Sudan University of Science and Technology

College of Graduate Studies

Cyclic Steam Stimulation Designing for Two Horizontal Wells in Sudanese Oil Field - Case Study FNE Oil Field

تصميم دورة التحفيز البخاري للابار الافقية في الحقول السودانية – دراسة حالة حقل (FNE)

Thesis Submitted to College of Graduate Studies in partial Fulfillment for the Degree of MS.C in petroleum Engineering

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الاستهلال

قال تعالي:-

(إنا عرضنا الامانه علي السموات والأرض والجبال فأبين أن يحملنها وأشفقن منها وحملها الإنسان انه كان ظلوما جهولا)

صدق الله العظيم

الايه : 72 سوره الأحزاب

Dedication

TO

My mother,

Who the words fail to describe, and I can't say anything more than she is my mother.

My father,

who supported me and encouraged me at every step of my life

*My supervisor D**r. Tagwa Musa**, and My co-**supervisor Husham Awadelsseid Ali*** for *their guidance and support throughout this study*.

,,,, I dedicate this Work ,,,,

Acknowledgment

First, I am grateful to Allah.

Then to my supervisor Dr/ **Tagwa Musa** and my co supervisor **Husham Awadelsseid Ali**, for their guidance and honest help in carefully reviewing this project.

I would like to thank everyone who provided me by information and for all who have encouraged and supported me to finish this research….

Abstract

Enhanced oil recovery (EOR) became more important at present time as the conventional resources deplete, EOR have many methods, thermal method is the most method used in EOR. thermal method reduces viscosity of heavy oil and residual oil saturation to improve mobility and achieve an economic recovery.

Cyclic Steam Stimulation (CSS)is one of the thermal methods, which has faster production, lower costs and lower pressure operations, it's of great interest in thermal methods.

Fula North East (FNE) Field is one of the Sudan's heavy oil field with low API of 17.7 and high oil viscosity 3800cP at29^{o}C. CSS have been implemented in this field.

This study concerns the simulation of cyclic steam stimulation process of two horizontal wells in FNE reservoirs and find the optimum parameter of this wells. the horizontal area can increase sweep efficiency.

optimum Cyclic Steam Stimulation (CSS) parameters and several simulation models for different development scenarios have been built, each scenario with different parameters and condition, all this to compare the feasibility of applying Cyclic Steam Stimulation in horizontal wells, all this is done by using STARS simulator of Computer Modeling Group (CMG) software.

the results obtained after the designing models and future prediction till 2030, it has been found that implementation of (CSS) in two horizontal wells with optimum conation will give 8% recovery factor more than to drill 10 CHOPS vertical wells.

the optimum Cyclic Steam Stimulation parameters have been determined as follows for (well-1005) injection rate of 250 m3/day and temperature of 330 (0C), steam quality equal 80% injection period 28 days and soaking period 3 days.

For (well-1003) injection rate of 200 m3/day and temperature of 200 (0C), steam quality equal 80% injection period 3 days and soaking period 2 days.

This work shows that oil recovery could be improved from 24.29% by cold vertical production to 32.18% by CSS in two horizontal wells.

خلاصة البحث

الاستخلاص المحسن للزيت اصبح مهم جدا في هذا الوقت مع استنزاف موارد النفط التقليدية .الاستخلاص المحسن للزيت له العديد من الطرق الحرارة ,ومن اكثر الطرق استخداما لتحسين استخلاص الزيت ,الطرق الحرارية تقلل اللزوجة للنفط الثقيل و تشبع الزيت المتبقي لتحسين الحركة وتحقيق عائد اقتصادي.

دورة التحفيز بالبخار هي واحده من الطرق الحرارية التي تتميز بإنتاج أسرع وتكاليف أقل وعمليات ضغط تشغيل أقل الذي له أهمية كبيرة في الأساليب الحرارية .

حقل الفولة الشمالي الشرقي هو أحد حقول النفط الثقيلة ذات فوالق مع ثقل نوعي منخفضة API 17.7 ولزوجة النفط 3800 cpعند درجة حرارة 29مئوية,تم تطبيق دورة البخار في هذا الحق .

في هذه الدراسة تمت بمحاكات دورة البخار في بئرين افقيتين في حقل الفولة الشمال الشرقي وإيجاد افضل المعاملات لهذين البيرين,المنطقفة الافقية في الابار تعمل علي زيادة كفائة مساحة الاستخلاص .
تم تحديد المعاملات المثالية لدورة التحفيز بالبخار وتم بناء العديد من نماذج المحاكاة لمختلف سيناريوهات التطوير ، كل سيناريو تم بناؤة بمعاملات وحالات مختلفة ، كل هذا لتحديد قابلية تطبيق دوري التحفيز البخاري في الآبار الأفقية ، كل ذلك تم باستخدام برنامج المحاكاة الحرارية لبرنامج (CMG).
النتائج التي تم الحصول عليها بعد التصميم والتنبؤ المستقبلي حتى عام 2030 ، دورة التحفيز بالبخار في اثنين من الابار الأفقية سيعطي استخلاص اعلي للنفط بمعدل 8% افضل من 10 ابار رأسية تنتج بالطريقة التقلدية بدون تحفيز بالبخار .
كما تم تحديد المعلمات المثالية لدورة التحفيز البخار على النحو التالي البئر -1005 : معدل الحقن 250 مترمكعب ودرجة الحرارة 330 مئوية وجودة بخار تساوي 80٪ مدة الحقت 28 يوم مدة قفل البئر 3 ايام .

البئر-1003: معدل الحقن200 مترمكعب ودرجة الحرارة 200 مئوية وجودة بخار تساوي 80٪ مدة الحقن 3 يوم مدة قفل البئر 2 ايام.
توضح الدراسة أنه يمكن تحسين استخلاص النفط من24.29% من انتاج 10 ابار باردة تنتج بالطريقة التقليدية إلى 32.64% بواسطة التحفيز بالبخار في بئران افقيتين.

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List of abbreviation

API	:	American Petroleum Institute
ASP	:	Alkaline-Surfactant-Polymer
BOPD	:	Barrel Oil per Day
OBIP	:	Bitumen Recovery levels
CHOPS	:	Cold Heavy Oil Production with Sand
CMG	:	Computer Modeling Group
CO_2	:	Carbon Dioxide
CSOR	:	Cumulative steam oil ration
CP	:	Centipoises
CSI	:	Cyclic Steam injection
CSS	:	Cyclic Steam Stimulation
DNC	:	Do Nothing Case
EEOR	:	Electro Enhanced Oil Recovery
EOR	:	Enhanced Oil Recovery
EUR	:	Enhanced Ultimate Recovery
FNE	:	Fula North East
HASD	:	Heated Annulus Steam Drive
Hw-CSS-S	:	Horizontal well- Cyclic Steam injection with solution
IFT	:	Interfacial Tension
IMEX	:	Implicit Explicit Black Oil Simulator

IOR	:	Improved Oil Recovery
ISC	:	In-situ Combustion
MPa	:	Megapascal
NP	:	Cumulative Oil Production
OOIP	:	Original Oil in Place
OPEC	:	Organization of petroleum exporting countries
PE	:	Petro Energy
RF	:	Recovery Factor
SAGD	:	Steam Assisted Gravity Drainage
SF	:	Steam Flooding
S_{or}	:	Residual Oil Saturation
STARS	:	Steam Thermal and Advanced Processes Reservoir Simulator
STB	:	Stock Tank Barrel
SWSC	:	Single well steam circulation
TAN	:	Total Acid Number
TEMP	:	Temperature
TEOR	:	Thermal Enhanced Oil Recovery
TSX	:	Texas

Chapter One

Introduction

1.1 Introduction.

World oil demand based on Organization of the Petroleum Exporting Countries (OPEC) statistics world oil demand averaging for 2017 is 94.40 mb/d, growth is expected to be around 1.15 mb/d, to be, at 95.55 mb/d, figure (1.1) presenting world oil demand growth until 2017, and total global energy demand expected to increase by 108.2 mboe/d (or 40%) from 273.9 mboe/d in 2014 to 382.1 mboe/d by 2040 (OPEC, 2016).

The consumption of petroleum in the world is growing up, so we need to produces more oil, to produces more oil there are three stages to produces oil, the general mechanism of oil recovery is movement of hydrocarbons to production wells due to a pressure difference between the reservoir and the production wells, the recovery of oil reserves is divided into three main categories worldwide, figure (1.2) illustrates these categories.

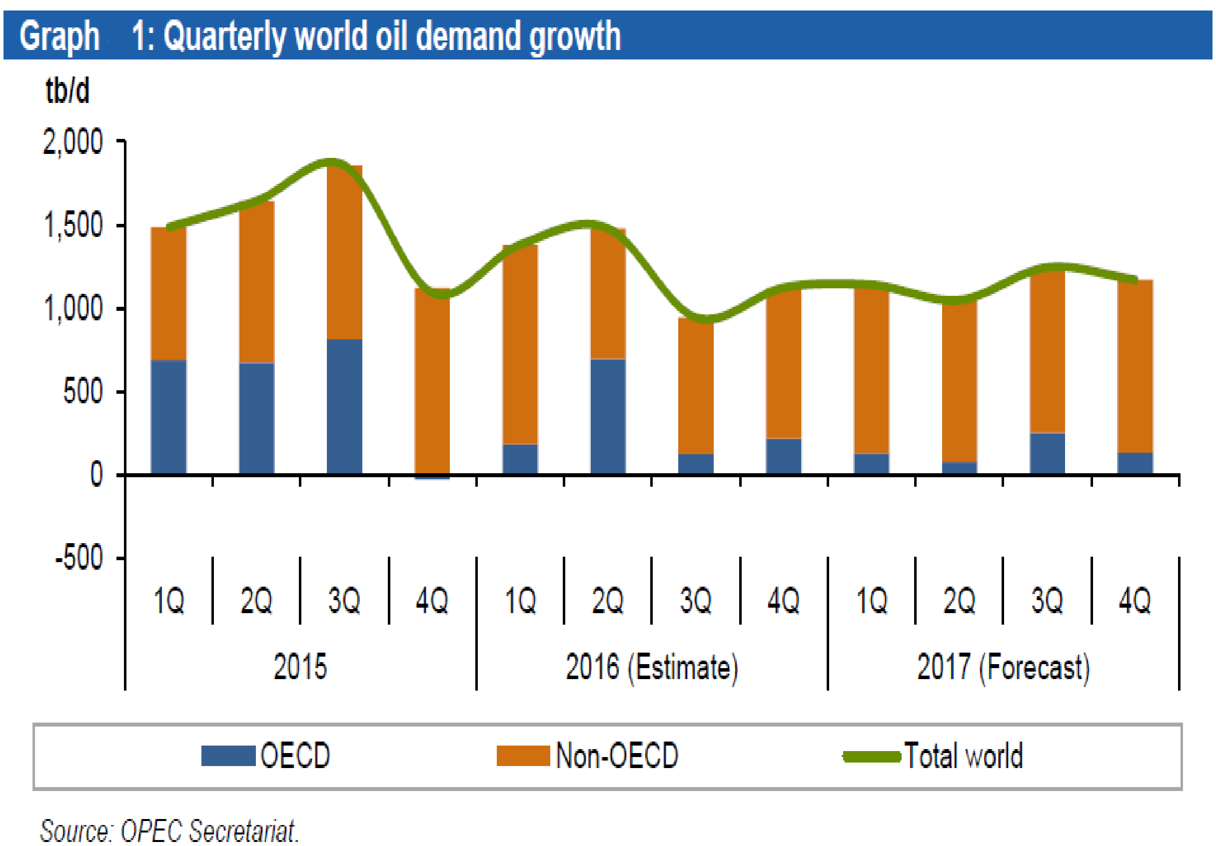


Figure (1.1): World Oil Demand (OPEC, 2016).

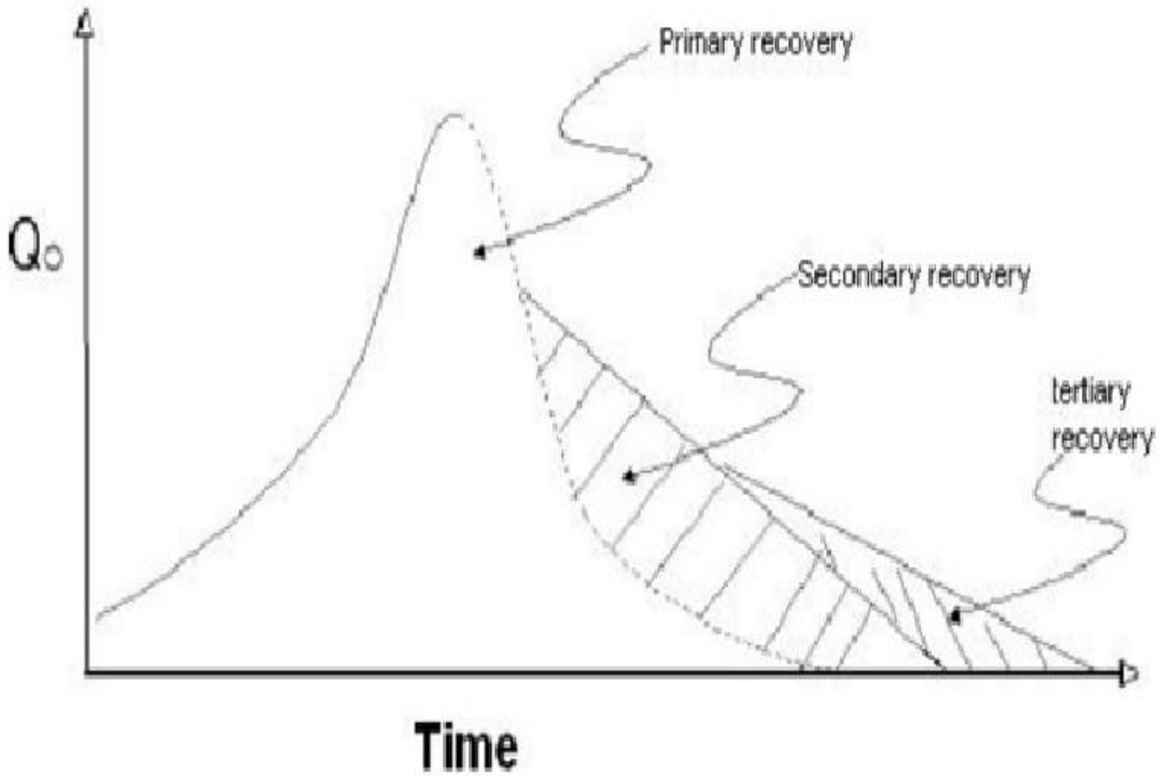


Figure (1.2): Stages of Produces Oil (Tom.A. J,2010).

Primary recovery techniques: this implies the initial production stage, resulted from the displacement energy naturally existing in a reservoir.

Secondary recovery techniques: normally utilized when the primary production declines, traditionally these techniques are water flooding, pressure maintenance, and gas injection, the recovery factor can rise up to 50%.

Tertiary recovery techniques or Enhanced Oil Recovery (EOR): these techniques are referred to the ones used after the implementation of the secondary recovery method. usually these processes use miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process has become uneconomical, the recovery factor may arise up to 12% additionally to the Recovery Factor (RF) obtained with the secondary recovery method.

We can find another category of recovery stage these are:

I. Primary recovery.
II. Secondary recovery.
III. Tertiary recovery (EOR).
IV. Infill recovery.

Primary recovery is the recovery of hydrocarbons from the reservoir using the natural energy of the reservoir as a drive.

Secondary recovery this is recovery aided or driven by the injection of water or gas from the surface.

Tertiary recovery (EOR) there are a range of techniques broadly labelled '(EOR)' that are applied to reservoirs in order to improve flagging production.

Infill recovery is carried out when recovery from the previous three phases have been completed. It involves drilling cheap production holes between existing boreholes to ensure that the whole reservoir has been fully depleted of its oil (Tom.A. J,2010).

1.2 Improved Oil Recovery and Enhanced Oil Recovery.

Improved Oil Recovery (IOR) is a term which implies improving oil recovery by any mean, for example, operational strategies such as infill drilling and horizontal wells can improve vertical and areal sweep, leading to an increased oil recovery, another term often used interchangeably is EOR, or enhanced oil recovery, however, EOR is more specific in concept and it can be seen as a subset of IOR (Thomas, S 2008).

It is important to define EOR; there is a lot of confusion around the usage of the terms EOR and IOR, figure (1.3) explaining these in terms of oil recovery, as defined by the Society of Petroleum Engineers SPE (Sunil.K,2010).

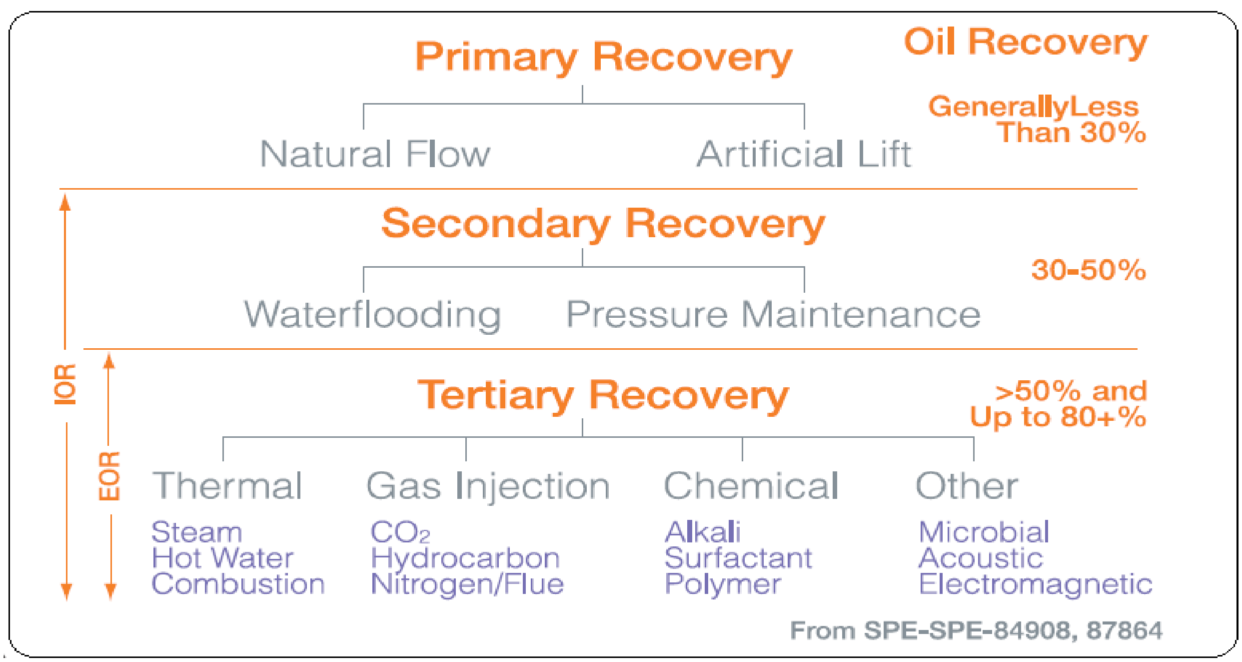


Figure (1.3): Define of IOR and EOR (Sunil.K,2010).

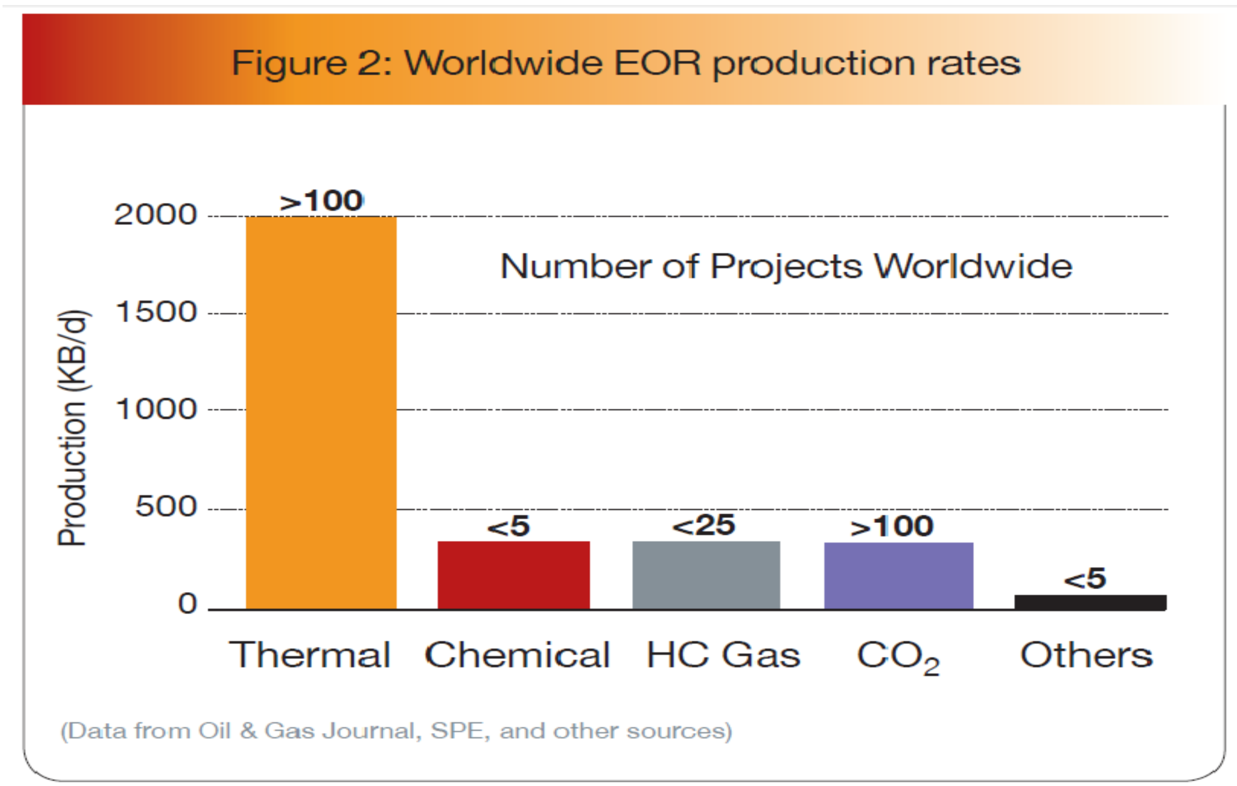


Figure (1.4): EOR Producing Rates (Vladimir.A, 2010).

IOR methods encompass (EOR) methods as well as new drilling and well technologies, intelligent reservoir management and control, advanced reservoir monitoring techniques and the application of different enhancements of primary and secondary recovery processes as presented in figure (1.4) (Vladimir.A,2010).

IOR processes are applied mainly in the secondary and tertiary reservoir depletion stage to increase reservoir sweep efficiency coefficients by displacing fluids – looking for trapped oil by denser well spacing pattern, drilling of horizontal wells and sidetracking from existing holes, fracturing and use of polymers to improve mobility ratio.

EOR methods, also known as tertiary recovery methods, mobilize oil trapped by capillary and viscosity forces during reservoir water flooding in the secondary stage.

Oil is freed by chemical and thermal activity, by injecting solvents and chemicals and heating of the reservoir figure (1.5) illustrate the different between EOR and IOR (J. Sečen, 2005).

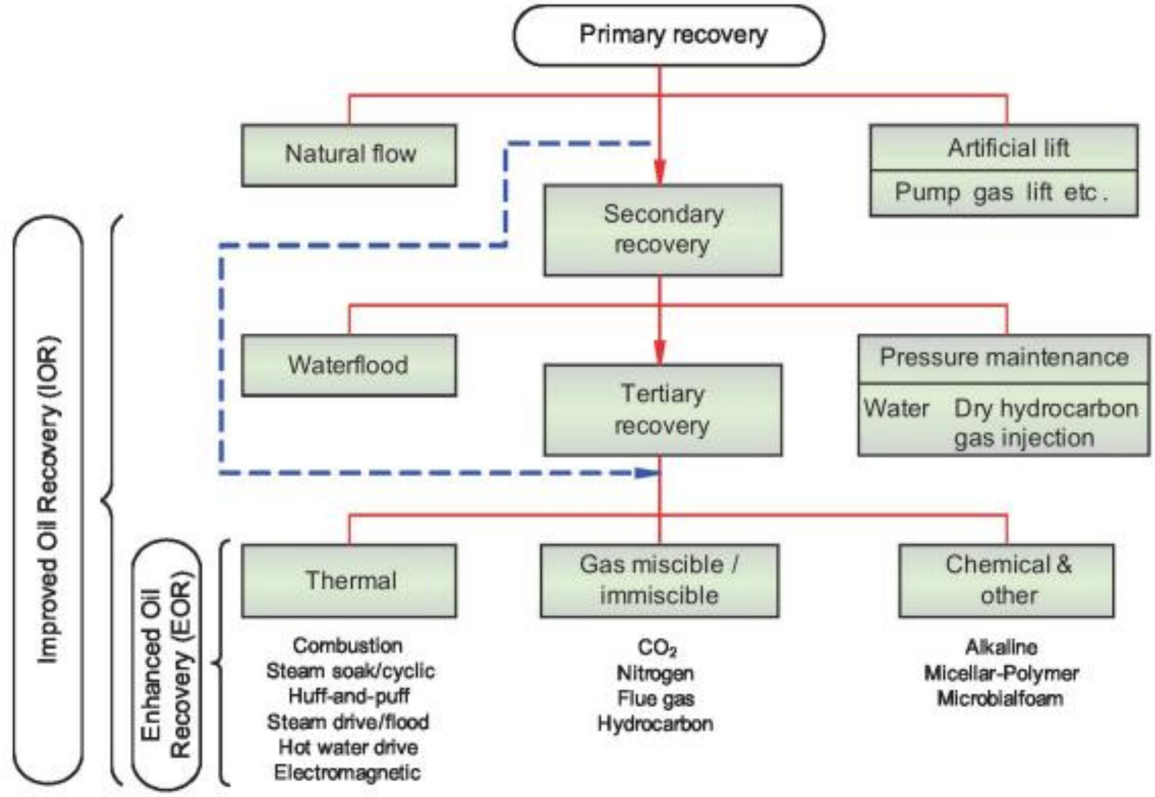


Figure (1.5): IOR and EOR (J. Sečen , 2005).

1.3 EOR Classifications

EOR processes include all methods that use external sources of energy and/or materials to recover oil that cannot be produced economically by conventional means.

EOR processes can be presented in figure (1.6) and classified broadly as:

- Thermal methods: steam stimulation, Steam Flooding (SF), hot water drive, and in-situ combustion.

- Chemical methods: polymer, surfactant, caustic (Alkaline), and Alkaline Surfactant Polymer ASP.
- Miscible methods: hydrocarbon gas, Carbon Dioxide (CO2), and nitrogen, in addition flue gas and partial miscible/immiscible gas flood may be also considered (Ahmed.T,2010).

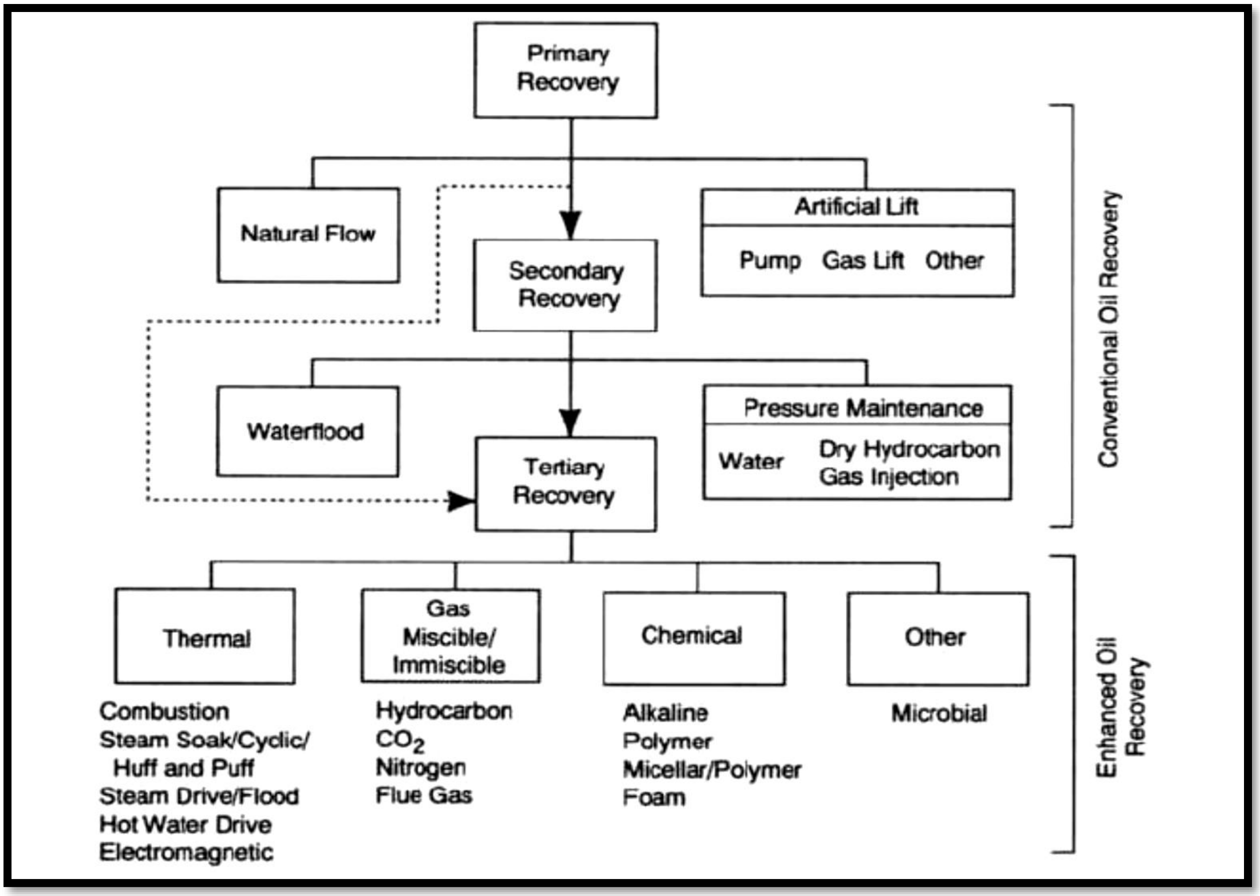


Figure (1.6): EOR Recovery Mechanisms (Ahmed.T,2010).

1.3.1 Thermal EOR (TEOR).

In 1982 Prats, M. indicate that Thermal Enhanced Oil Recovery (TEOR) is a family of tertiary processes defined as "any process in which heat is introduced intentionally into a subsurface accumulation of organic compounds for the purpose of recovering fuels through wells (Prats, M. 1982).

There are many Types of thermal EOR:

1- Steam Injection.
2- Cyclic Steam Stimulation (CSS).
3- Steam Assisted Gravity Drainage (SAGD)
4- In-situ Combustion (ISC).
5- Solar EOR.
6- Electro EOR (EEOR).
7- Heated Annulus Steam Drive (HASD).
8- Steam and Solvent Processes.

1.3.1.1 Cyclic Steam Stimulation (CSS).

CSS is a “single well” process, and consists of three stages, as shown in figure 5 in the initial stage, steam injection is continued for about a month, the well is then shut in for a few days for heat distribution, denoted by soak, following that, the well is put on production.

Oil rate increases quickly to a high rate, and stays at that level for a short time, and declines over several months, cycles are repeated when the oil rate becomes uneconomic, steam-oil ratio is initially 1-2 or lower, and it increases as the number of cycles increase, near-well bore geology is important in CSS for heat distribution as well as capture of the mobilized oil.

CSS is particularly attractive because it has quick payout, however, recovery factors are low (10-40% OIP), in a variation, CSS is applied under fracture pressure, the process becomes more complex as communication develops among wells, figure (1.7) presenting the process of CSS (Tomas,2008).

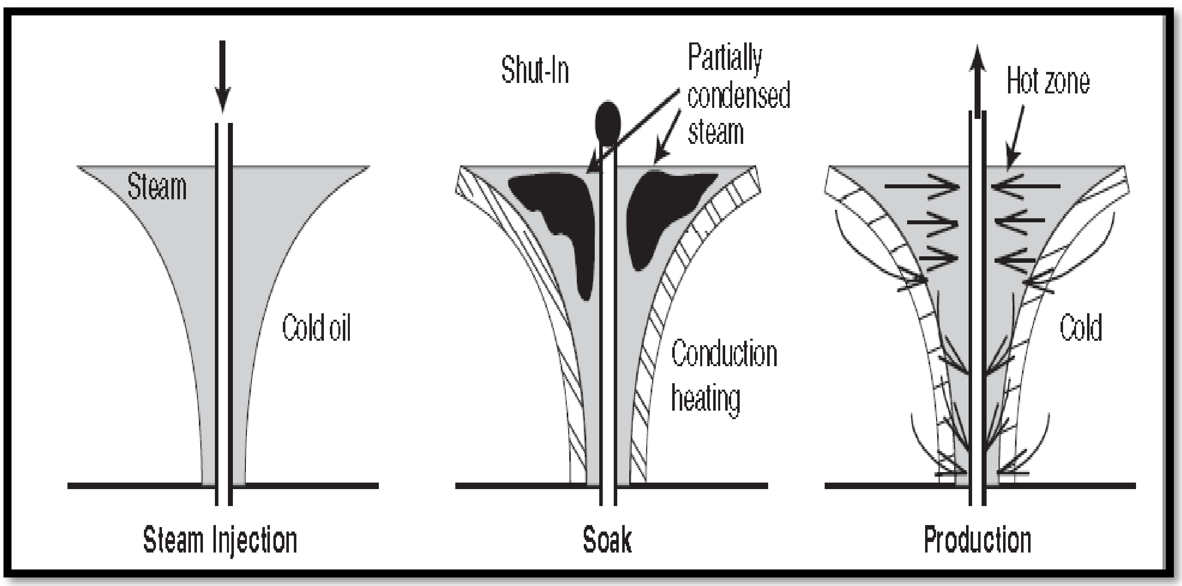


Figure (1.7): CSS Process (Thomas, S, 2008).

Cyclic Steam Injection (CSI) is a single well process and involves the injection of steam for 2 to 6 weeks into a producing well after a short soak period of 3 to 6 days, the well produces at a higher rate for several months to a year also called the huff and puff method, figure (1.8) explain Huff and Puff (Saleem. Q. T, 2011).

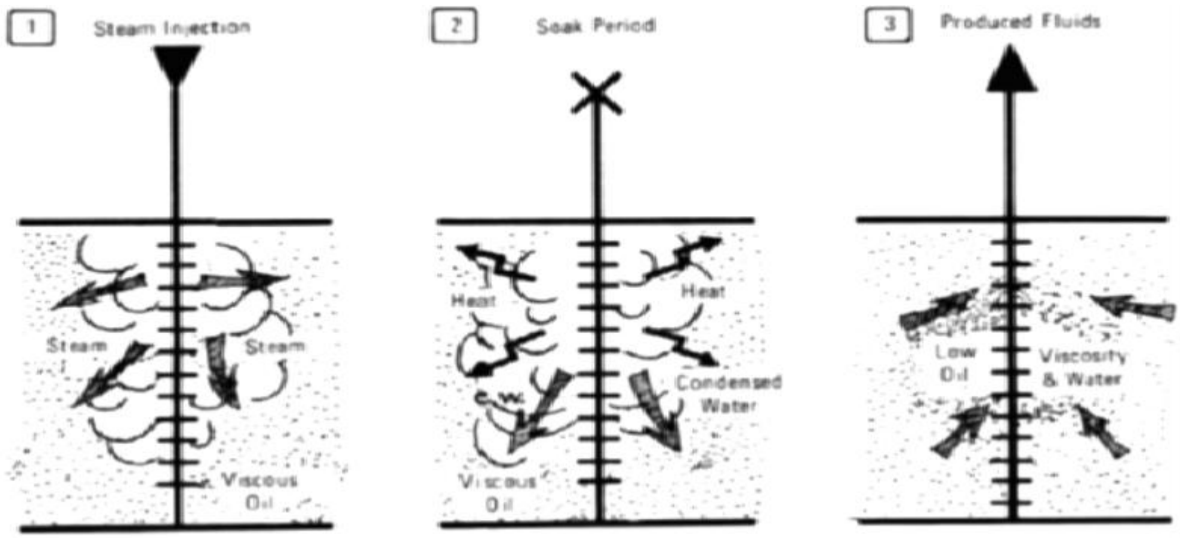


Figure (1.8): Huff and Puff (Saleem. Q. T, 2011).

CSS or Huff and Puff as mentioned earlier, is one of the most applicable thermal EOR methods, it is a three-stage single-well process, its process compromises of a steam injected down hole a horizontal or vertical single well, this single well works as an injector and producer at the same time, the steam injected to raise the oil temperature to that degree which allows the crude to mobile, that means the function of injected steam is to reduce oil viscosity hence increase heavy oil mobility, in other simple words, the steam tends the oil to lose some degrees of its American Petroleum Institute (API) "viscosity reduction" after heating up that oil, figure (1.9) explaining CSS Stages (Johannes A,2013).

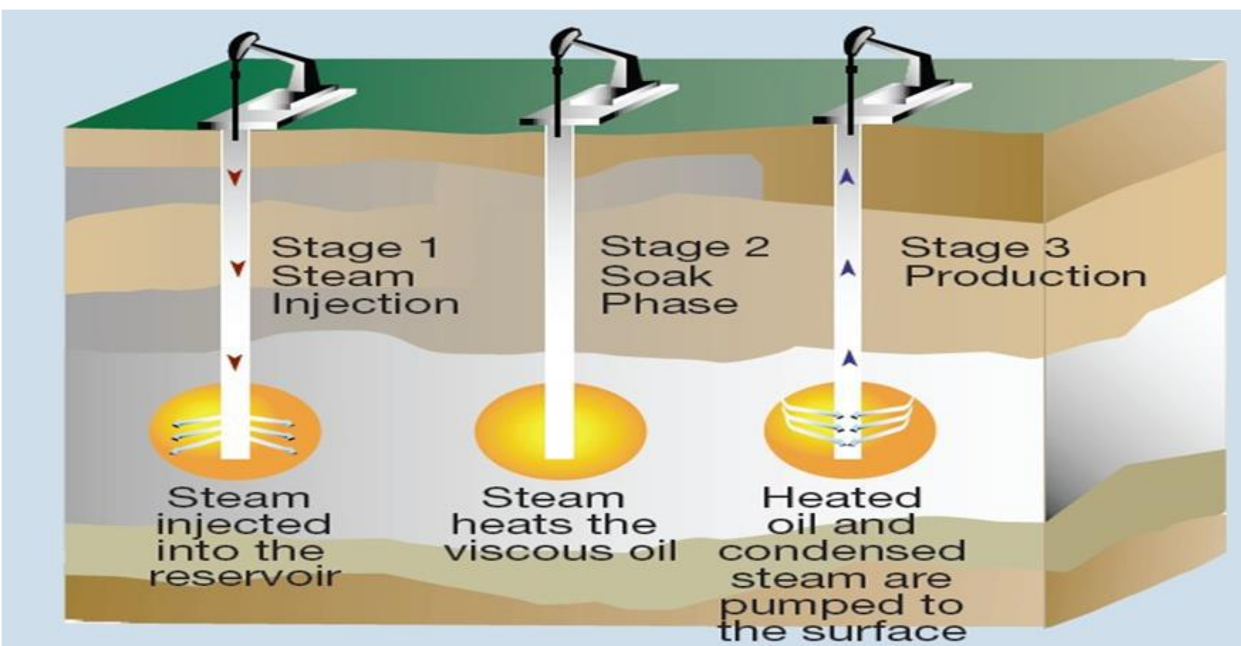


Figure (1.9): CSS Stages (Johannes A, 2013).

1.3.1.2 Horizontal Well.

Horizontal well is horizontal drilling the process of drilling and completing, for production, a well that begins as a vertical or inclined linear bore which extends from the surface to a subsurface location just above the target oil or gas reservoir called the "kickoff point," then bears off on an arc to intersect the reservoir at the entry point, and, thereafter, continues at a near-horizontal attitude tangent to the arc, to substantially or entirely remain within the reservoir until the desired bottom hole location is reached (Robert F.K,1993)

The Advantages of Horizontal Wells Include.

- Reduced water and gas coning because of reduced drawdown in the reservoir for a given production rate, thereby reducing the remedial work required in the future.
- Increased production rate because of the greater wellbore length exposed to the pay zone.
- Reduced pressure drops around the wellbore.
- Lower fluid velocities around the wellbore.
- A general reduction in sand production from a combination of items 3 and 4.
- Larger and more efficient drainage pattern leading to increased overall reserves recovery.

1.3.1.3 CSS in Horizontal Wells.

Horizontal wells are becoming a very important component in the thermal recovery of heavy oil reservoirs, the success of a CSI project depends strongly on the selection of key parameters, such as cycle length and amount of steam injected, the numerical simulation of horizontal wells, especially under non-isothermal conditions, is computationally demanding.

When optimization is combined with numerical simulation, the computing time requirement may be prohibitive and it is not guaranteed that the optimal conditions will be found (Escobar, E,2000).

Horizontal wells are applied increasingly in steam injection projects for recovering heavy-oil (Basham et al., 1998).

There are two important reasons to study CSI with horizontal wells, firstly the thermal efficiency of cyclic operation is high, and it is thus attractive, Secondly cyclic steaming to promote effective initial reservoir heating might precede continuous steam injection during a SW-SAGD recovery process (Elliott.K.T ,1999).

In Iran, there are a number of heavy oil reservoirs whose importance is growing as the conventional resources deplete, this study concerns the numerical simulation of CSS of one of the heavy oil reservoirs, results are encouraging and should be tested by field pilots; heavy oil is characterized by its high viscosity; thermal methods reduce viscosity and residual oil saturation Sor to improve mobility and achieve an economic recovery.

CSS which has faster production, lower capital costs and lower pressure operations than steam-flooding is of great interest in thermal methods, oil recovery with steam injection has been enhanced with horizontal well is by increasing sweep efficiency, the contact area opened to ow, producible reserves, steam infectivity and also by decreasing the number of well ls required so that higher oil production is reached (Razavi, S.D, 2009).

1.4 Problem Statements.

FNE has big STOOIP and low recovery factor, since 2010 only 5% has been produced, low productivity of oil due to property of oil (heavy cold oil), in these thesis feasibility study to increase oil recovery using CSS in horizontal well in Fula North East (FNE) oil filed.

