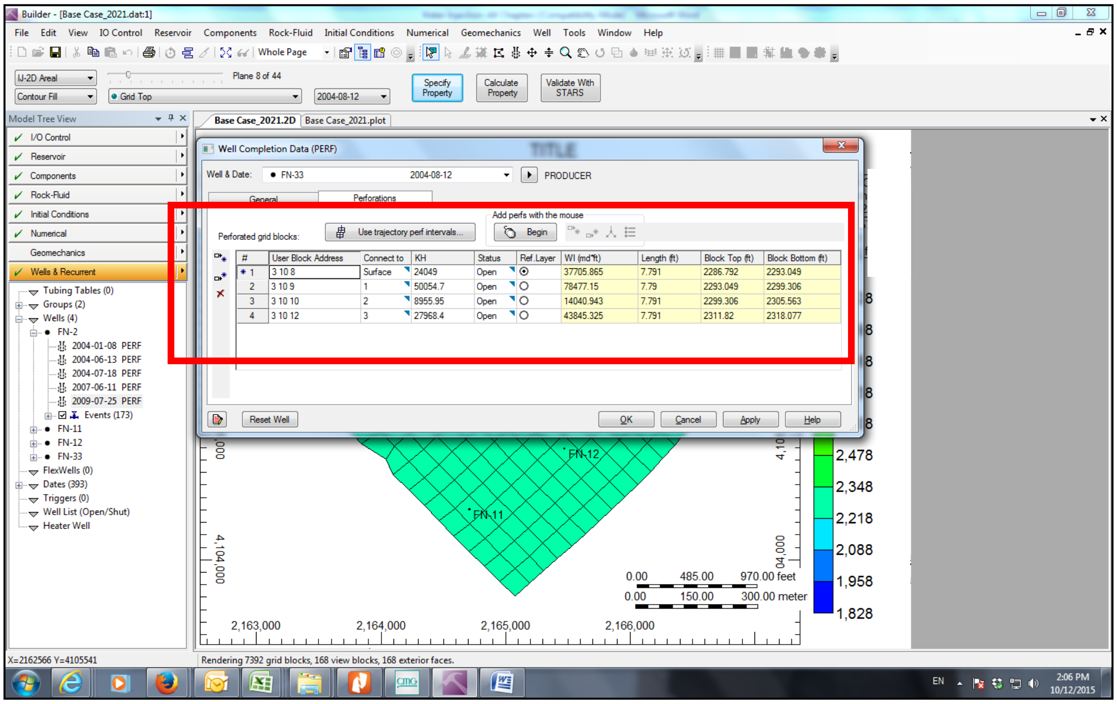

Figure (3.12): wells & recurrent – change the perforation depth for (FN-33)

Chapter Four

Results and Discussion

4.1 Introduction:

The water injection has been implemented in **Fula North** field since 2003 and performance is good but they face the problem of high water cut from producer and water oil ratio (WOR) need to be optimized.

4.2 Basic Information of Fula N Field Location:

Muglad basin is located in the south of Sudan, covering an area of 112,000 km^2. Block 6 is the biggest concession of Muglad basin with area of 59,580 km^2. Fula oilfield located in the southern part of Fula sub-basin and covers an area of 625 km^2. Three reservoirs namely Aradeiba, Bentiu and Abu Gabra are developed in Fula Oilfield.

4.3 Reservoir Characteristics:

4.3.1 Reservoir Type

Aradeiba is a reservoir with weak edge water not like Bentiu reservoir with strong bottom water.

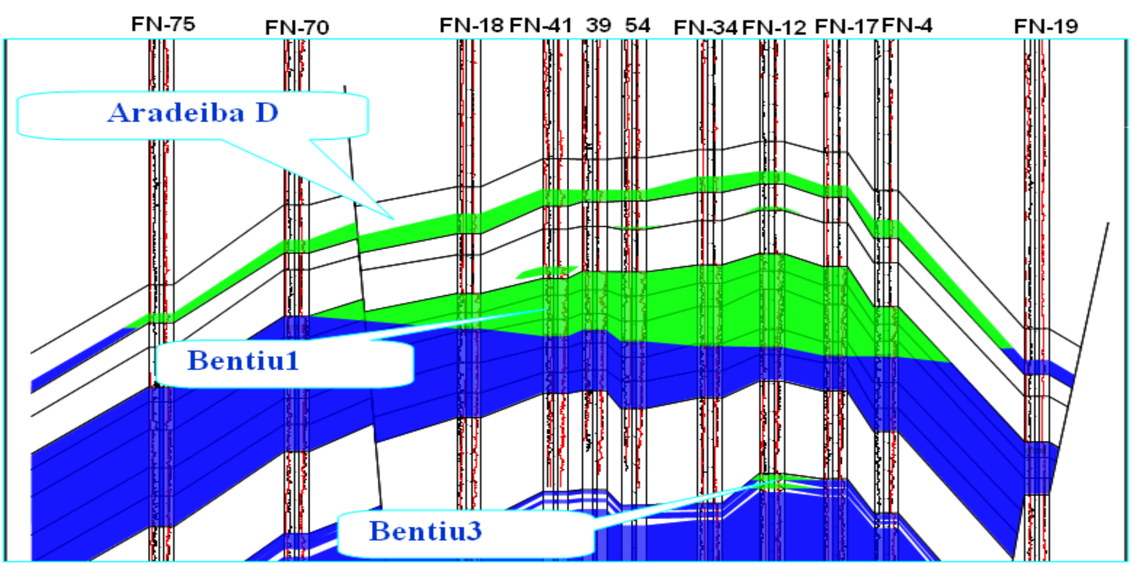

Figure (4.1): Fula N-75~Fula N19 Well Cross Section

4.3.2 Original oil In place (OOIP)

Table (4.1): OOIP of Aradeiba

Block	OOIP (2P) (MMSTB)	Reserves (2P) (MMSTB)
Fula N	82.67	22.05
Fula C	12.65	3.38
Fula-6	14.52	3.88
Fula	3.99	0.7
Total	113.73	30

Contained an estimated 113.7MMSTB of OOIP according to Fula and 30 MMSTB Reserves in depth study.

4.3.3 Basic Reservoir Parameter

Table (4.2): Basic Reservoir Parameter

Parameter	Aradeiba	Bentiu	Abu Gabra
Top Depth (mKB)	1203	1276	1759
Pressure (psi)	600	1187	2253
Temperature (℃)	57.4	61	82.1
Porosity (%)	25-30	30	25-16
Permeability (mD)	1000	2000-5000	1500-1000

As a comparison between the three layers Abu Gabra has the highest pressure with 2253 psi, highest top depth with 1759 (mKB) and highest temperature with 82 (℃) .

For Bentiu it has the highest viscosity ranging between 6000-10000 (mPa.s), the best permeability ranging between 2000-5000 (mD) and good porosity 30% the same as Aradeiba porosity ranging between 25-30 % with lowest parameters according to other layers.

4.3.4 Fluid Properties

Table (4.3): Average Surface Dead Oil Viscosity of Heavy Oilfield

Aradeiba		Bentiu	
API	Viscosity @ 29°C (mPa.s)	API	Viscosity @ 29 °C (mPa.s)
19	1400~2000	19	6000~10000

Table (4.4): Production Performance of Fula

Status as of Mar.20l0	Fula North	
Pool	Aradeiba	
STOOIP (MMSTB)	318.52	
EUR (MMSTB)	86	
NP (MMSTB)	43.8	
REMAING EUR (MMSTB)	44	
EUR TO-DATE (%)	49.8	
RF (%)	27	
RF TO-DATE (%)	13.74	

Table (4.5): Aradeiba Properties (API, Viscosity)

Aradeiba	
API	Viscosity @ 29°C (mPa.s)
19	1400~2000

Table (4.6): PVT Result of Oil from Aradeiba in Fula N-15

Well Name	Sample No	Reservoir Temperature	Reservoir Pressure	Viscosity
Fula -15	815548	58 °C	1070 psi	84.9cp
	815546	58 °C	1070 psi	40cp
Avg	Avg			62.5cp

Table (4.7): Aradeiba Formation Water Data

formation	Well name	Content of Ion (mg/L)							Water Type	pH
		K++Na+	Ca2+	Mg2+	SO4 2-	HCO3	Cl-	Salinity		
XX	FN-69	266.8	54.11	15.8	0	793.26	92.17	825.51	NaHCO3	7.00
	FN-70	303.6	12.02	9.72	28.82	750.55	60.27	789.71	NaHCO3	8.00
	FN-75	146.48	16.42	6.22	0	305.1	95.72	417.39	NaHCO3	7.85
	FN-78	232.3	28.06	7.29	4.8	622.4	63.81	647.46	NaHCO3	7.00
	FN-50	395.03	39.08	13.67	26.42	942.76	150.66	1096.23	NaHCO3	7.16

Aradeiba formation water type is NaHCO3 contains many ions with Salinity ranging between 800 to 1100 (mg/L) with PH between 7 & 8

The ions concentration from the highest average concentration is HCO3 with 683 (mg/L) then 268.84 (mg/L) K++Na+, then Cl with 92.5 (mg/L) , then Ca2+ with 30 (mg/L) , then SO4 with 12 (mg/L) , the lowest concentration is Mg2+ with 10.5 (mg/L)

Waterflooding can be done by using one injection well or more and there are many factors must be studied carefully before selecting well/s location including:

- Reservoir uniformity and pay continuity
- Reservoir geometry and depth
- Fluid properties and saturations
- Lithology and rock properties
- Reservoir driving mechanisms

4.3.5 Sector Area Selection

It’s not easy to select the sector area after analysis it has been found that the area of FN-2, FN-11, FN-12 and FN-33 is most likely to be the suitable area because of the following:

- Good permeability
- Good porosity
- Good sand thickness and continuity
- Optimum well spacing and location for regular well pattern.

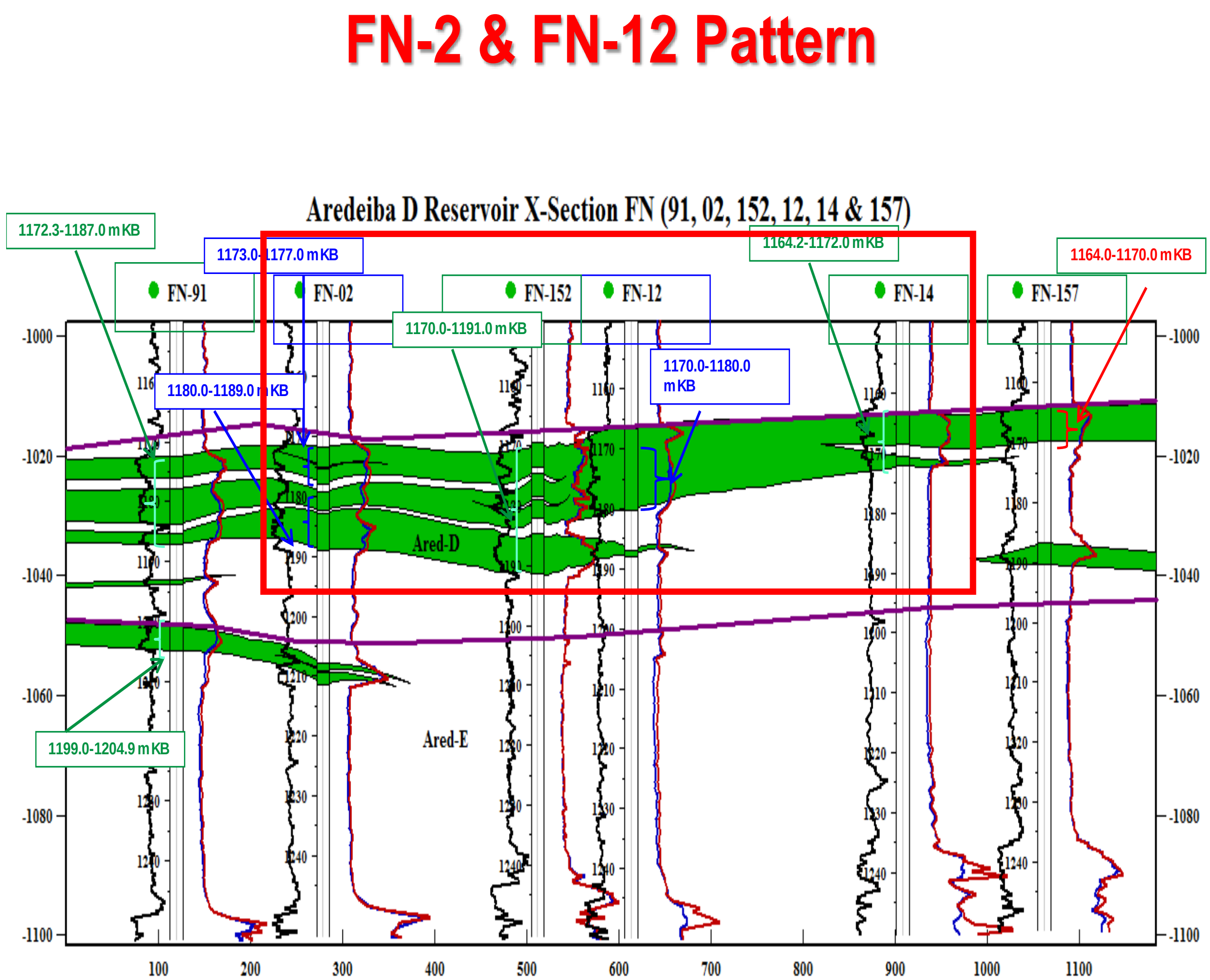

Figure (4.2): Aradeiba D Reservoir X-Section FN (02, 12, 14)

4.3.6 Water Injection Model

The field has static and dynamic model by Eclipse software , so the first challenge for this research is to convert the model to CMG Software and we used Eclipse 100 converter to convert the black oil model IMEX which the black oil simulator in CMG software package.