1.5 Objectives.

The objectives of this study are:

- To propose optimum design for CSS in two horizontal wells.
- To study the ability of apply CSS in two horizontal wells in FNE field.
- To know the effect of cyclic steam stimulation in horizontal wells in FNE oil field.
- To determine the optimum direction and optimum length of horizontal section of two wells in FNE felid.
- To comparison between cold Vertical wells and CSS in Horizontal wells in FNE field.

1.6 Introduction to the Case Study.

FNE Oilfield is geographically located in the southwest of Sudan, about 700 km from the capital, Khartoum; structurally located in the north East of Fula sub-basin of Muglad basin and in the southwest of the Moga Oilfield.

FNE Oilfield exploration began in 1989, the first well FNE-1 has been drilled in 2005, it was found one of the largest heavy oil fields in Petro-Enrgy (PE) block 6 areas**,** figure (1.11) determine location of the field (Husham et al, 2018).

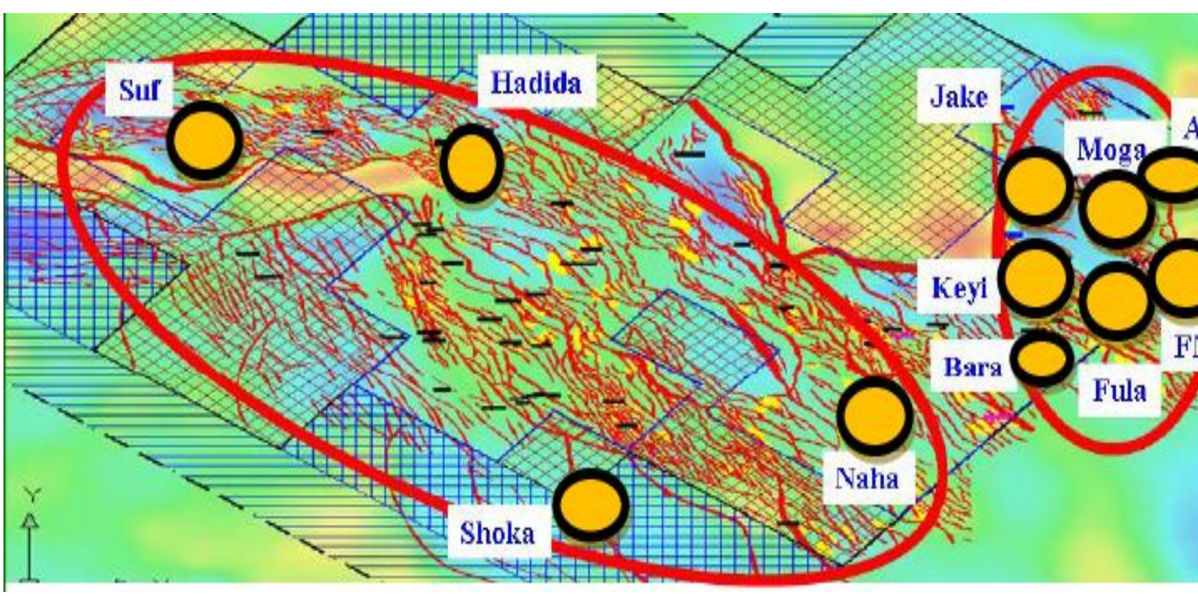


Figure (1.10): FNE Oilfield Location Map (OEPA, 2018).

The oilfield was put into development in June 2010 By May 2011 before the steam flooding study started, a total of 43 wells has been drilled, including one horizontal well; 36 wells have been put into operation, of which 23 wells are producing as cold, and 13 wells for steam stimulation; 33 wells were opened, with a daily oil production of 5722bbl, a daily fluid production of 6097bbl, a water cut of 6.1%, the total Original Oil in place (OOIP) is 298.7 MM Stock Tank Barrel (STB), and the up to date recovery factor of reserves is 0.75%, the average daily production for steam stimulation is 2 to 3 times of the cold wells, Table (1-1) and figure (1.2) summaries FNE OOIP and reserve status (Husham. E, 2016).

Table (1.1): OOIP and Reserve Status (Husham. E, 2016).

Item	CHOPS	Thermal	Total
OOIP (MMSTB)	298.73	298.7	298.7
Enhanced Ultimate Recovery (EUR) (MMSTB)	56	137	137
NP (MMSTB)	3.21	7.54	10.75
Remaining EUR	52.41	131.9	126.3
Up to Date EUR	6.41	3.74	6.36
Expected RF%	18.9	45.96	45.96
Up to Date RF%	1.07	2.52	3.60

Figure (1.11): OOIP, Reserve and Cumulative Oil for FNE (Husham. E, 2016).

From table and figure (1.12) (OOIP) 298.73(MMSTB), estimated ultimate recovery (EUR) by CHOPS 56 (MMSTB) and by thermal 137(MMSTB) Cumulative Oil Production (NP) 10.75 (MMSTB) by CHOPS 3.21 (MMSTB) and by Thermal 7.54 (MMSTB).

1.7 Thesis Outlines.

In this thesis chapter one includes the general introduction of world oil demand, important of EOR and classification, objective, problem statement and introduction to case study, chapter two includes the literature review and theoretical background of CSS, while chapter three is illustrating the methodology starting by designing the optimum injection parameters using Computer Modeling Group (CMG) software, chapter four contains the results and discussion of the research and finally chapter five is the conclusion and recommendations of the study.

Chapter Two

Theoretical Background and Literature Review

2.1 Introduction

In the literature review and theoretical background will description and illustrate steps of CSI and definition of horizontals well, will mention CSI, horizontal well and implement CSI in horizontal well previous case studies in Sudan and around the world.

2.2 Theoretical Background

In the background there will be description for the concept and mechanism of CSI and horizontal well and mention the benefits of each one.

The general mechanism of CSI proceeds through cycles of steam injection, soak, and oil production, first steam is injected into a well at a high temperature for a period of weeks, next the well is allowed to sit for days to week to allow heat to soak into the formation, finally the hot oil is pumped out of the well for a period of weeks or months.

And horizontal wells are high-angle wells (with an inclination of generally greater than 85°) drilled to enhance reservoir performance by placing a long wellbore section within the reservoir.

2.2.1 Cyclic Steam Injection Mechanism.

CSI also called Huff n' Puff, is a thermal recovery method which involves periodical injection of steam with purpose of heating the reservoir near wellbore, in which, one well is used as both injector and producer, and a cycle consisting of 3 stages, injection, soaking and production, repeats to enhance the oil production rate as shown in figure 1.10 steam is injected into the well for certain period of time to heat the oil in the surrounding reservoir to a temperature at which it flows 200~300°C under 1 Megapascal (MPa) of injection pressure.

When enough amount of steam has been injected, the well is shut down and the steam is left to soak for some time no more than few days, this stage is called soaking stage, the reservoir is heated by steam, consequently oil viscosity decreases.

Well is opened and production stage is triggered by natural flow at first and then by artificial lift, the reservoir temperature reverts to the level at which oil flow rate reduces then, another cycle is repeated until the production reaches an economically determined level figure (2.1) presenting the steps of CSS (Johannes. A,2013).

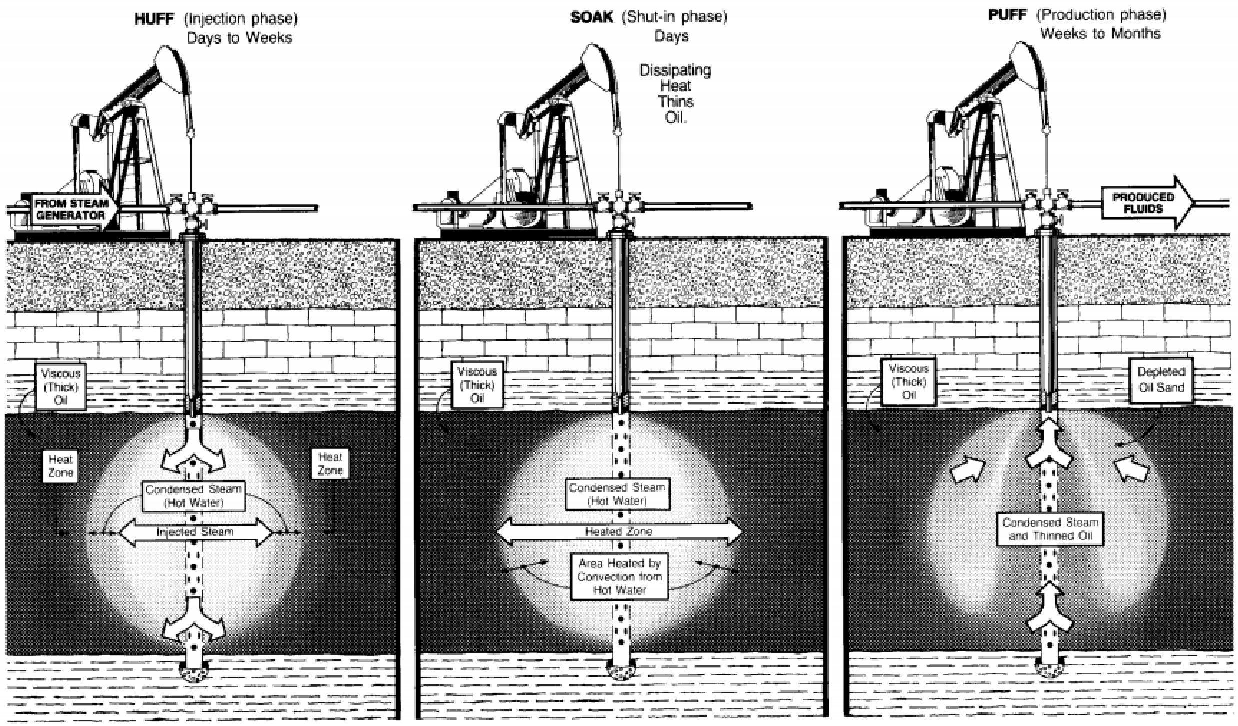


Figure (2.1): CSI Process (Johannes. A, 2013).

Typical CSI process is well suited for the formation thickness greater than 30 ft. and depth of reservoir less than 3000 ft. with high porosity (>0.3) and oil saturation greater than 40%. Near-wellbore geology is critical in CSI for steam distribution as well as capture of the mobilized oil. unconsolidated sand with low clay content is favorable, above 10 API gravity and viscosity of oil between 1000 to 4000 Centipoises (cp) is considerable while permeability should be at l East 100 md (Thomas, S,2008).

Figure (2.2) describing three phases of CSS, first, high-temperature, high-pressure steam is injected for up to one month, Second the formation is allowed to soak for one or two weeks to allow the heat to diffuse and lower the heavy oil viscosity, third heavy oil is pumped out of the well until production falls to uneconomical rates, then the cycle is repeated, until production can no longer be recovered, artificial lift is required to bring the heavy oil to surface.

The steam heats the reservoir in the vicinity of the well bore, and thus causes a reduction in oil viscosity where the converging oil stream experiences the highest resistance to flow, this increases the oil production rate by making warmed heavy oil back into the well, however the steam injection contributes little to the physical mechanisms that move the oil to the well, therefore reservoirs with little or no primary energy are not suitable candidates for steam injection.

CSI is suitable for the reservoirs with the following characteristics: depth: the minimum depth for applying CSS is on the order of 1,000 feet, Porosity: should be no less than 30%, Permeability: good horizontal permeability is important for production, thick pay zone: this process is economical on reservoirs that contain pay zones of 10 meters and above (Syed.A, 2012).

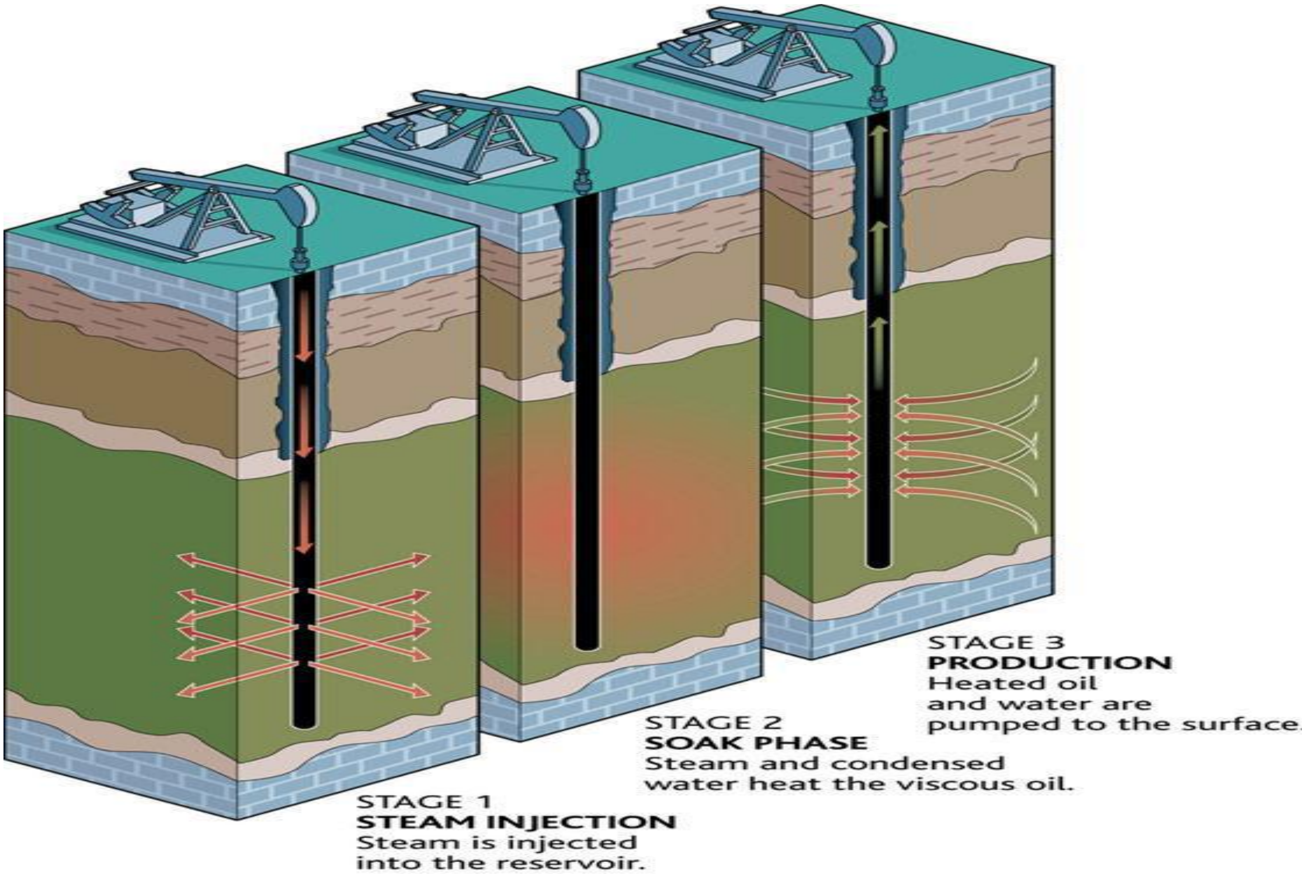


Figure (2.2): Stages of CSI (Syed.A, 2012).

CSS technique simply using an injection and extraction process, it injects steam down hole and heated bitumen which facilitates the extraction process, this inclusive process contains a number of sub processes (injection, heating, flow and extraction) which combined together to make a cycle, each cycle composes of three phases:

A-Injection Phase:

It's the first step which by it a cycle of CSS begins to operate, so as previously noted, an amount of hot steam must be injected into a certain well (it doesn't matter horizontal or vertical) for a small duration, then a chamber is generated from that injected steam for pressure maintenance in the formation to make a pressure build-up facing the pressure of the injected steam.

As everyone knows, it has become a truism that the temperature is directly proportional with the viscosity especially in liquids, that means by the increment of the reservoir temperature, the viscosity of the crude is always decreases which helps in getting more initial oil rate, in additional augment in the oil velocity is noticed due to a rising in the reservoir pressure adjacent the wellbore.

While this phase "injection phase", the steam saturation degree of temperature is put equal to the average temperature of the chamber which is formed by the injected steam, after this degree is reached the injection period has been stopped and the soaking period is had to start by closing the well for a while until the chamber of the steam is created and the temperature is begun to rise.

B- Soaking Phase:

This is the shut-in period in the CSS cycle for the preparing and fulfillment of the injection goals and objectives, during soaking the well is closed for a certain short duration which is selected precisely making the chamber expands by extending of the steam and allowing the steam to reach to further possible point in the formation to heat a bigger possible area.

Due to the gravity segregation the chamber of the steam and the crude oil after the heat distribution takes place to decrease crude viscosity, surely the lighter component will raise upwards and another one will force to drop downwards because of its density, Therefore the heavier component "oil" will go downwards while the steam which is the lighter one floats up inside the reservoir due to gravity effect.

When looking from the side of heat transfer study, it can be logically considered that this segregation happened by convection process between two fluids with different densities aiming in the enhancement of the whole process, the soaking time is a sensitive phase affected by the fluid's properties and it's an achievement step to the injection phase, as the soaking period decreases, the ratio of the produced oil to that oil in place increases.

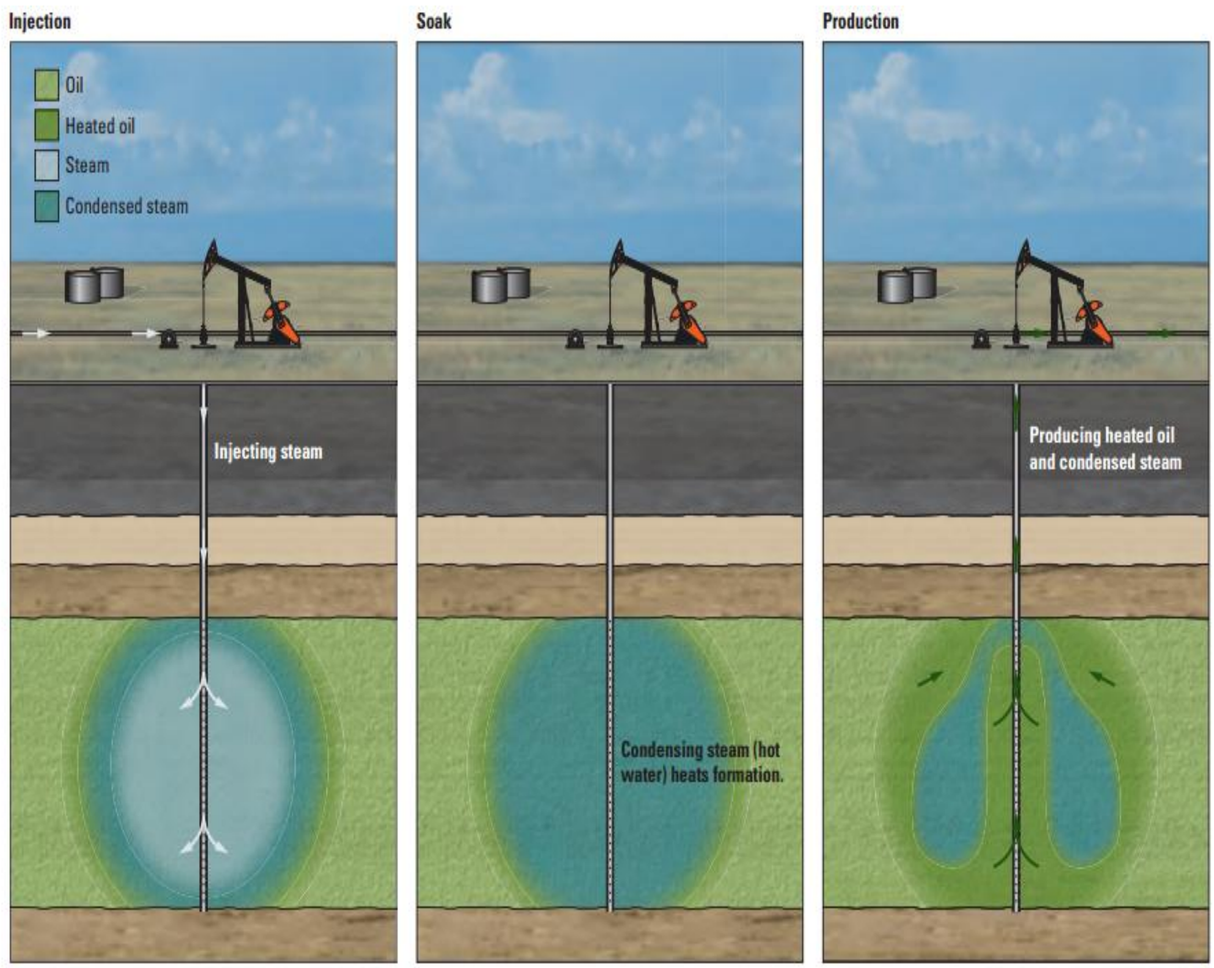
C- Production Phase:

This phase is the last phase in a single CSS cycle, it comes directly after the small duration shut-in period "Soaking time", as noted earlier, the oil which is heated by the hot injected steam is forced to go down in the reservoir according to the density differences and gravity segregation effect and due to the variety in the pressures inside the well which will produce, after that the well will start to produce this oil.

By the injection of the hot steam many zones have been heated and its degree of temperature will be large affecting in the initial oil rate which will become higher, by passage of time, more oil will be produced and that high degrees of temperature in the heated zone will decrease leading to the decline of that initial rate, then the injected steam will again continue heating the oil which its temperature decreased and it became in a cold area in the zones which previously heated.

The increment of the temperature is followed by the decrement of viscosity of the crude oil which leads to a high enhancement in the oil producing rate when comparing with the production without CSS, the variety in pressures and the gravity segregation effect is combined together to represent the two-essential mechanism in the CSI to induce oil (Johannes A,2013).

In addition, the chamber of the steam which had been begun during the injection phase and completed in the Soaking period by the increment of the oil production continues expanding to compensate that produced oil and replaces it to conserve the reservoir energy and figure (2.3) explaining the CSS (Rifaat.A,2011).



^ Cyclic steam injection. This single-well process injects steam into the near-well region for days to weeks (*left*). The soak period lasts a few days (*middle*) during which time the heat reduces the oil viscosity. Production follows for an extended period of time (*right*). The cycle can repeat, or the well can be converted to an injection well in a pattern flood.

Figure (2.3): Cyclic Steam Injection (Rifaat.A,2011).

2.2.2 Horizontal Well Mechanism.

Horizontal drilling is the process of drilling and completing, for production, a well that begins as a vertical or inclined linear bore which extends from the surface to a subsurface location just above the target oil or gas reservoir called the "kickoff point," then bears off on an arc to intersect the reservoir at the "entry point," and, thereafter, continues at a near-horizontal attitude tangent to the arc, to substantially or entirely remain within the reservoir until the desired bottom hole location is reached, figure (2-4) explaining the different between horizontal and vertical well (Joshi, S.D,1991).

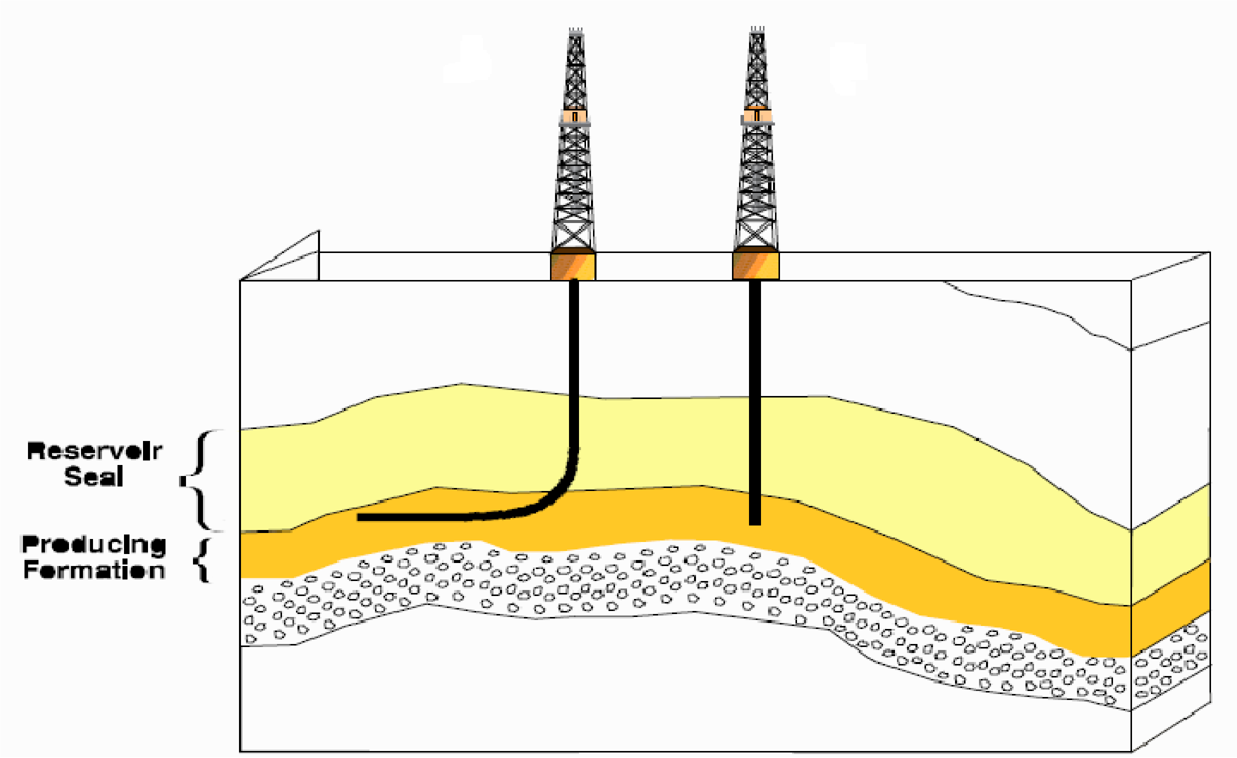


Figure (2.4): Horizontal Well, (Joshi, S.D,1991).

Since 1980, horizontal wells began capturing an ever-increasing share of hydrocarbon production Horizontal wells offer the following advantages over those of vertical wells:

1. Large volume of the reservoir can be drained by each horizontal well.
2. Higher productions from thin pay zones.
3. Horizontal wells minimize water and gas zoning problems.
4. In high permeability reservoirs, where near-wellbore gas velocities are high in vertical wells, horizontal wells can be used to reduce near-wellbore velocities and turbulence.
5. In secondary and EOR applications, long horizontal injection wells provide higher infectivity rates.
6. The length of the horizontal well can provide contact with multiple fractures and greatly improve productivity (Ahmed.T,2010).

2.3 Literature Review.

In the literature review will illustration of previous case studies for CSI, horizontal wells and CSI in horizontal wells in Sudan and around the world, this study is the first study in Sudan's oil field about CSI in horizontal well, so no case studies about CSI in horizontal wells in Sudan has been pulsed before.

2.3.1 Cyclic Steam Stimulation CSS World Case Studies.

Chiou, R (1989) described the performance of a cyclic steam pilot project in a steeply dipping, (40 degrees) heavy oil reservoir in the Sho-Vel-Tum field in southern Oklahoma, the cyclic steam response shows a significant increase in oil production, as expected relative to pre-stimulation production.

Ali, S. M. F (1983) presents a numerical treatment of the phenomena involved in this process, viz. fluid flow in CSS, formation parting, fracture propagation, and closure, the latter part of the model involves the calculation of stresses and strains in the formation as well as in the surrounding rocks, as a result of pressure and temperature changes, which are used to calculate the fracture length at various times.

Mao, M. L (2000) describes an innovative system to measure continuously, from surface to downhole, the pressure, temperature, and spinner responses in these steam injectors, compelling data is presented to evaluate wellbore heat loss, steam injection profiles, and reservoir properties, the analysis of pressure fall-off curves yields wellbore skin and reservoir permeability, a new model to analyze temperature fall-off curves, by applying the marx- langenheim theory and a new set of type curves, yields heat transfer coefficients and steam swept zone size in the reservoir.

Batycky (1997) the unprecedented commercial success of in situ bitumen recovery by CSS) at Cold Lake has relied on progressive reservoir interventions that have increased bitumen recovery levels to 25% of OBIP, these interventions were the consequences of continual improvement in understanding of how the CSS recovery process works.

A mechanistic model has now been developed describing the recent progress in describing CSS process physics.

Pascual, M. R. (2001) describes the studies, implementation and results of the first cyclic steam pilot project in the Los Perales Field located in the San Jorge Basin, in the province of Santa Cruz, Argentina.

The well-produced almost a year before it reached the forecasted primary oil production, the history match had a good fit with the gontijo and aziz analytical stimulation model that was prepared by the people of Repsol YPF, the well is being prepared for the second cycle.

Putra, E. A. P, (2011) presents the result and effect of CSS to well and offset wells production rate and fluid properties, many experiences acquired from the project of CSS perform in Sihapas formation, one of them is the effect to offset well that indicates there is a connection and high heat conductivity between wells.

Incremental of initial production rate about 40% occurred in first well, in second well, this operation gives an effect to offset well with the incremental of production rate reach 100% in nearest well, oil properties changes with different in viscosity, oil gravity and pour point value after CSS

(Bott, R. C. 1967) discusses the production techniques and results obtained by the first two CSI wells in the virgin vaca tar sand, the two wells drilled by American Petrofina Co. of Texas and partners are located 1,700 ft. apart.

One well was partially successful before being shut in due to mechanical problems, the second well is now in its fifth cycle and has recovered 43,900 bbl. of the 5 deg, API oil in 18 months this project illustrates a situation where thermal recovery has provided an effective production technique for a reservoir which previously had been considered nonproductive.

Ambastha, A. (2001) presents Cymric 1Y is a heavy oil diatomite reservoir in California, U.S.A. with an estimated original oil-in-place (OOIP) of 425 MMSTB, diatomite reservoirs have low permeability (average of 5 md or less) and high porosity (50-60%), results show that fine grids (of the order of one ft.), perpendicular to the steam-induced fracture orientation, are necessary to properly capture the effects of sharp temperature and saturation gradients in the primary fluid flow direction.

Initial saturation, reservoir matrix permeability, fracture half-length, capillary pressure, and flowing bottom-hole pressure were identified as key parameters at Cymric 1Y, results also show that the cyclic steam development at 5/8-acre may result in 22% recovery, infilling to 5/16-acre spacing could increase the recovery to 34% OOIP.

Payne, R. W.,.(1965) discusses the past four years the Creole Petroleum Corporation has been actively testing the use of steam as a production stimulant in the quasisquare Field of Eastern Venezuela, the method being tested is the so-called "huff- and-puff" method where steam is injected into the formation and the well later returned to production, this method of stimulation has been used for eight wells in the quasisquare field, in the most successful case, a well-produced 60 percent more oil over a 490-day period following start of steam injection than would have been obtained had the well been produced in its normal fashion.

2.3.2 Horizontal Well World Case Studies.

Marino, A. W, (1992) reviews the Yowlumne horizontal well was completed in March 1991 at a measured depth of 14,005' (11,253' true vertical depth), the 2252' horizontal lateral developed a thin Stevens Sand interval that could not be economically developed using vertical wells.

The increased pay exposure and drainage radius from a horizontal well provided higher rates and reserves, at lower capital and operating costs, than vertical wells, the horizontal well has produced at more than three times the rate of previous vertical wells in this part of the Yowlumne field.

Al-Haddad, S. M., (1991) pointed out many horizontal wells are being drilled all over the world, one of the objectives is to increase the well productivity, compared to vertical wells, this increase in productivity occurs in a naturally productivity occurs in a naturally fractured reservoir because many fissures are intercepted by the horizontal well.

the horizontal well, in general, gives a lower water oil ratio and a higher cumulative oil recovery. It was also found that the horizontal well productivity is better in low matrix productivity is better in low matrix permeability, fractured reservoirs, permeability, fractured reservoirs.

Hardman, P. (1989) pointed out that BP Petroleum Development Ltd. successfully drilled and completed the first horizontal well in the United Kingdom as part of its 1985 R and D program. The well, Buckingham 36 (BK 36), was drilled on an existing land field near Gainsborough, U.K. This discusses the detailed planning for and the execution of the drilling operation, conclusions and recommendations are presented for future wells.

Gonzalez, O. R. (1990) In recent years, horizontal operations involving drilling and well completion techniques in the oil and gas industry have increased considerably, and the main reasons for this are economic feasibility and good production results.

Focusing primarily on the drilling and completion techniques, very little attention has been placed on the workover aspects; therefore, this has been written in an attempt to describe the workover experience gained from well TJ-1095, drilled in Lake Maracaibo by lagoven, S.A., a subsidiary of petroleum de Venezuela (PDVSA).

Koonsman, T. L.,(1992) reviews the Ness field has contributed significantly to the oil production volumes and revenue for the partners in the Mobil-operated Block 9/13 in the U.K. sector of the North Se, when the horizontal well was drilled, the partners were Amerada Hess, enterprise oil, North Sea holdings, and mobilm at the end of 1988, production rates began to decrease because of water production, which was thought to be caused by water coning, by Summer 1989, it was apparent that additional production wells had to be drilled to maintain a plateau production rate, alternatively, the partnership would have to accept an extended production life associated with increasing water production rates production life associated with increasing water production rates and lower ultimate recovery.

Sharp, D. A.(1989) the Winter pool, a heavy oil reservoir located in the L1oydminster area of Saskatchewan, was selected as a suitable candidate for the introduction of a horizontal well production system, an initial two-phase program comprised of five horizontal wells and four vertical monitoring wells has been undertaken by CS resources and its partners to evaluate the applicability of horizontal wells to improve primary production, reservoir performance will be assessed within the context of ultimately employing other enhanced recovery methods to compliment horizontal wells.

Tzanco, E. (2000) pointed out the history of horizontal drilling in North America, although brief, has been one filled with dramatic developments, nearly 95% of all the horizontal wells drilled in the world are in Canada and the United States, the development of horizontal well technology in the US brought revolutionary advances to the drilling sector such as the development of poly-crystalline compact bits, downhole drilling motors, top-drive drilling rigs, logging-while-drilling, geo-monitoring with steerable drill systems, and re-entries from existing vertically cased wells with coiled tubing, these achievements were accomplished mainly in the Austin chalk of texas (1989) and the bakken shales of North Dakota (1991), these tools brought a higher drilling rate, lower drilling cost, reduced rig time, better interpretation of the drilling bit position, and faster geological descriptions.

2.3.3 Cyclic Steam Stimulation in Horizontal Well World Case Studies.

Mirza, M. (2014) Medco LLC has initiated steam stimulation of horizontal wells using CSS injection and production within the same well, the wells located in the Southern Oman, area of biodegraded oil with heavy oil viscosity as the main characteristics, horizontal wells typically yield a higher primary recovery than vertical wells due to their larger contact area with the reservoir, this paper described the started from the completion design, cold production performance, preparation and the execution as well as well evaluation of the practical application of CSS are the main keys to understanding reservoir performance and identifying that opportunities of steam stimulation will improve the ultimate recovery.

Mendoza, H. (1997) has initiated steam stimulation of horizontal wells using two processes: conventional (CSS) and Single-Well Steam Circulation (SWSC), horizontal wells typically yield higher primary recovery than vertical wells due to their larger contact area with the reservoir; with the use of steam as both heating and lifting agent, additional recovery is achieved.

The well completion designs utilized conventional equipment to minimize costs and to focus efforts on the new stimulation processes with the use of standard completion, preliminary results for SWCS in the Tia Juana field indicate success as one well has increased its oil production rate by 200 Barrel Oil per Day, (BOPD) for one year, the results for CSS in the Becquerel Field indicate 1000 and 600 BOPD as initial productions.

Escobar, E, (2000) mention in this research, a new methodology has been developed for optimizing the CSI process for vertical and horizontal wells, the optimization algorithm was successfully validated with published results obtained from the discrete maximum principle, the methodology was then applied to determine the optimal conditions of CSI for a horizontal well located in Becquerel field, Venezuela.

Uribe Hidalgo, C. A. (2013) this paper illustrates the technical and financial evaluation of applying CSI using horizontal wells in these fields, using the injectivity and the benefit of the location Horizontal wells, and viscosity reductions product with steam heating, to carry out this process, it was evaluated the effect of each operational and reservoir parameters.

Once the best scenario was determined it was performed a sensitivity and process optimization, seeking operating conditions that showed the best results with CSI in horizontal wells, for further financial analysis that would provide a comprehensive feasibility study.

Cosentino, L. (1998) Bachaquero) this paper presents the results of development of 2 field (Lake Maracaibo, Venezuela) a multi-disciplinary project focused on the drilling of a pair of horizontal wells for CSI, the project involved a reservoir characterization and a numerical simulation phase, the drilling, steam injection and production of these wells, a data acquisition project and eventually a final detailed simulation stage.

The experience allowed us to set the best production strategy for the 2-horizontal well system, in terms of sequence and duration of the cycles, steam rate, total injected steam, steam quality and soak time, it also helped in setting guidelines for the future development of the Becquerel 2 Field.

2.3.4 Cyclic Steam Stimulation CSS Sudan Case Studies.

Wang, R, (2011) demonstrates the first CSS) pilot test in Sudan, which was applied in FNE shallow heavy oil reservoir, B reservoir of FNE field is a shallow, heavy oil reservoir with strong bottom water, burial depth is 520 m.

Well tests have shown low oil rates under cold production, averaging at 50-150 BOPD. Successful CSS pilot test in this paper highlighted CSS well screening criteria, perforation strategy, steam injection optimization and natural gas utilization, giving a cost-effective staircase for CSS pilot design and implementation.

Tewari, R. (2011) illustrates the successful design, implementation and evaluation of CSS pilot in heavy oil field of Sudan, this field contains heavy oil in multiple reservoirs of Bentiu formations of late cretaceous age occurring at depths of 550-600m.

Reservoirs are highly porous (~30%), permeable (1000-2000 mD) and unconsolidated in nature. Fluid properties include viscous crude of degree API 15 - 17 and corresponding viscosities in the range of 3700 cp and 3000 cp at reservoir conditions, Actual results are better than predicted in simulation studies with lower steam intensity of 120 m3/m compared to planned 160m3/m.

Wu,Y. (2013).In this paper, mention according to the petro physical properties and geologic characteristics of the target block F in Greater Fuld oilfield in Sudan, based on the oil test results, detailed 3D geologic model is established and the type well model for CSS and SF is extracted, to study the real performance with the real geological properties, the simulation results indicate that the thermal recovery technique especially 4 cycles of CSS followed by SF can acquire satisfied performance, which shows an effective and economic future in the development of the heavy oil deposits in Greater Fula Oilfield.

Wang, R. (2011) demonstrates application of Cold Heavy Oil Production with Sand (CHOPS) in Sudan, which has been successfully applied in B heavy oil reservoir of FN field, B reservoir is a series of massive sandstones with strong bottom water drive, which are loosely consolidated and interbedded with shale barriers, burial depth is 1250m average net pay thickness is 35 m, in-situ viscosity is around 300 mPa.s, cold production well tests indicated average productivity of 500

BOPD,2-3 times of sand-controlled productivity Successful CHOPS in this paper highlighted fine barriers (interbed/ intrabed) characterization and optimized perforation strategy, infill well drilling, optimized borehole lifting and facilities design, giving a cost-effective staircase for CHOPS implementation.

2.3.5 Horizontal Wells Sudan Case Studies.

Liu, B. (2010) demonstrates the two main target formations of shallow horizontal wells in Sudan are Bentiu formation and Aradeiba formation, they are becoming more and more important with the exploration of oilfield, and they are all about or shallower than 1000m underground, we get the pore pressure, collapse pressure, and the fracture pressure by studying the formation pressure system using professional software upon the logging data.

Study the relationship between the content of clay and the stability of borehole, it shows that the clay content has significant effect to borehole stability in Sudan, then we analyze the collapse period of the upper stratums, based on the results and the study of the data of those wells drilled, the horizons of leakage and collapse are indicated, according this and the formation pressure, we optimize the whole structure and casing program, finally the KCl-polymer system is sifted as the drilling fluid, we determine the mud density according to the formation pressure first.

Now there are 5 shallow horizontal wells have been drilled in Sudan, the research achievements have been applied in the drilling operations, the average drilling cycle is about 17 days, moreover, the hole diameter enlargement rate is decreased remarkably.

After previous studies in the world and in Sudan case study about CSS and horizontal wells, this research study the possibility of applying CSS in horizontal wells in FNE field as case study in Sudanese oil field using real model for simulation by CMG Software and the prediction of the field performance till 2030, this study can be concern as the first study to illustrate the effect of CSI in horizontal wells in Sudanese field, therefore there are no scientific papers study the effect of CSI in horizontal wells in Sudan.

Chapter Three

Methodology

3.1 Introduction.

FNE reservoirs are highly porous (~30%), permeable (1000-2000 md) and unconsolidated in nature, the fluid properties include viscous crude with 15 to 17.7 API. Corresponding viscosities are in the range of 250 cp and 500 cp at reservoir conditions.

The analysis will be done through steps in order to identify the main reason of the problem, and then propose the suitable solution, which will be applied to do the simulation model for the new cycle optimization (Husham et al, 2016).

3.2 Computer Modeling Group (CMG).

CMG company began in 1978 as an effort to develop a simulator by Khalid Aziz of the University of Calgary's Chemical Engineering department, with a research grant from the government of Alberta.

A commercial product was being sold by late 1980s, for the first 19 years of the company's history it was a non-profit entity, in 1997 it became a regular public company when it was listed on the Texas (TSX), the company now claims over 400 clients in 49 countries figure (3.1) presenting CMG product (CMGL, 2016).

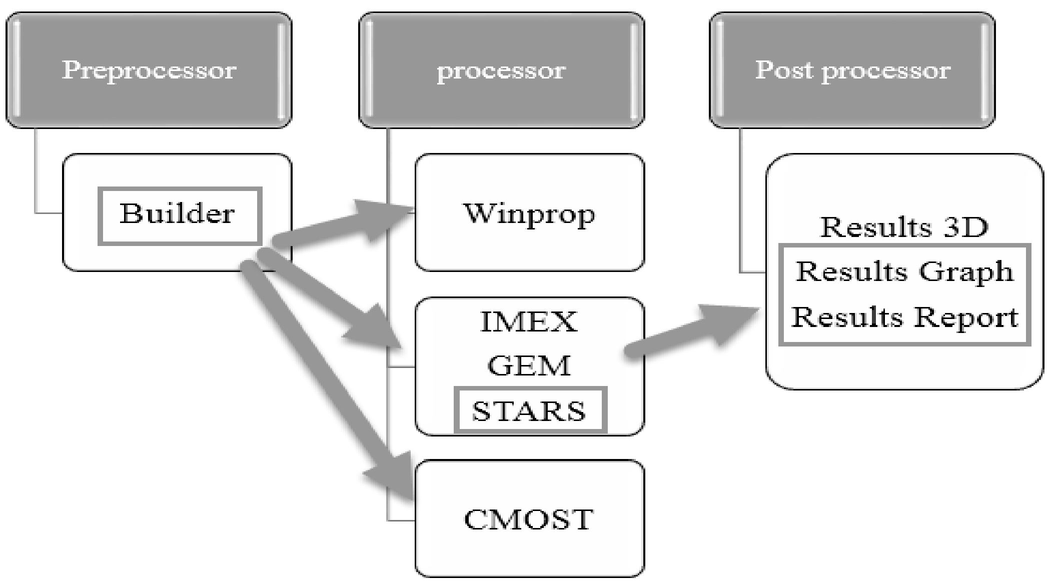


Figure (3.1): CMG Product (CMG, 2016).