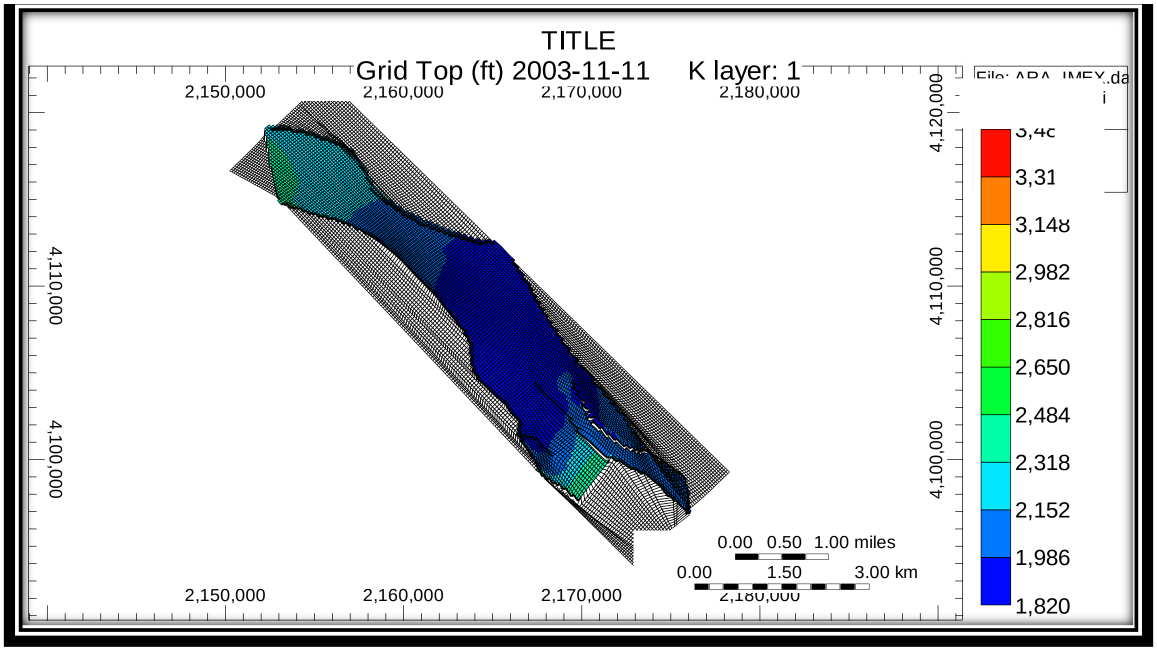

Figure (4.3): Top of Aradeiba Formation

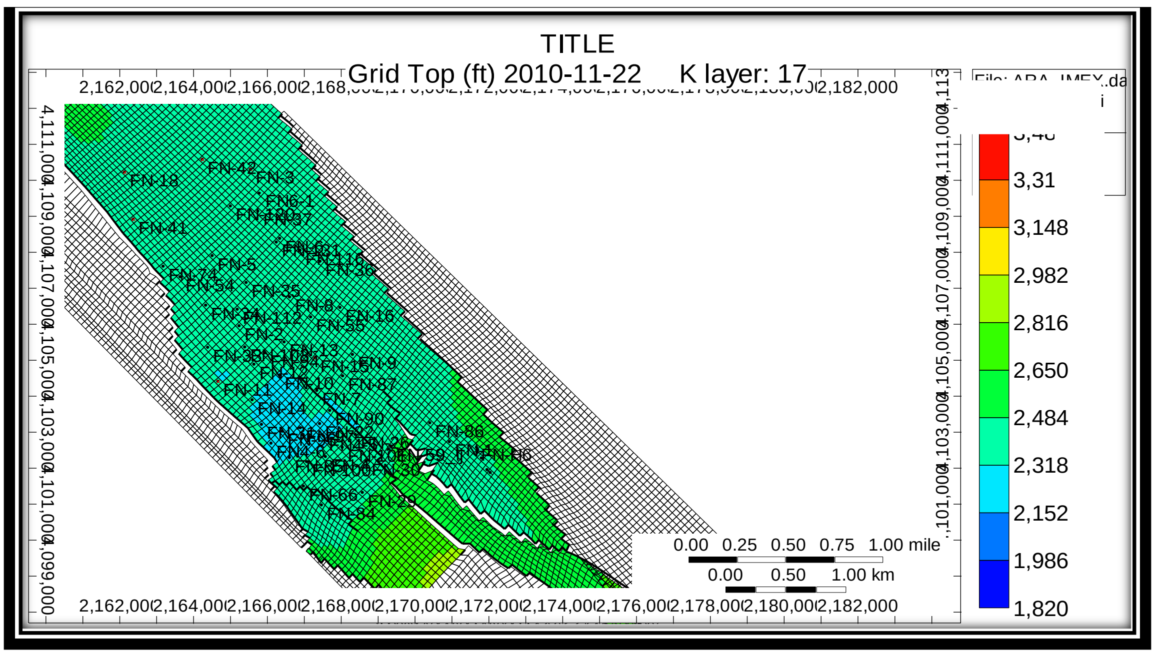

Figure (4.4): Grid Top for Aradeiba Formation

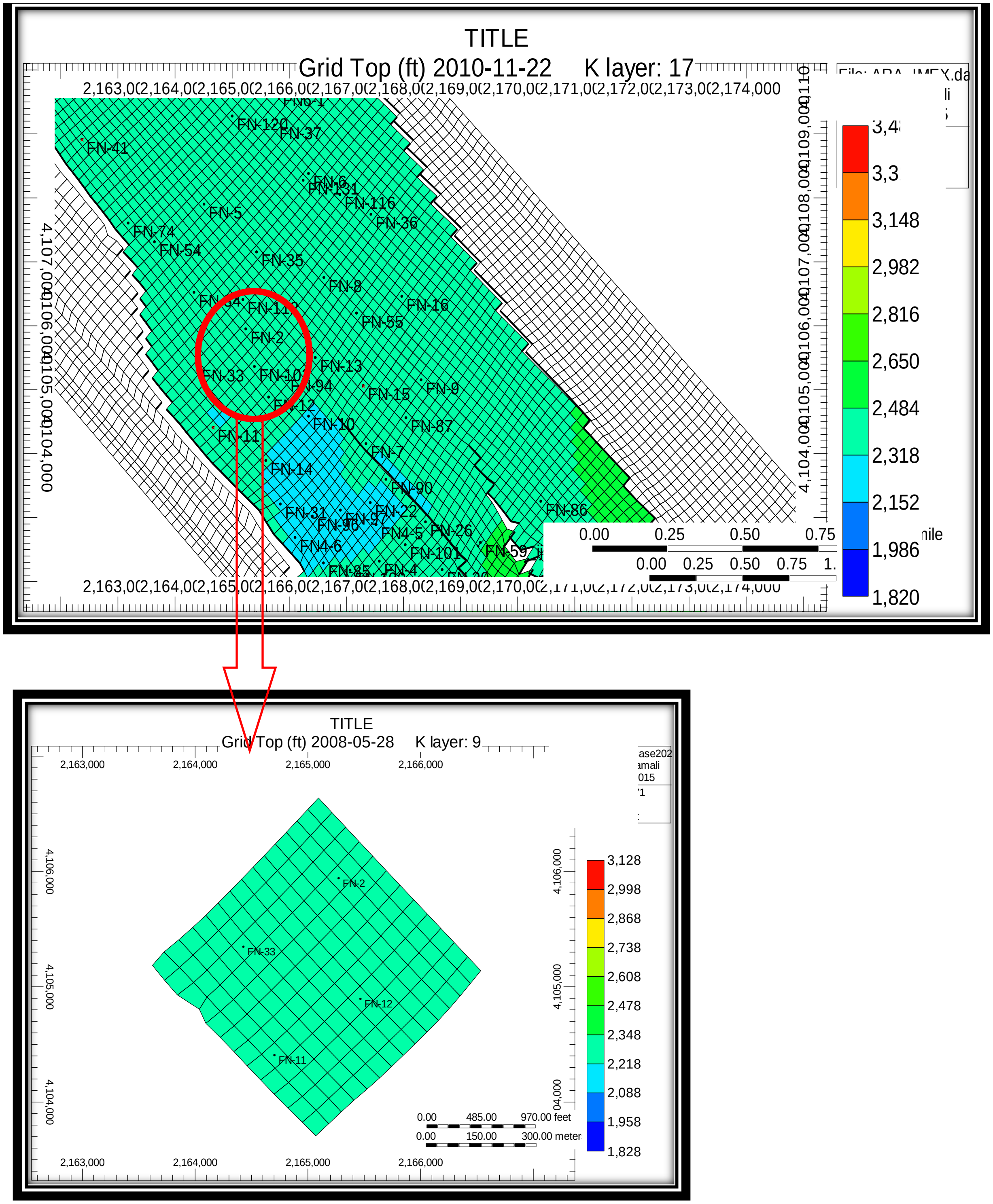

Figure (4.5): Sector model location in Aradeiba Formation

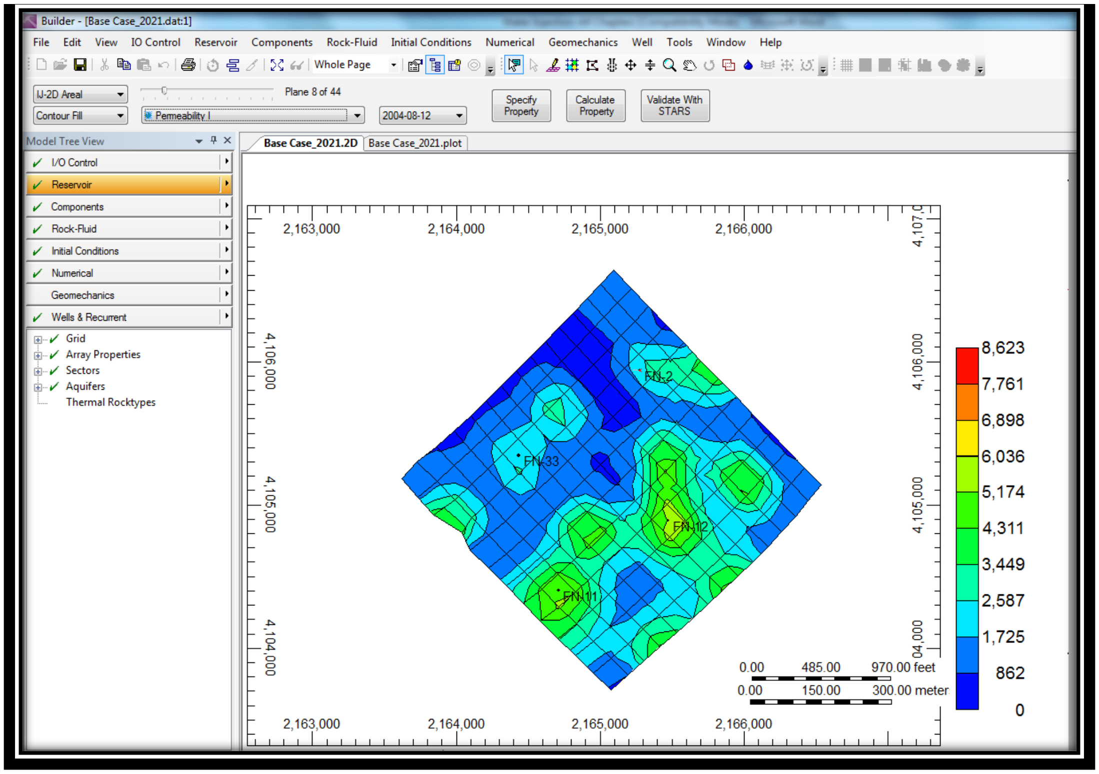

Figure (4.6): Aradeiba Formation permeability

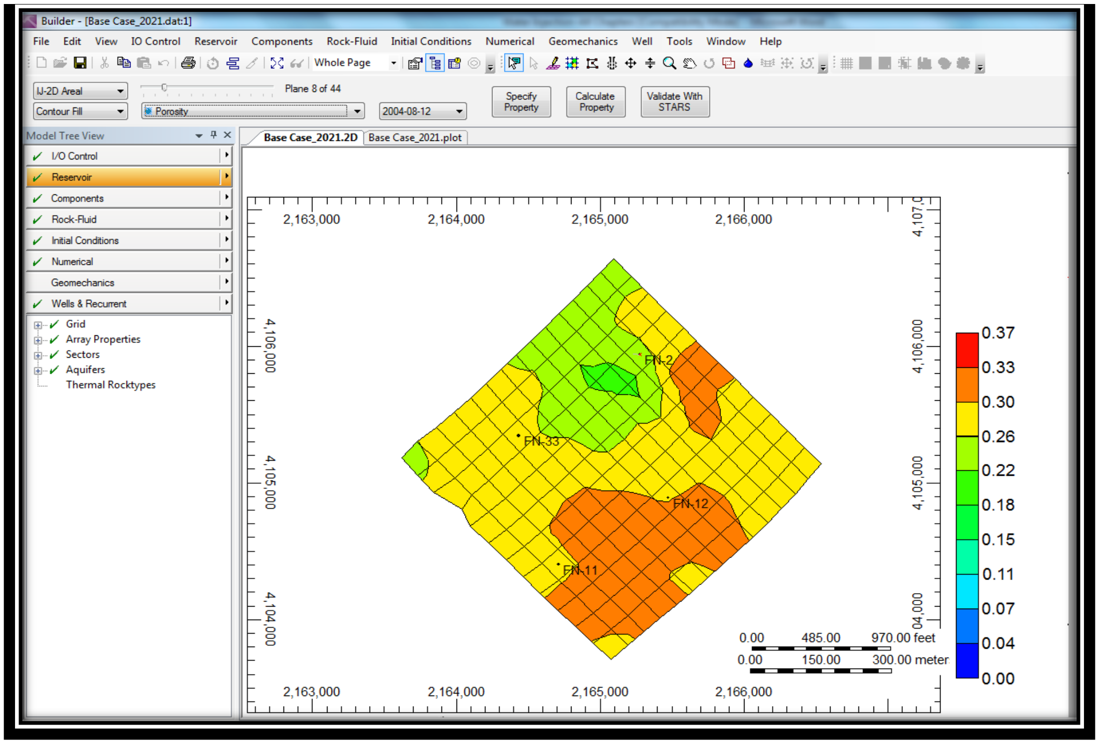

Figure (4.7) Aradeiba Formation porosity

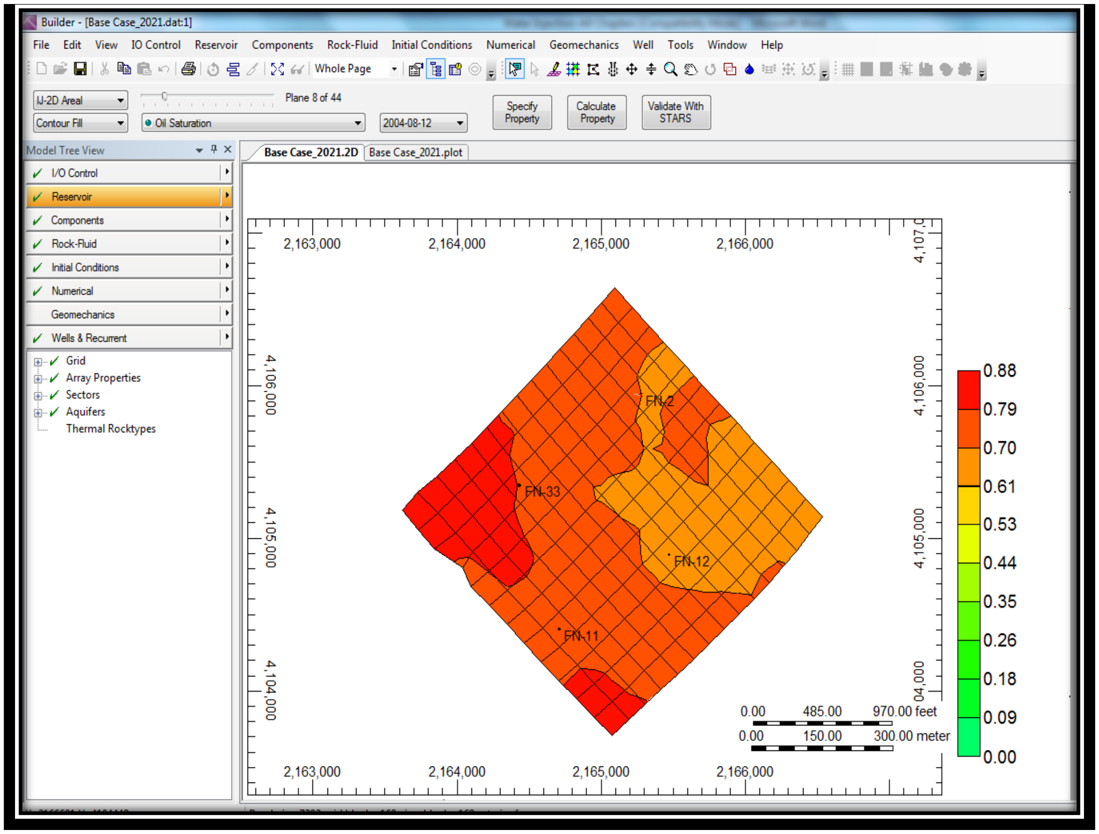

Figure (4.8) Aradeiba Formation Oil Saturation

4.4 Case Study:

Four cases has been studied in this thesis in order to come up with more suitable scenarios for Fula north field and the case are follow:

Case One: - Base Case

In this case nothing has been done for the wells just continue production from the current four well up to 2021 Figure (4.9 & 4.10) shows the location for the wells and time line view for this case.