STARS -Thermal and Advanced Processes Reservoir Simulator

STARS is the undisputed industry standard in thermal and advanced processes reservoir simulation, STARS is a thermal, k-value (KV) compositional, chemical reaction and geomechanics reservoir simulator ideally suited for advanced modeling of recovery processes involving the injection of steam, solvents, air and chemicals, the robust reaction kinetics and geomechanics capabilities make it the most complete and flexible reservoir simulator available (CMG, 2016).

3.3 Methodology.

1. Collect the data (model of FNE-physical properties).
2. build different models with different conditions Using CMG Software.
3. Running Models.
4. Analysis of the Result.
5. determine the best condition.
6. build the now model based on the previous result.

3.3.1 Location Sensitivity Methodology.

1. build model with different location wills based on porosity and oil saturation.
2. run the model.
3. analysis the date (compare between cumulative oil produced for all wells).
4. Determine the best location based on productivity

3.3.2 Horizontal Section Sensitivity.

1. build model with different location wills, different horizontals section and different direction of horizontals section.
2. run the model
3. analysis the date (compare between cumulative oil produced for all wells).
4. Determine the best horizontals section length and best direction based on productivity.

3.3.3 CSS Sensitivity.

1. Based on the location sensitivity, length and direction of horizontals section from privies study
2. Build models with different CSS condition (T, Q, flowrate injection period soaking period)
3. run the model
4. analysis the date (compare between cumulative oil produced for every models).
5. Determine the best condition of CSS.

3.3.4 Methodology Using Software in Steps.

1. Open CMG launcher click on browse for folder click on Select the file location.
2. Drag the file of model (.dat) on the builder.
3. click on well and recurrent right click on wells click on new.
4. Name (write name of the well-1003) type (chose type of the well-producer) click on OK.
5. well and recurrent wells show the new additional wells click on the (+) near the selected well(well-1003) double click on (perf) click on Perforation than click on the (insert before selected node) and insert in the (user block address) to insert the perforated cell or can use (Begin) button and use mouse to determine the perforated cells (Begin button usually use to perforated horizontal wells) than OK.
6. Repeat the previous steps for all wells to determine the perforated cells for every well.
7. To determine the best location of wells (location sensitivity), change the location of wells and compare between result of cumulative oil for every well.
8. To determine the best direction of horizontal section (direction sensitivity), change the direction of horizontal section in many directions for same well and compare between result of cumulative oil for every direction.
9. To determine the best length horizontal section (length sensitivity), change the length of horizontal section of same well and compare between result of cumulative oil of every length.
10. To determine the best parameter of CSS-temperature, quality, injection rat, injection period, soaking period (CSS sensitivity)
11. click on the well click on copy wells click on select the wells than click on next click on next than click on select copy geometry (default that geometry will be used if not copied) click on next click on next than click on finish.
12. To determine the production parameter
13. click on Wells and recurrent than wells double clicks on well-1003 click on type select producer.
14. click on Constraints click on constraint definition than constraint select OPERATE in Parameter select BHP bottom hole pressure in Limit/Mode select MIN in Value select 200 KPa.
15. In Constraint click on constraint select operate than Parameter select STL surface liquid rate in Limit/Mode select Max in Value select 200 m3/day than apply.
16. To copy the Event for other producer, select the new Event in the well (producer, constraints) right click on the selected event click on copy Events using filter than select the wells that need same production parameter (need same Event) than Dates to select the date of copy the Event than double click on (search and add) click on OK.
17. Repeat the previous steps for all wells to determine the production parameter for every well.
18. To determine the injection parameter for well-1003
19. click on Well and recurrent double click on well-1003_inj select the type of the well (injector mob weight explicit) click on apply.
20. In Constraints click on constraint definition click on constraint select operate than in Parameter select BHP bottom hole pressure in Limit/Mode select Max than in Value select 12000 KPa.

21. In Constraint click on constraint select operate click on Parameter select STW surface water rate than in Limit/Mode select Max and in Value select 250 m3/day than click on apply.
22. To determine the best injection rate (injection rate sensitivity) change the Value select in (STW surface water rate) change injection rate and compare between result of cumulative oil of every injection rate.
23. Then select injection fluid click on injection fluid select water click on mole fraction add number (1) near H2O.
24. Click On temperature write temperature 200C.
25. To determine best temperature (temperature sensitivity) change temperature of fluid and compare between result of cumulative oil of every temperature.
26. Click on steam quality write steam quality 0.5.
27. To determine best steam quality (steam quality sensitivity) change quality of steam and compare between result of cumulative oil of every steam quality.
28. Then apply.
29. To copy the Event for other injectors, select the new Event in the well (injector, constraints, injection fluid, steam quality steam temperature) right click on the selected event click on copy Events using filter than select the wells than need same injection parameter (need same Event) than Dates to select the date of copy the Event than double click on (search and Add) than click on OK.
30. To add wells in groups
31. click on Wells and recurrent right click on groups click on new Write field in name of group than click on add new group.
32. Write Group-1 in name in parent group select field than OK.
33. click on Well and recurrent click on (+) near the groups double click on the (2009-05-06 group)
34. Click on the group-1 than Attached wells in well Group select (group -1) than select the well-1003 with well-1003_inj and apply.
35. And attached all wells with the injectors which have same name and same parameter.
36. In Group Events select (group-1) select cycling group than select cycle part number (3) click on production and water injection.
37. In steam target types select production in value 3select (STL-stock)
38. In Min inj rate for cycle switching select add/remove in value 1write 70m3/day Than in other options Select in max cycle part duration click on add/remove than in value1 write 14 day in value 2 write 3day in value 3 write 348 day this step is to determine the duration of cycle(value 1 for injection period, value2 for soaking period, value 3 for production period) for injection period sensitivity change injection period and compare between result for cumulative oil of every injection period , and for soaking period sensitivity change the soaking period and compare between result of cumulative oil for every soaking period .
39. Then select add/remove in stating time step size in value 1, value 2and value3 write 0.1
40. In total number of cycles select add/remove and write 20 than OK.
41. To copy the previous parameter for other wells right click on concyclic in Group-1 and click on copy events using filter than select the groups than click on dates to determine the date of copying the data than double click on search and add than OK.

42. To run any model, click on (validate with STARS) in main screen of the software select Run normal immediately than click RUN after model run analyses the data and compare the result to determine the best result.

Chapter Four
Results and Discussions

4.1 Introduction.

FNE consist of 23wells on CHOPS, 8wells have been converted from CHOPS to CSS 4wells (3rd cycle) 4wells (4th cycle) 25wells started with CSS: 3wells (1st cycle) 12wells (3rd cycle) 8wells (4th cycle) 2wells (5th cycle), then the total number of wells is 56, it has two main Pay Zones, Aradeiba with OIIP: 33.23 MMSTB and Weak edge water, second Bentiu (a, b and c) with OIIP: 265.5 MMSTB, massive sand, burial depth (460~580 m) and Bottom water support

Pressure and Temperature System.

At 529 m depth the average pressure is 576 Pound per Square Inch (psi) and the average temperature is 43.9^{0}c.

Reservoir Fluid Properties.

Conventional heavy oil in both Aradeiba and Bentiu, table (4.1) summarizes fluid properties of FNE oil field (Husham, 2016).

In order to implement CSS in this field the Screening Criteria has been used for thermal recovery of FNE can be summarizes in Table (4.3).

Table (4.1): Crude Oil Properties and Water Properties of FNE Oil Field (Husham, 2016).

No.	Crude properties	
1	API	17.7
2	TAN(mgKOH/l)	5.4
3	Pour point(0c)	4
4	Viscosity @290c(cp)	3800
5	Viscosity @500c(cp)	727.33
	Water properties	
1	Water type	NaHCO3
2	PH value	7.64
3	Salinity (mg/L)	1067.82
4	Chloride content (mg/L)	524.66

4.2 Reservoir Characterization.

the reservoir characterization of FNE oil field is different from formation to another and properties of each formation can be found in table (4.2).

Table (4.2): Reservoir Characterization of FNE Oil Field (Husham et al, 2016).

No.	Formation	Aradeiba	Bentiu
1	Φ(%)	25 to 30	29 to 34
2	K(md)	100 to 5000	1000 to 10000
3	Net pay	3.3	31.5

Table (4.3): Screening Criteria for Thermal Recovery (Husham et al, 2016).

No.	Item	SF	FNE
1	Pay depth (m)	<1300	550
2	Pay thickness(m)	7~60	30
3	NTG	>0.4	0.6
4	Horizontal perm	>200	4000
5	Porosity%	>20	32
6	Oil Saturation%	>45	70
7	Oil viscosity	<10000	661 @50^{0}C
8	Reservoir pressure	<725	610

Considering the abundance of reserves in the test area, reservoir properties can represent the oilfield properties, taking B1a, B1b and B1c oil formation for examples, it can be determined with the porosity, permeability, oil saturation field, the abundance distribution of reserves, most wells in the selected pilot area are the steam stimulation wells, and the reservoir thicknesses greater than 9m, selected pilot test area is located in the high parts of the local structure; with good cross-hole connectivity and a unified oil-water system, figure (4.1) presenting structural map of FNE.

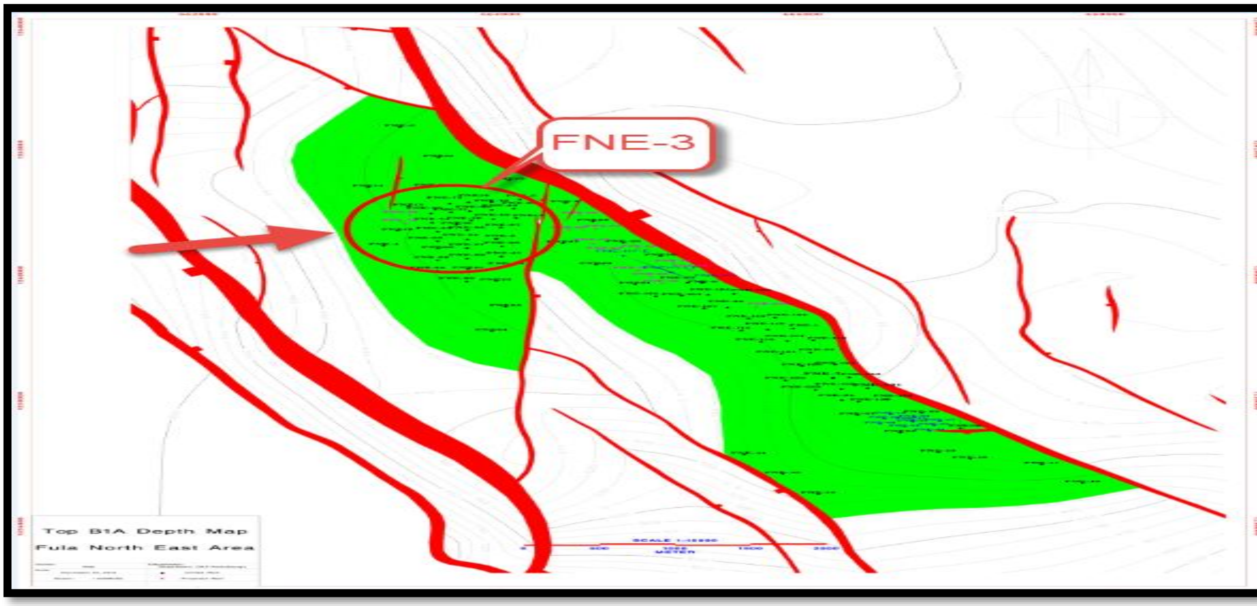


Figure (4.1): Structural Map of FNE Top B1A (Husham, 2016).

By analysis of the reserve, structure, connectivity, oil saturation and other parameters of FNE; the area is in line with the selection principle for steam injection pilot test area, so it is recommended as the area for steam flooding pilot test (Husham, 2016).

4.3 Model Data.

model consists of (61*53*27=87291 block), no wells has been drilled in the model, with single porosity, simulation begins from 6-5-2009 to 6-9-2030 as a prediction, running the simulation model in different scenarios with different length and direction of horizontal section, different steam parameters to make an optimization between all the scenarios.

Simulation implement on the model with next assumption:

- Dynamic model is built.
- All wells have been deleted.
- No history matches.

4.4 Scenarios Implemented to Determine the Best Parameters.

Many models will build and runs to determine the following parameter:

1. Best location of wells (location sensitivity).
2. Best direction for horizontal section and Best horizontal section length (length and direction sensitivity).
3. CSS optimization, CSS parameter (Temperature, Quality, injection rate, injection period and soak period).

4.4.1 Case One: Location Sensitivity.

In location sensitivity section, there are three cases -with DNC (do nothing case). In this thesis there are:

1. 10 vertical wells (through B1A-B1B) with DNC.
2. 10 horizontal wells in layer B1A with DNC.
3. 10 horizontal wells in layer B1B with DNC.
4. comparing between productivity of wells.

In location sensitivity; 10 wells will be drilled in different places depending on oil saturation and porosity.

There are no injected wells, just producing from wells, without using any injection processes (without doing anything-DNC), so it will give almost less oil production results as compared with the other cases which will be discussed later in this chapter.

4.4.1.1 Location Sensitivity-with DNC (DNC for 10 Vertical Wells).

There are no wells has been drilled in the model, figure (4.2) show that there are no wells in the model.

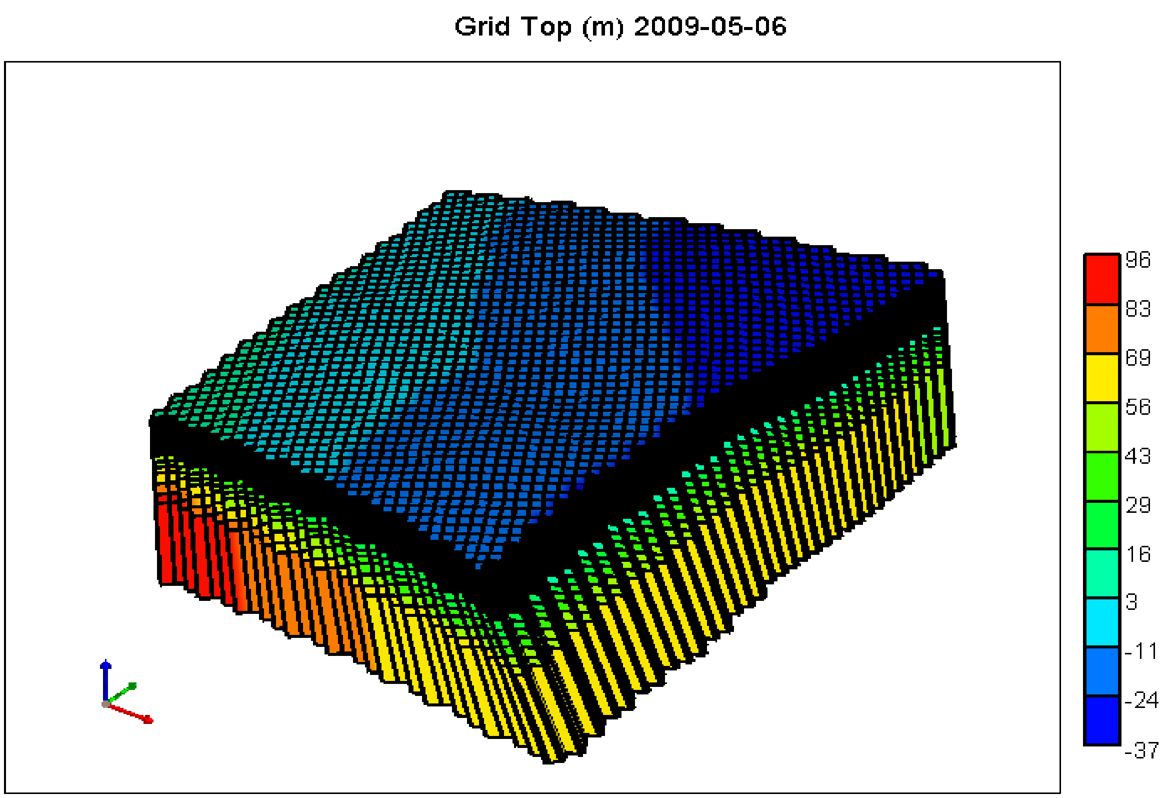
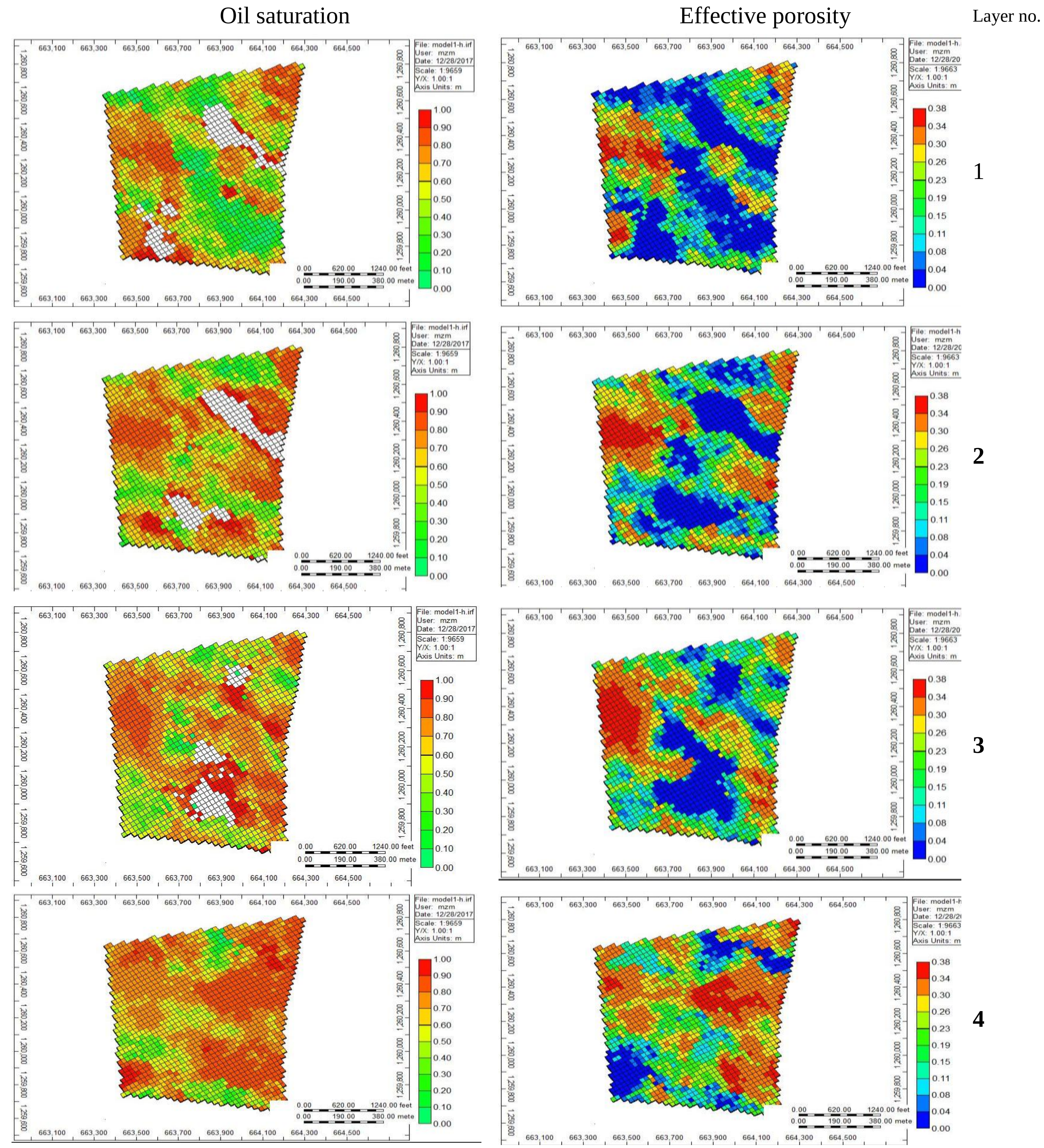
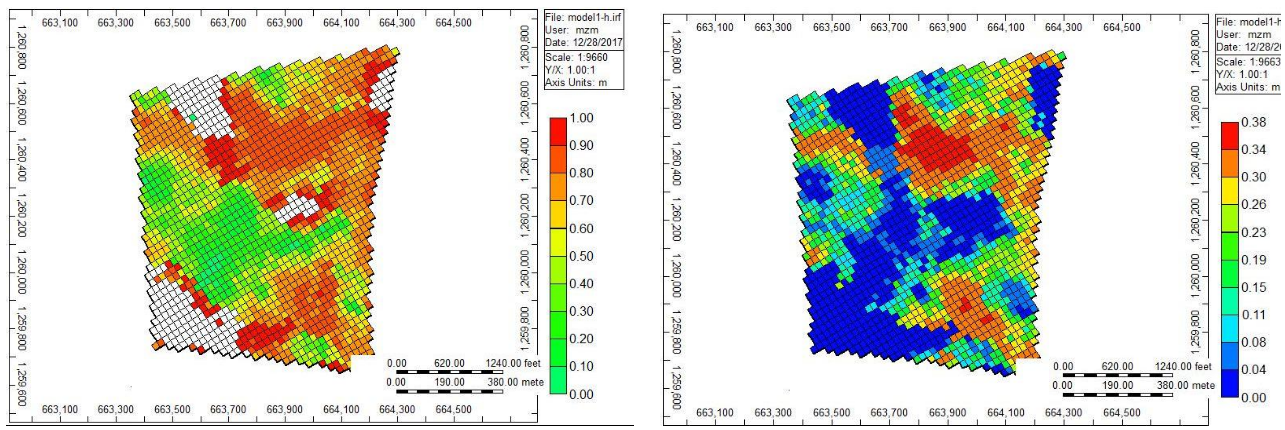


Figure (4.2): Grid Top in 3D with no Wells in the Model.

10 vertical wells have been drilled in different places (through B1A-B1B) depending on oil saturation and porosity distribution, figure (4.3) shows distribution of oil saturation and effective

porosity to determine the best location for the well, figure (4.4) Determines location of wells and the states of wells explained by time line view in figure (4.5).

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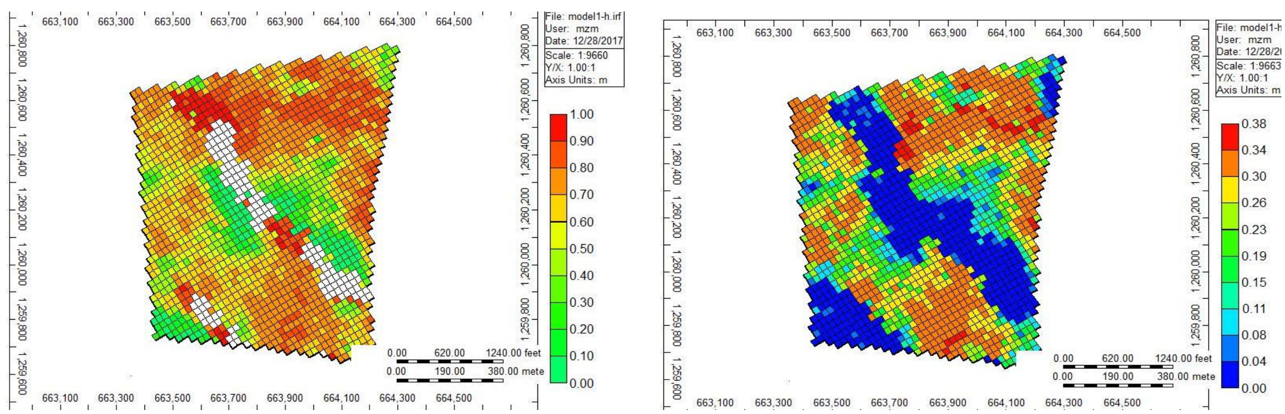

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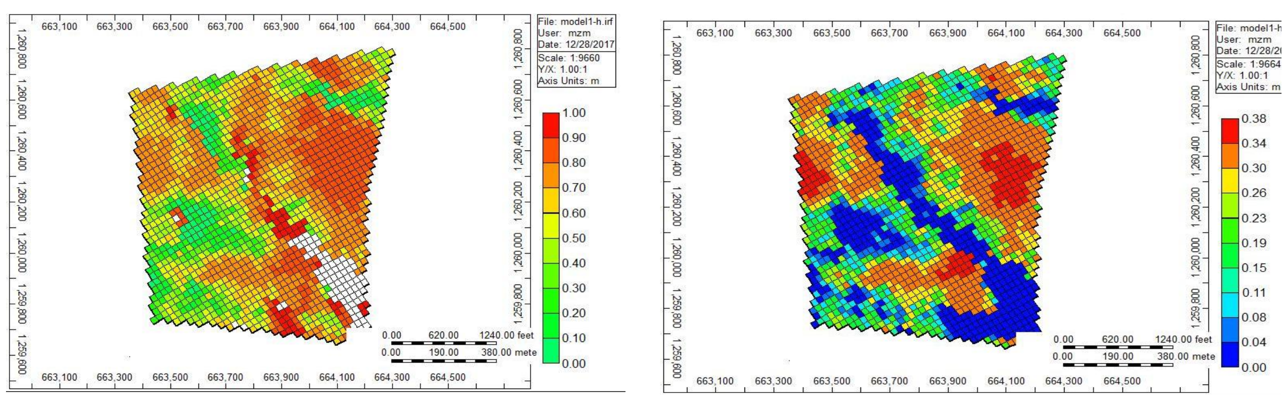

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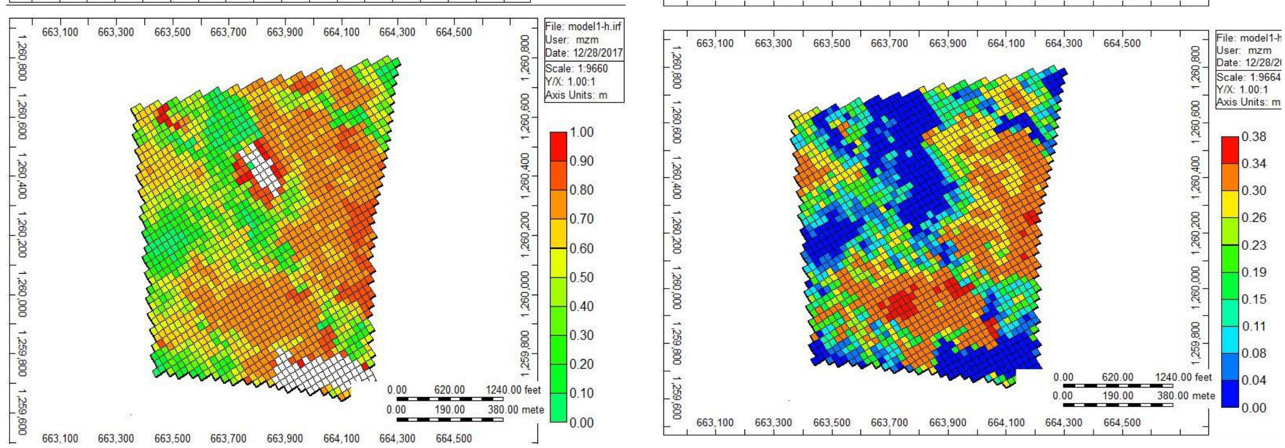

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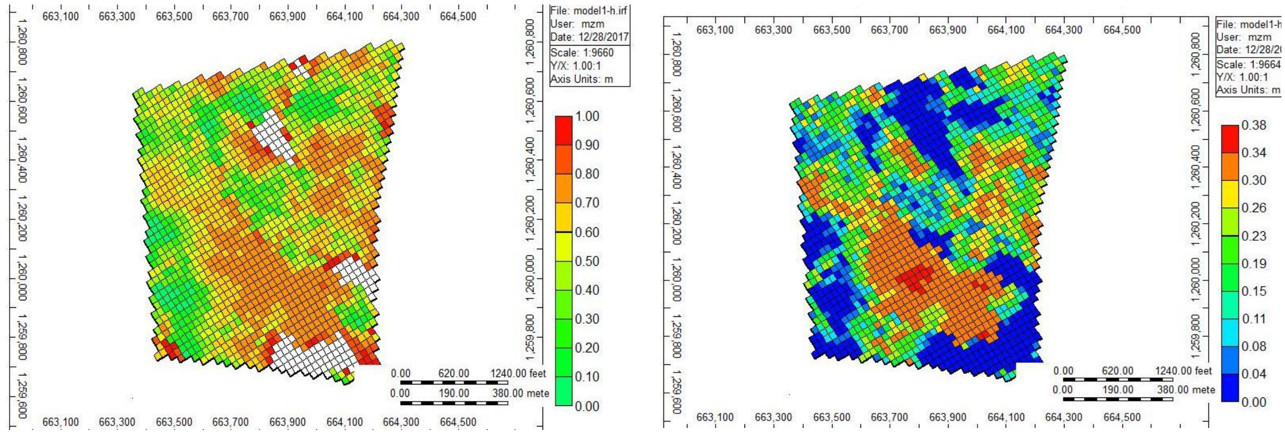
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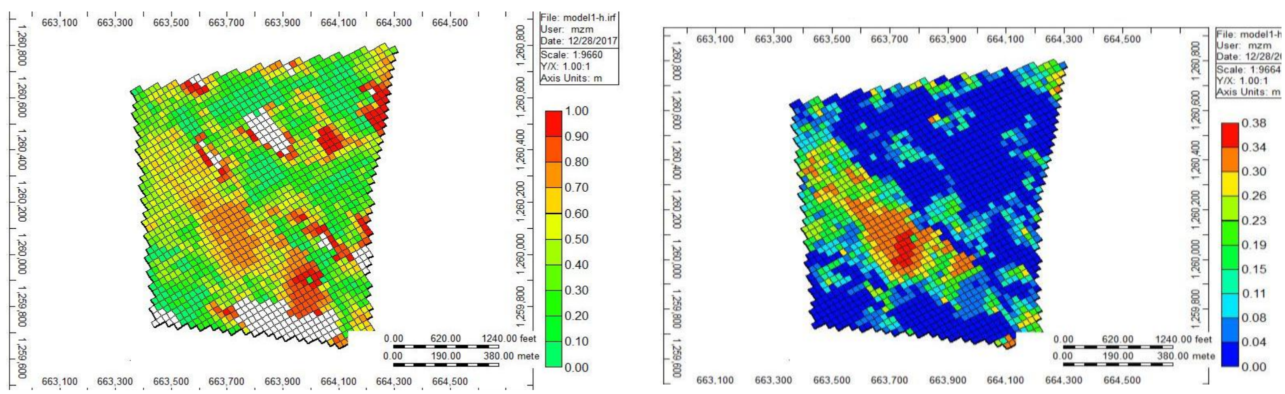
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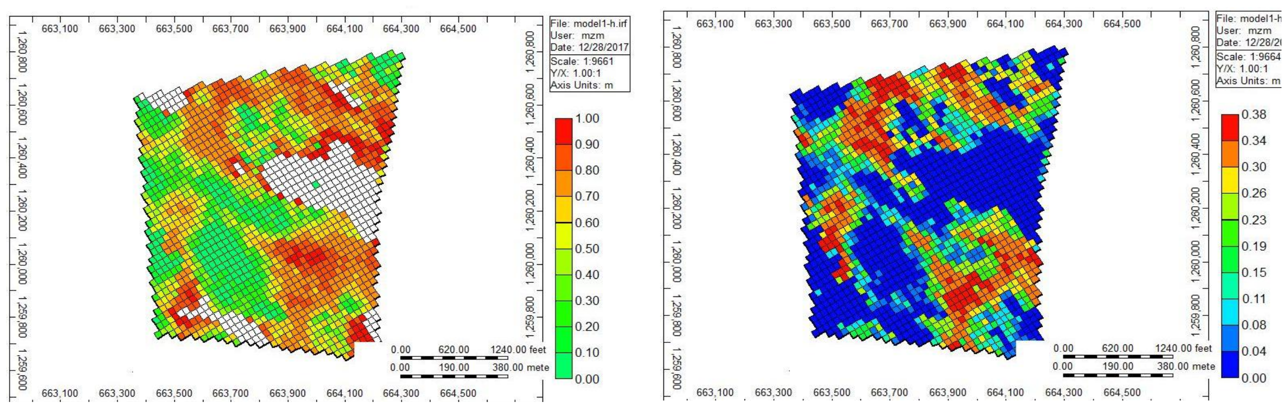
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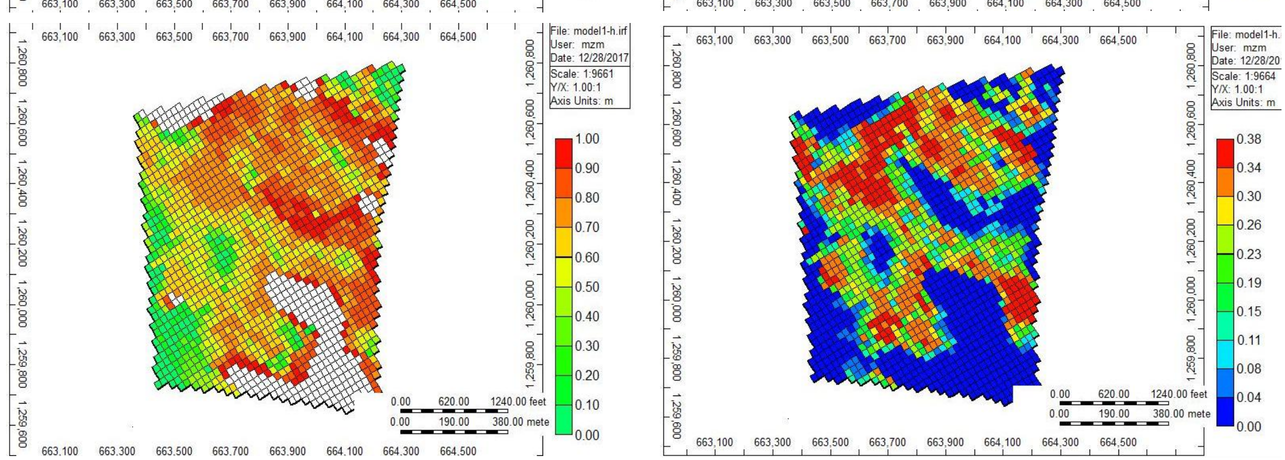
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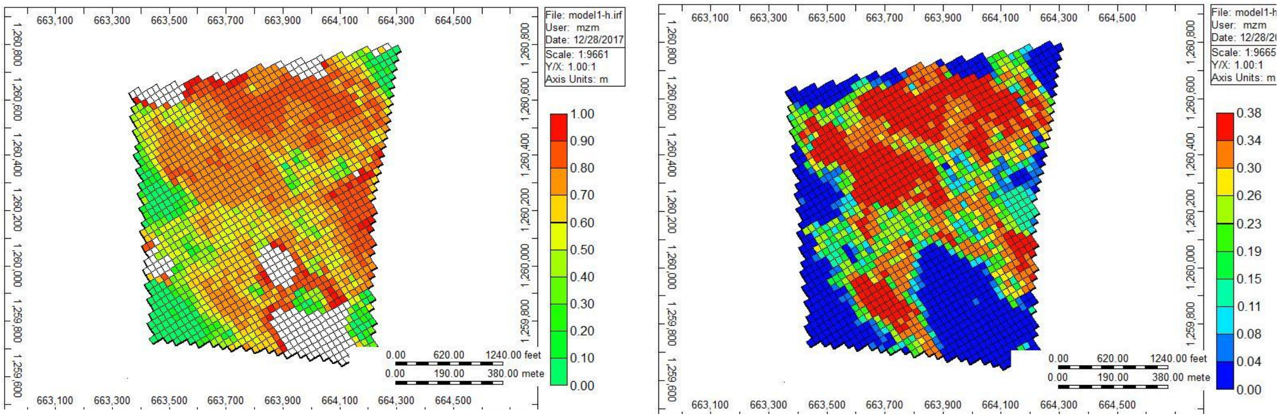

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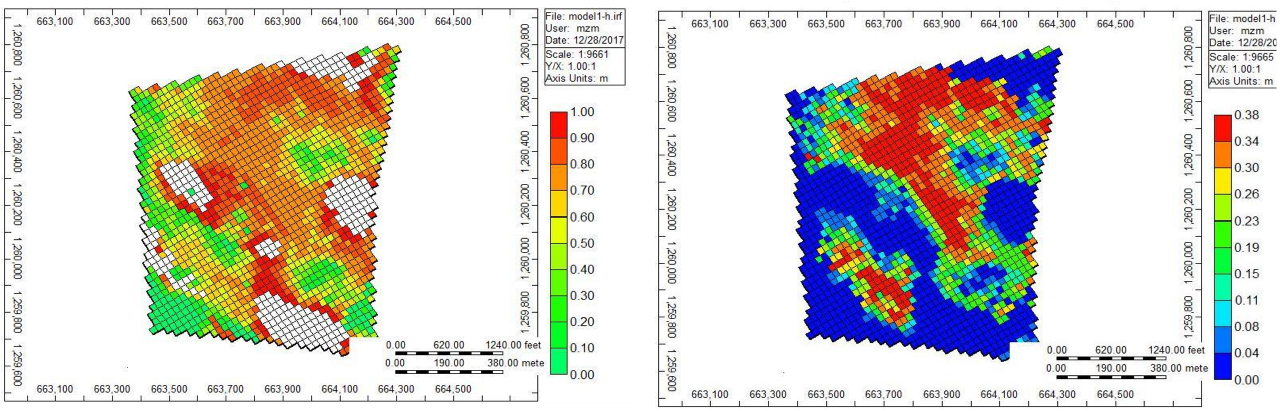

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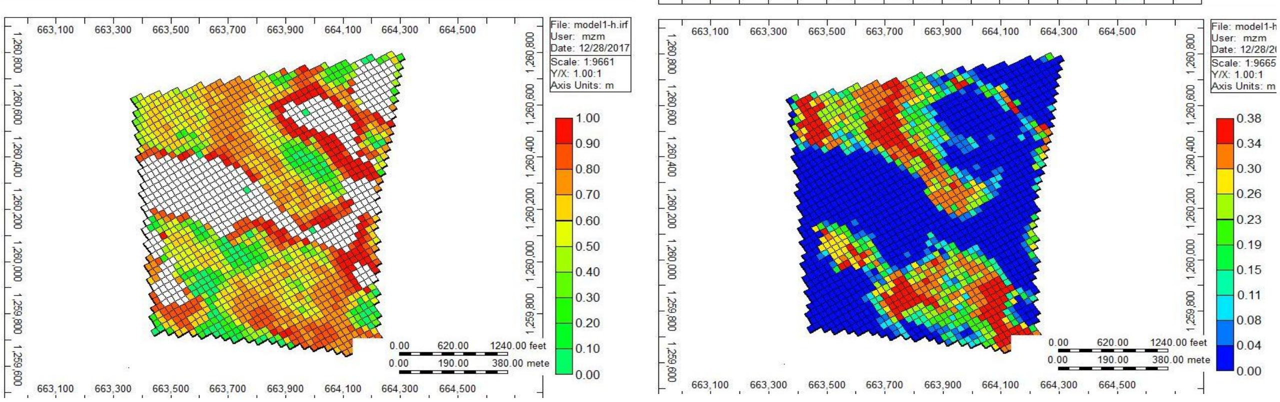

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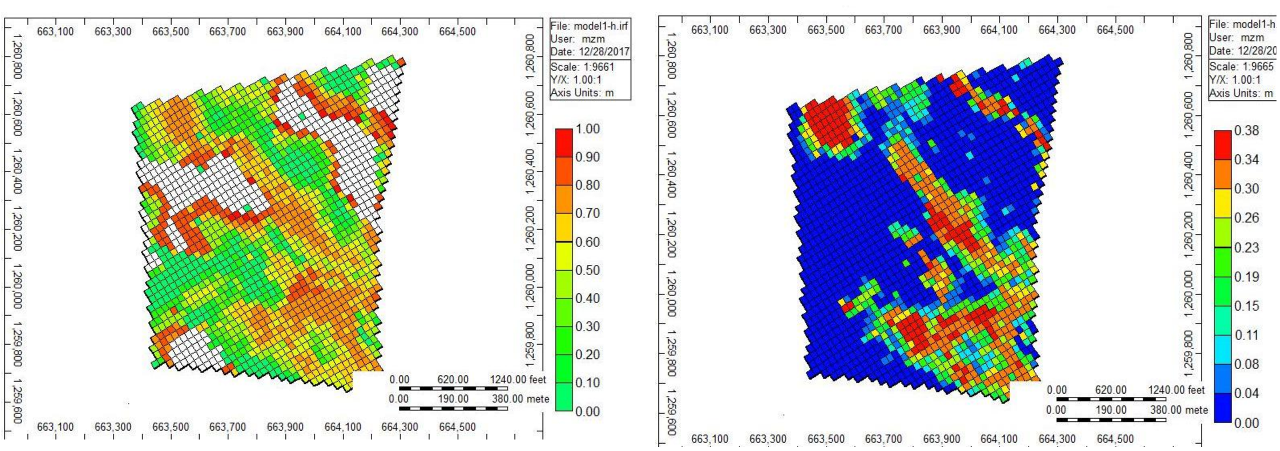

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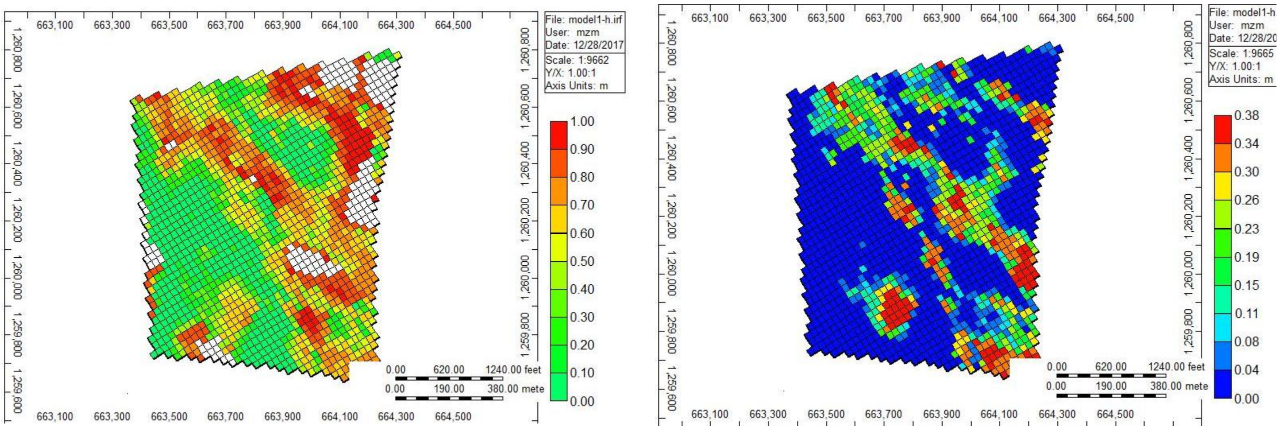
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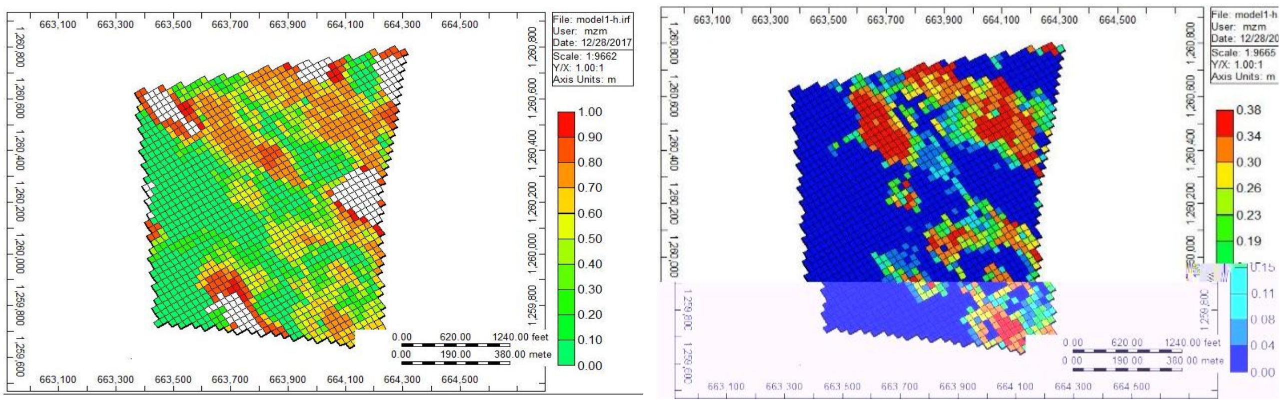
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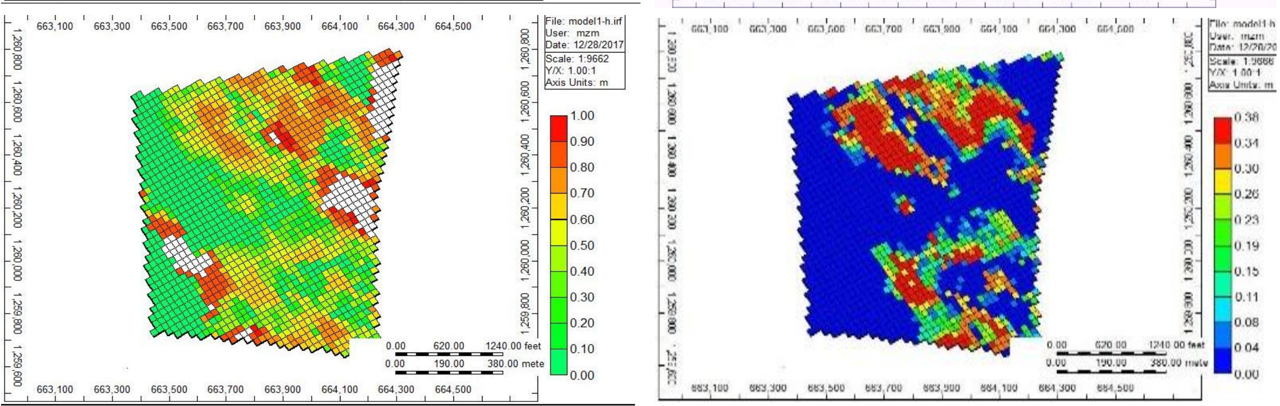
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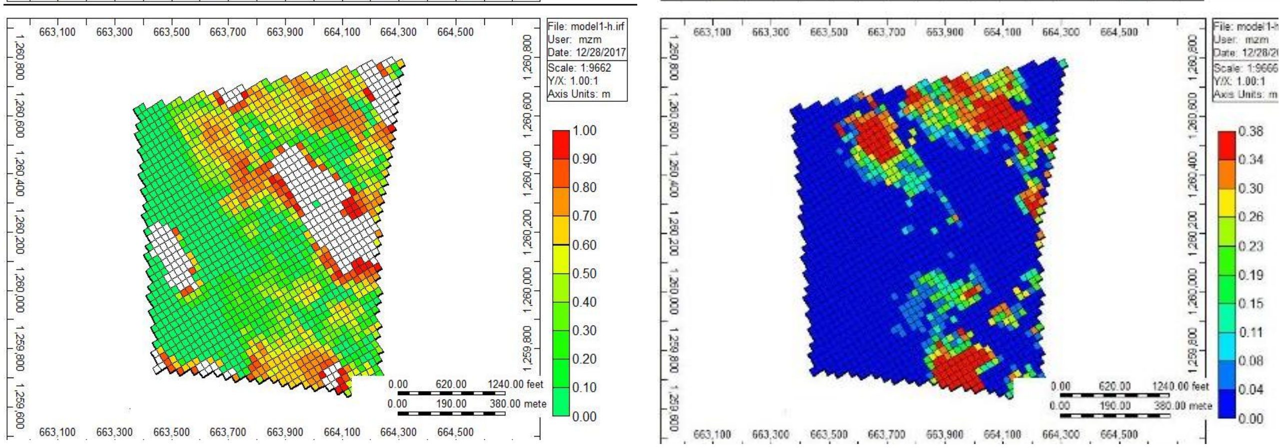
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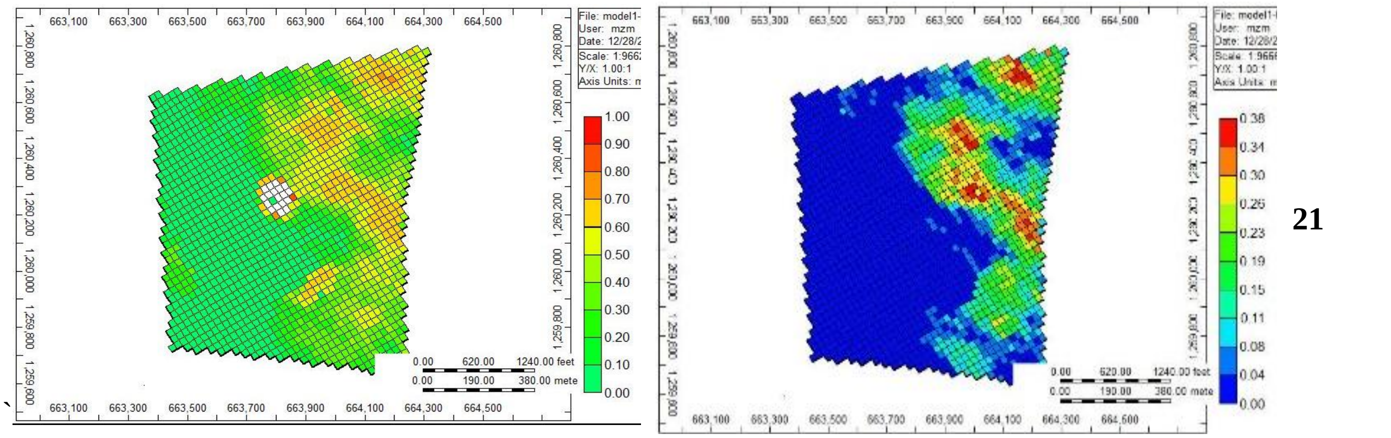


Figure (4.3): Oil Saturation and Effective Porosity with Layers Number.

Layers from 22 to 27 have low oil saturation and low porosity so no need to study, from previous study for layers in Bentiu 1A and Bentiu 1B, layer 4 and 3 have highest porosity and oil saturation in Bentiu 1A, in Bentiu 1B layer 13 have highest porosity and oil saturation, but layer 4 have highest porosity and oil saturation between all layers in model.

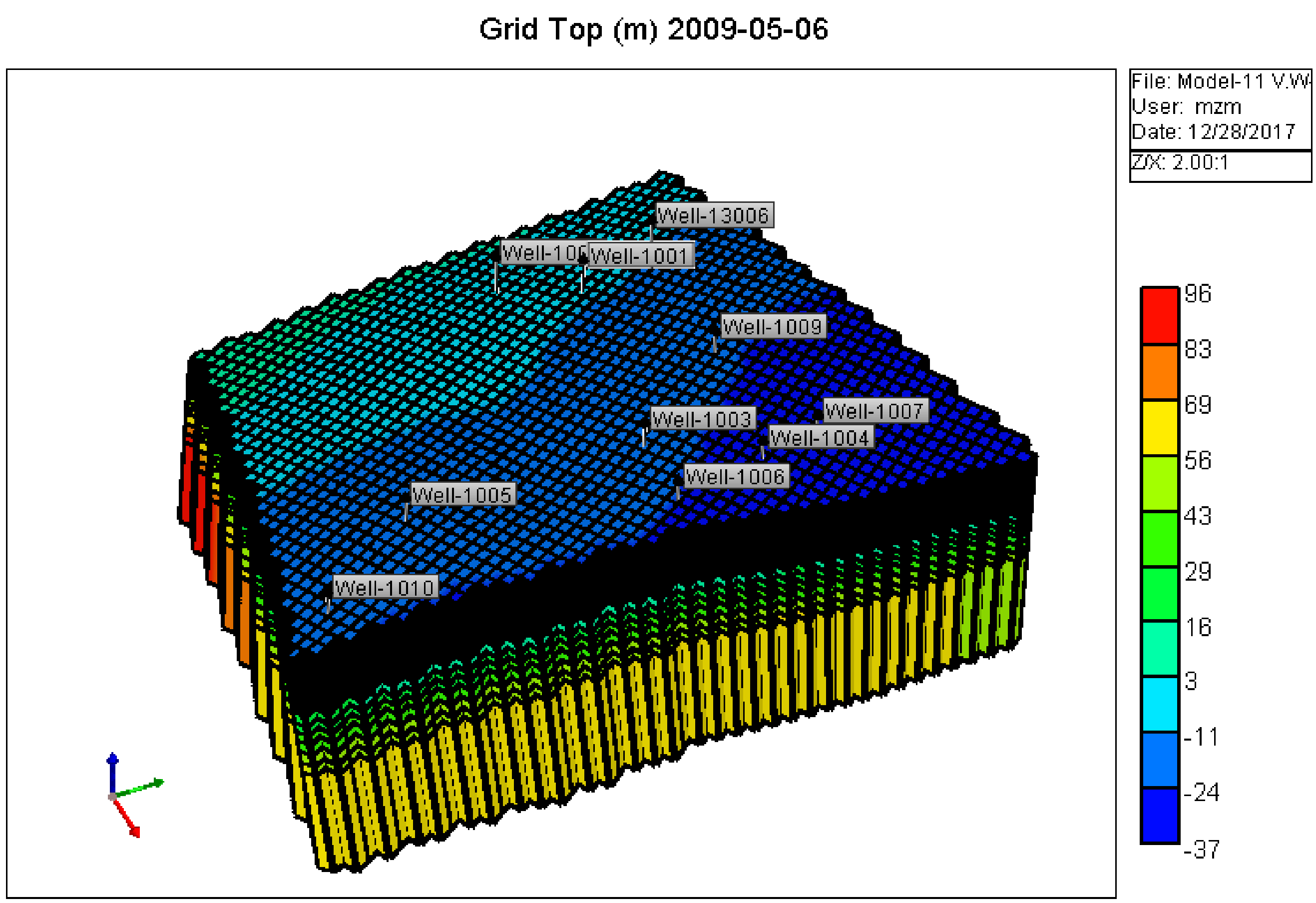


Figure (4.4): Grid Top in 3D Shows Location of Wells Depend on Porosity and Oil Saturation.

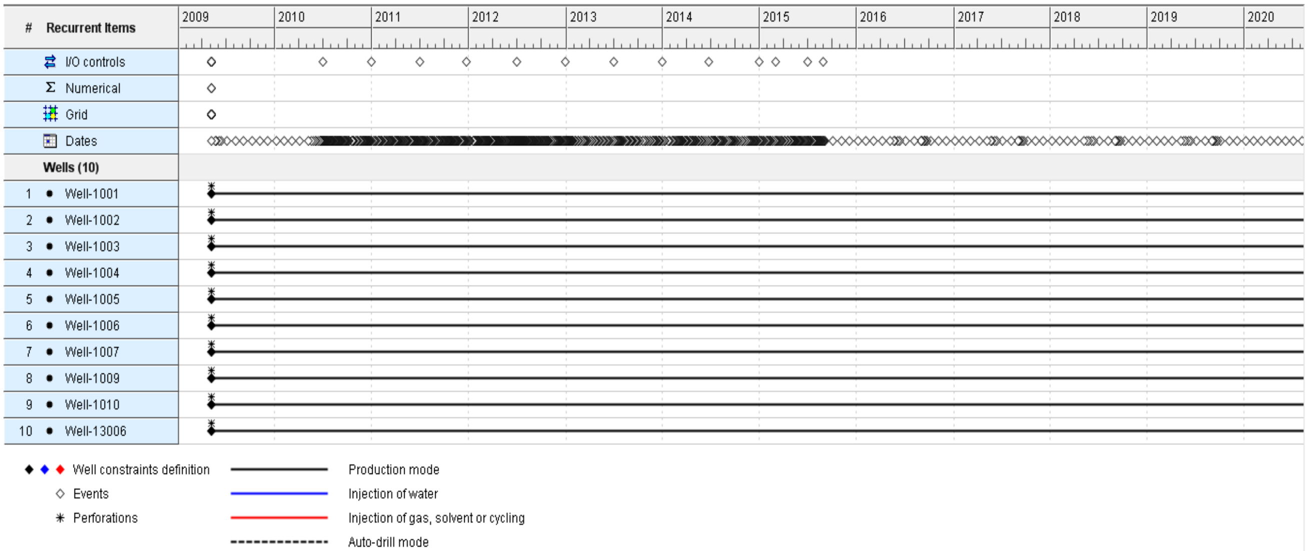


Figure (4.5): Time Line View of DNC for Ten Vertical Wells.

The time line view explained that there are no injected wells working, production is running without doing anything (DNC), so it will give almost less oil production results as compared with the other cases which will be discussed later in this chapter.

DNC scenario had been done by using production parameter as follows (production rate 200 m^3/day and production pressure of 200 kPa).

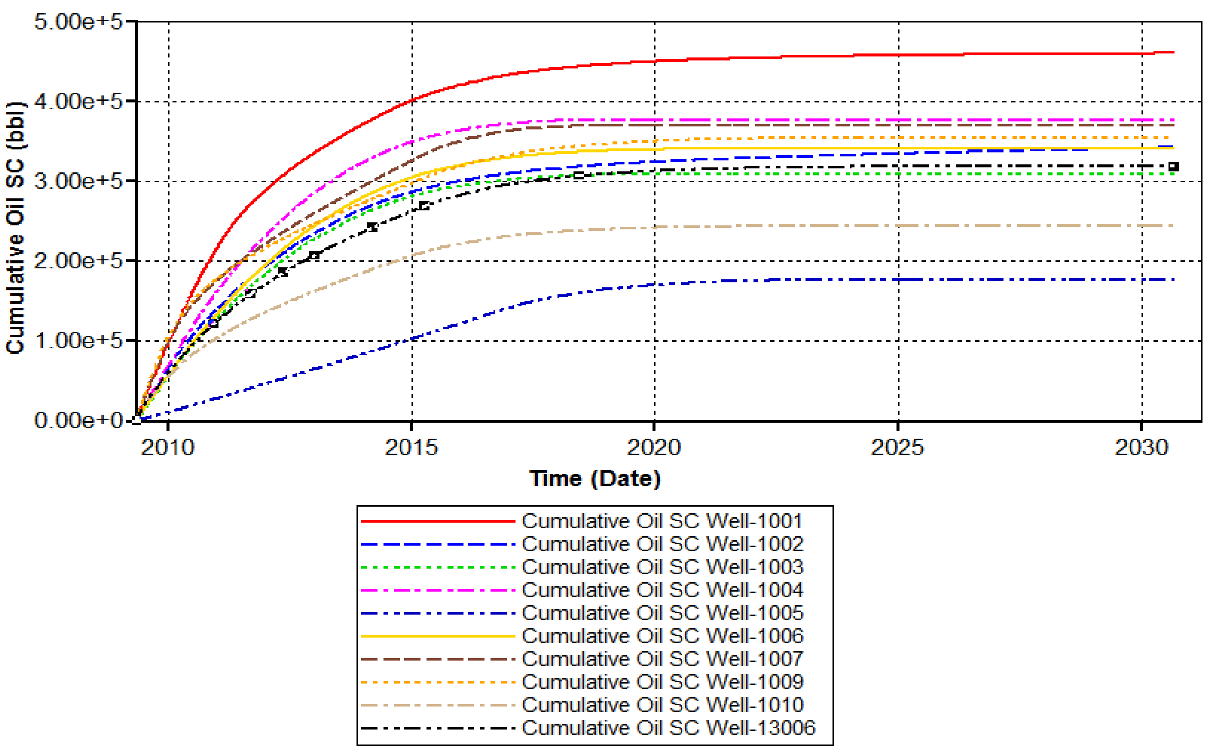


Figure (4.6): Cumulative Oil for Ten Vertical Wells.

Table (4.4): Cumulative Oil of Ten Vertical Wells with DNC.

No.	Well Name	Cumulative Oil (bbl.)
1	1001	460394
2	1002	342095
3	1003	308736
4	1004	377411
5	1005	177601
6	1006	340507
7	1007	369144
8	13006	318778
9	1009	354319
10	1010	244273

After running the models with ten vertical wells with DNC, the cumulative oil for each well as presenting in table (4.4), figure (4.6) presented well-1001 with best cumulative oil between all vertical wells with (460394 bbl.), the cumulative oil of well-1001 increased until 2018 after that the cumulative oil of well-1001 is almost stable until 2030, and almost all of the wells have same trend but with less values.

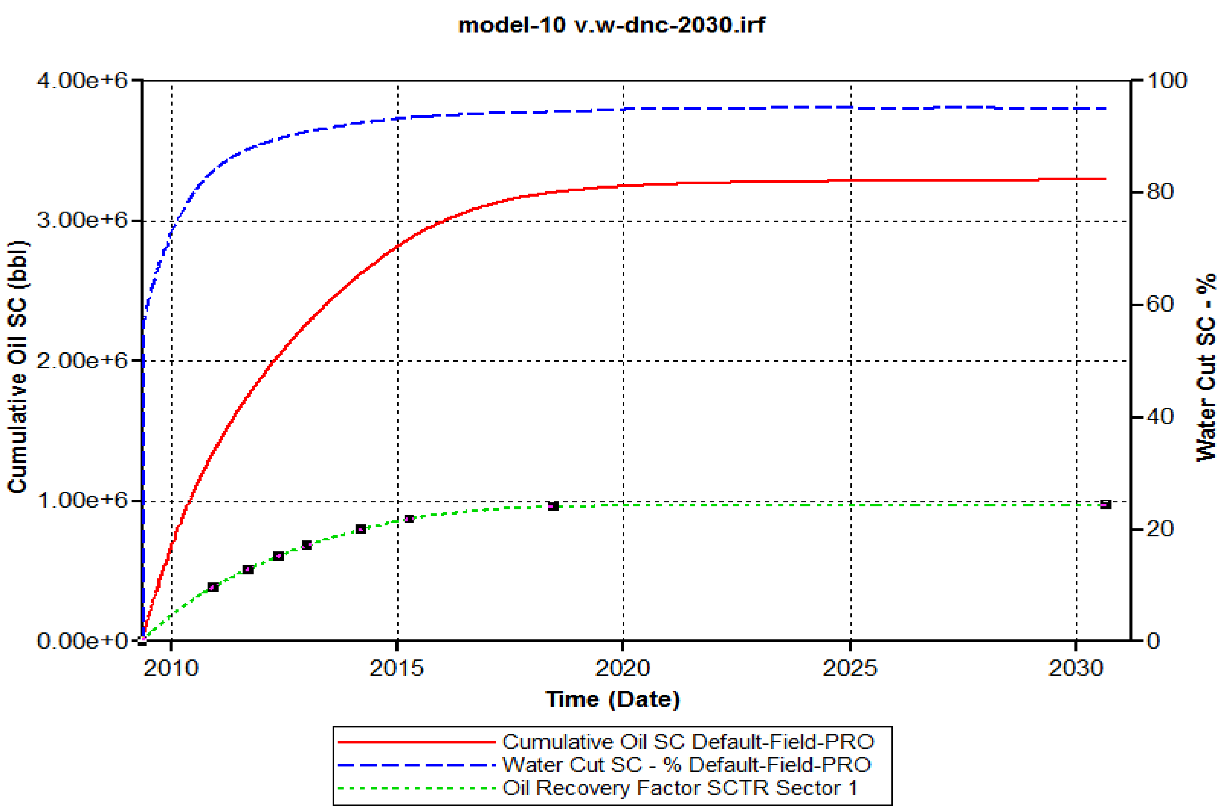


Figure (4.7): Cumulative Oil SC, Water Cut SC %, Recovery Factor Versus Time of DNC.

DNC for ten vertical wells scenario which had been done and plotting of the results (cumulative oil SC, water cut SC %, oil recovery factor) versus (time) as a prediction of the field performance till 2030.

Figure (4.7) presenting the cumulative oil of the field increasing until 2018, the cumulative oil will be stable in value till 2030 with final value (3.29346 E6 bbl.), the water cut 94.8799% and the recovery factor is 24.2904% as presenting in table (4.5).

Table (4.5): Cumulative Oil SC, Water Cut SC %, Recovery Factor for Ten Vertical Wells with DNC.

No.	Cumulative oil (bbl.)	W.C(%)	RF (%)
1	3.29346 E6	94.8799%	24.2904%

4.4.1.2 Location Sensitivity-with DNC (10 Horizontal Wells in Bentiu 1A).

In this case, ten horizontals will have been drilled in Bentiu 1A layer, depending on oil saturation and porosity distribution in Bentiu 1A, as presenting in figure (4.8).
figure (4.9) showing the horizontal section of wells, all wells have same lengths of horizontal section.

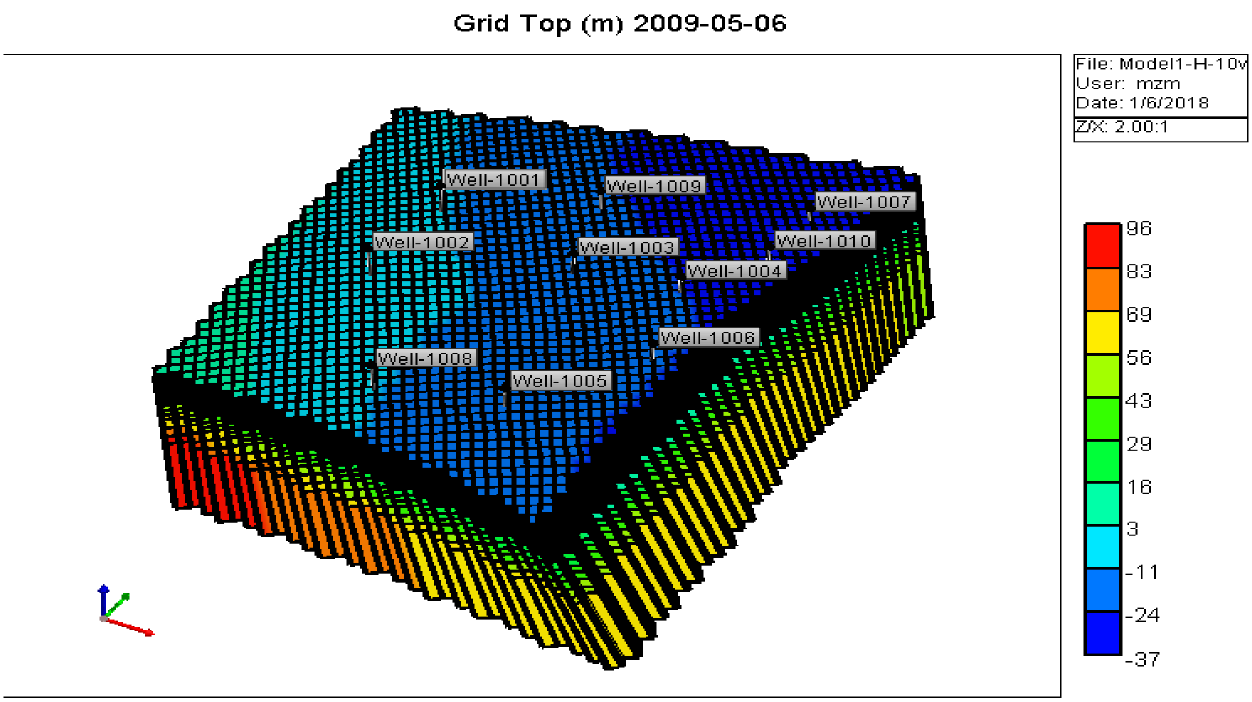


Figure (4.8): Grid Top in 3D Shows Location of Ten Horizontal Wells in Bentiu 1A Layer Depends on Oil Saturation and Porosity.

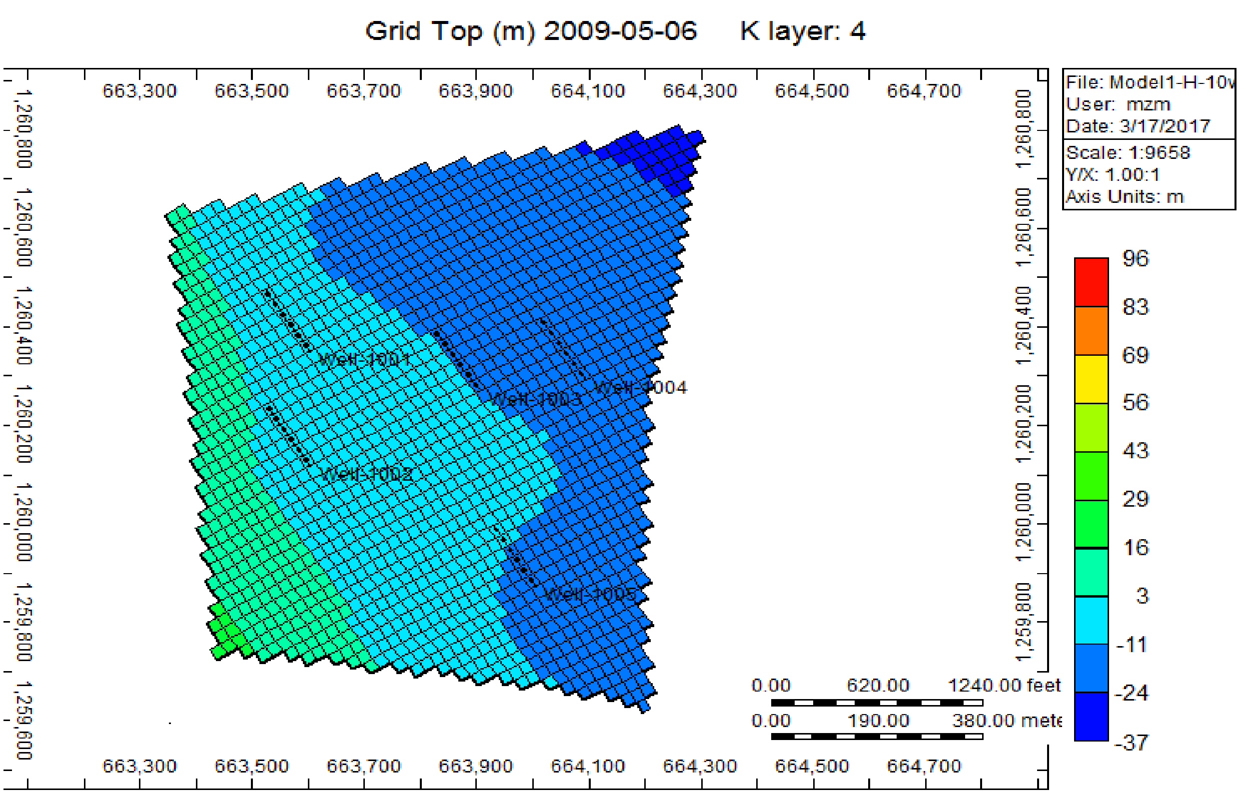


Figure (4.9): Grid Top in 2D Shows the Horizontals Section of Wells in Layer 4.

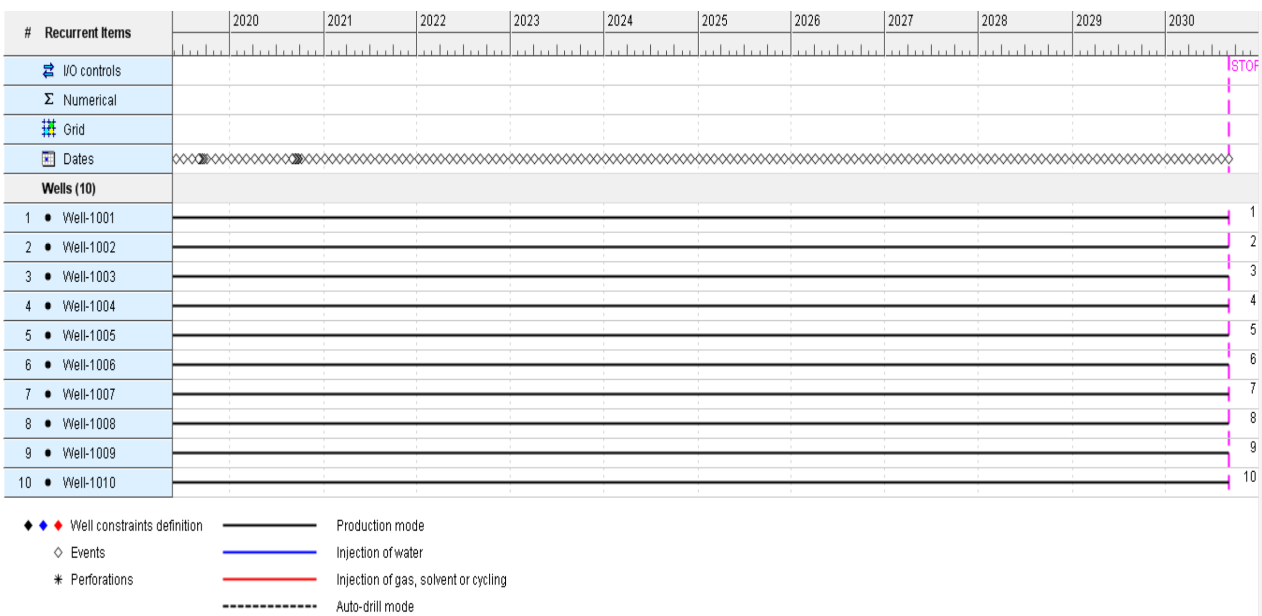


Figure (4.10): Time Line View of the Wells in DNC until 2030.

states of wells presented by time line view in figure (4.10), time line view explained that there are no injection wells, just produce from the production wells in period from 2009 until 2030.

DNC scenario had been done by using production parameter as follows:(production rate 200 m3/day and production pressure of 200 kPa).

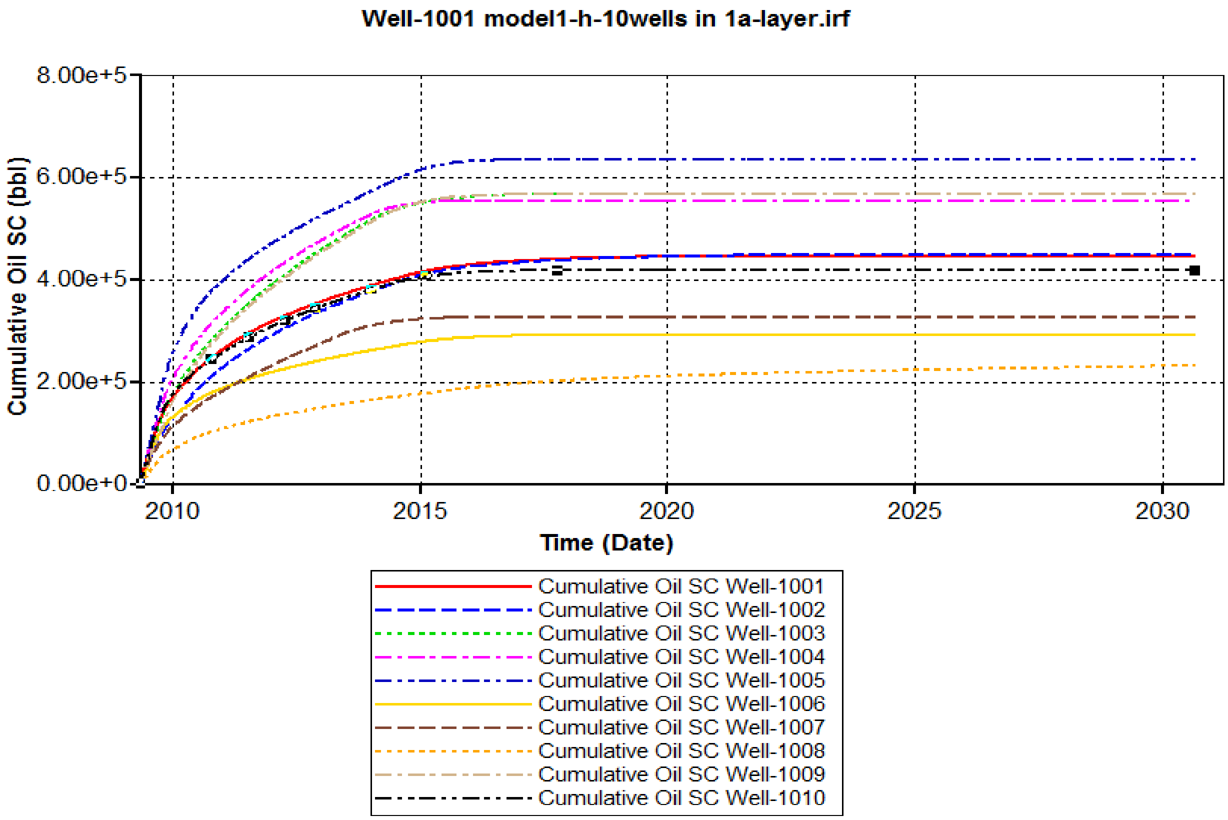


Figure (4.11): Cumulative Oil of Wells in Layer 1A.

Table (4.6): Cumulative Oil of Ten Horizontal Wells in Layer1a with DNC.

No.	Well name	Cumulative oil
1	1001	444504
2	1002	447763
3	1003	567088
4	1004	553781
5	1005	633803
6	1006	290932
7	1007	326182
8	1008	231626
9	1009	566002
10	1010	417188

After running the models with ten horizontal wells in layer 1A with DNC, the cumulative oil for each well collected in table (4.6), figure (4.11) All wells in the same condition (same length of horizontal section-same production rate-same production pressure), table (4.6) summarizing the cumulative oil of wells, well-1005 have best cumulative oil with (633803 bbl.) until 2030 in layer 1A the cumulative oil of well-1005 increasing until 2016 after that the cumulative oil of well-1005 almost stable until 2030, and almost of the wells have same trend but with less value.

4.4.1.3 Location Sensitivity-With DNC (DNC for Ten Horizontal Wells in Bentiu 1B).

In this case, ten horizontals will have been drilled in Bentiu 1B layer, depend on oil saturation and porosity distribution, as presenting in figure (4.12), figure (4.13) presenting horizontal section of wells in layer 13, all wells have same lengthened of horizontal section.

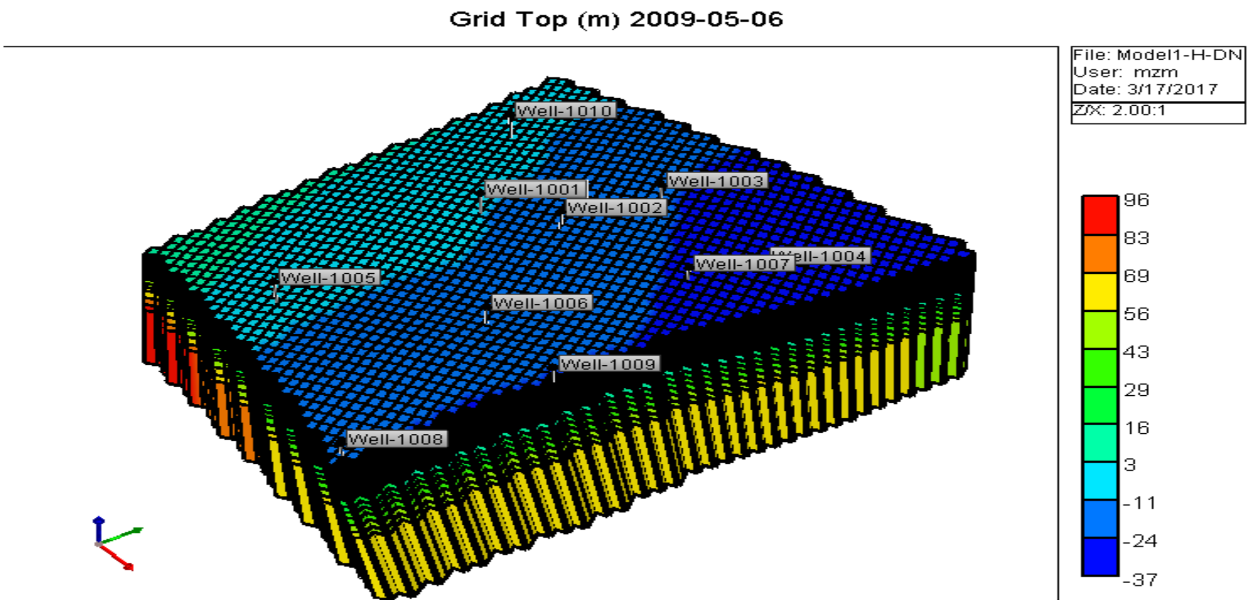


Figure (4.12): Grid Top in 3D shows Location of the Horizontal Wells in 1B layer.

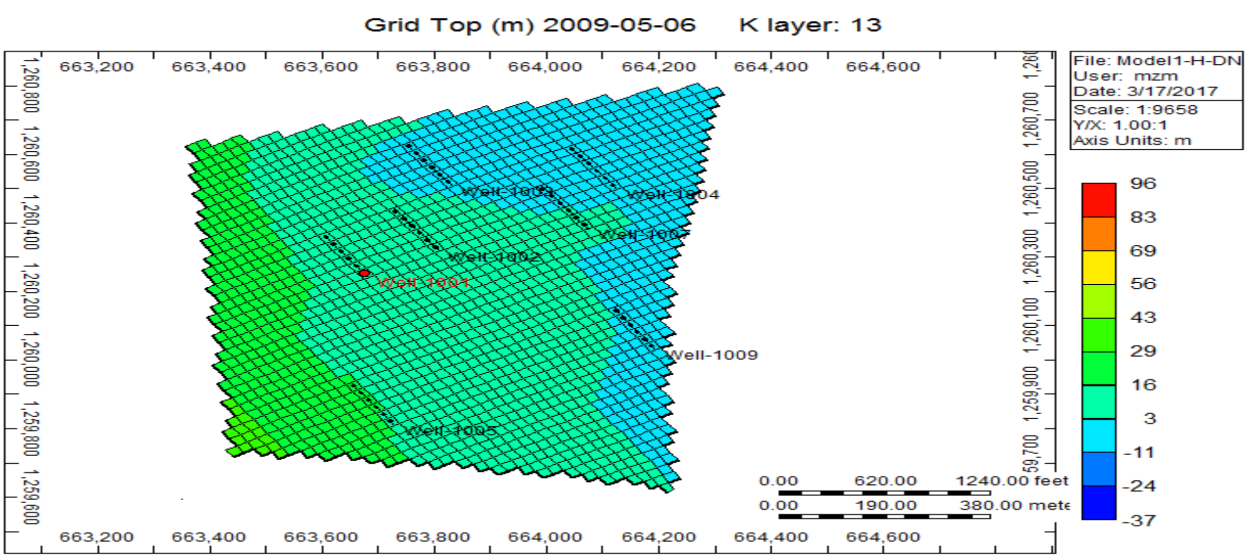


Figure (4.13): Grid Top in 2D Shows Horizontals Section of Wells in Layer 13.

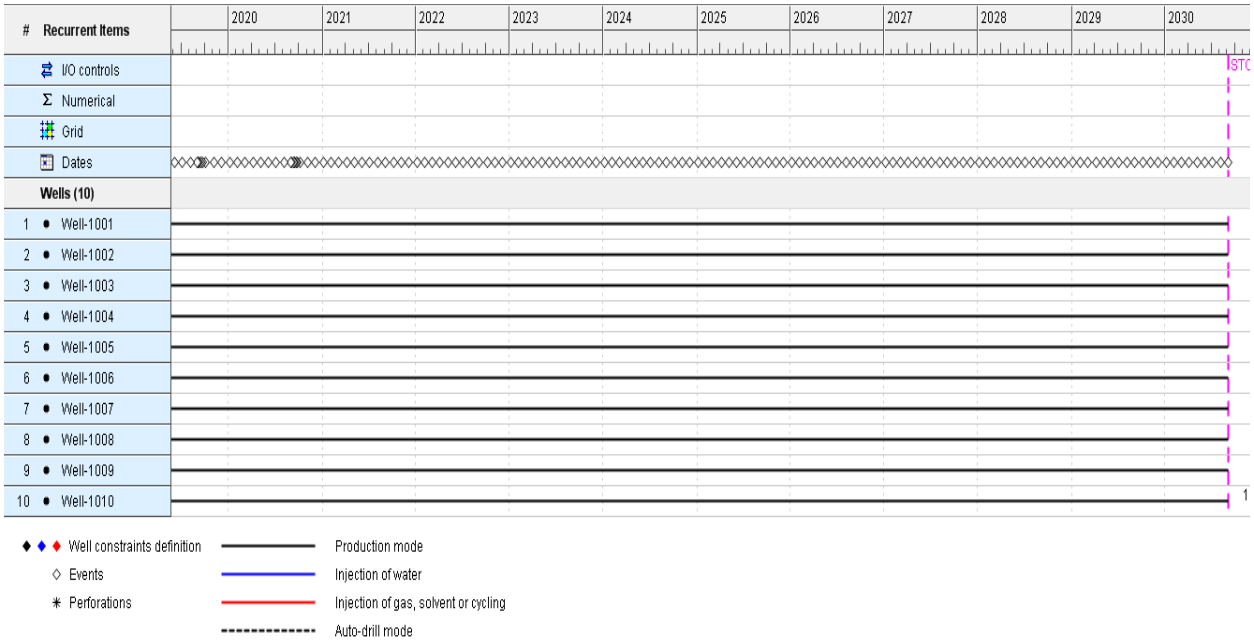


Figure (4.14): Time Line View of the Horizontals Wells in DNC until 2030.

states of wells explained by time line view in figure (4.14), time line view shows that there are no injection wells working, just produce from the production wells in period from 2009 until 2030.