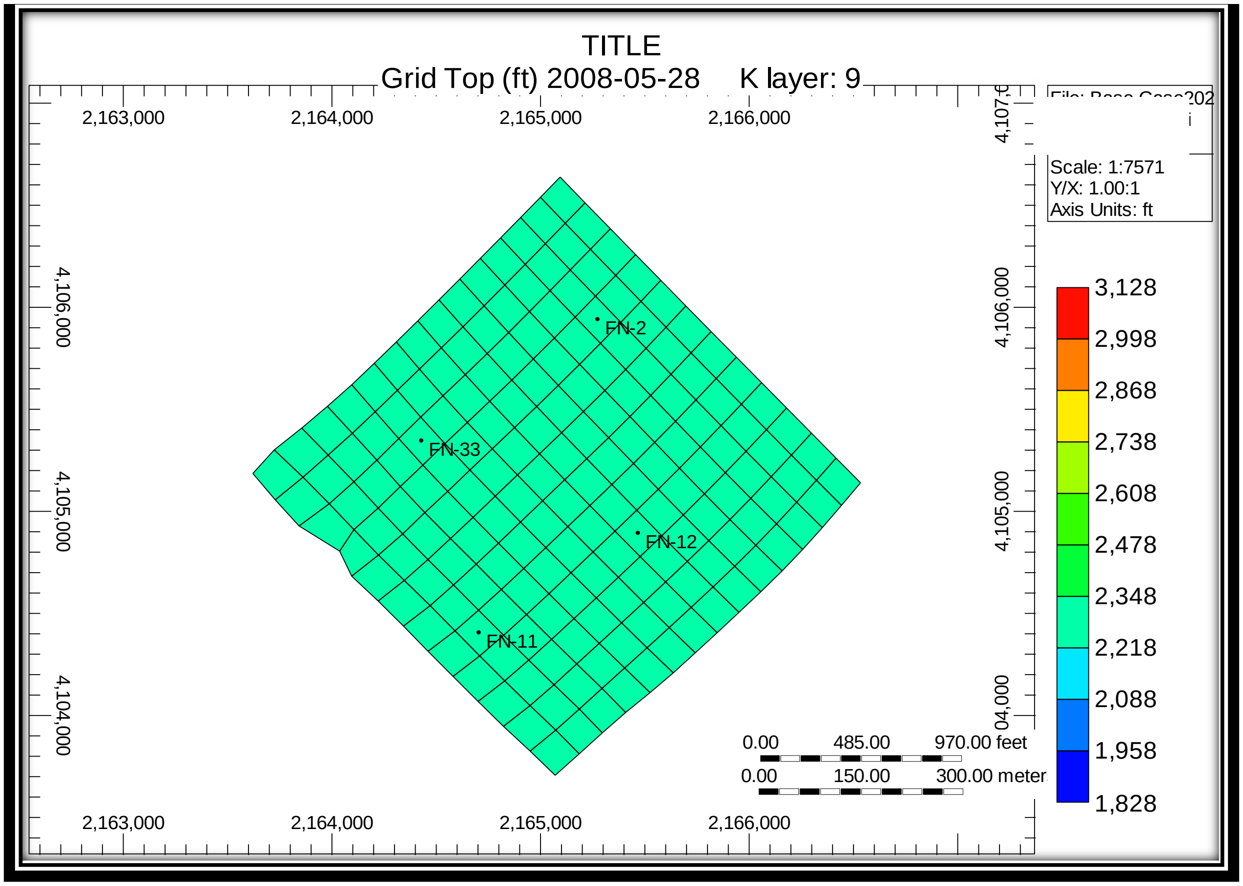

Figure (4.9): Base Case scenario Aradeiba Formation

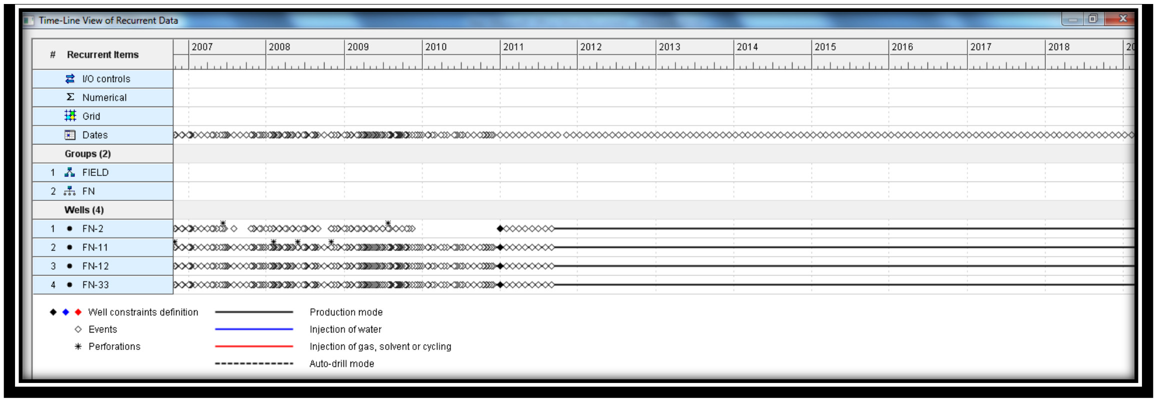

Figure (4.10): Time Line View for Base Case Aradeiba Formation

Case two: - Infill Well Case (five wells producer)

In this case drilling fifth wells to complete the pattern as 5 spot and production from the all five wells up to 2021 Figure (4.11 & 4.12 & 4.13) shows the location for the wells in 2D and 3D and time line view for this case.