DNC scenario had been done by using production parameters as follows:(production rate 200 m3/day and production pressure of 200 kPa), injection wells are closed, so the changes in injection parameters will not affect the DNC performance.

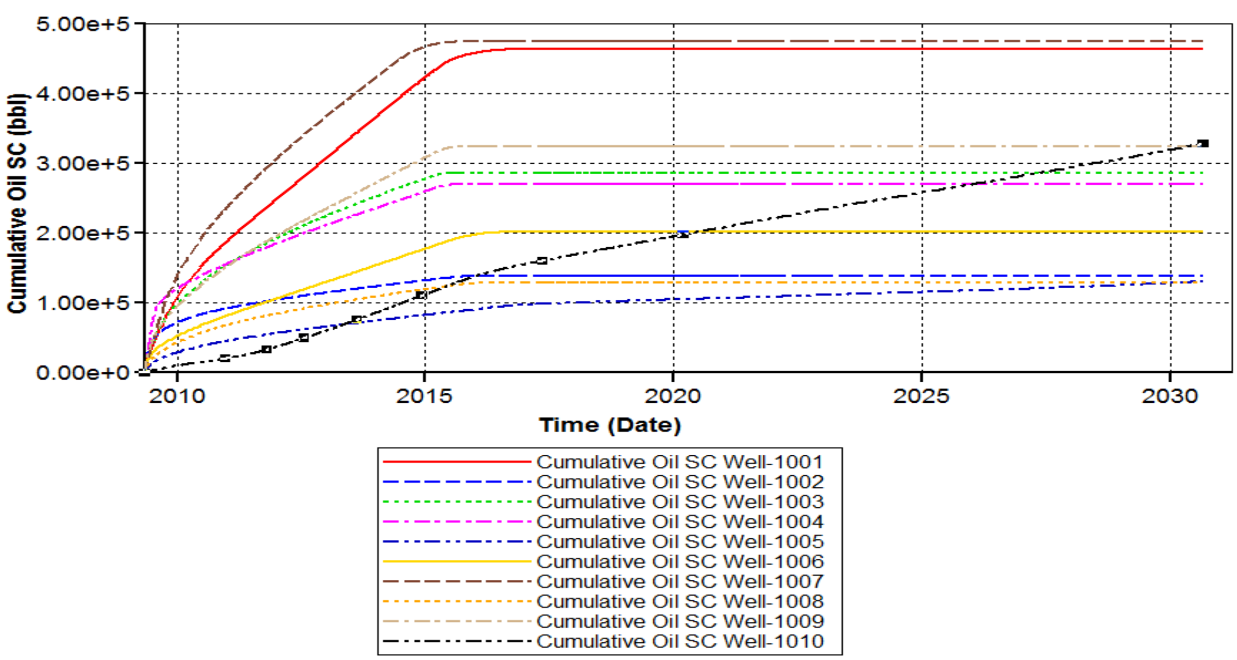


Figure (4.15): Cumulative Oil of Wells in Layer 1B.

Table (4.7): Cumulative Oil of Ten Horizontal Wells in Layer1B with DNC.

No.	Well name	Cumulative oil(bb
1	1001	463945
2	1002	138693
3	1003	286031
4	1004	270378
5	1005	130963
6	1006	202255
7	1007	474884
8	1008	128755
9	1009	324000
10	1010	328335

After running the models with ten horizontal wells in layer 1B with DNC, all wells in the same conditions (same length of horizontal section-same production rate-same production pressure), the cumulative oil for each well summarized in table (4.7) and figure (4.15), well-1007 have best cumulative oil with (474884 bbl.) until 2030 in layer 1B the cumulative oil of well-1007 increasing until 2016 after that the cumulative oil of well-1007 almost stable until 2030, and almost all of the wells have same trend but with less values**.**

4.4.1.4 Comparing between Productivity of Wells.

In this section the best two productive wells will be determined by comparing between cumulative oil of horizontal wells in DNC for layer 1A and layer 1B until 2030 as collected in table (4.8). Note that all wells have the same conditions of length, direction of horizontal section, and same period of simulation.

Table (4.8): Cumulative Oil for All Wells in Layer 1A and 1B.

No.	Well name	Cumulative oil of layer 1A	Cumulative oil of layer 1B
1	1001	441857	463945
2	1002	444715	138693
3	1003	562313	286031
4	1004	548098	270378
5	1005	630175	130963
6	1006	288992	202255
7	1007	323226	474884
8	1008	228051	128755
9	1009	561745	324000
10	1010	414270	328335

After comparing between Cumulative oil in layer 1A and layer 1B from table (4.8) well-1005 and well -1003 in layer 1A have highest cumulative oil with (630175 bbl.) for well-1005 and (562313 bbl.) for well-1003, therefore well-1005 and well-1003 have been selected to implement length sensitivity and CSS sensitivity to find the best results and conditions.

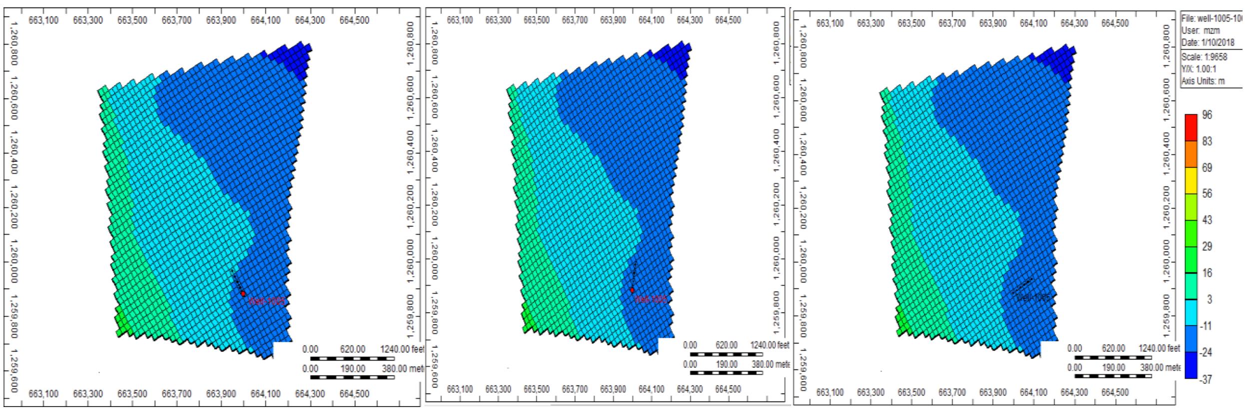
4.4.2 Length and Direction Sensitivity.

In this section, the best length and best direction of horizontal section will be determined for well-1005 and well-1003, by changing length and direction of horizontal section to note the change in cumulative oil and find the difference between cumulative oil of every section to determine the best incremental (incremental-the ratio between length of horizontal section and cumulative oil). The proposed lengths of horizontal section will be (100M, 200M, 300M, 400M, 500M, 600M, 700M,800M) in three directions. (North, North East and East).

4.4.2.1 Length and Direction Sensitivity for Well-1005.

First Scenario of 100 M.

In this scenario length of horizontal section will be (100 M) in three directions and will compare between cumulative oil in the three directions to determine best direction of horizontal section, figure (4.16) presenting the horizontal section of well-1005 in three directions.



North direction North East direction East direction well

Figure (4.16): Grid Top in 2D of Horizontal Section in Three Directions for Well-1005 with 100m length.

After models run the cumulative oil of three directions shows in table (4.9).

Table (4.9): Cumulative Oil of Wells for 100m Horizontal Section in Three Direction for well-1005.

No.	Direction	Cumulative Oil(bbl.)
1	North direction of horizontal section	1.42116E6
2	North East direction	1.39055 E6
3	East direction of horizontal section	1.53043 E6

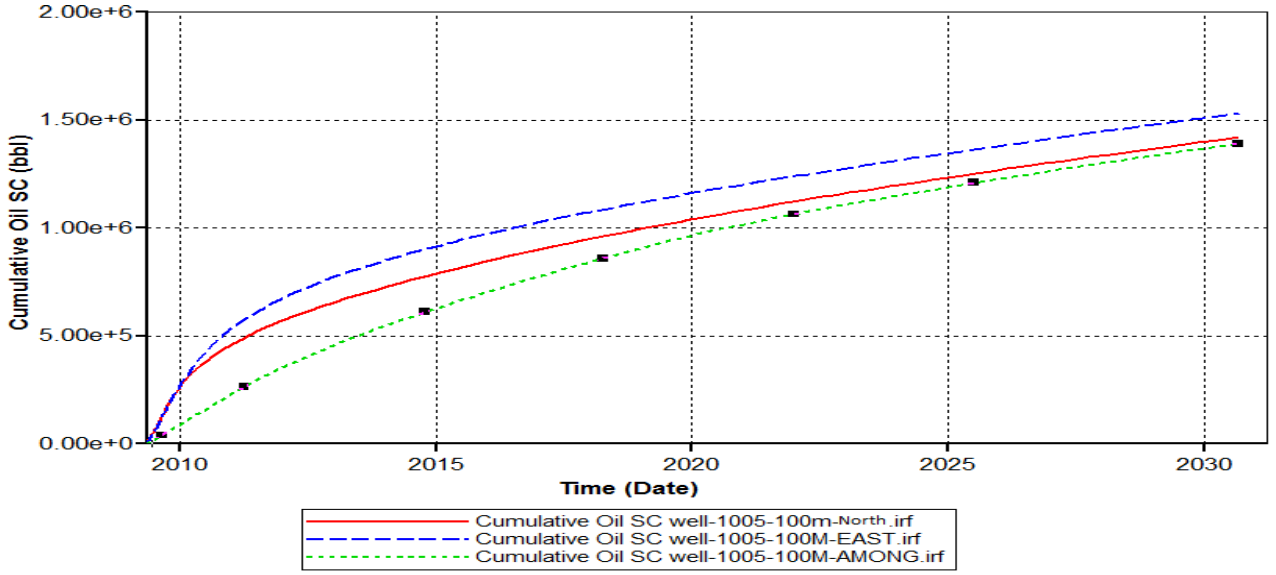
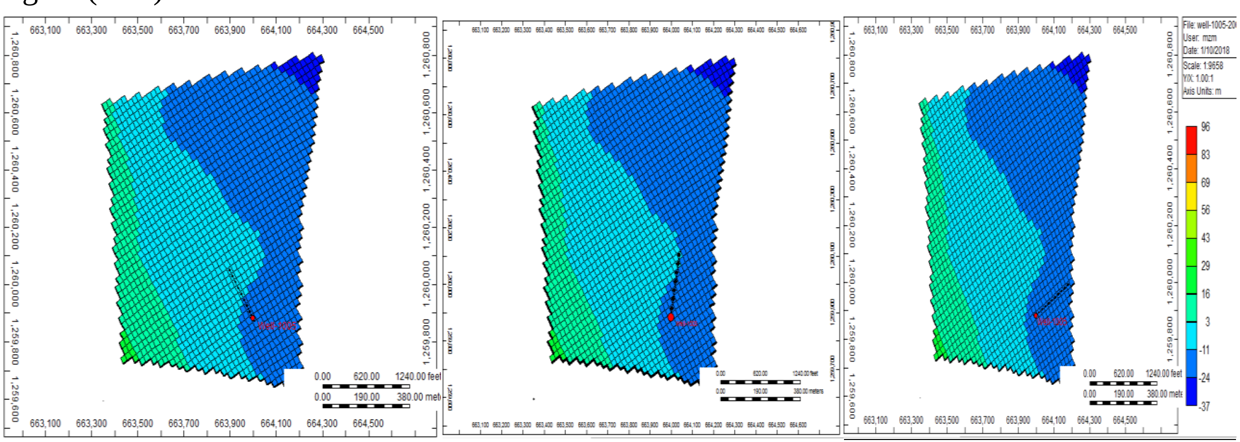


Figure (4.17): Compare between Cumulative Oil in Three Directions for Well-1005 with Length 100m.

After build and run three models in different direction for horizontal section with length 100m and DNC, all wells are in the same conditions of length of horizontal section, production rate and production pressure, the cumulative oil for each well presented in table (4.9) and figure (4.17), the cumulative oil of East direction is higher than both North and North East directions till 2030. From the table (4.9) East direction have highest cumulative oil (1.53043 E6 bbl.), from figure (4.17) the curve of cumulative oil in three directions is increased gradually until 2030 but with different value and East direction has highest cumulative oil.

Second Scenario of 200 M.

In this scenario length of horizontal section will be (200 M) in three directions and will compare between cumulative oil in the three directions to determine best direction of horizontal section figure (4.18) show the horizontal section of well-1005 in three directions.



North direction North East direction East direction

Figure (4.18): Grid Top in 2D Shows Horizontal Section in Three Directions for Well-1005 with 200m Length.

After models run the cumulative oil of three directions will be as show in table (4.10).

Table (4.10): Cumulative Oil of Wells for 200m Horizontal Section in Three Direction for well-1005.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	1.43061E6
2	North East direction	1.5285 E6
3	East direction of horizontal well	1.59739 E6

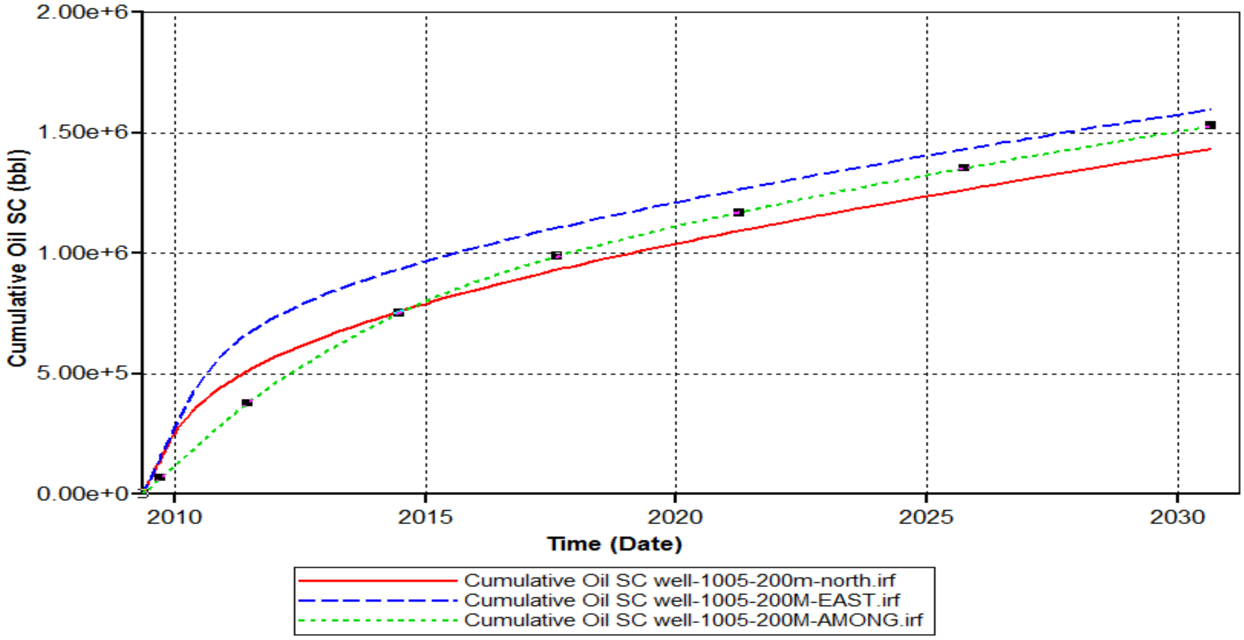


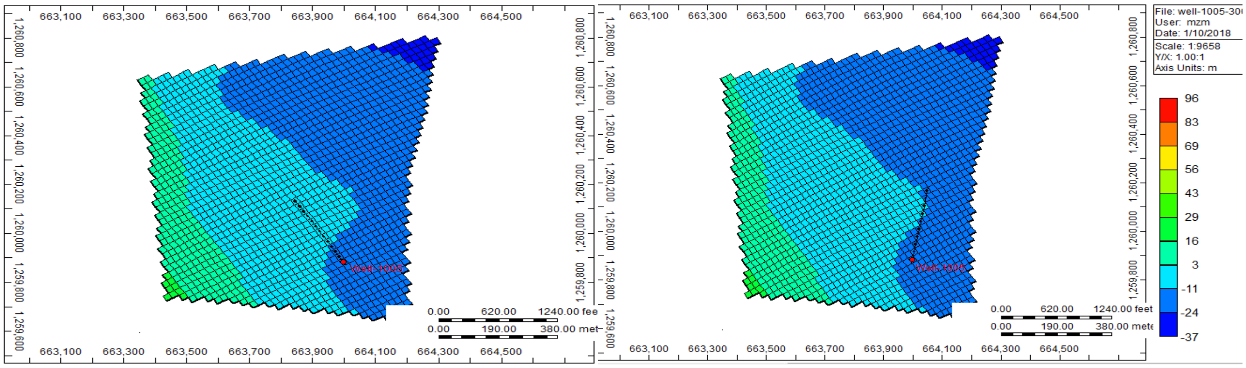
Figure (4.19): Compare between Cumulative Oil in Three Directions for Well-1005 with Length 200m.

After build and run three models in different direction for horizontal section with length 200m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well presented in table (4.10) and figure (4.19), the cumulative oil of East direction higher than both North and North East directions till 2030. From table (4.10) East direction have highest cumulative oil with (1.59739 E6 bbl.) from figure (4.19) the curve of cumulative oil in North direction and East direction was almost equal until 2011after that cumulative oil of East direction increased gradually until 2030.

Note: The East direction arrived to the boundary of model so it is the final limit of East direction length.

Third Scenario of 300 M.

In this scenario length of horizontal section will be (300 M) in two directions and will compare between cumulative oil in two directions to determine best direction of horizontal section, figure (4.20) showing the horizontal section of well-1005 in two directions North and North East.



North direction of horizontal section   North East direction of horizontal section

Figure (4.20): Grid Top in 2D Shows Horizontal Section in Two Directions for well-1005 with Length 300m.

After models run the result of cumulative oil of two directions show in table (4.11)**.**

Table (4.11): Cumulative Oil of Wells for 300m Horizontal Section in Two Direction for well-1005.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	1.43671 E6
2	North East direction of horizontal well	1.64087 E6

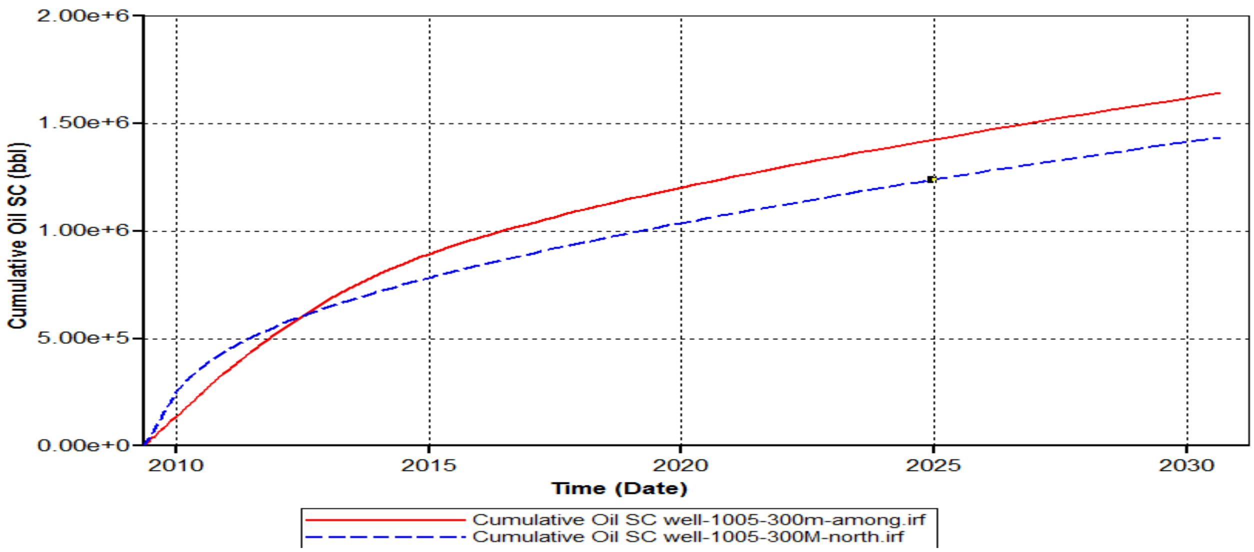
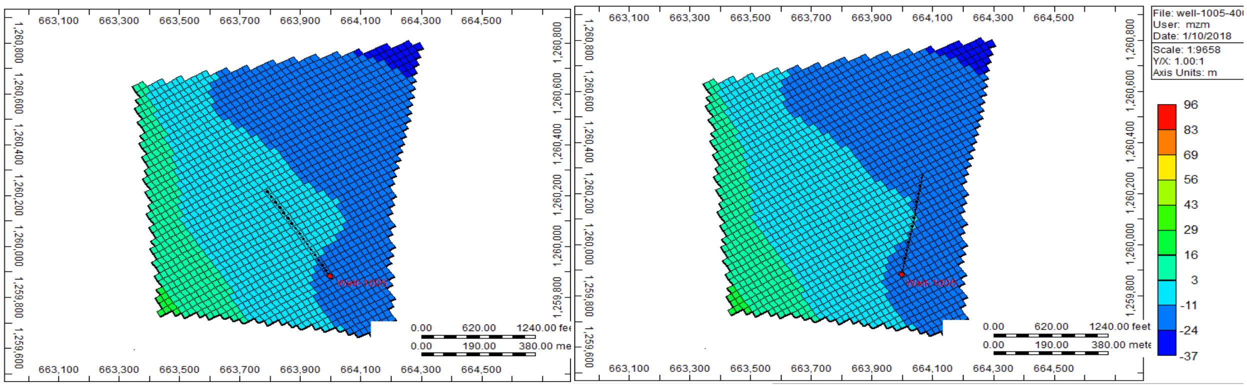


Figure (4.21): Compare between Cumulative Oil in Two Directions for well-1005 with 300m Length.

After build and run two models in different direction for horizontal section with length 300m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.11) and figure (4.21), the cumulative oil of North East direction higher than North direction till 2030, from the table (4.11) East direction have highest cumulative oil with (1.64087 E6 bbl.) from figure (4.21) the carve of cumulative oil for North direction greater than North East direction until 2013 after that North East direction cumulative oil become greater than North direction until 2030.

Fourth Scenario of 400 M

In this scenario length of horizontal section will be (400 M) in two directions and will compare between cumulative oil in two directions to determine best direction of horizontal section,
figure (4.22) presenting the horizontal section of well-1005 in two directions North and North East.



north direction of horizontal section North East direction of horizontal section

Figure (4.22): Grid Top in 2D Shows Horizontal Section in Two Directions for well-1005 with Length 400m.

After models run the cumulative oil of two directions will be as show in table (4.12).

Table (4.12): Cumulative Oil of Wells for 400m Horizontal Section in Two Direction for well-1005.

No.	Direction	Cumulative oil (bbl.)
1	North direction of horizontal well	1.49861 E6
2	North East direction of horizontal well	1.89553 E6

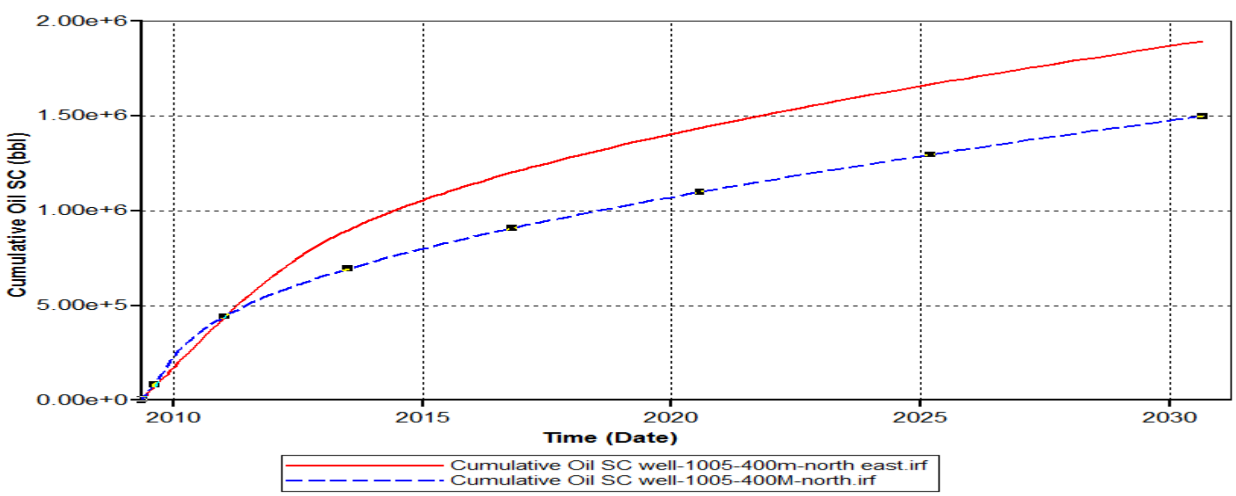
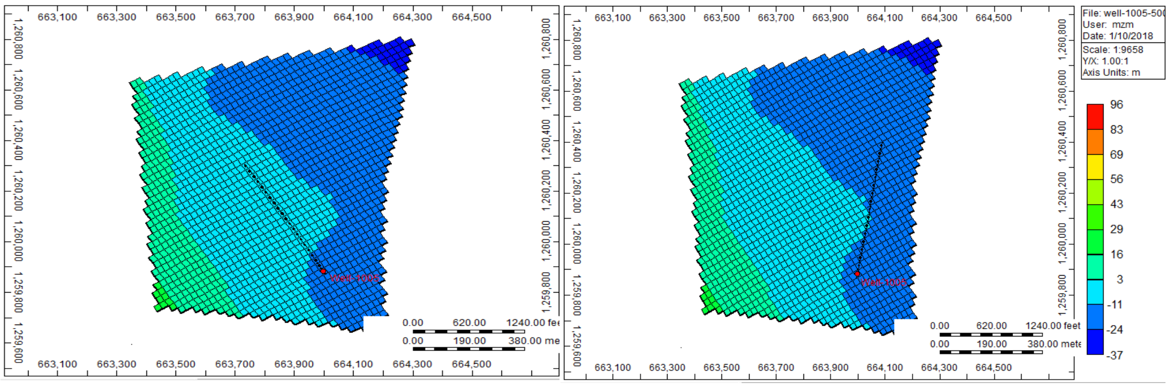


Figure (4.23): Compare between Cumulative Oil in Two Directions for well-1005 with 400m Length.

After build and run two models in different direction for horizontal section with length 400m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.12) and figure (4.23), the cumulative oil of North East direction higher than North direction till 2030, from the table (4.12) North East direction have highest cumulative oil with (1.89553 E6 bbl.) from figure (4.23), the carve of cumulative oil for North direction greater than North East direction until 2012 after that North East direction cumulative oil become greater than North direction until 2030.

Fifth Scenario of 500 M:

In this scenario length of horizontal section will be (500 M) in two directions and will compare between cumulative oil in two directions to determine best direction of horizontal section, figure (4.24): presenting the horizontal section of well-1005 in two directions North and North East.



North direction of horizontal section North East direction of horizontal section

Figure (4.24) Grid Top in 2D Shows Horizontal Section in Two Directions for well-1005 with 500m Length.

After model run the cumulative oil of two directions will be as show in table (4.13)

Table (4.13): Cumulative Oil of Wells for 500m Horizontal Section in Two Direction for well-1005.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	1.59525 E6
2	North East direction of horizontal well	2.3001 E6

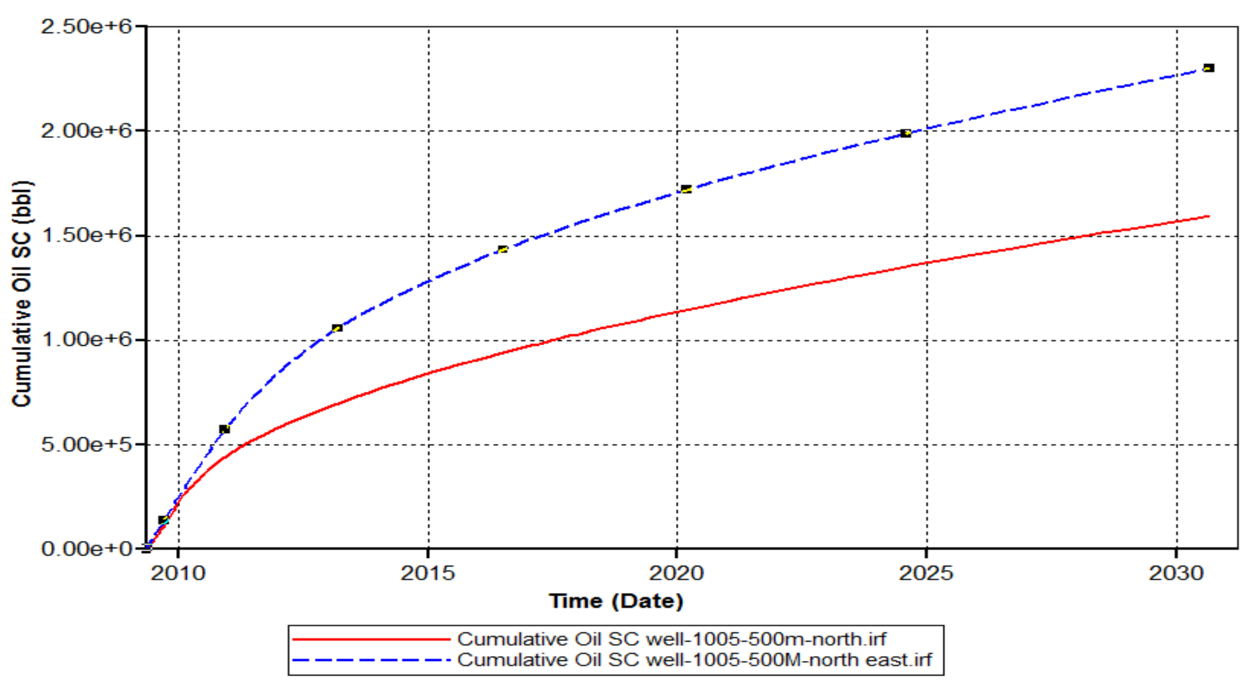
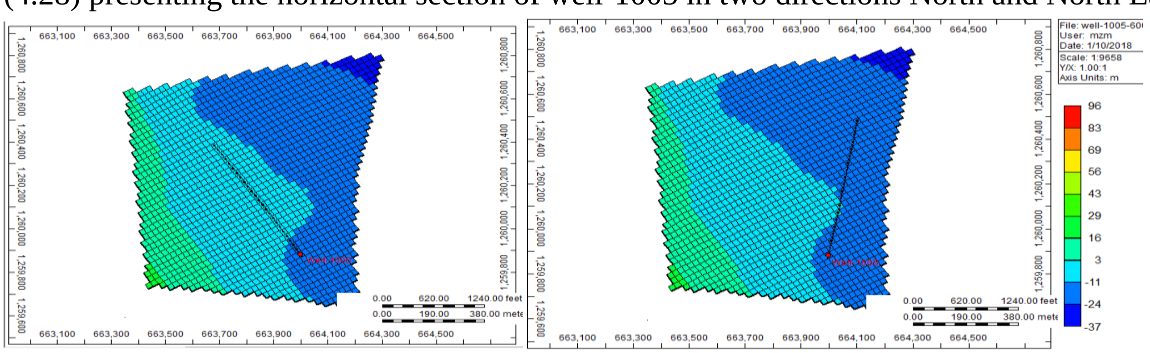


Figure (4.25): Compare between Cumulative Oil in Two Directions for well-1005 with 500m Length.

After build and run two models in different direction for horizontal section with length 500m and DNC All wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.13) and from figure (4.25), the cumulative oil of North East direction higher than North till 2030.
from table (4.13) North East direction have highest cumulative oil with (2.3001 E6 bbl.) from figure (4.25) the cumulative oil of North East direction is greater than North direction until 2030.

Sixth Scenario of 600 M.

In this scenario length of horizontal section will be (600 M) in two directions and will compare between cumulative oil in two directions to determine best direction of horizontal section, figure (4.28) presenting the horizontal section of well-1005 in two directions North and North East.



North direction of horizontal section   North East direction of horizontal section

Figure (4.26): Grid Top in 2D Shows Horizontal Section in Two Directions for well-1005 with 600m Length.

After models run the cumulative oil of two directions will be as show in table (4.14)

Table (4.14): Cumulative Oil of Wells for 600m Horizontal Section in Two Direction for well-1005.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	2.43092 E6
2	North East direction of horizontal well	1.9373 E6

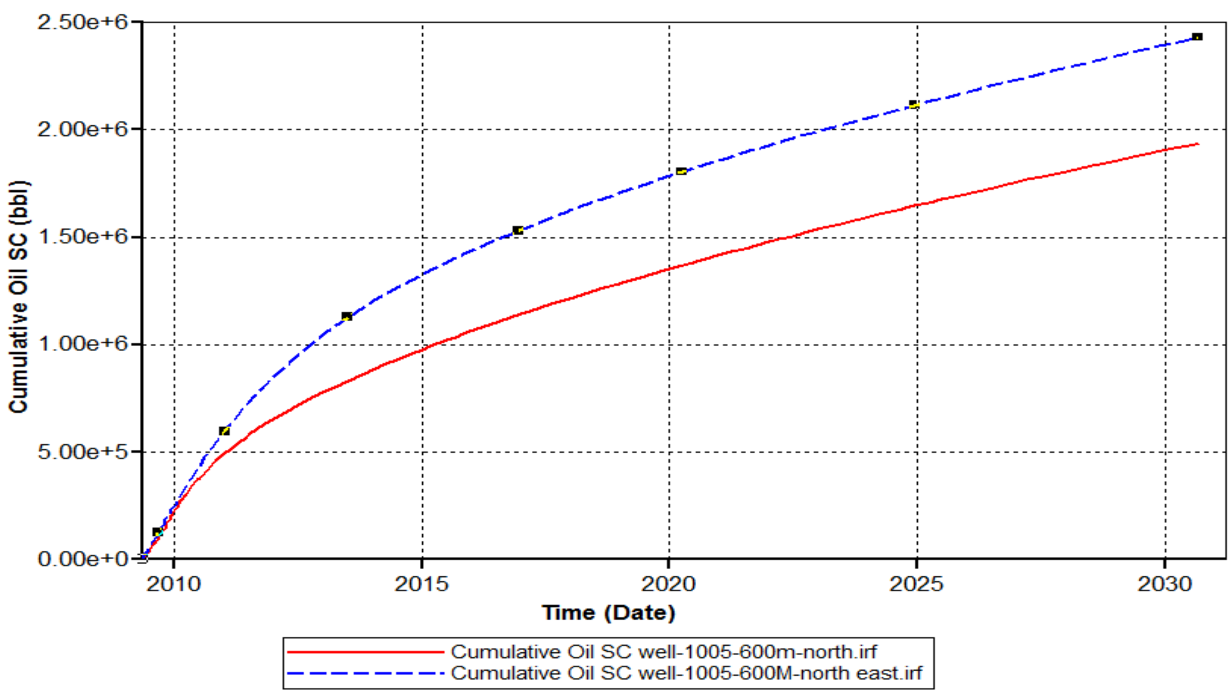


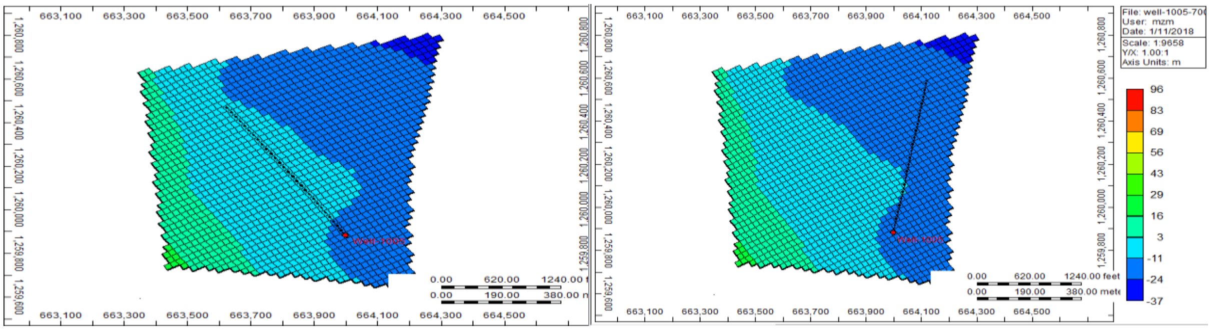
Figure (4.27): Compare between Cumulative Oil in Two Directions for well-1005 with 600m Length.

After build and run two models in different direction for horizontal section with length 600m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.14) and figure (4.27), the cumulative oil of North East direction higher than North till 2030.

From the table (4.14) East direction have highest cumulative oil with 2.43092 E6 bbl.) from figure (4.27) the cumulative oil of North East direction is greater than North direction until 2030.

Seventh Scenario of 700 M.

In this scenario length of horizontal section will be (700 M) in two directions and will compare between cumulative oil in two directions to determine best direction of horizontal section, figure (4.28) presenting the horizontal section of well-1005 in two directions North and North East.



North direction of horizontal section North East direction of horizontal section

Figure (4.28): Grid Top in 2D Shows Horizontal Section in Two Directions for well-1005 with 700m Length.

After models run the cumulative oil of two directions will be as show in table (4.15)

Table (4.15): Cumulative Oil of Wells for 700m Horizontal Section in Two Direction for well-1005.

No.	Direction	Cumulative oil (bbl.)
1	North direction of horizontal well	2.20265 E6
2	North East direction of horizontal well	2.49184 E6

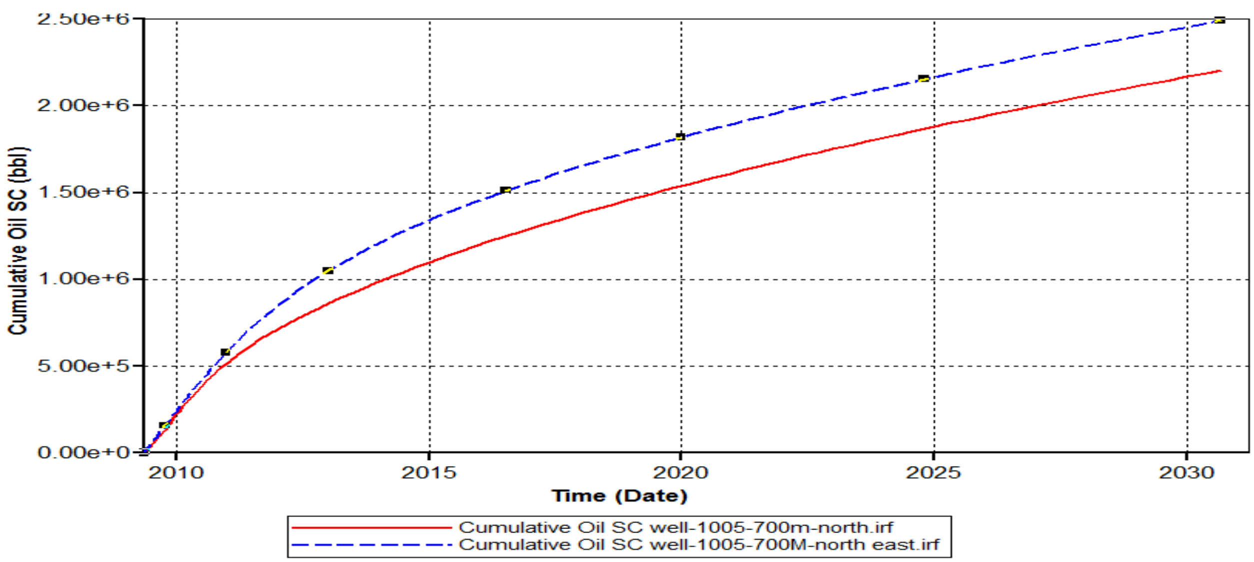
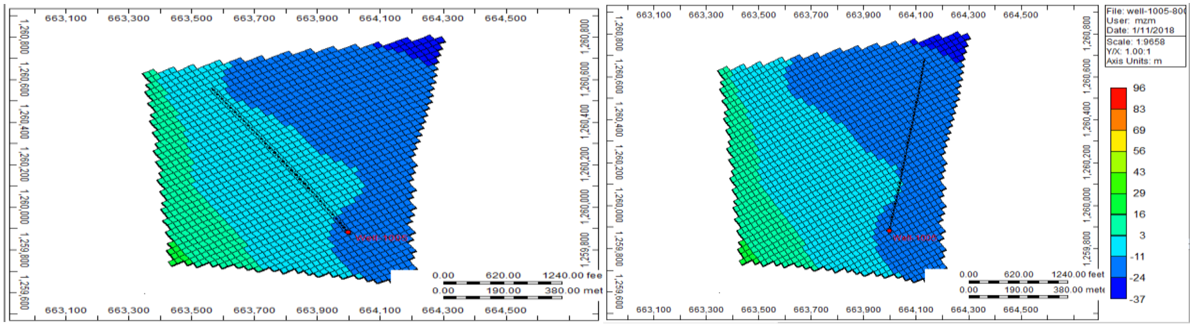


Figure (4.29): Compare between Cumulative Oil in Two Directions for well-1005 with 700m Length.

After build and run two models in different direction for horizontal section with length 700m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.15) and figure (4.29), the cumulative oil of North East direction higher than North till 2030, from the table (4.14) North East direction have highest cumulative oil with (2.49184 E6 bbl.) from figure (4.29) the cumulative oil of North East direction is greater than North direction until 2030.