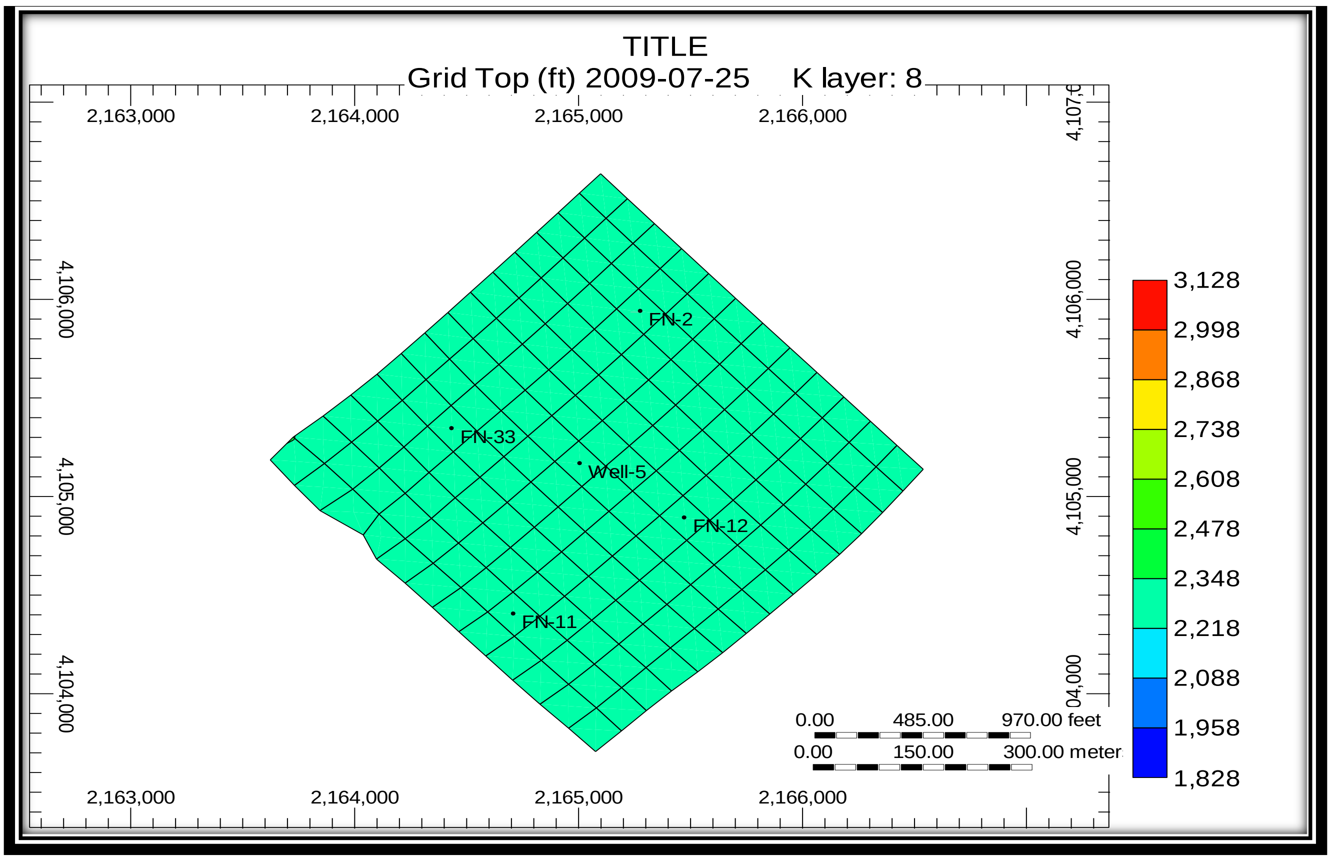

Figure (4.11): Normal Five Spot Aradaiba Formation

Figure (4.12): 3D Model of Normal Five Spot Aradeiba Formation

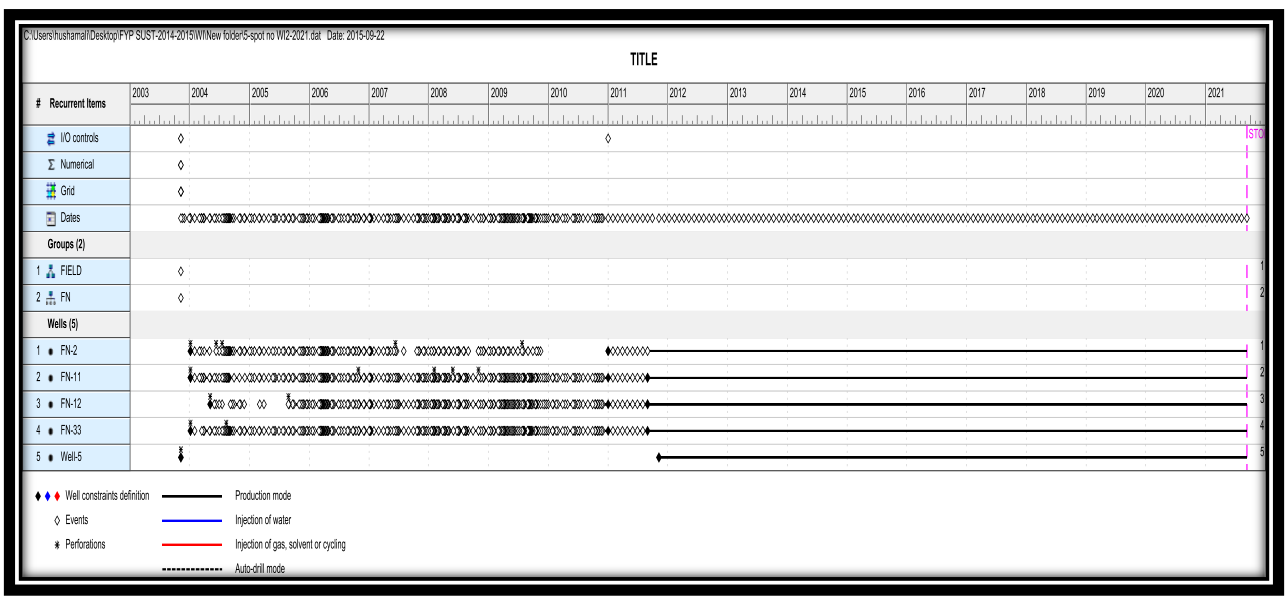

Figure (4.13): Time line view – 5-wells producer

Case three: - Water Injection Case (Inverted Five Spot)

In this case drilling of infill injection wells and produce from the current four wells as 5 spot pattern and production up to 2021 Figure (4.14 & 4.15) shows the location for the wells in 2D and time line view for this case.

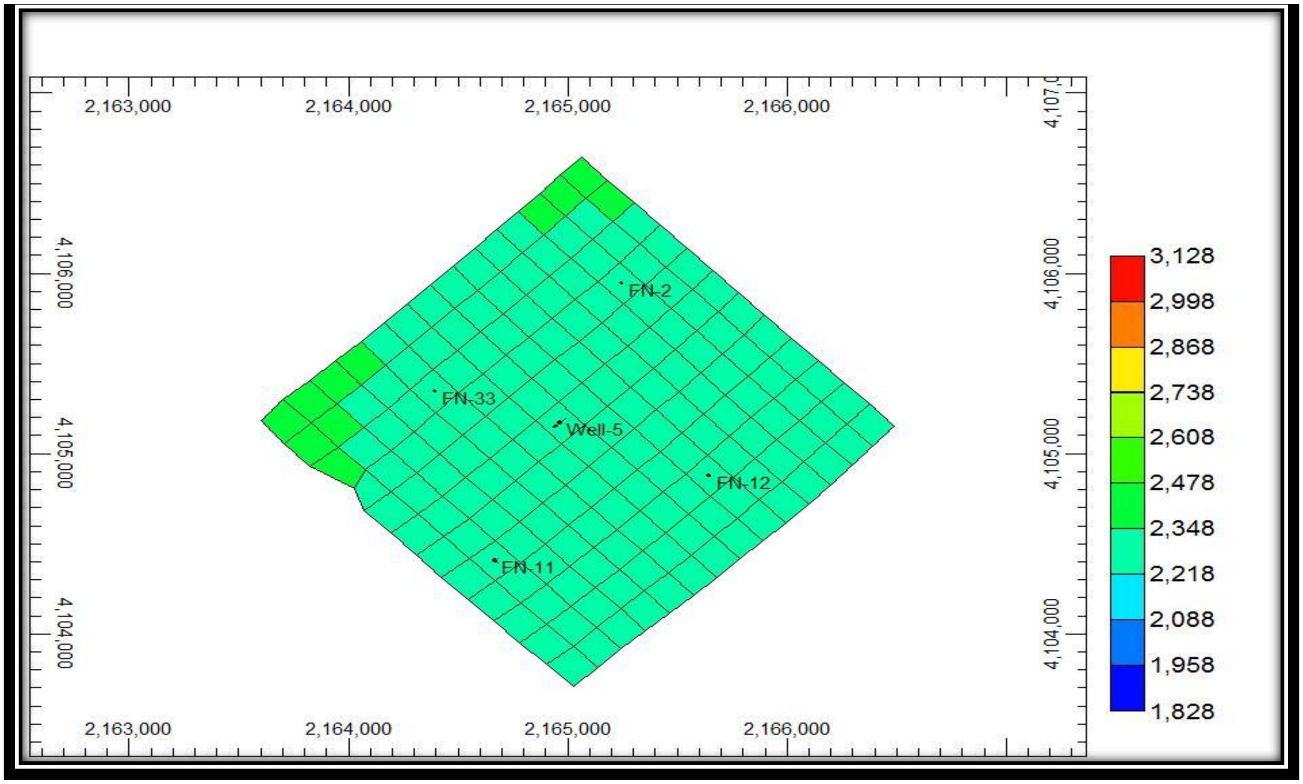

Figure (4.14): Inverted Five Spot Aradeiba Formation

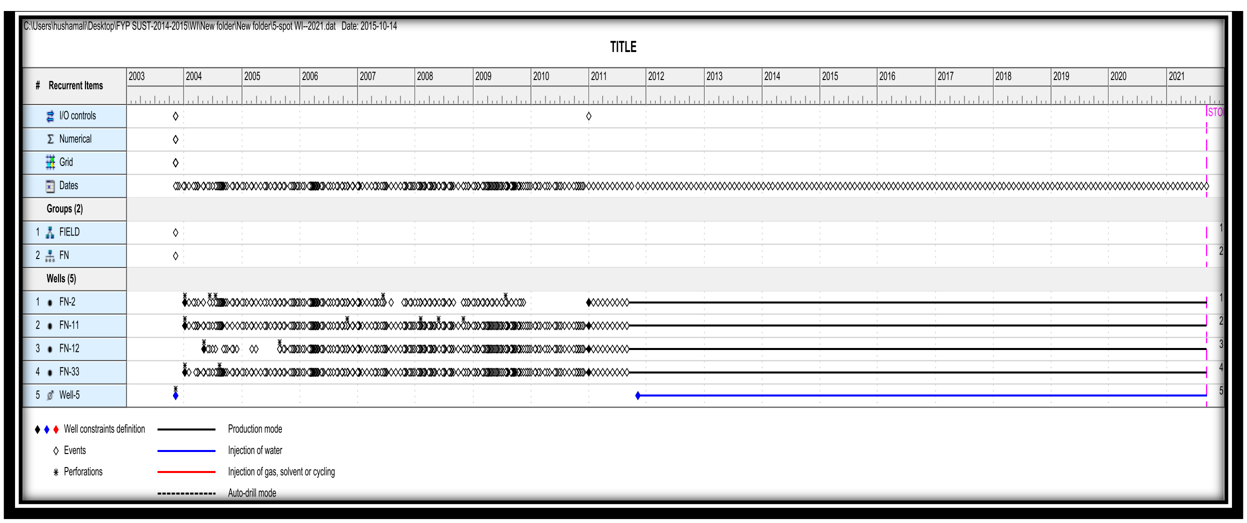

Figure (4.15): Time Line View for 4-wells producer & 1-well injector Aradeiba Formation

Case Four: - Water Injection Case (Normal Five Spot)

In this case drilling of infill as producer and convert all the current wells as injector and then produce from the current well as 5 spot pattern (normal) and production up to 2021 Figure (4.16 & 4.17) shows the location for the wells in 2D and time line view for this case.