Seventh Scenario of 800 M.

In this scenario length of horizontal section will be (800 M) in two directions and will compare between cumulative oil in two directions to determine best direction of horizontal section, figure (4.30) presenting the horizontal section of well-1005 in two directions North and North East.



North direction of horizontal section North East direction of horizontal section

Figure (4.30) Grid Top in 2D shows Horizontal Section in Two Directions for well-1005 with 800m Length.

After model run the cumulative oil of two directions will be as show in table (4.16)

Table (4.16): Cumulative Oil of Wells for 800m Horizontal Section in Two Direction for well-1005.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	2.31019 E6
2	North East direction of horizontal well	2.52029 E6

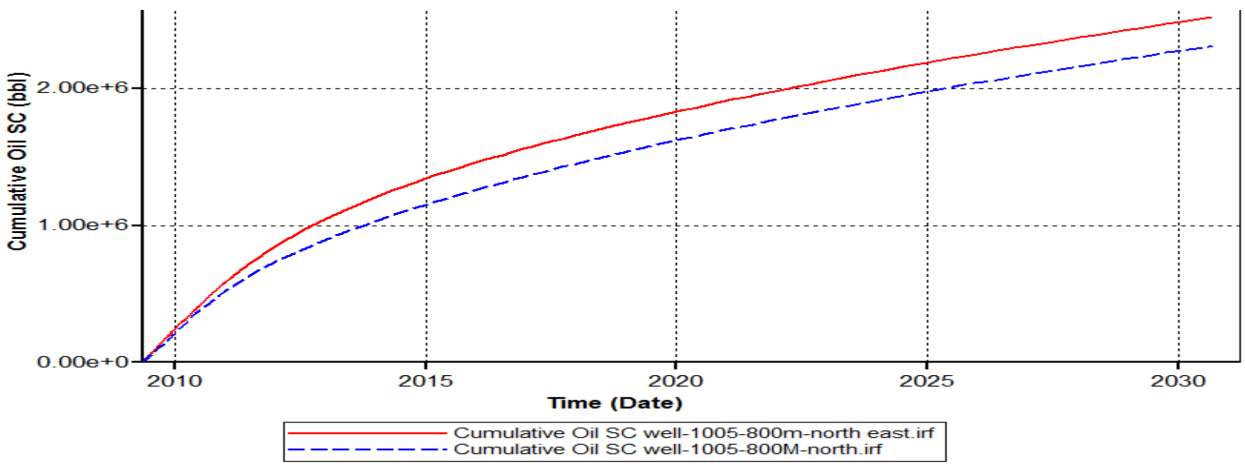


Figure (4.31): Compare between Cumulative Oil in Two Directions for well-1005 with 800m Length.

After build and run two models in different direction for horizontal section with length 800m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.16) and figure (4.31), the cumulative oil of North East direction higher than North till 2030. From the table (4.14) North East direction have highest cumulative oil with (2.52029 E6 bbl.) from figure (4.31) the cumulative oil of North East direction is greater than North direction until 2030.

Incremental.

In this section the difference between cumulative oil will be calculate for every difference in length of wells in two directions to calculate the incremental, figure (4.32) and figure (4.33) show the incremental in cumulative oil for every 100M in two direction North and North East but West direction is neglect.

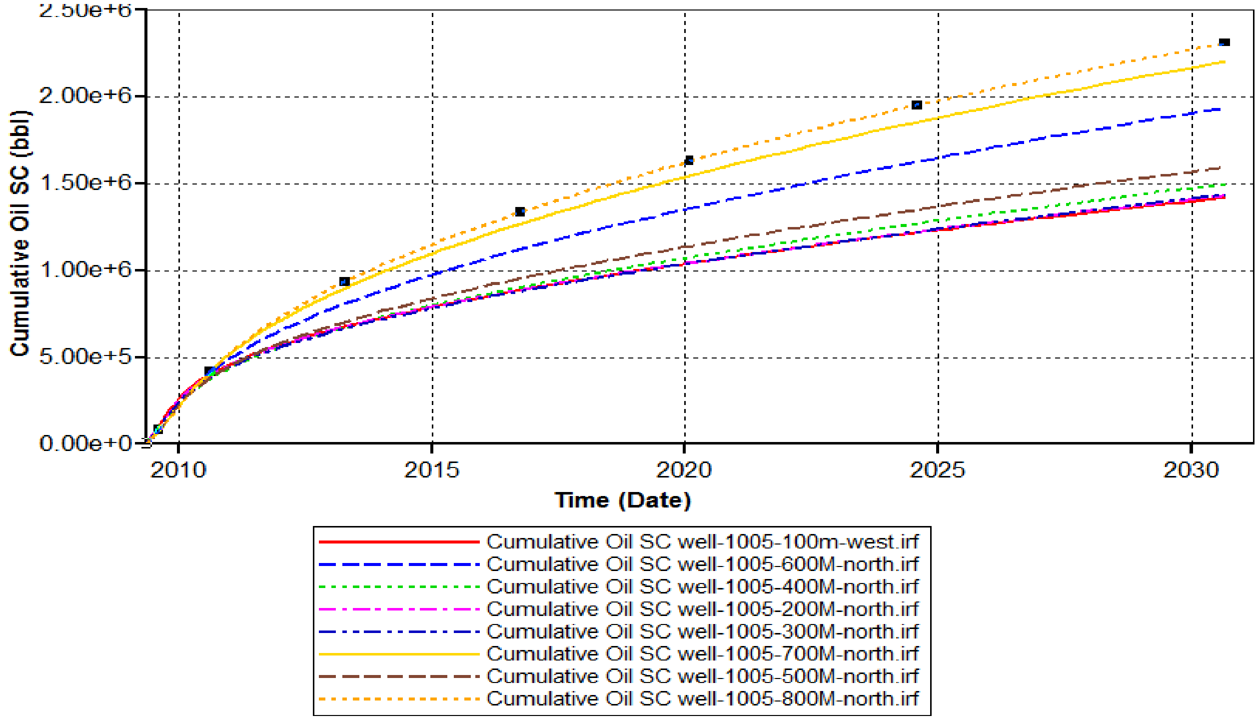


Figure (4.32): Incremental of Cumulative Oil on North Direction Wells for Well-1005 for Every 100m.

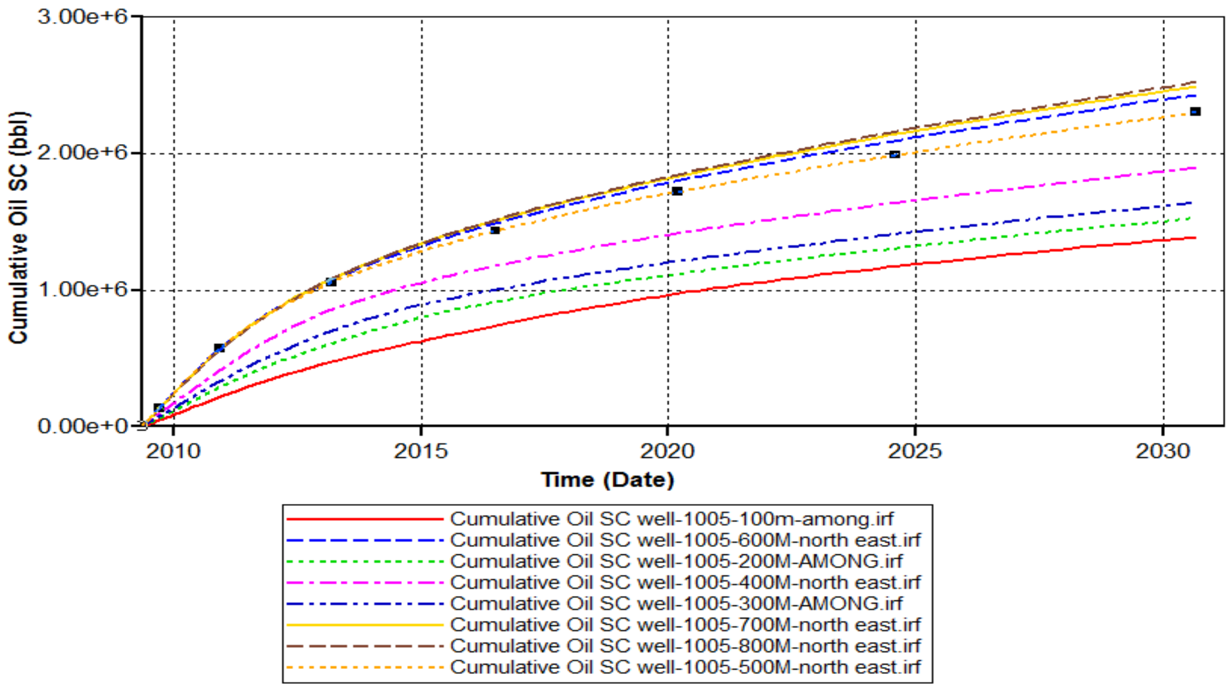


Figure (4.33): Incremental of Cumulative Oil on North East Direction for Well-1005 for Every 100m.

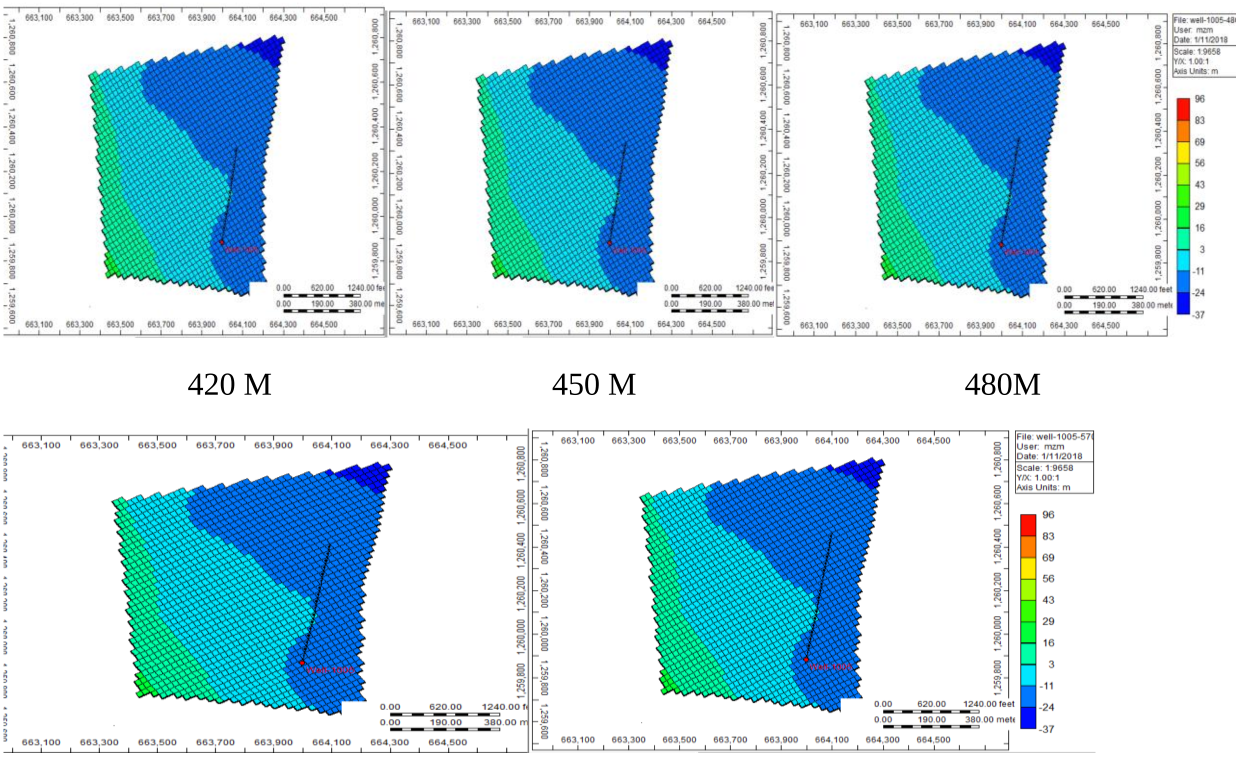
Table (4.17): Incremental Cumulative Oil for All Direction for Well-1005.

No.	Length (M)	Cumulative oil of North direction / bbl.	Incremental in oil with length /bbl.	Cumulative oil of North East direction /bbl.	Incremental in oil with length /bbl.	Cumulative oil of East direction /bbl.	Incremental in oil with length /bbl.
1	100	1.42116 E6		1.39055 E6		1.53043 E6	
2	200	1.43061 E6	9450	1.5285 E6	137950	1.59739 E6	66960
3	300	1.43671 E6	6100	1.64087 E6	112370		
4	400	1.49861 E6	61900	1.89553 E6	254660		
5	500	1.59525 E6	96640	2.3001 E6	404570		
6	600	1.9373 E6	342050	2.43092 E6	130820		
7	700	2.20265 E6	265350	2.49184 E6	60920		
8	800	2.31019 E6	107540	2.52029 E6	28450		

After build and run 18 model to determine the best direction for well -1005 all previous result show in table (4.17) the best incremental for North direction wells is in 600M with (342050 bbl.) incremental, But the best incremental for North East direction wells is in 500M with (404570 bbl.) incremental, the cumulative oil increase more than any other length in North East direction from 400M to 500M, from the previous result for well-1005 the best direction is North East because it is more productive than any other direction and the best length is between 400M and 500M because it has best incremental of cumulative oil with length, but in the second section the length of well-1005 will be more specific.

Best Length of Horizontal Section for Well-1005.

From previous study the best direction of well-1005 is North East and best length is 500M, but in this section the length for horizontal section will be more specific between 400M and 500M by determine the best incremental of cumulative oil for (420M,450M ,480M 540 M, 570 M) as described in figure (4.34), figure (4.35) summarizing cumulative oil for these lengths to determine the best incremental to determine best length of well-1005.



420 M 450 M 480M

540M 570M

Figure (4.34): Grid Top in 2D of the Difference Length of Horizontals Section between 400m to 600m for North East Direction in Well-1005.

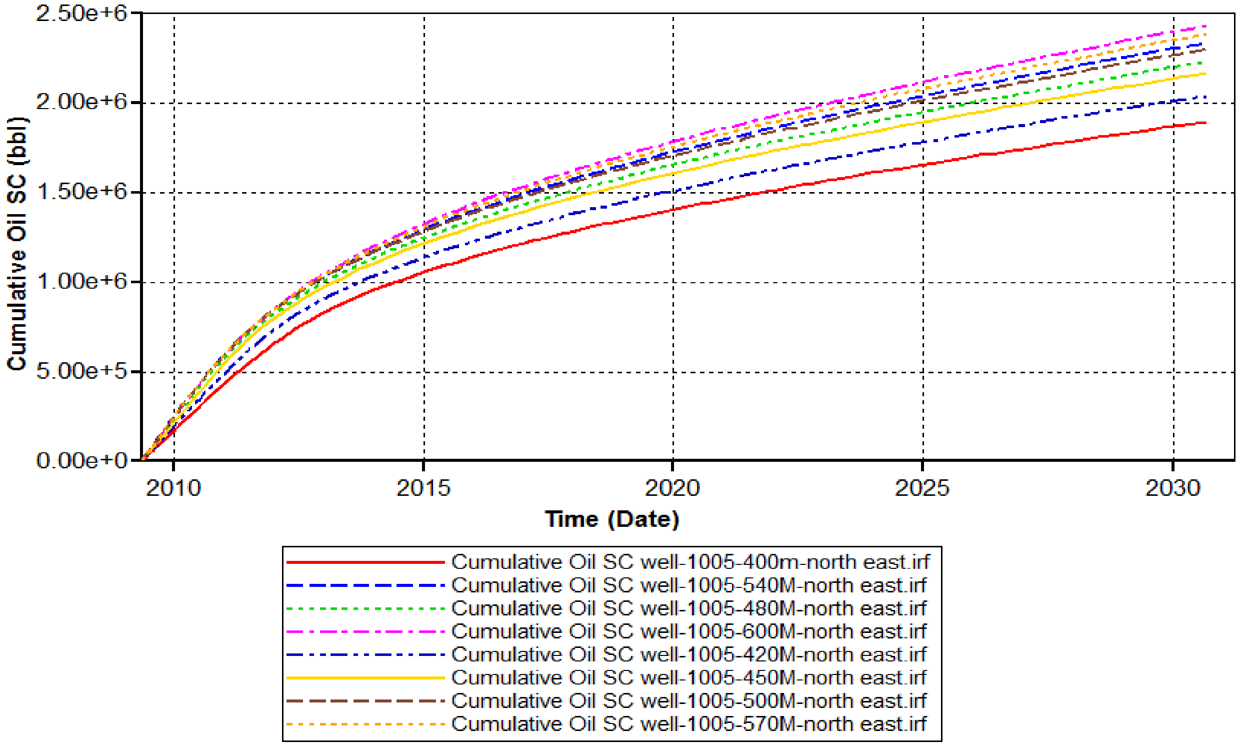


Figure (4.35): Incremental of Cumulative Oil for Length between 400m and 600m for North East Direction in Well-1005.

Table (4.18): Incremental in Cumulative Oil for Length between 400m and 600m for well-1005.

No.	Length(M)	Cumulative oil(bbl.)	Incremental in oil with length(bbl.)
1	400	1.89553 E6	
2	420	2.04021 E6	144680
3	450	2.16496 E6	124750
4	480	2.23065 E6	65690
5	500	2.3001 E6	69450
6	540	2.33568 E6	35580
7	570	2.38347 E6	47790
8	600	2.43092 E6	47450

After build and run 8 models to determine the best length of horizontal section for well-1005 from previous study for well-1005 the best length of horizontal section is 420 M as presented in table (4.18) the best incremental with length at 420M with (144680 bbl.).

4.4.2.2 Length and Direction Sensitivity for Well-1003.

After determining the best length and best direction of horizontal section of well-1005 in previous study, in this section well-1005 will be closed and well -1003 will be open to determine the best length and best direction of horizontal section of well-1003, figure (4.40) describing time line view for well-1005 and well-1003 and show well-1005 is closed and well -1003 is open.

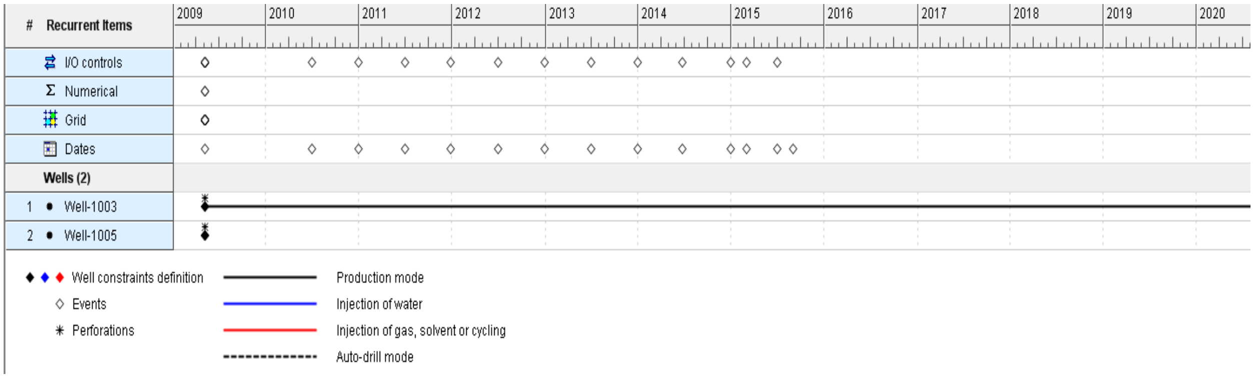
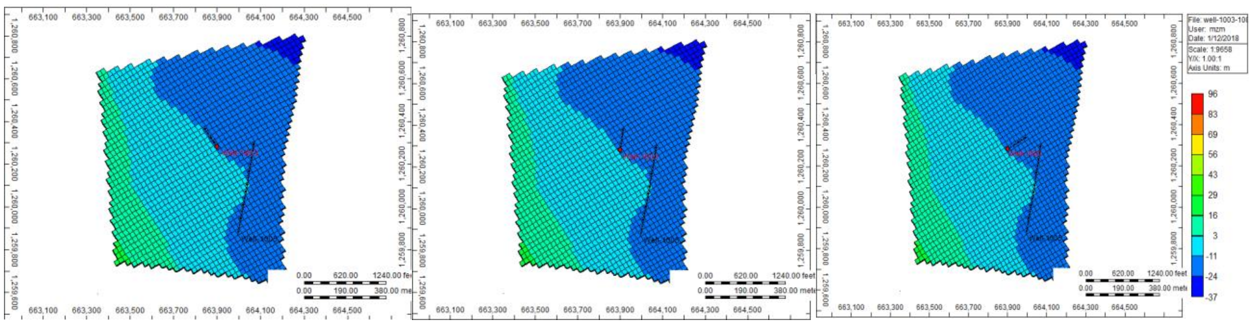


Figure (4.36): Time Line View of Well-1005 is Closed and Well -1003 is Open.

First Scenario of 100 M.

In this scenario length of horizontal section will be (100 M) in three directions and will compare between cumulative oil in the three directions to determine best direction of horizontal section, presenting (4.37) show the horizontal section of well-1003 in three directions.



North direction North East direction East direction well

Figure (4.37): Grid Top in 2D Shows Horizontal Section in Three Directions for well-1003 with 100m.

After models run the cumulative oil of three directions shows in table (4.19)

Table (4.19): Cumulative Oil of 100m Horizontal Section in Three Direction for well-1003.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal section	2.60494 E6
2	North East direction	2.31823 E6
3	East direction of horizontal section	2.46803 E6

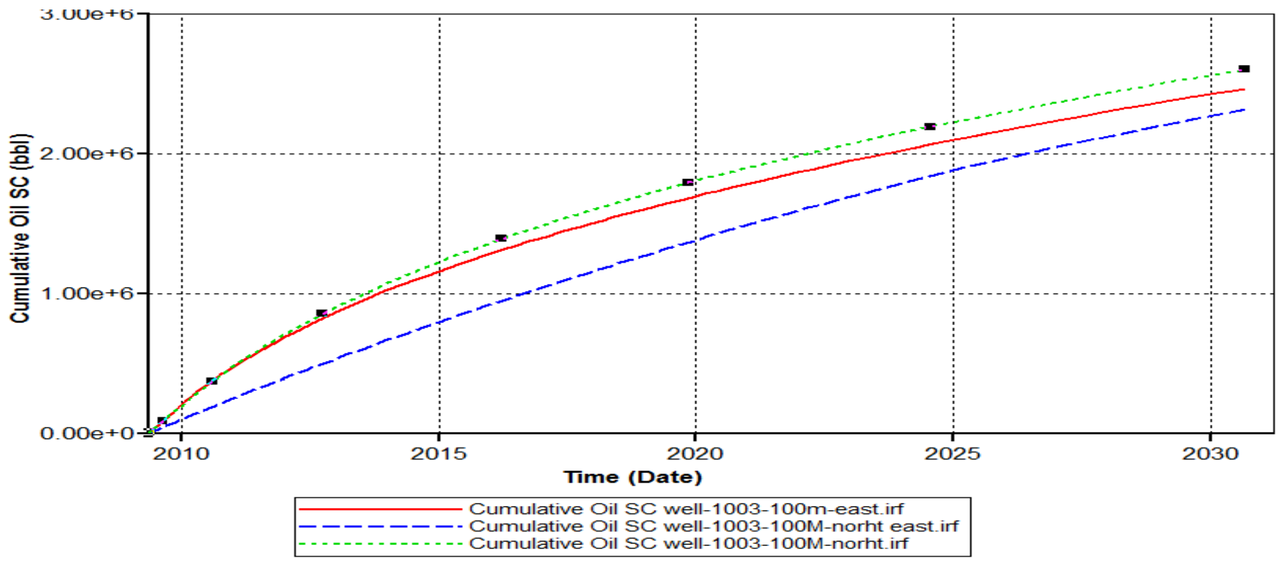
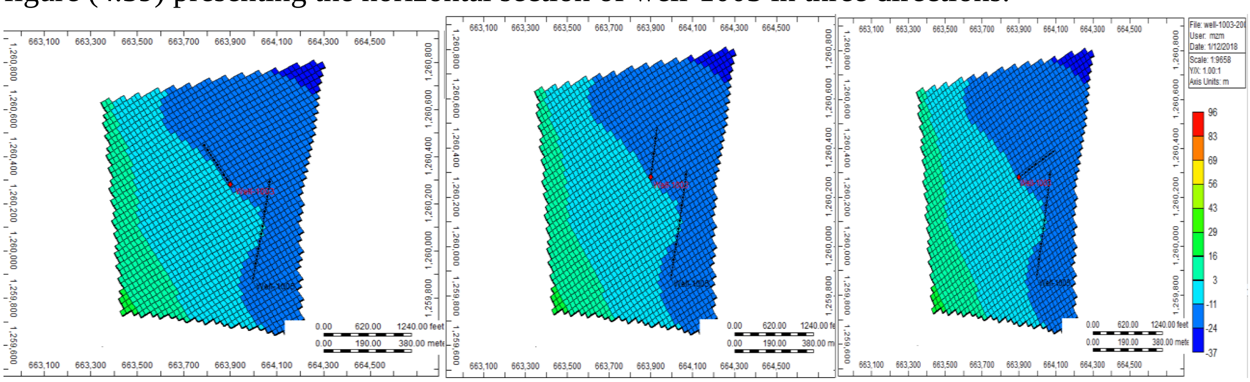


Figure (4.38): Compare between Cumulative Oil in Three Directions for Well-1003 with 100m Length.

After build and run three models in different direction for horizontal section with length 100m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.19) and figure (4.38), the cumulative oil of North direction higher than North East and East direction till 2030, from the table (4.19) East direction have highest cumulative oil with (2.60494 E6 bbl.) from figure (4.38) the cumulative oil increase gradually for all direction with different value, but the North direction have the highest value.

Second Scenario of 200 M.

In this scenario length of horizontal section will be (200 M) in three directions and will compare between cumulative oil in the three directions to determine the best direction of horizontal section figure (4.39) presenting the horizontal section of well-1003 in three directions.



North direction North East direction East direction

Figure (4.39): Grid Top in 2D Shows Horizontal Section in Three Directions for well-1003 with 200m.

After models run the cumulative oil of three directions shows in table (4.20).

Table (4.20): Cumulative Oil of 200m Horizontal Section in Three Direction for well-1003.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	2.63152 E6
2	North East direction	2.55337 E6
3	East direction of horizontal well	2.43045 E6

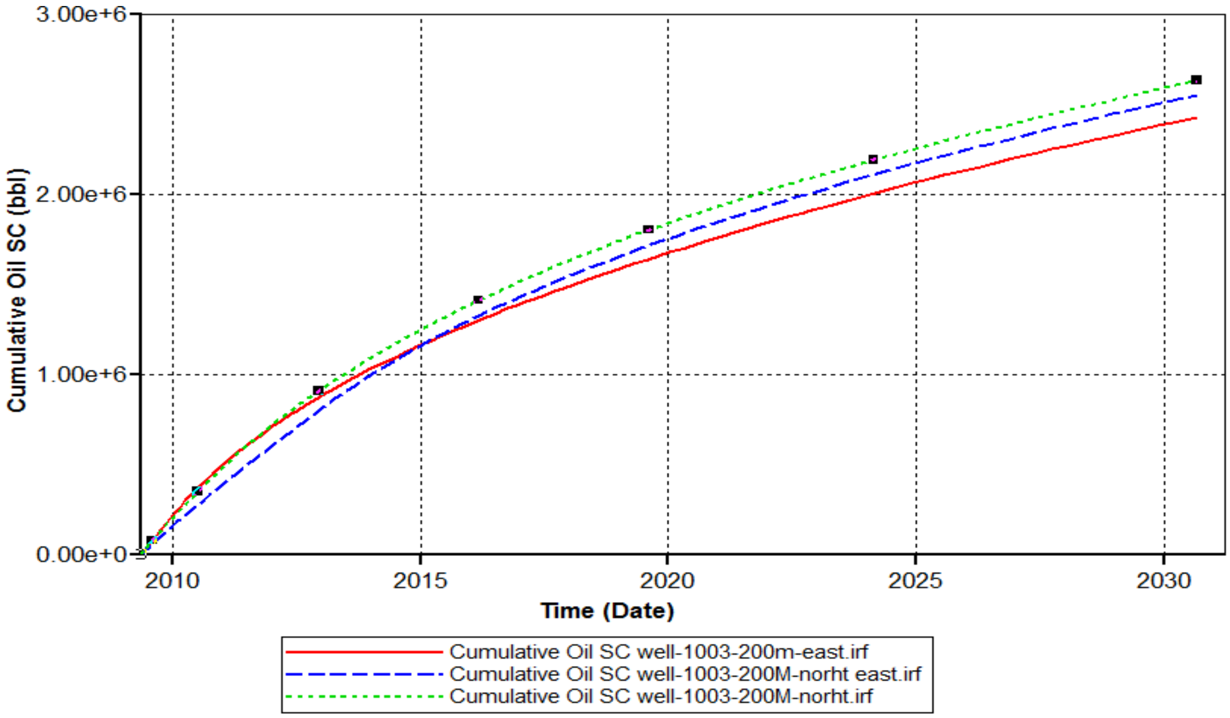


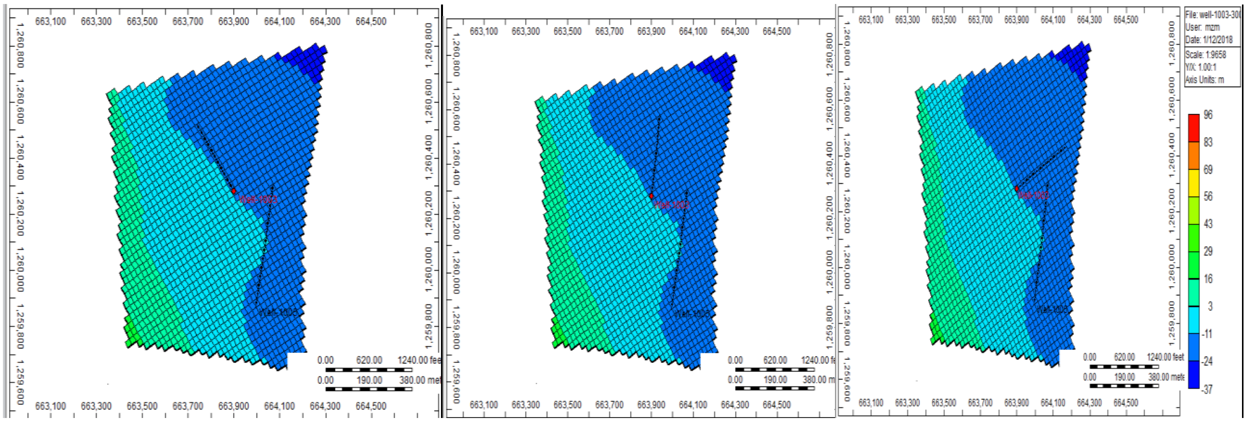
Figure (4.40): Compare between Cumulative Oil in Two Directions for well-1003 with 200m Length.

After build and run three models for well-1003 in different direction of horizontal section with length 200m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.20) and figure (4.40), the cumulative oil of North direction higher than North East and East direction till 2030, from the table (4.20) East direction have highest cumulative oil with (2.63152 E6 bbl.), from figure (4.40) the cumulative oil for three direction increase gradually but North and North East direction was equals until 2013 after that cumulative oil for North direction become greater than other direction until 2030.

Third Scenario of 300 M.

In this scenario length of horizontal section will be (300 M) in three directions and will compare between cumulative oil in three directions to determine the best direction of horizontal section.

figure (4.41) presenting the horizontal section of well-1003 in three directions north, North East and East.



North direction North East direction East direction

Figure (4.41): Grid Top in 2D Shows Horizontal Section in Three Directions for Well-1003 with 300m.

After models run the cumulative oil of the three directions will be as show in table (4.21)**.**

Table (4.21): Cumulative Oil of 300m Horizontal Section in Three Direction for Well-1003.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	2.63099 E6
2	North East direction	2.56454 E6
3	East direction of horizontal well	2.40005 E6

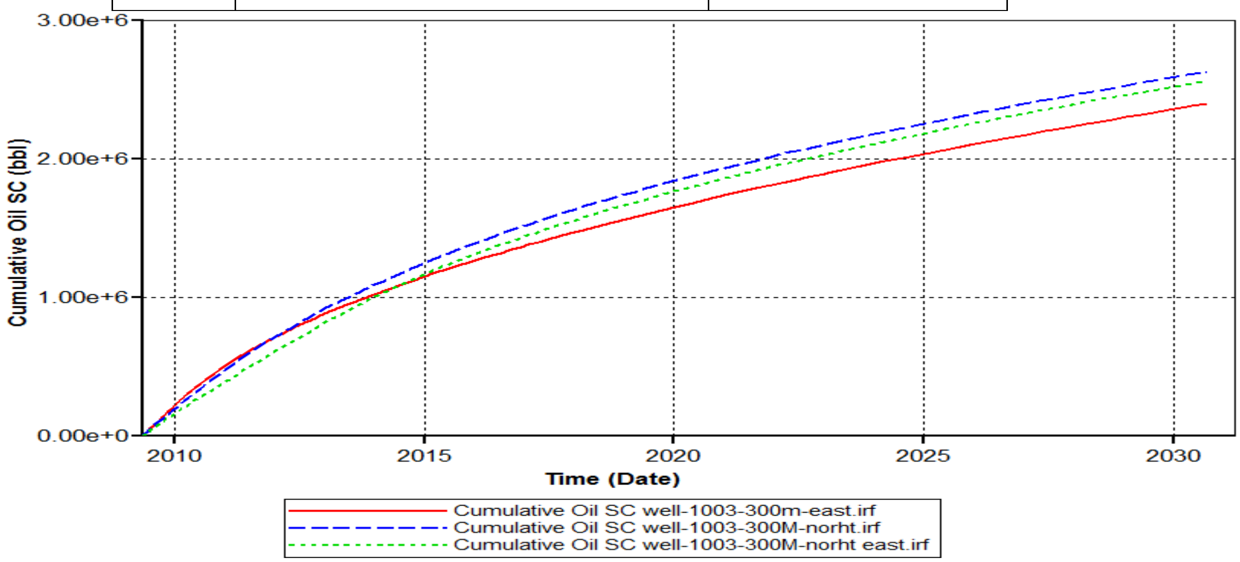


Figure (4.42): Compare between Cumulative Oil in Two Directions for well-1003 with 300m Length.

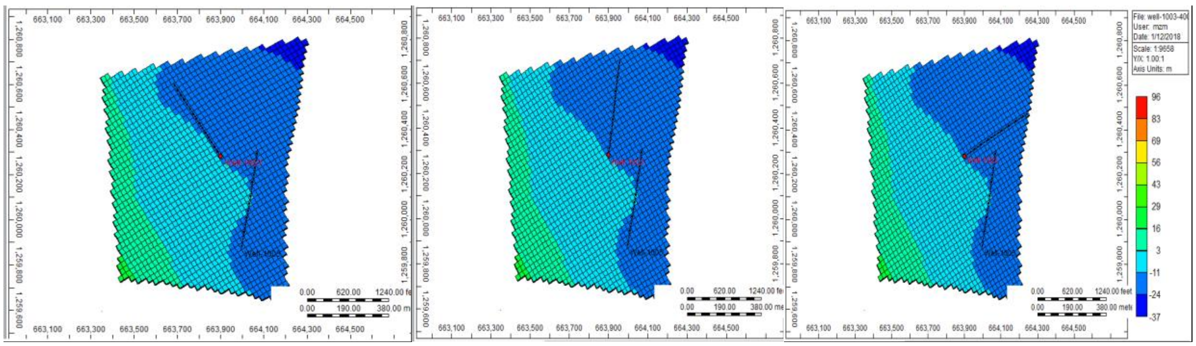
After build and run three models for well-1003 in different direction of horizontal section with length 300m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.21) and figure (4.42), the cumulative oil of North direction higher than North East and East direction till 2030.

From the table (4.21) North direction have highest cumulative oil with (2.63099 E6 bbl.), from figure (4.42) cumulative oil for three direction increase gradually but North and East direction was almost equal until 2013 after that cumulative oil for North direction become greater than other direction until 2030.

Fourth scenario of 400 M.

In this scenario length of horizontal section will be (400 M) in three directions and will compare between cumulative oil in three directions to determine best the direction of horizontal section.

figure (4.43) shows the horizontal section of well-1003 in three directions North, North East and East, maxim length of East direction is 390M because the length of well arrived to the boundary.



North direction North East direction East direction

Figure (4.43): Grid Top in 2D Shows Horizontal Section in Three Directions for well-1003 with 400m.

After models run the cumulative oil of three directions show in table (4.22)

Table (4.22): Cumulative Oil of 400m Horizontal Section in Three Direction for well-1003.

No.	Direction	Cumulative oil(bbl.)
1	North direction of horizontal well	2.66448 E6
2	North East direction	2.59666 E6
3	East direction of horizontal well	2.33196 E6

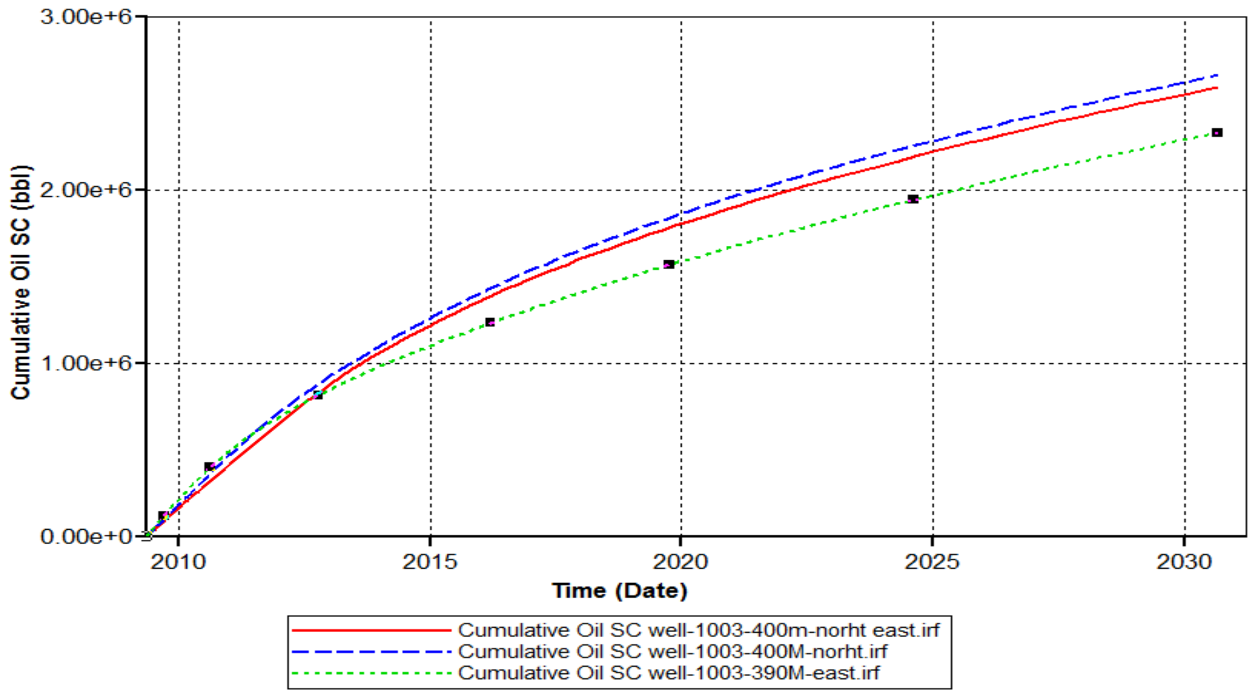


Figure (4.44): Compare between Cumulative Oil in Three Directions for well-1003 with 400 m length.

After build and run three models for well-1003 in different direction of horizontal section with length 400m and DNC all wells in the same condition of length of horizontal section, production rate and production pressure, the cumulative oil for each well showed in table (4.22) and figure (4.44), the cumulative oil of North direction higher than North East and East direction till 2030, from the table (4.22) North direction have highest cumulative oil with (2.66448 E6 bbl.), from figure (4.44) the cumulative oil for three direction increase but with different value.

Incremental.

From the previous study the best direction of well-1003 in North because the North direction has best productivity between other direction, in this section the difference between cumulative oil will calculate for every difference in length of wells in North directions to calculate the incremental, figure (4.45) show the incremental for cumulative oil for every 100M.

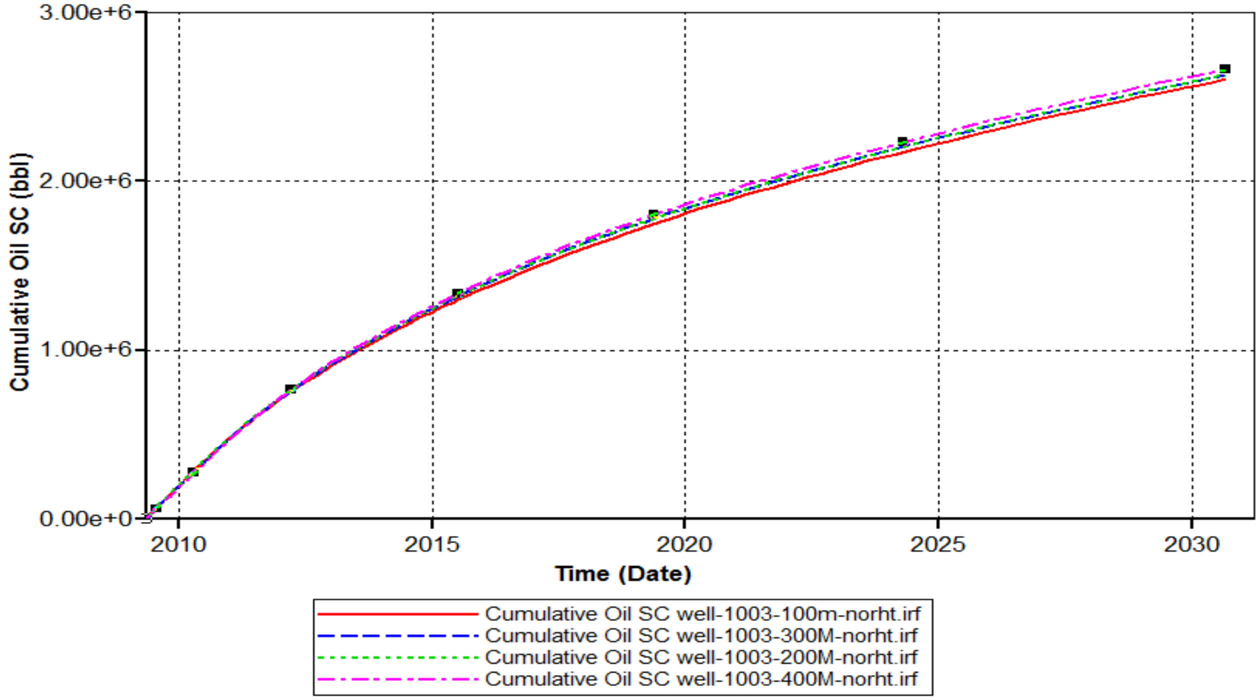


Figure (4.45): Incremental of Cumulative Oil on North Direction Wells for well-1003 for Every 100m.

Table (4.23): Incremental for North Direction for Well-1003.

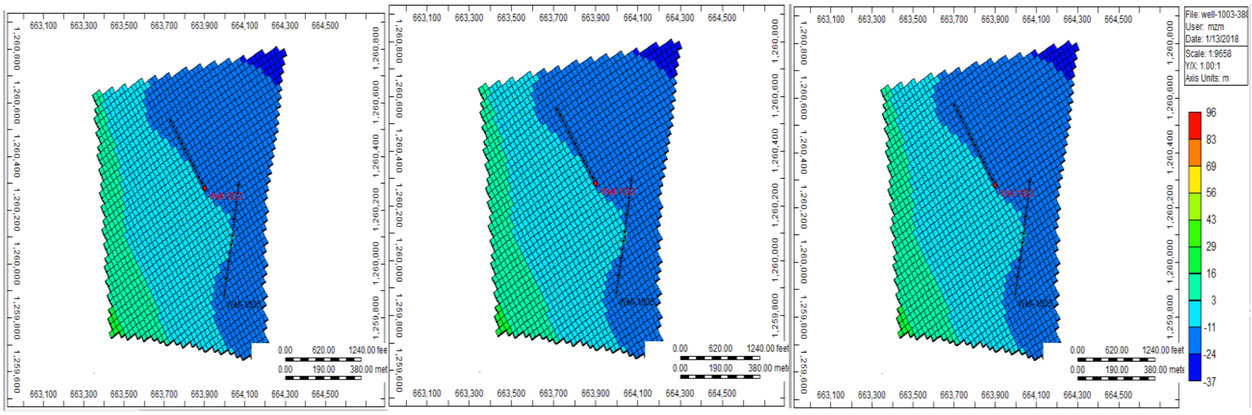
No.	Length(M)	Cumulative Oil of North Direction(bbl.)	Incremental in Oil with length (bbl.)
1	100	2.60494 E6	
2	200	2.63152 E6	26580
3	300	2.63099 E6	-530
4	400	2.66448 E6	33490

After build and run 12 models for well-1003 in different direction to determine the best direction of horizontal section, from table (4.23) the best incremental for North direction is between 300M and 400M with (33490 bbl.) incremental, the cumulative oil increase more than any other length in North direction at length between 300M to 400M.

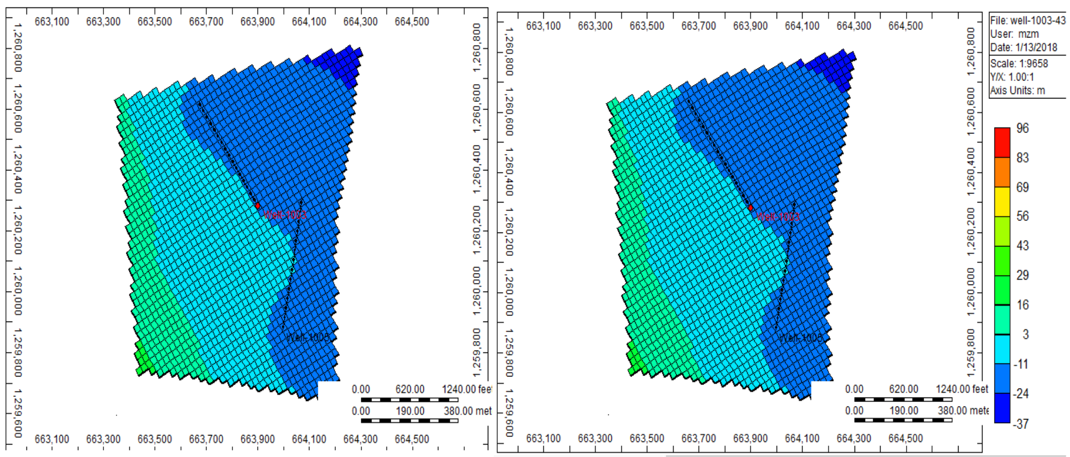
From the previous result for well-1003 the best direction is North because it is more productive than any other direction and the best length between 300M and 400M because it has best incremental of cumulative oil with length, but in the second section the length of well-1003 will be more specific.

Best Length of Horizontal Section for Well-1003.

From previous study the best direction of well-1003 is North and best length between 300M and 400M, but in this section the length for horizontal section will be more specific between 300M and 400M by determine the best incremental of cumulative oil for proposed length (330M,360M ,380M 430 M, 460 M) as described in figure (4.46), figure (4.47) summarizing cumulative oil for proposed lengths to determine the best incremental to determine best length.



330 M 360 M 380M



430M 460M

Figure (4.46): Grid Top in 2D Shows the Difference Length of Horizontals Section between 300m to 460m for well-1003.

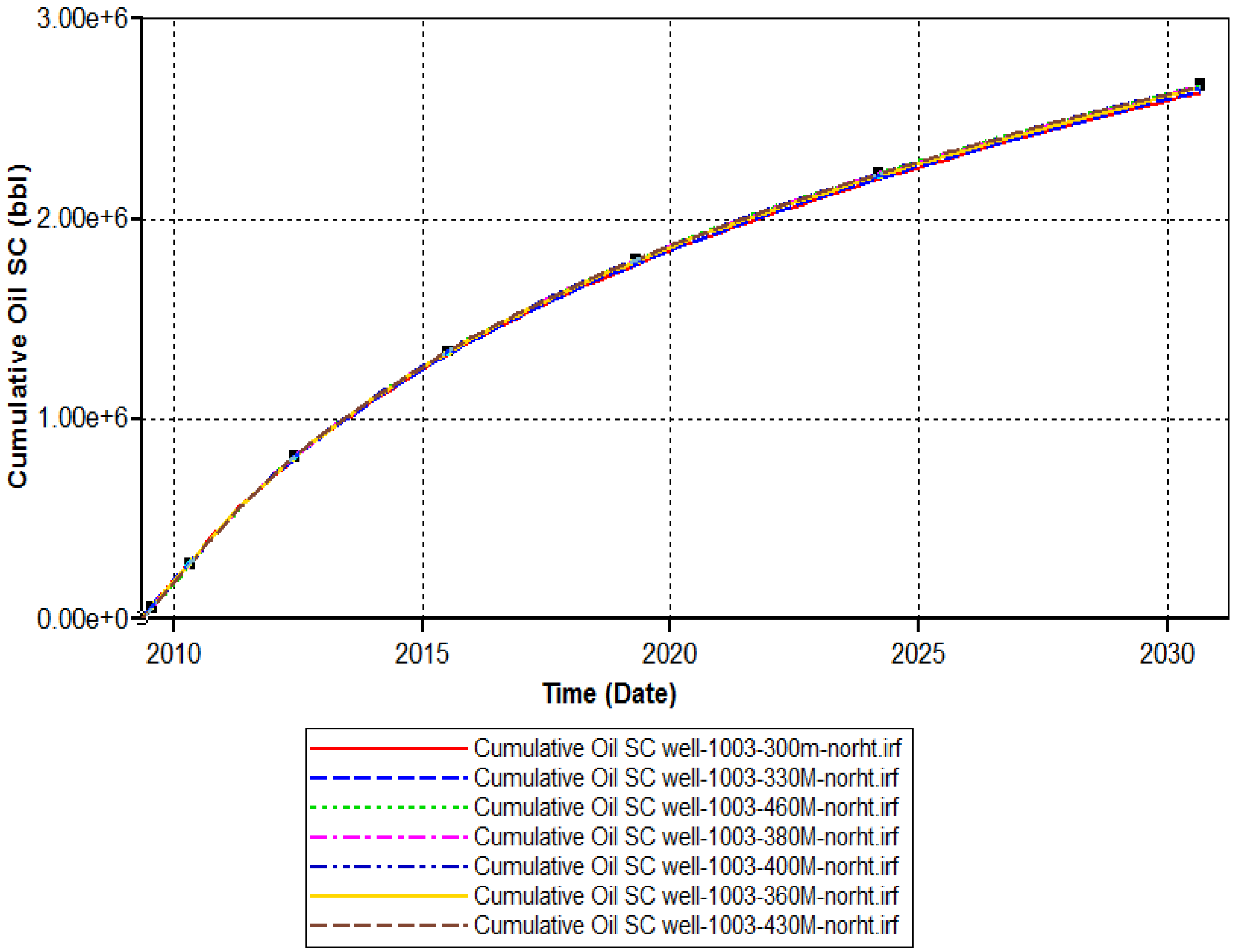


Figure (4.47): Incremental of Cumulative Oil for Length between 400m and 600m for well-1003.

Table (4.24): Incremental for Length between 400m and 600m for Well-1003.

No.	Length(M)	Cumulative oil (bbl.)	Incremental in oil with length (bbl.)
1	300	2.63099 E6	
2	330	2.63433 E6	3340
3	360	2.65359 E6	18930
4	380	2.66088 E6	7290
5	400	2.66448 E6	3600
6	430	2.6641 E6	-380
7	460	2.66679 E6	3800

After run and build 8 models to determine the best length of horizontal section for well-1003 from previous study for well-1003 the best length of horizontal section is 360 M as shows in table (4.24), because the best incremental of cumulative oil at length 360M in North direction.

From previous study of direction sensitivity section and length sensitivity of horizontals section for well-1005 and well-1003 the best direction of well-1005 is North East with 420M of length and for well-1003 the best direction is North with 360 M of length.

the last model will run with opening both of wells 1005-1003 to calculate the recovery factor and compare result with previous result of models.

The Optimum Model with Best Location Best Direction of Horizontals Section and Best Length of Horizontals Section for Well-1005 And Well-1003.

In this part the model will run with opining both of wells (1005-1003) as shows in figure (4.48) from time line view to determine the recovery factor and compare with previous result, figure (4.49) presenting the horizontals section of wells.

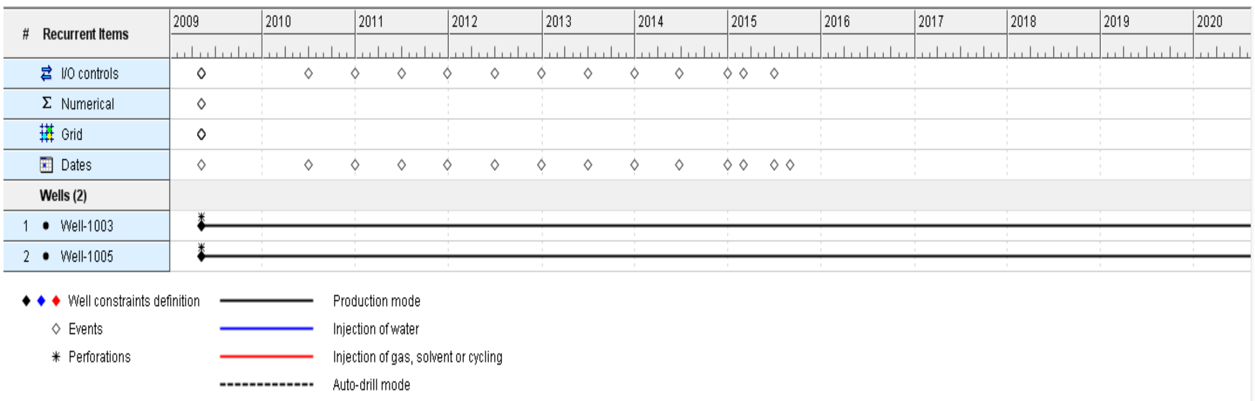


Figure (4.48): Time Line View of Wells Are Opened Well-1005 and Well-1003.

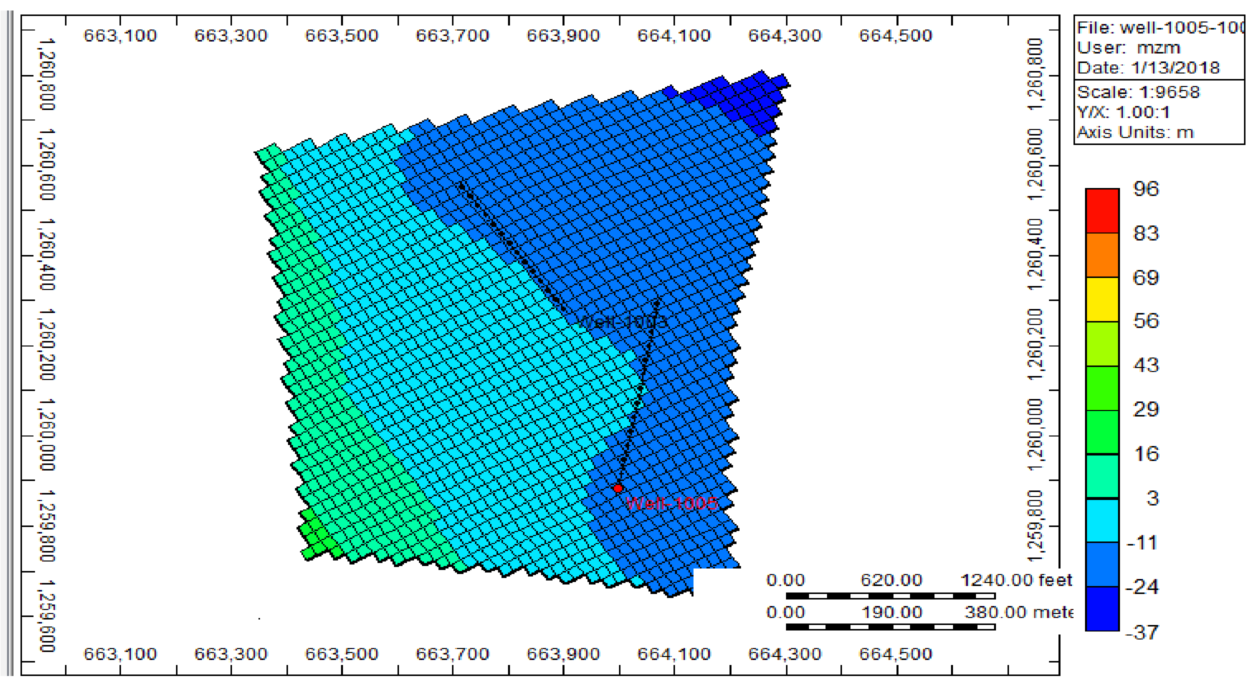


Figure (4.49): Grid Top in 2D Shows the Horizontals Section for Well-1005 and Well-1003.

DNC scenario have been done by using production parameter as follows (production rate 200 m3/day and production pressure of 200 kPa).

After run models with Previously mentioned parameters the cumulative oil, water cut% and recovery factor in figure (4.50) and table (4.25).

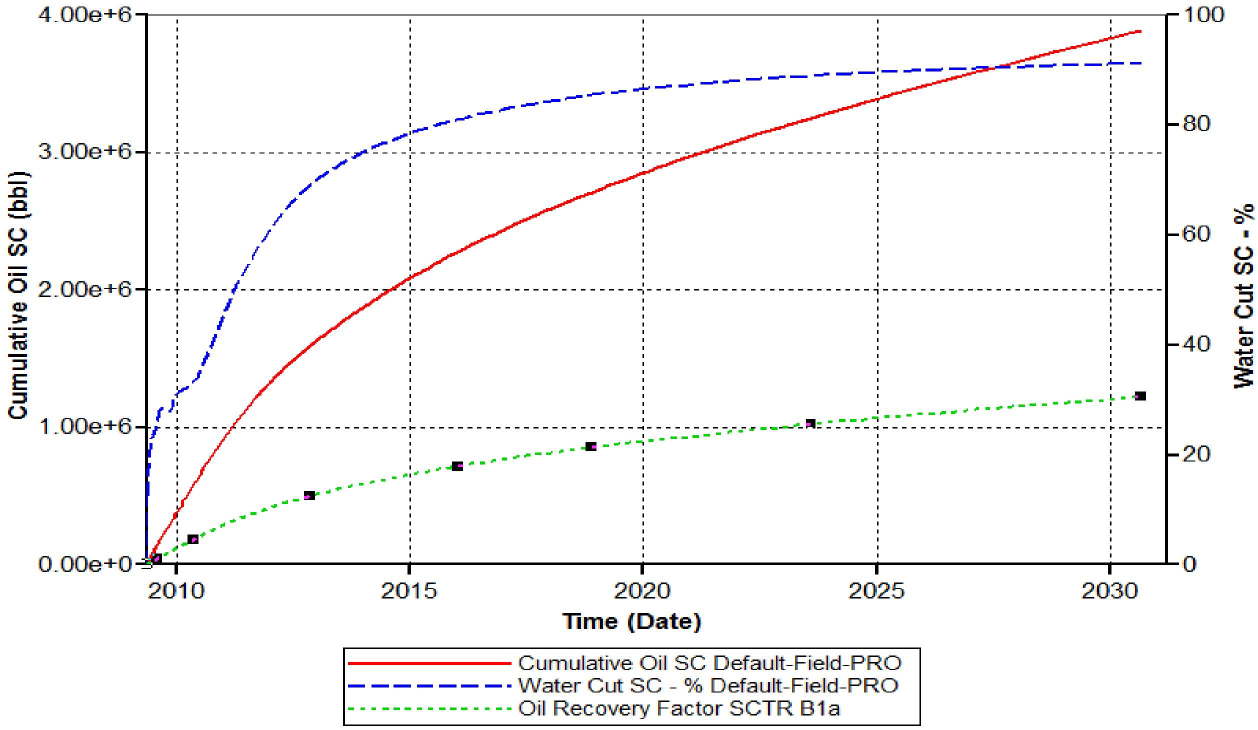


Figure (4.50): Cumulative Oil SC, Water Cut SC %, Recovery Factor Versus Time in DNC for Field.

DNC for two horizontals wells scenario which had been done and plotting of the results: (cumulative oil SC, water cut SC %, oil recovery factor) versus (time) as a prediction of the field performance till 2030.

Table (4.25): Cumulative Oil SC, Water Cut SC %, Recovery Factor for the Reservoir with DNC.

No.	Cumulative oil (bbl.)	W.C(%)	RF (%)
1	3.88241 E6	91.2274 %	30.5986 %

After build and run the models and calculate the recovery factor as show in table (4.25), this result will compare with model of 10 verticals well to determine how match recovery factor increases as show in table (4.26).

Table (4.26): Compare between Ten Vertical Wells and Two Horizontal Wells in DNC

No.		Cumulative oil (bbl.)	W.C(%)	RF (%)
1	Ten vertical wells with DNC.	3.29346 E6	94.8799%	24.2904%
2	Two Horizontals Wells with Optimum Length and Direction In DNC.	3.88241 E6	91.2274 %	30.5986 %

From table (4.26) the cumulative oil of Ten verticals well increase from (3.29346 E6 bbl.) to (3.88241 E6 bbl.) in 2 horizontals wells with optimum length and direction, water cut % decrease for Ten verticals well from (94.8799 %) to (91.2274 bbl.) in 2 horizontals wells with optimum length and direction, recovery factor of Ten verticals well increase from (24.2904%) to (30.5986 %) in 2 horizontals wells with optimum length and direction.

4.4.3 CSS Optimization.

CSS means cyclic steam stimulation, in this part the injection wells will be used to inject steam to increase oil recovery, CSS consists of three periods; first injection period second soaking period third production period.

In CSS sensitivity many parameters for well-1005 and well-1003 Will be Changed to determine the best condition and best scenario, the parameters are: Temperature sensitivity T (C^o), Quality of steam sensitivity Q (%), Injection rate sensitivity STW (bbl./ day), Injection period sensitivity (days), Soaking period sensitivity (days).

4.4.3.1 Temperature Sensitivity.

In this section the optimum temperature of steam will be determined by changing the temperature of steam to determine the best temperature by comparing between cumulative oil produced for every temperature, all parameters will be constant only temperature is changed to determine the best temperature of steam, the proposed temperatures are (200-250-300-350-400℃), table (4.27) shows the proposed models' parameter and change in temperatures.

Table (4.27): Proposed Models for Temperature Sensitivity.

No.	Temperature (Co)	Steam Quality (%)	Injection Rate (M3/day)	Injection Period (Day)	Soaking Period (Day)
1	200	0.5	200	14	3
2	250	0.5	200	14	3
3	300	0.5	200	14	3
4	350	0.5	200	14	3
5	400	0.5	200	14	3

Temperature Sensitivity for Well-1005.

In this section best temperature for well-1005 will determine by comparing between cumulative oil for all proposed temperature, all proposed models will implement and plotting, the proposed temperatures are (200-250-300-350-400) C^o.

After run models' figure (4.51) and table (4.28) presenting the different of cumulative oil for proposed temperature.

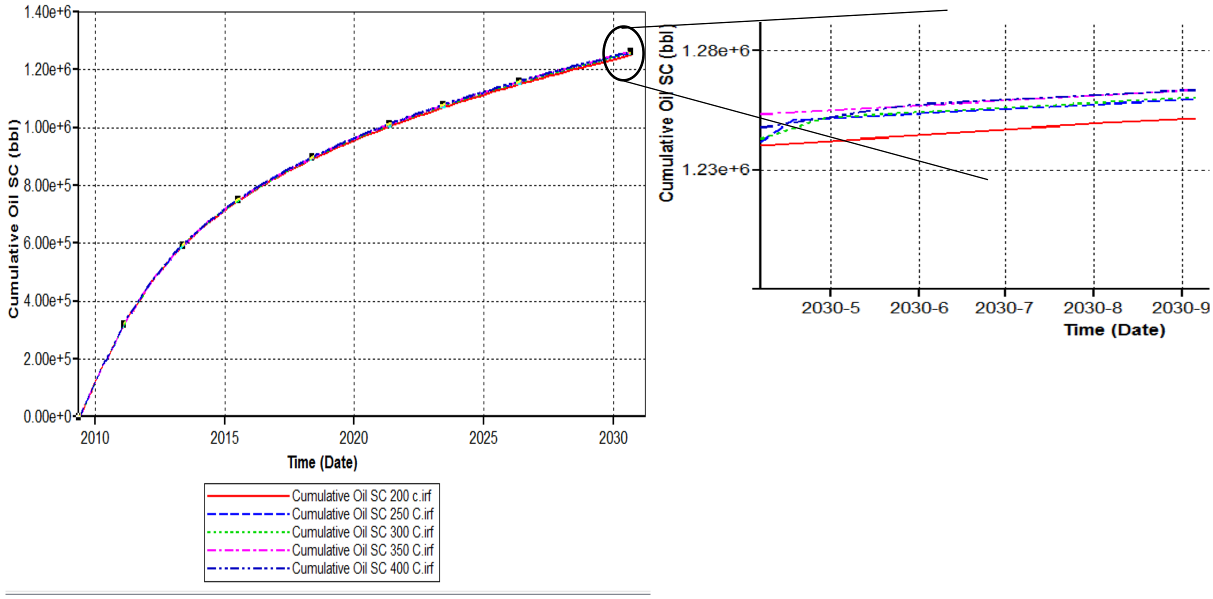


Figure (4.51): Cumulative Oil of Different Temperature(200-400C) for Well-1005.

Table (4.28): Cumulative Oil of Different Temperature between (200-400C) for Well-1005.

No.	Temperature Co	Cumulative oil well-1005(bbl.)
1	200	1.25145 E6
2	250	1.2593 E6
3	300	1.26009 E6
4	350	1.26315 E6
5	400	1.26353 E6

After build and run five models and change the temperature in range between (200-400 C^o), as showed in table (4.28) and figure (4.51) for well-1005, the best Cumulative oil at 400 C^o, but the difference in cumulative oil between (350 C^o and 400 C^o) is too small, so will analyze temperature between (300 C^o) and (400 C^o) to determine the best Temperature, the proposed temperatures are (310-320-330-340-360-370-380-390) C^o, figure (4.52) and table (4.29) summarizing the cumulative oil.

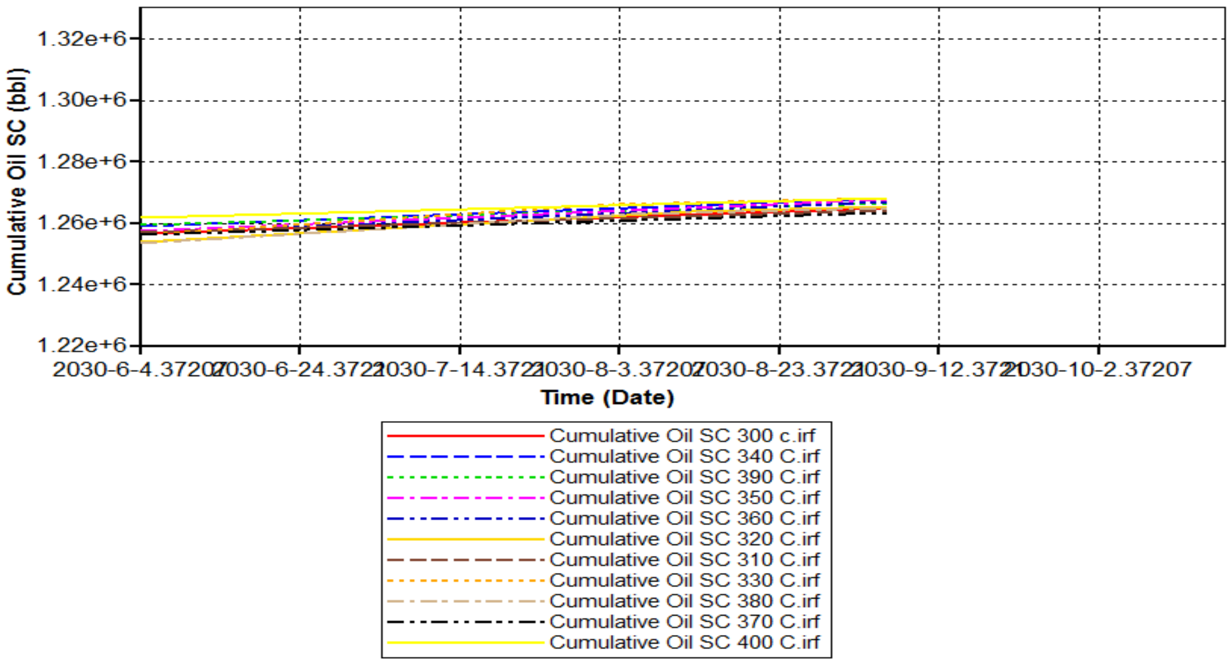


Figure (4.52): Cumulative Oil of Different Temperature (300C to 400C) for Well-1005

Table (4.29): Cumulative Oil of Different Temperature between (300C-400C) for Well-1005.

No.	Temperature Co	Cumulative Oil Well-1005(bbl.)
1	300	1.26009 E6
2	310	1.25934 E6
3	320	1.26046 E6
4	330	1.26361 E6
5	340	1.26331 E6
6	350	1.26315 E6
7	360	1.26224 E6
8	370	1.25862 E6
9	380	1.26039 E6
10	390	1.26192 E6
11	400	1.26353 E6

After build and run all 16 models to determine the best temperate for well-1005 in range between (200-400°C), according to figure (4.54) and table (4.29) the best temperature is 330C^{o} which gives best cumulative oil of (1.26361E6 bbl.).

Temperature Sensitivity for Well-1003.

This section will determine best temperature for well-1003 by comparing between cumulative oil of all proposed temperature, all proposed models will implement and plotting, the proposed temperatures are (200-250-300-350-400) C^{o}.

After run models' figure (4.53) and table (4.30) presenting the different of cumulative oil for proposed temperatures.

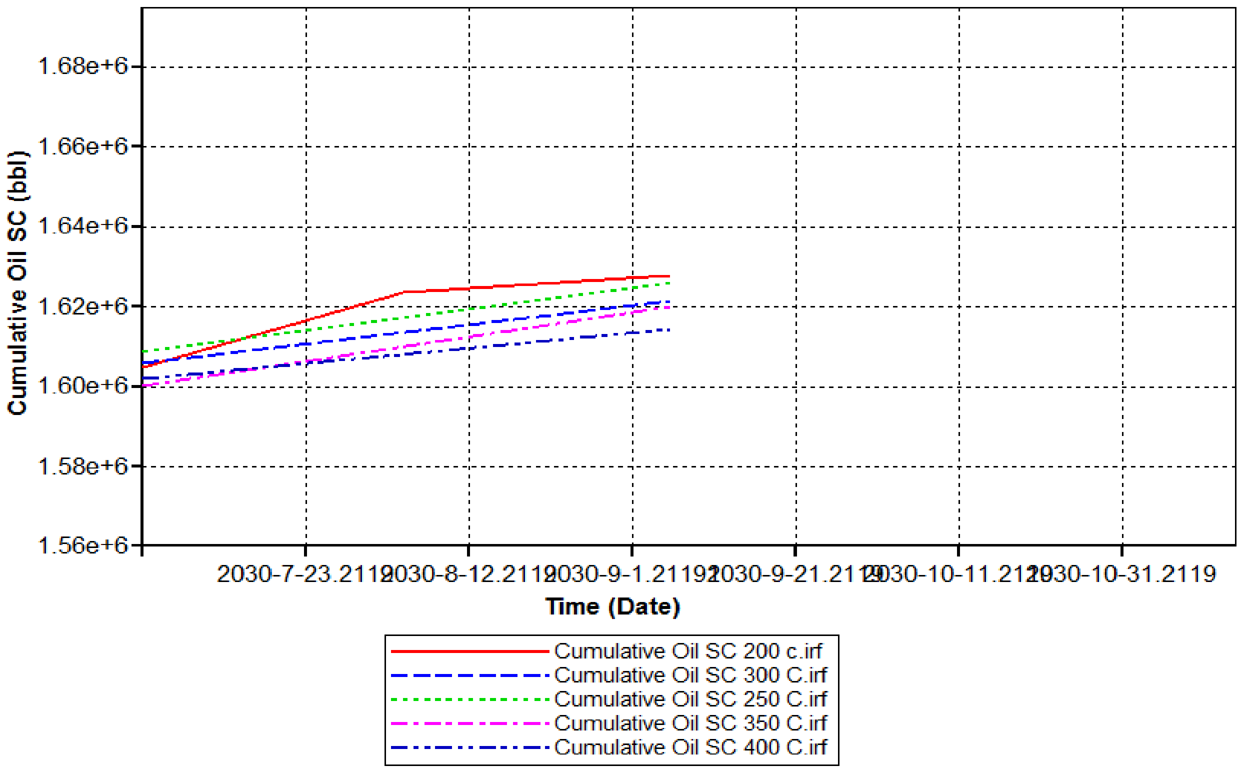


Figure (4.53): Cumulative Oil of Different Temperature (200-400C^{o}) for Well-1003.

Table (4.30): Cumulative Oil of Different Temperature between (200-400C^{o}) for Well-1003.

No.	Temperature Co	Cumulative oil well-1003(bbl.)
1	200	1.63186 E6
2	250	1.63032 E6
3	300	1.62581 E6
4	350	1.62427 E6
5	400	1.61854 E6

After build and run five models with different temperatures in range between (200-400C) to determine the best temperature for well-1003, from table (4.30) and figure (4.53) the highest cumulative oil is (1.63186 E6 bbl.) at 200C^{o}

From figure (4.555) when temperature increases the cumulative oil decreases, so to be more specific will analyze temperature greater than 200C^{o} and less than 250C^{o}, the proposed temperature is (210-220-230-240℃).

After run the models figure (4.54) and table (4.32) presenting the difference in cumulative oil for proposed temperatures in range between (200-250C°).

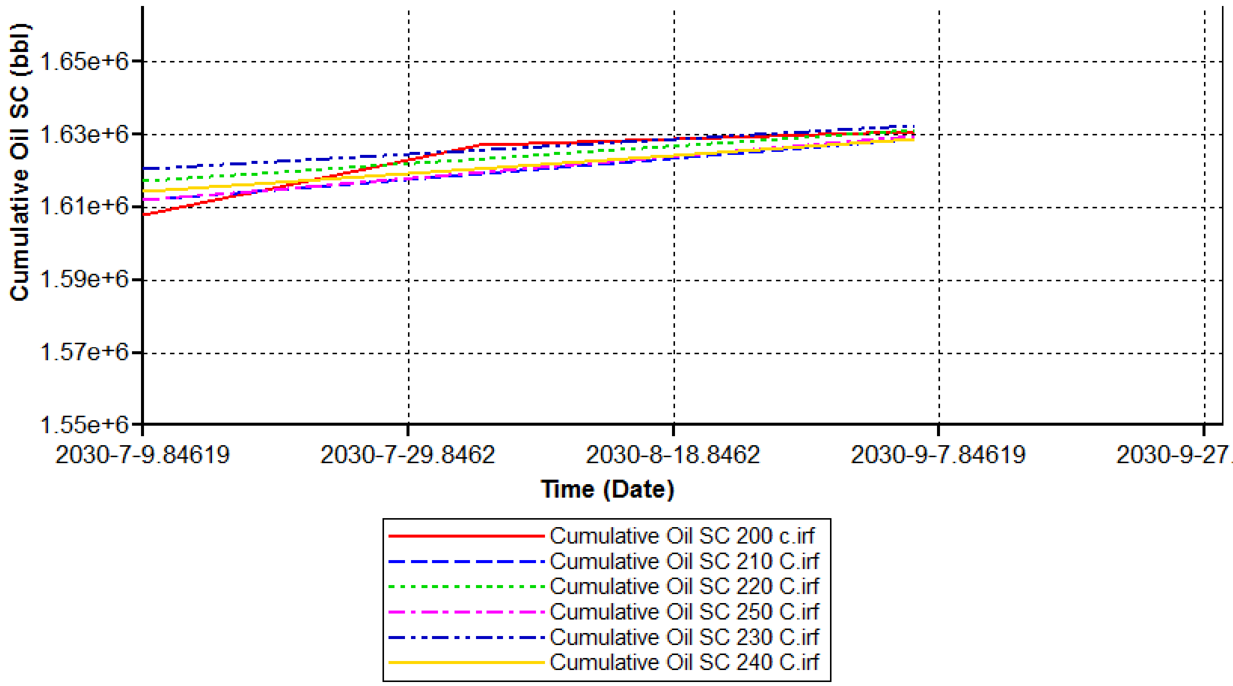


Figure (4.54): Cumulative Oil of Different Temperature (200-250C°) for Well-1003.

Table (4.31): Cumulative Oil of Different Temperature between (200-250C°) for Well-1003.

No.	Temperature Co	Cumulative Oil Well-1003(bbl.)
1	200	1.63186 E6
2	210	1.62979 E6
3	220	1.63204 E6
4	230	1.6334 E6
5	240	1.62953 E6
6	250	1.63032 E6

After build and run all eleven models to determine the best temperature for well-1003, from figure (4.54) and table (4.31) the best temperature is 230C° with (1.6334 E6 bbl.) cumulative oil.

After build and run all 27 previous models to determine best temperature in range between (200-400 C) (temperature sensitivity) for well-1005 and well-1003 the best temperature for well-1005 is 330C° with (1.26361E6 bbl.) cumulative oil, and best temperature for well-1003 is 230C° with (1.6334 E6 bbl.) cumulative oil.

4.4.3.2 Steam Quality Sensitivity.

In this section the optimum steam quality will be determined by changing the quality of the steam to reach the best quality of steam which gives best Cumulative oil.
Steam quality is one of the important parameters which affects oil and reservoir temperature.
In Quality of steam sensitivity all parameters will be constant only quality of steam will be changed to determine the best quality of steam, the proposed steam quality models are (0.5-0.6-0.7-0.8), table (4.32) presenting the proposed model parameters.

Table (4.32): Proposed Models for Steam Quality Sensitivity.

No.	Temperature C		Steam Quality	Injection Rate (M3/day)	Injection Period (Day)	Soaking Period (Day)
	1005	1003				
2	330	230	0.5	200	14	3
3	330	230	0.6	200	14	3
4	330	230	0.7	200	14	3
5	330	230	0.8	200	14	3
6	330	230	0.9	200	14	3

Steam Quality Sensitivity for Well-1005.

In this section best steam quality will be determines by comparing between cumulative oil for all proposed steam quality models for well-1005, all proposed models will be implemented and plotted; the proposed steam quality models are (0.5-0.6-0.7-0.8-0.9).

After run the model's figure (4.55) and table (4.33) presenting the difference in cumulative oil for proposed steam qualities.

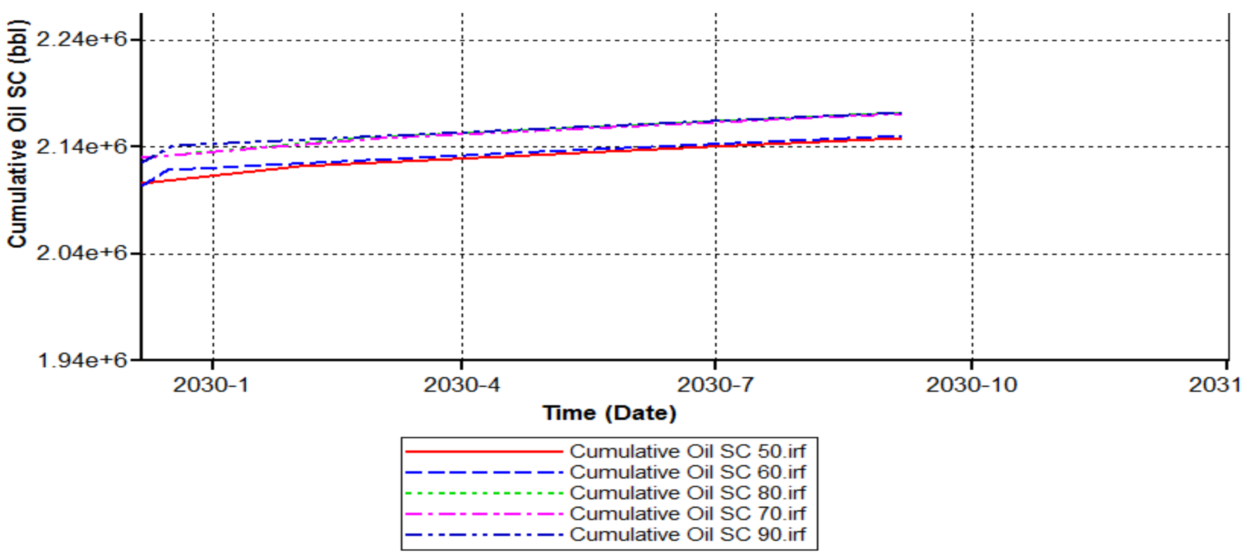


Figure (4.55): Cumulative Oil of Different Steam Quality (0.5 To 0.9) for Well-1005.

Table (4.33): Cumulative Oil of Different Steam Quality between (0.5-0.9) for Well-1005.

No.	Steam Quality	Cumulative Oil Well-1005(bbl.)
1	0.5	2.14929 E6
2	0.6	2.15152 E6
3	0.7	2.17193 E6
4	0.8	2.17258 E6
5	0.9	2.17318 E6

After build and run all five models and change the steam quality in range between (0.5 -0.9) to determine the best steam quality for well-1005, from table (4.33) and figure (4.55) the best steam quality is 0.9 with (2.17318 E6 bbl.) but steam quality at 0.9 needs super boiler and also steam quality 0.8 almost have same cumulative oil with (2.17258 E6 bbl.) so the best steam quality is 0.8.

Steam Quality Sensitivity for Well-1003.

In this section best steam quality will determine by comparing between cumulative oil for all proposed steam quality models for well-1003, all proposed models will implement and plotting, the proposed steam quality models are (0.5-0.6-0.7-0.8-0.9).

After run the model's figure (4.56) and table (4.34) presenting the difference in cumulative oil for proposed steam quality.

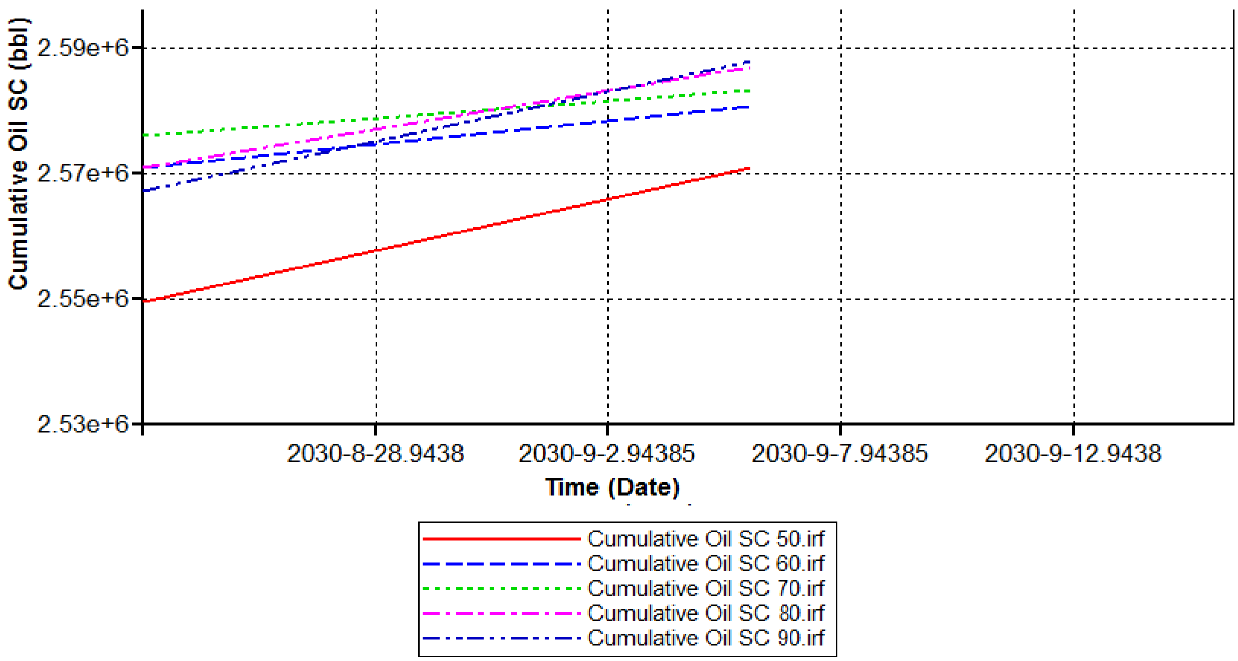


Figure (4.56): Cumulative Oil of Different Steam Quality (0.5-0.9) for Well-1003.