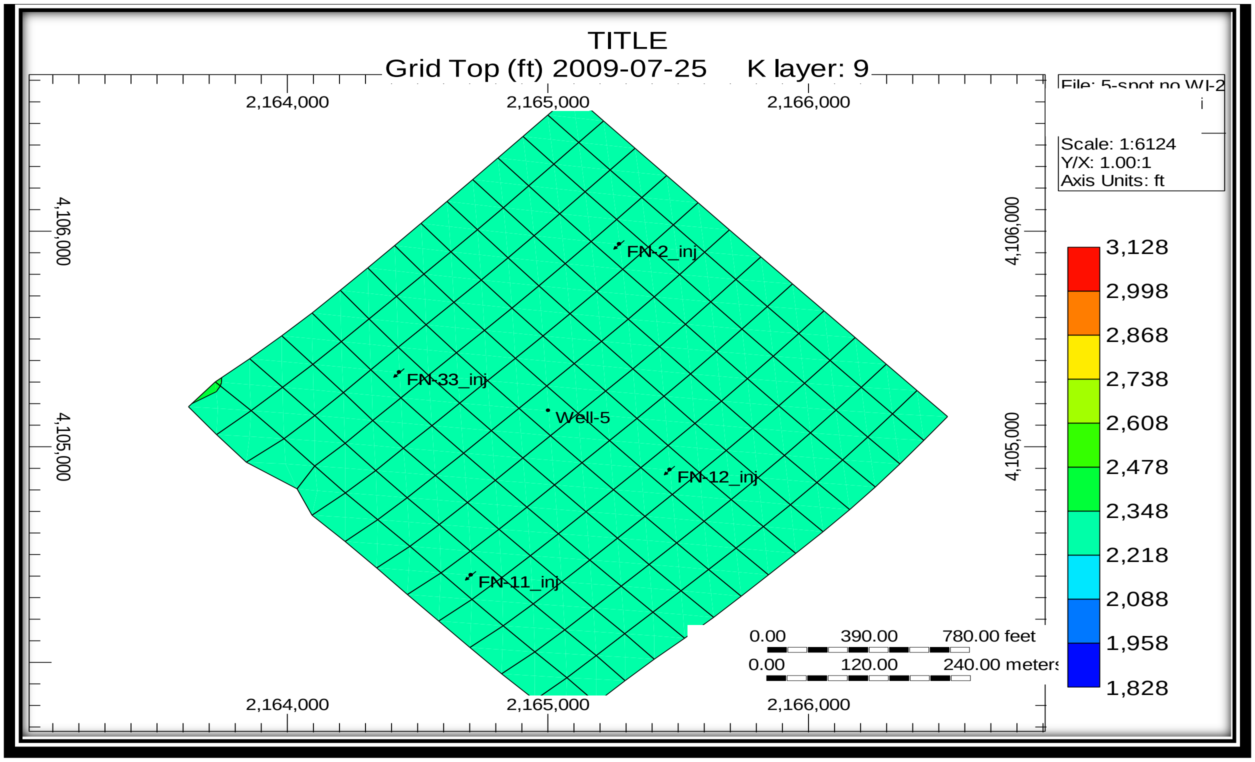

Figure (4.16): Normal five spot (One Producer and Four Injector) Aradeiba Formation

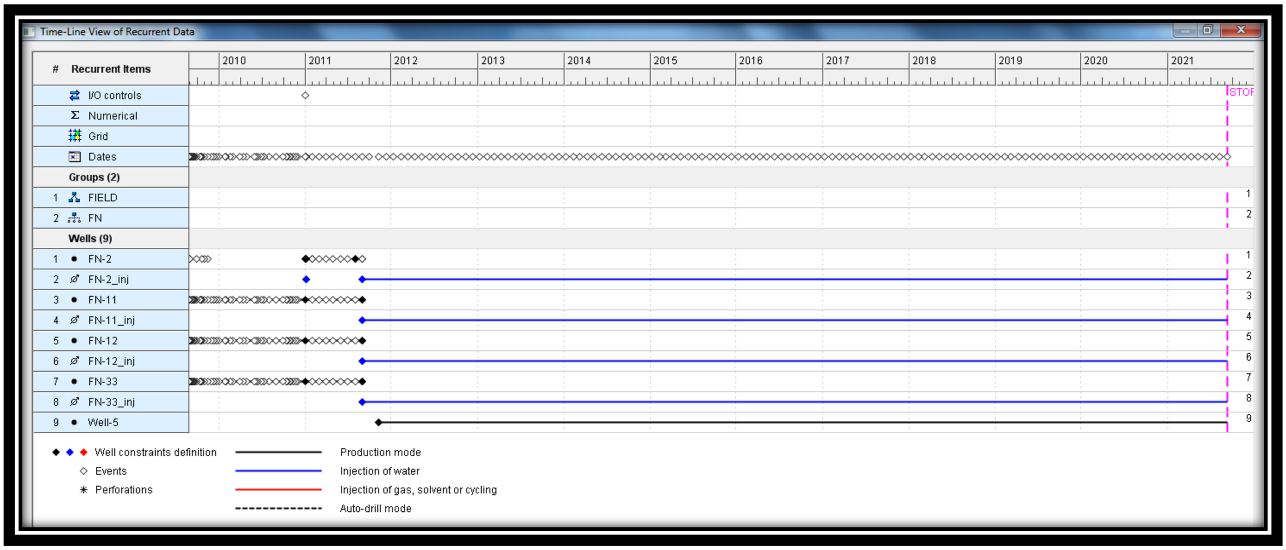

Figure (4.17): Time Line View for 4- wells injector & 1 producer Aradeiba Formation

4.5 Sensitivity Analysis Results:

After running the simulation model it has been found that the case three give high cumulative oil and it has been selected for more sensitive analysis and optimization for water injection rate.

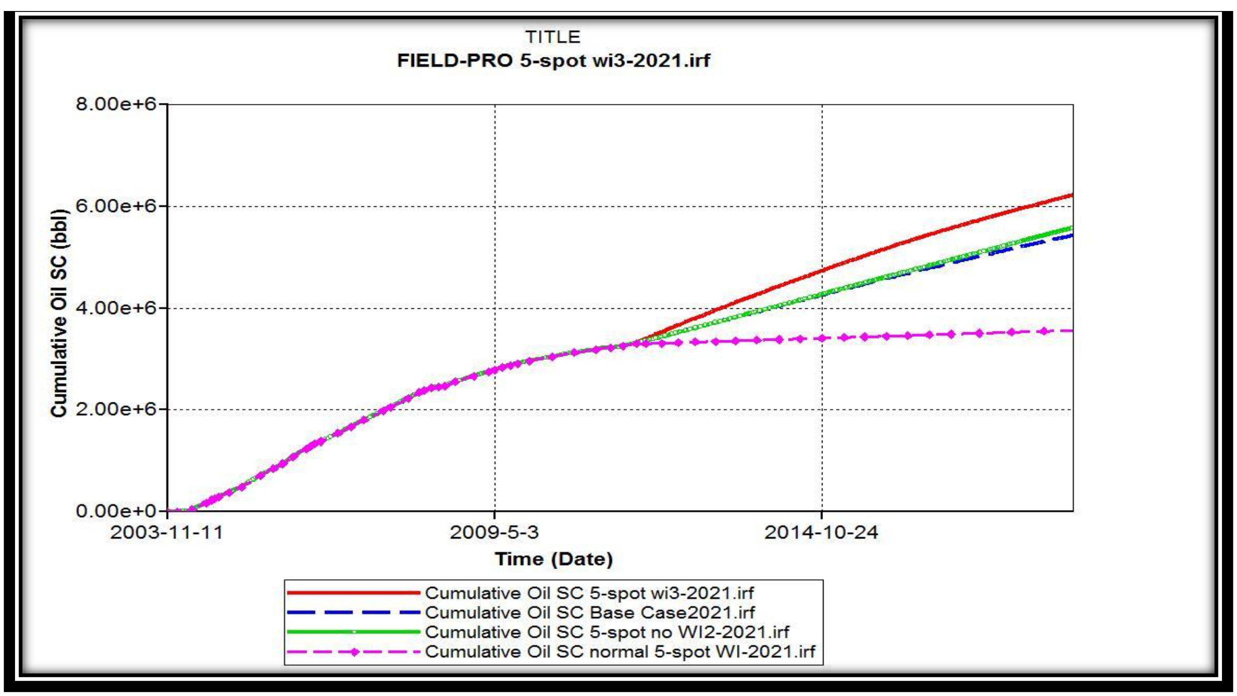

Figure (4.18): Cumulative Oil (bbl) for Different Cases

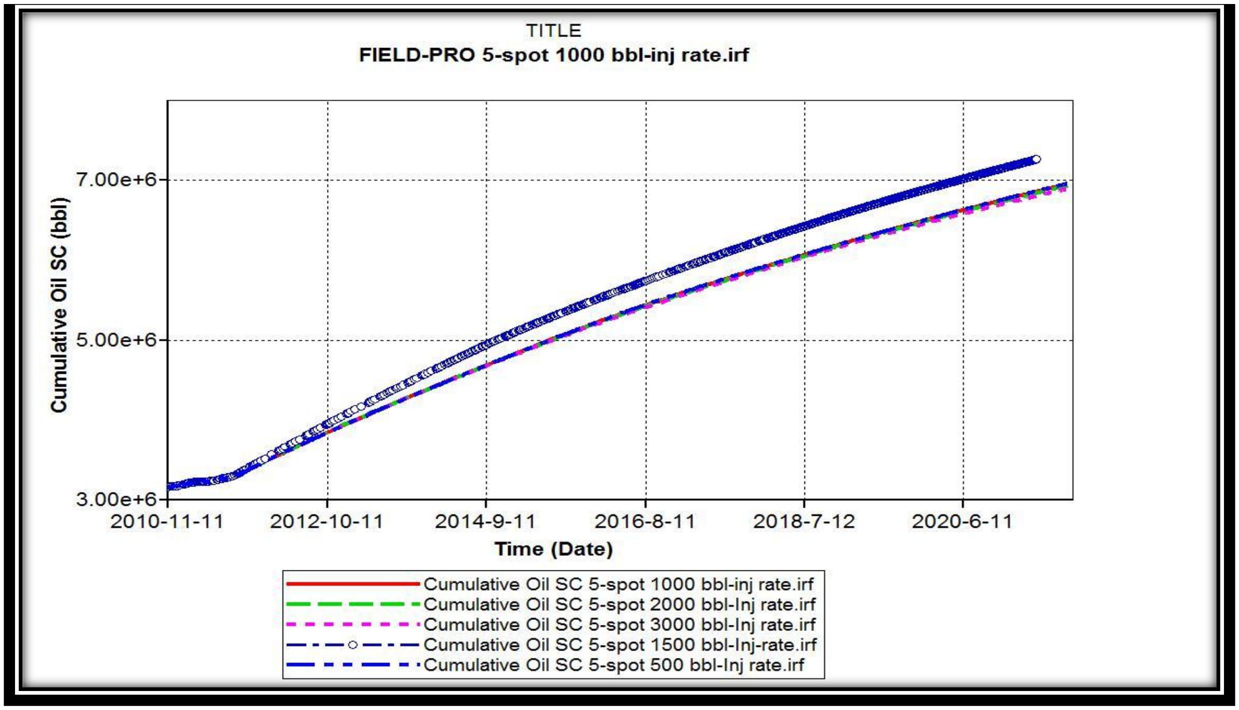

Figure (4. 19): Cumulative Oil (bbl) for Different Cases of Injection Rate

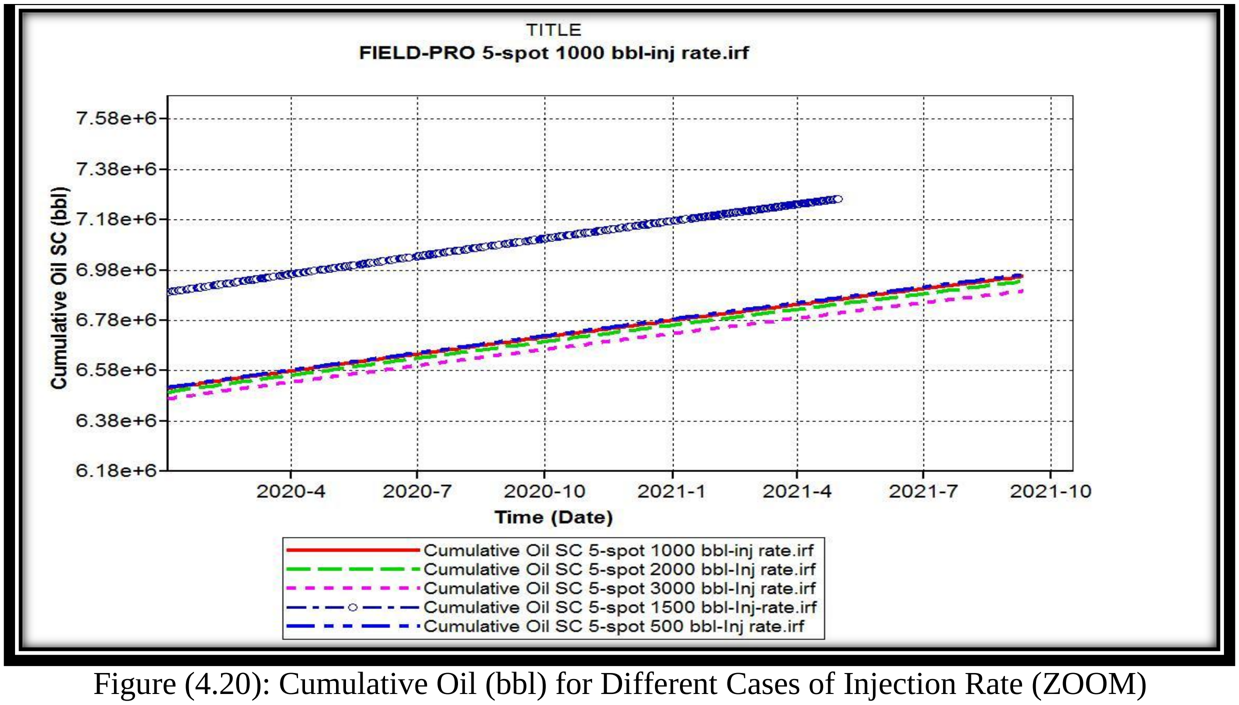

Figure (4.20): Cumulative Oil (bbl) for Different Cases of Injection Rate (ZOOM)

Chapter Five

Conclusion and Recommendation

5.1 Conclusion:

The sector area has been selected Good permeability, Good porosity, Good sand thickness and continuity and Optimum well spacing and location for regular well pattern.
The model has been converted from Eclipse to CMG cause cut the sector area.

Four scenarios has been suggested which it Do nothing case, 5-wells producer, 4-wells producer & 1-well injector and 4-wells injector & 1-well producer

It has been found that the best scenario Case Three which is (4-wells producer & 1-well injector)

In the scenario of (4-wells producer & 1-well injector) several rates between (500-3000) bbl/d -inj rate have been tested, the rate 1500 bbl/d -inj has been found the best rate.

5.2 Recommendations:

Detail analysis for other water injection parameter is need before implementation.
Reservoir pressure must be supported by using water flooding to avoid formation fracture.
It’s highly recommended to run Economic evaluation for this pilot project before execution.
Environmental effect of water production should be studies before project implementation.

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