Table (4.34): Cumulative Oil of Different Steam Quality between 0.5-0.9 for Well-1003.

No.	Steam quality	Cumulative oil well-1003 (bbl.)
1	0.5	2.56777 E6
2	0.6	2.57765 E6
3	0.7	2.58024 E6
4	0.8	2.58392 E6
5	0.9	2.58492 E6

After build and run all five models and change the steam quality in range between (0.5 -0.9) to determine the best steam quality for well-1003, from table (4.34) and figure (4.58) the best steam quality is 0.9 with (2.58392 E6 bbl.) but steam quality at 0.9 needs super boiler and also steam quality at 0.8 almost have same cumulative oil with (2.58392 E6 bbl.) so the best steam quality is 0.8.

After build and run all 10 previous models to determine best steam quality in range between (0.5-0.9) (steam quality sensitivity) for well-1005 and well-1003 the best steam quality for well-1005 is 0.8 with (2.17258 E6 bbl.) cumulative oil, and for well-1003 is 0.8 with (2.58392 E6 bbl.) cumulative oil.

4.4.3.3 Injection Rate Sensitivity.

Injection rate one of the parameters which effect on oil and reservoir temperature, all parameters will be constant only Injection rate will be changed to determine the best Injection rate, the proposed Injection rate models are (200-250-300-350) M3/day, table (4.35) shows the proposed models' parameter.

Table (4.35): Proposed Models for Injection Rate Sensitivity.

No.	Temperature C		Steam quality		Injection rate M3/day	Injection period Day	Soaking period Day
1	1005	1003	1005	1003			
2	330	230	0.8	0.8	200	14	3
3	330	230	0.8	0.8	250	14	3
4	330	230	0.8	0.8	300	14	3
5	330	230	0.8	0.8	350	14	3
6	330	230	0.8	0.8	400	14	3

Injection Rate Sensitivity for Well-1005.

In this section best injection rate will determine by comparing between cumulative oil for all proposed injection rates, all proposed models will be implemented and plotted; the proposed injection rate models are (200-250-300-350-400) M3/day.

After run the model's, figure (4.57) and table (4.36) presenting the difference in cumulative oil for each proposed injection rate.

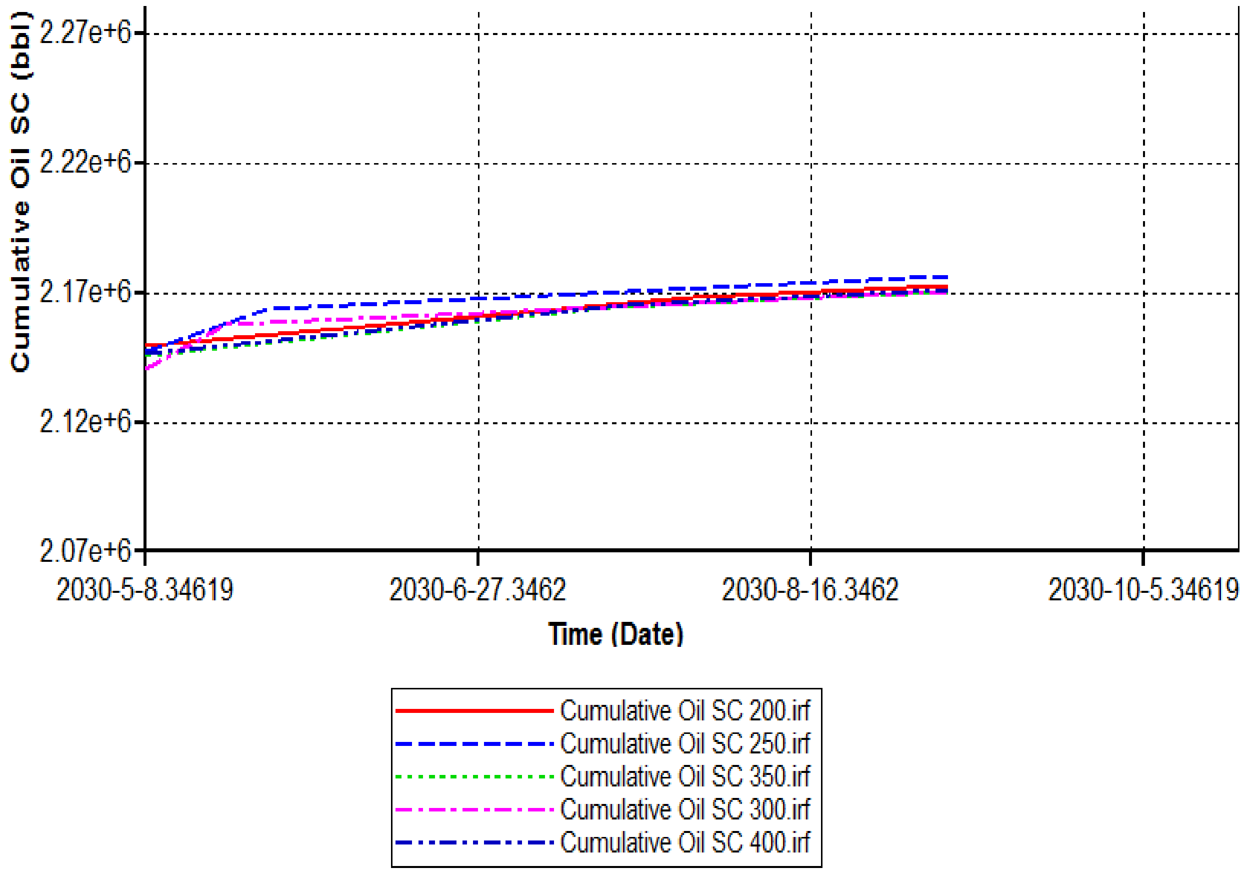


Figure (4.57): Cumulative Oil of Different Injection Rate (200-400) for Well-1005.

Table (4.36): Cumulative Oil for Different Injection Rate between (200-400) for Well-1005.

No.	Injection Rate(M3/day)	Cumulative Oil Well-1005 (bbl.)
1	200	2.17258 E6
2	250	2.17626 E6
3	300	2.1704 E6
4	350	2.17036 E6
5	400	2.17096 E6

After build and run five models and change the injection rate in range between (200-400M^3/day), from table (4.36) and figure (4.57) for well-1005, the highest cumulative oil at 250M^3/day with (2.17626 E6 bbl.), to be more specific will analyze injection rate greater than 200 M^3/day and less than 250 M^3/day, proposed models are (210-220-230-240).

After run the model's figure (4.58) and table (4.37) presenting the difference in cumulative oil for proposed injection rate.

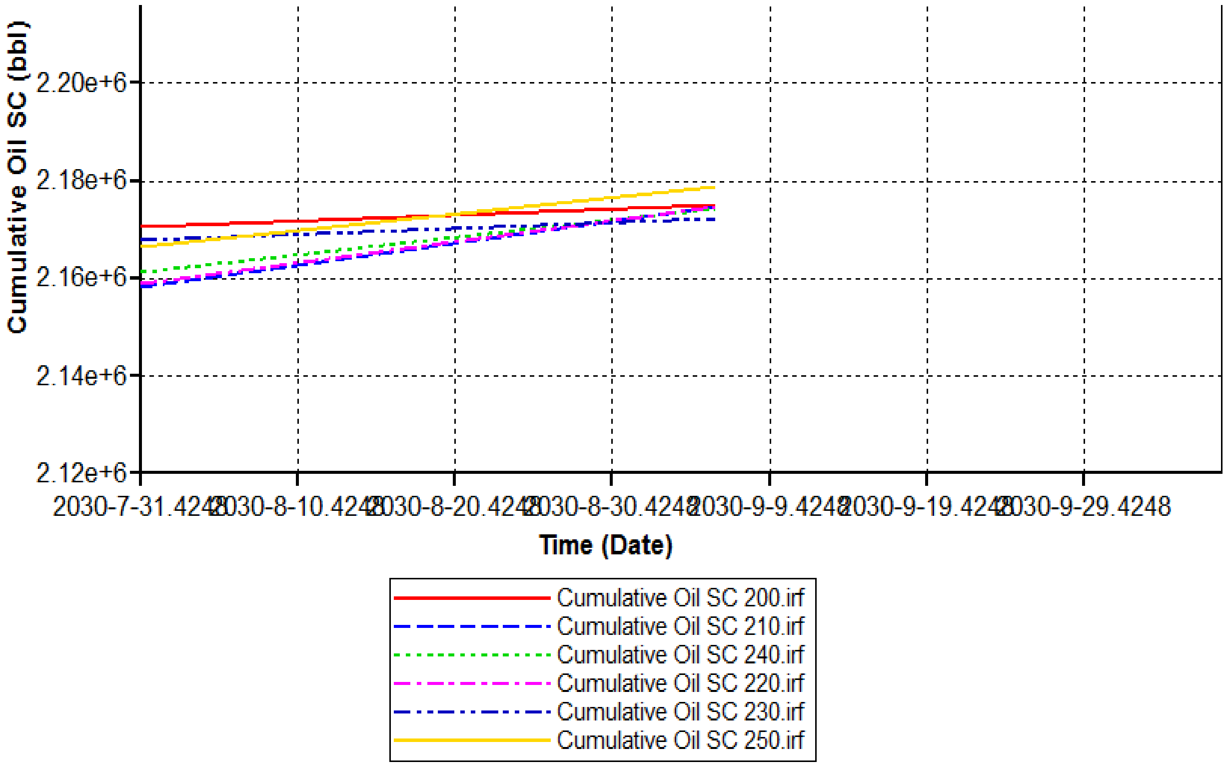


Figure (4.58): Cumulative Oil of Different Injection Rate (200-250) M³/day for Well-1005.

Table (4.37): Cumulative Oil for Different Injection Rate between 200-250 Well-1005.

No.	Injection Rate(M3/day)	Cumulative Oil Well-1005(bbl.)
1	200	2.17258 E6
2	210	2.17219 E6
3	220	2.17219E6
4	230	2.16987E6
5	240	2.17177 E6
6	250	2.17626 E6

After build and run all eleven models to determine the best injection rate for well -1005 in range between (200-400 M^3/day), from table (4.37) and figure (4.58) the best injection rate for well -1005 is 250 M^3/day with (2.17626 E6 bbl.) Cumulative oil.

Injection Rate Sensitivity for Well-1003.

In this section the best injection rate will be determine for well-1003 by comparing between cumulative oil of all proposed injection rates, all proposed models will be implemented and plotted, the proposed injection rate models are (200-250-300-350) M^3/day,

After run the model's figure (4.59) and table (4.38) presenting the difference in cumulative oil for proposed injection rates.

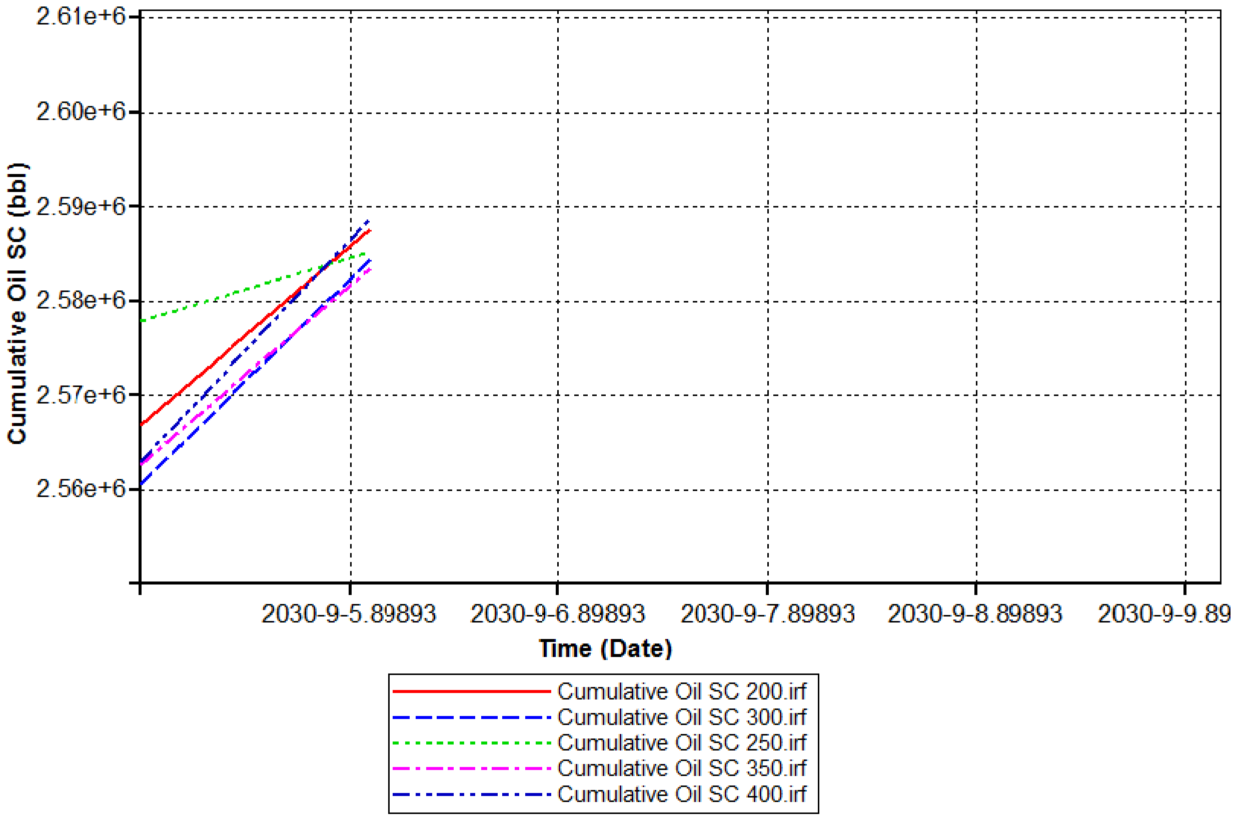


Figure (4.59): Cumulative Oil of Different Injection Rate (200-400) for Well-1003.

Table (4.38): Cumulative Oil for Different Injection Rate between (200-400) for Well-1003.

No.	Injection Rate(M3/day)	Cumulative Oil Well-1003(bbl.)
1	200	2.58492 E6
2	250	2.58251 E6
3	300	2.58162 E6
4	350	2.58066 E6
5	400	2.58602 E6

After build and run five models to determine the best injection rate for well-1003 in range between (200-400M^3/day), from table (4.38) and figure (4.59) the highest cumulative oil at 400M^3/day with (2.58602 E6 bbl.), the different in cumulative oil between 400M^3/day and 200 M^3/day is too small so the best injection rate is 200.

From previous studies when injection rate increases the cumulative oil increase so to be more specific will analyze flow rate greater than 200 M^3/day and less than 250 M^3/day (210-220-230-240).

After run the model's figure (4.60) and table (4.40) presenting the difference in cumulative oil for proposed injection rates.

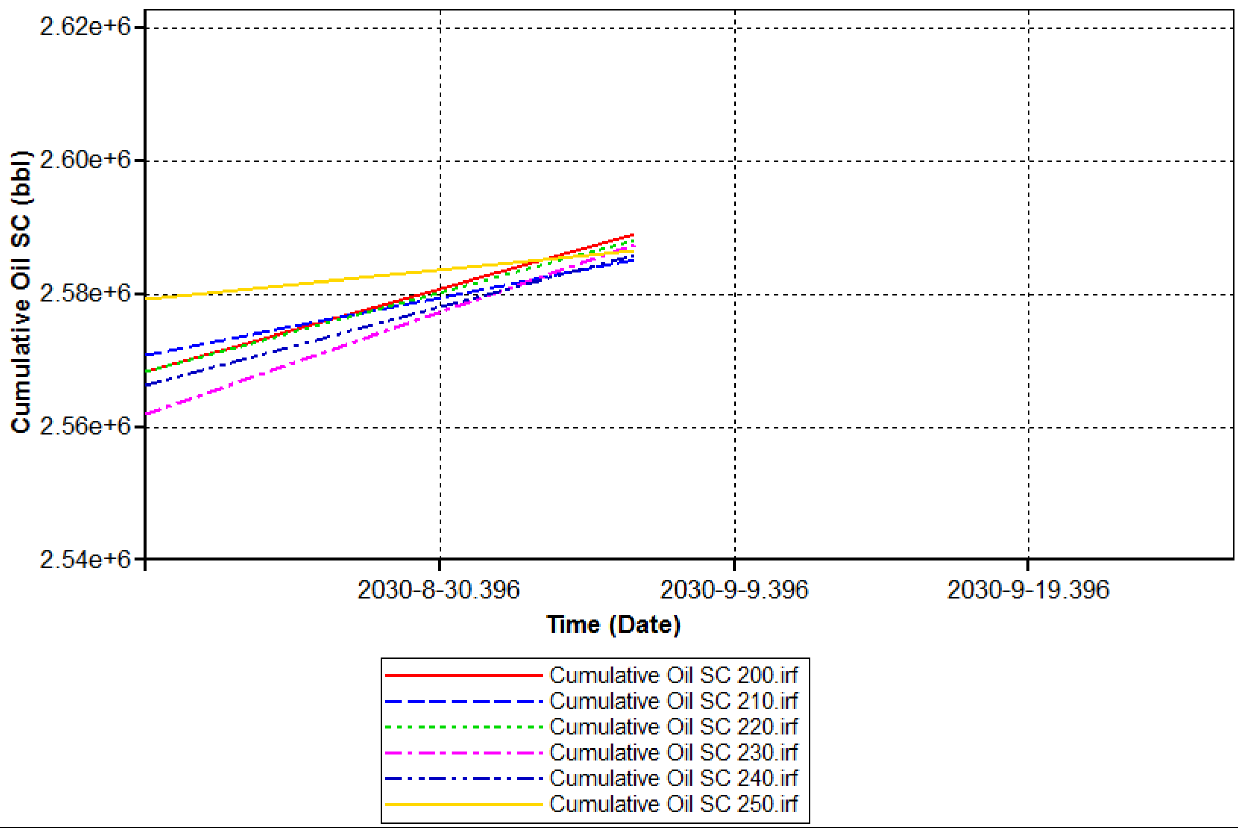


Figure (4.60): Cumulative Oil of Different Injection Rate for Well-1003 (200-250) (M^3/day).

Table (4.39): Cumulative Oil for Different Injection Rate between (200-250) for Well-1003.

No.	Injection Rate(M3/day)	Cumulative Oil Well-1003(bbl.)
1	200	2.58492 E6
2	210	2.58107 E6
3	220	2.58395 E6
4	230	2.58348 E6
5	240	2.58179 E6
6	250	2.58251 E6

After build and run all eleven models to determine the best injection rate for well-1003 in range between (200-400 M^3/day), from table (4.39) and figure (4.60) the best Injection rate for well -1003 is (200 M^3/day) with (2.58492 E6 bbl.) Cumulative oil.

After build and run all twenty-two previous models to determine best injection rate in range between (200-400 M^3/day) (injection rate sensitivity) for well-1005 and well-1003 the best injection rate for well-1005 is 250 M^3/day with (2.17626 E6 bbl.) Cumulative oi, and the best injection rate for well-1003 is (200 M^3/day) with (2.58492 E6 bbl.) Cumulative oil.

4.4.3.4 Injection Period Sensitivity.

Injection period is one of the parameters which effects on oil and reservoir temperature.
In Injection period sensitivity all parameters will be constant only Injection period will be changed to determine the best Injection period, the proposed Injection period models are (7-14.21-28-35) days, table (4.40) summarizing the proposed models' parameters.

Table (4.40): Proposed Models for Injection Period Sensitivity.

No.	Temperature C		Steam Quality %		Injection Rate M3/day		Injection Period (Day)	Soaking Period (Day)
1	1005	1003	1005	1003	1005	1003		
2	330	230	0.8	0.8	250	200	7	3
3	330	230	0.8	0.8	250	200	14	3
4	330	230	0.8	0.8	250	200	21	3
5	330	230	0.8	0.8	250	200	28	3
6	330	230	0.8	0.8	250	200	35	3

Injection Period Sensitivity for Well-1005.

This section will determine the best injection period of steam for well-1005 all proposed steam period will implement and plotting, the proposed steam period models are (7-14.21-28-35) day.

After run the model's figure (4.61) and table (4.41) presenting the different in cumulative oil for proposed injection rate.

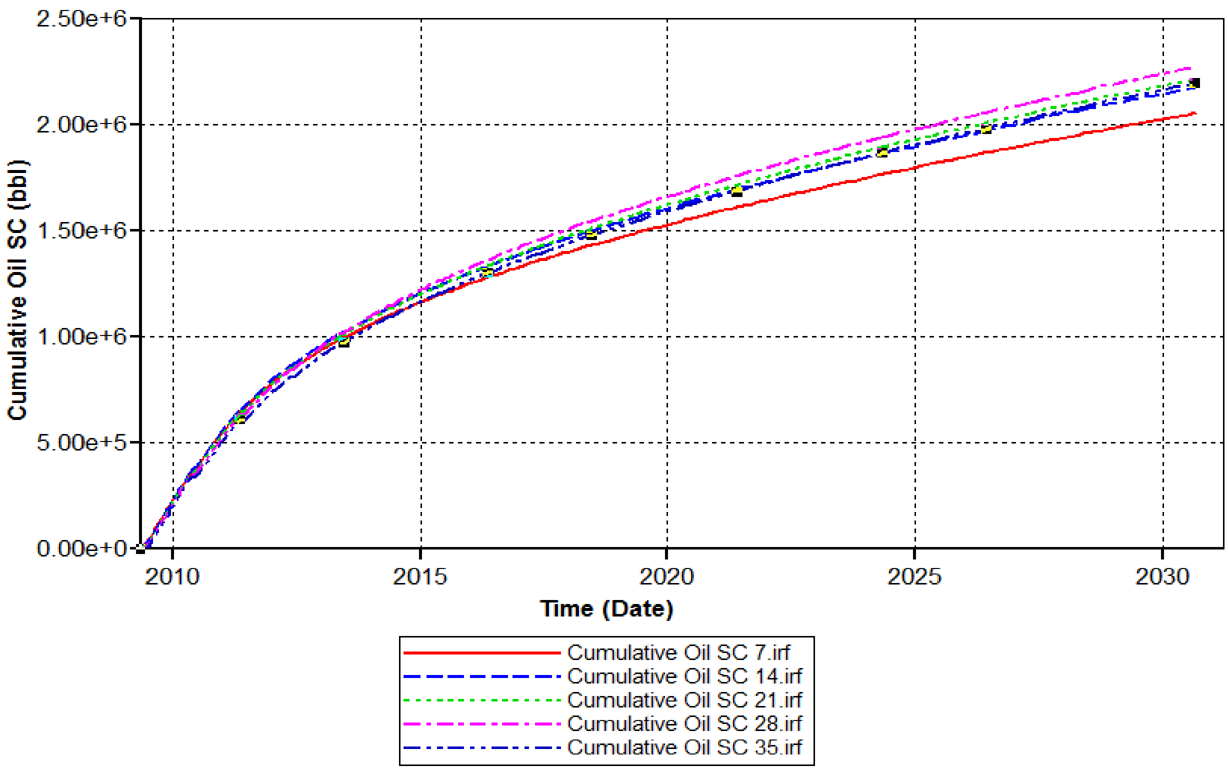


Figure (4.61): Cumulative Oil of Different Injection Period (7-35) Days for Well-1005.

Table (4.41): Cumulative Oil for Different Injection Period between (7-35) Days Well-1005.

No.	Injection period (Days)	Cumulative oil well-1005 (bbl.)
1	7	2.05679 E6
2	14	2.17626 E6
3	21	2.21699 E6
4	28	2.27255 E6
5	35	2.21699 E6

After build and run five models to detrain the best injection period for well-1005 in range between (7-35 day), from table (4.41) and figure (4.61) the highest cumulative oil at 28 days with (2.27255 E6 bbl.).

From previous studies the highest productivity at 28 days of injection, so to be more specific will analyze injection period greater and less than 28 days, the proposed models are (22-23-24.25-26-27-29-30-31-32-33-34).

After run the model's figure (4.62) and table (4.46) presenting the difference in cumulative oil for proposed injection periods.

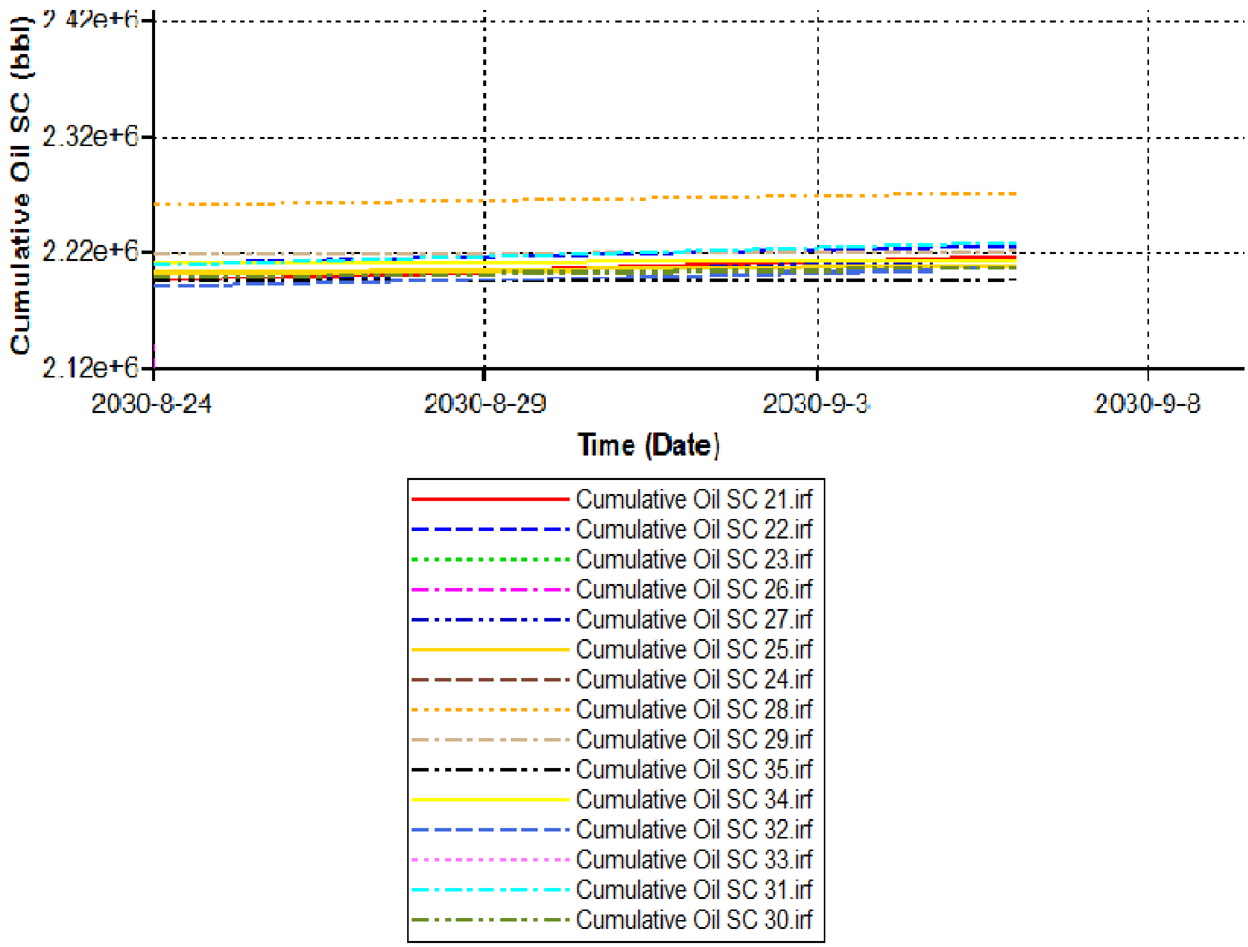


Figure (4.62): Cumulative Oil of Different Injection Period for Well-1005 (22-34) Days.

Table (4.42): Cumulative Oil for Different Injection Period between (21-35) Days Well-1005.

No.	Injection Rate (Days)	Cumulative Oil Well-1005 bbl.
1	21	2.21699 E6
2	22	2.2723 E6
3	23	2.06099 E6
4	24	2.21087 E6
5	25	2.20902 E6
6	26	2.14213 E6
7	27	2.2138 E6
8	28	2.27255 E6
9	29	2.22247 E6
10	30	2.20808 E6
11	31	2.2297 E6
12	32	2.20859 E6
13	33	2.19432 E6
14	34	2.21359 E6
15	35	2.21699 E6

After build and run all twenty models to determine the best injection period for well-1005 in range (7-35days), from table (4.42) and figure (4.62) the best injection period for well 1005 is 28 days with (2.27255 E6) cumulative oil.

Injection Period Sensitivity for Well-1003.

This section will determine the best injection period for well-1003, all proposed steam period will be implemented and plotting, the proposed steam period models are (7-14.21-28) days.

After run the model's figure (4.63) and table (4.43) show the difference in cumulative oil for proposed injection period.

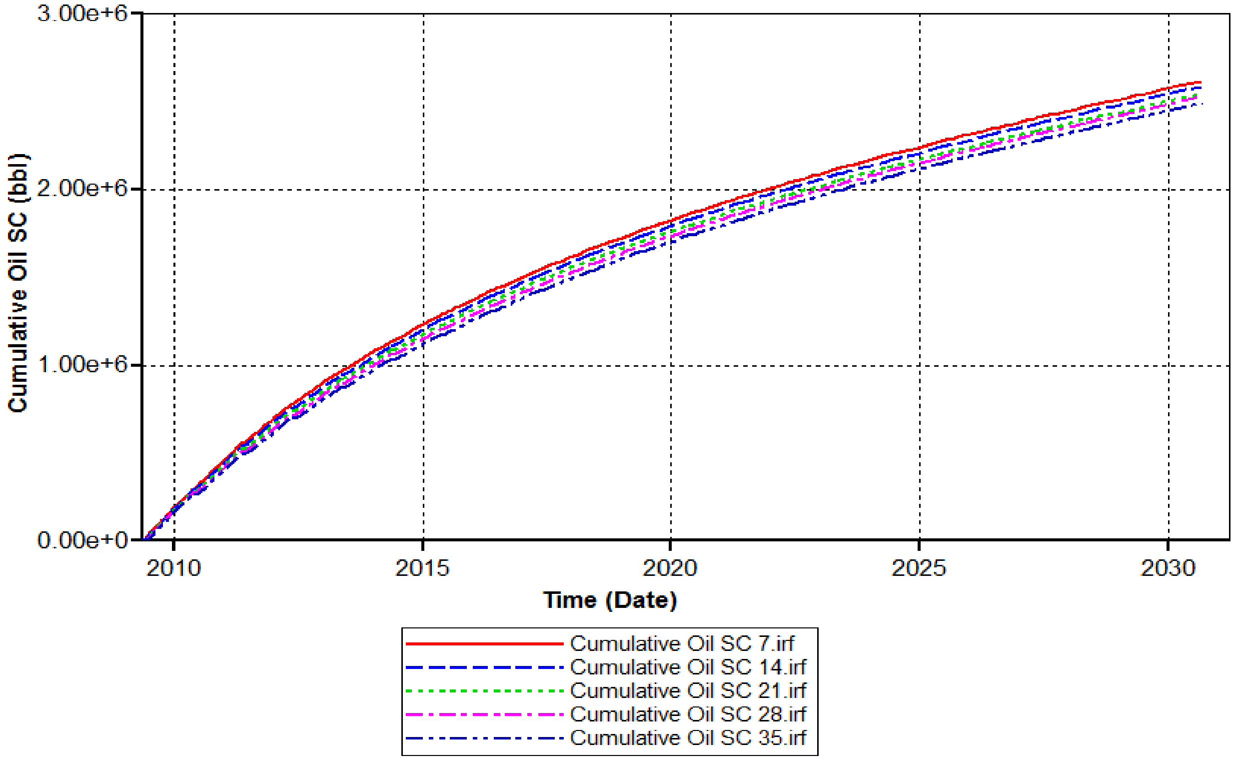


Figure (4.63): Cumulative Oil of Different Injection Period (7-35) Days for Well-1003.

Table (4.43): Cumulative Oil for Different Injection Period between (7-35) Day Well-1003.

No.	Injection Period (Days)	Cumulative Oil Well-1003 (bbl.)
1	7	2.61665 E6
2	14	2.58492 E6
3	21	2.54506 E6
4	28	2.52648 E6
5	35	2.49293 E6

After build and run five models to detrain the best injection period for well-1003 in range between (7-35 day), from table (4.43) and figure (4.63) the highest cumulative oil at 7day with (2.61665 E6 bbl.), from previous study the highest productivity at 7 days of injection, so to be more specific will analyze injection period greater and less than 7 days, the proposed models are (2-3-4.5-6-8-9-10-11-12-13) days.

After run the model's figure (4.64) and table (4.44) presenting the difference in cumulative oil for proposed injection period.

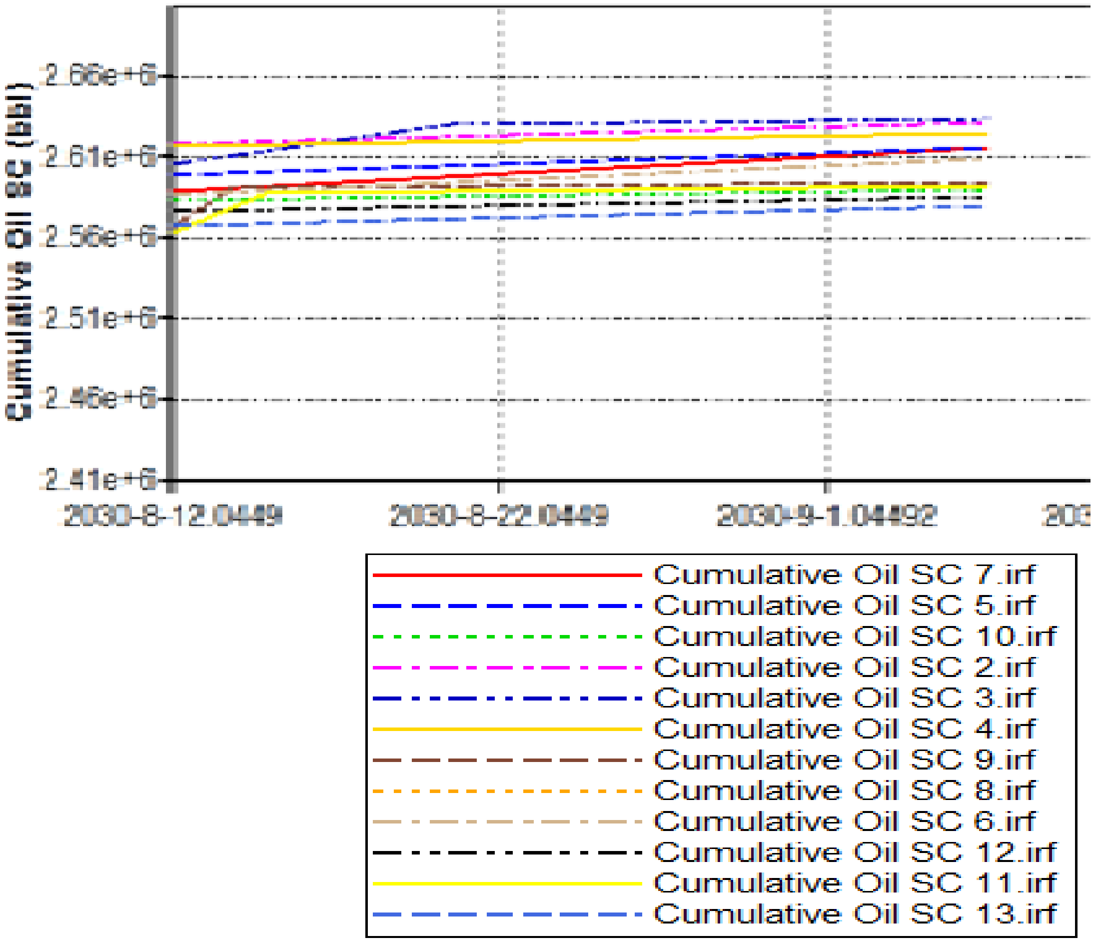


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Figure (4.64): Cumulative Oil of Different Injection Period for Well-1003 (7 -13) Days.

Table (4.44): Cumulative Oil for Different Injection Rate between (2-13) Days Well-1003.

No.	Injection Period (Da	Cumulative Oil Well-1003(bb
1	2	2.63176 E6
2	3	2.63414 E6
3	4	2.6249 E6
4	5	2.61638 E6
5	6	2.61011 E6
6	7	2.61665 E6
7	8	2.6777 E6
8	9	2.59558 E6
9	10	2.59122 E6
10	11	2.59238E6
11	12	2.58565 E6
12	13	2.58103 E6

After build and run all seventeen models to determine the best injection period for well-1003 in range (7-35days), from table (4.44) and figure (4.64), the best Injection rate is 3 days for well-1003 with (2.63414 E6 bbl.) cumulative oil.

After build and run all thirty-seven previous models to determine best injection period in range between (7-35 day) (injection period sensitivity) for well-1005 and well-1003 the best injection period for well-1005 is 28 days with (2.27255 E6) cumulative oil, and the best injection period for well-1003 is 3 days for well-1003 with (2.63414 E6 bbl.) cumulative oil.

4.4.3.5 Soaking Period Sensitivity.

soaking period one of the parameters which effect on oil and reservoir temperature.
In soaking period sensitivity all parameters will be constant only soaking period will be changed to determine the best soaking period, the proposed soaking period models are (3-5-10-15-20) days, table (4.45) summarizing the proposed models' parameter.

Table (4.45): Proposed Models for Injection Period Sensitivity.

No.	Temperature C		Steam quality %		Injection rate M3/day		Injection period Day		Soaking period Day
	1005	1003	1005	1003	1005	1003	1005	1003	
1	330	230	0.8	0.8	250	200	28	3	3
2	330	230	0.8	0.8	250	200	28	3	5
3	330	230	0.8	0.8	250	200	28	3	10
4	330	230	0.8	0.8	250	200	28	3	15
5	330	230	0.8	0.8	250	200	28	3	20

Soaking Period Sensitivity Well-1005.

This section will determine the best soaking period of steam for well-1005 all proposed steam soaking period will be implemented and plotting, the proposed steam soaking period models are (3-5-10-15-20) day.

After run the model's figure (4.65) and table (4.46) presenting the difference in cumulative oil for proposed soaking period.

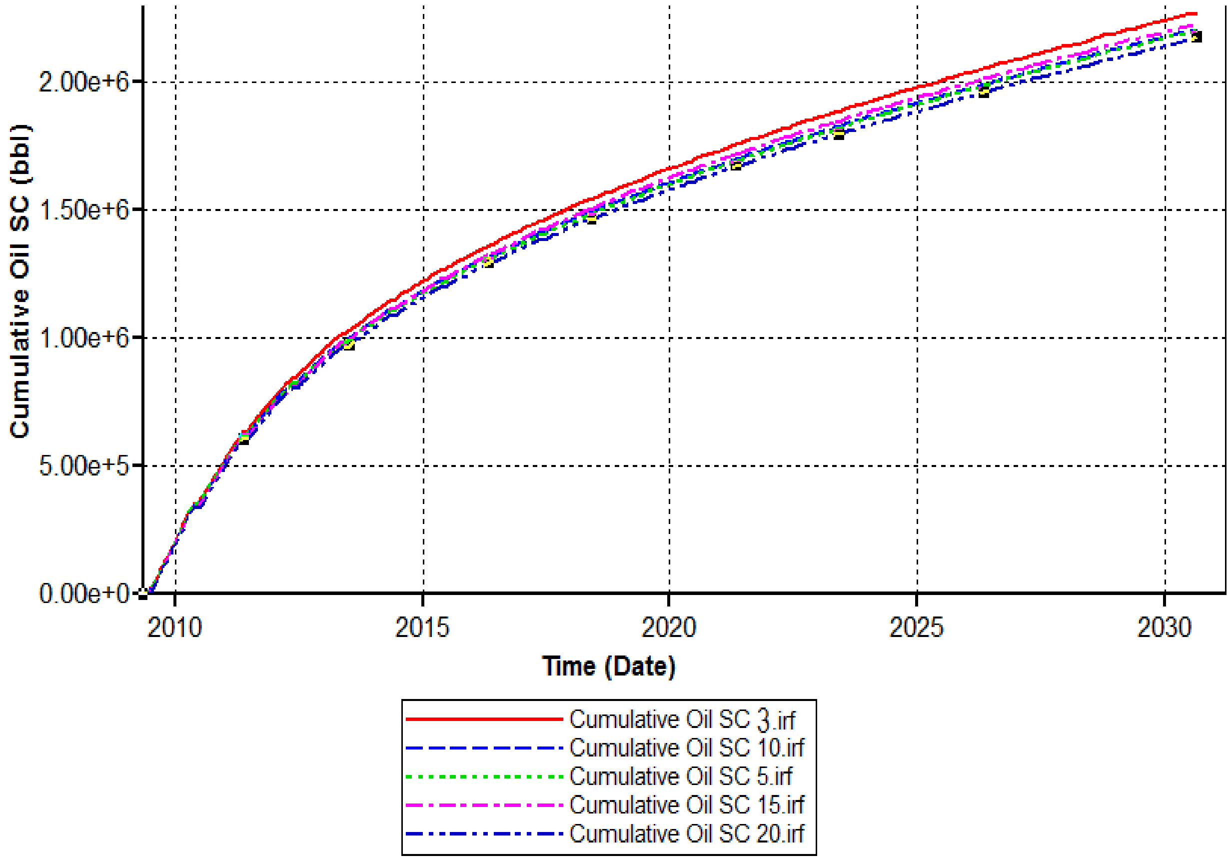

Figure (4.65): Cumulative Oil of Different Soaking Period for (3-20) Well-1005.

Table (4.46): Cumulative Oil for Different Soaking Period between (3-20) Days Well-1005.

No.	soaking period (Days)	Cumulative oil well-1005(bbl.)
1	3	2.27255 E6
2	5	2.20281 E6
3	10	2.20764 E6
4	15	2.23024 E6
5	20	2.17541 E6

After build and run five models to detrain the best soaking period for well -1005 in range between (3-20 day), from table (4.46) and figure (4.65) the highest cumulative oil for well-1005 is 3 days of soaking with (2.27255 E6 bbl.), from previous study the highest productivity is 3 days of soaking, to be more specific will analyze soaking period greater and less than 3 days the proposed models (2-4).

After run the model's figure (4.66) and table (4.47) presenting the difference in cumulative oil for proposed soaking period.

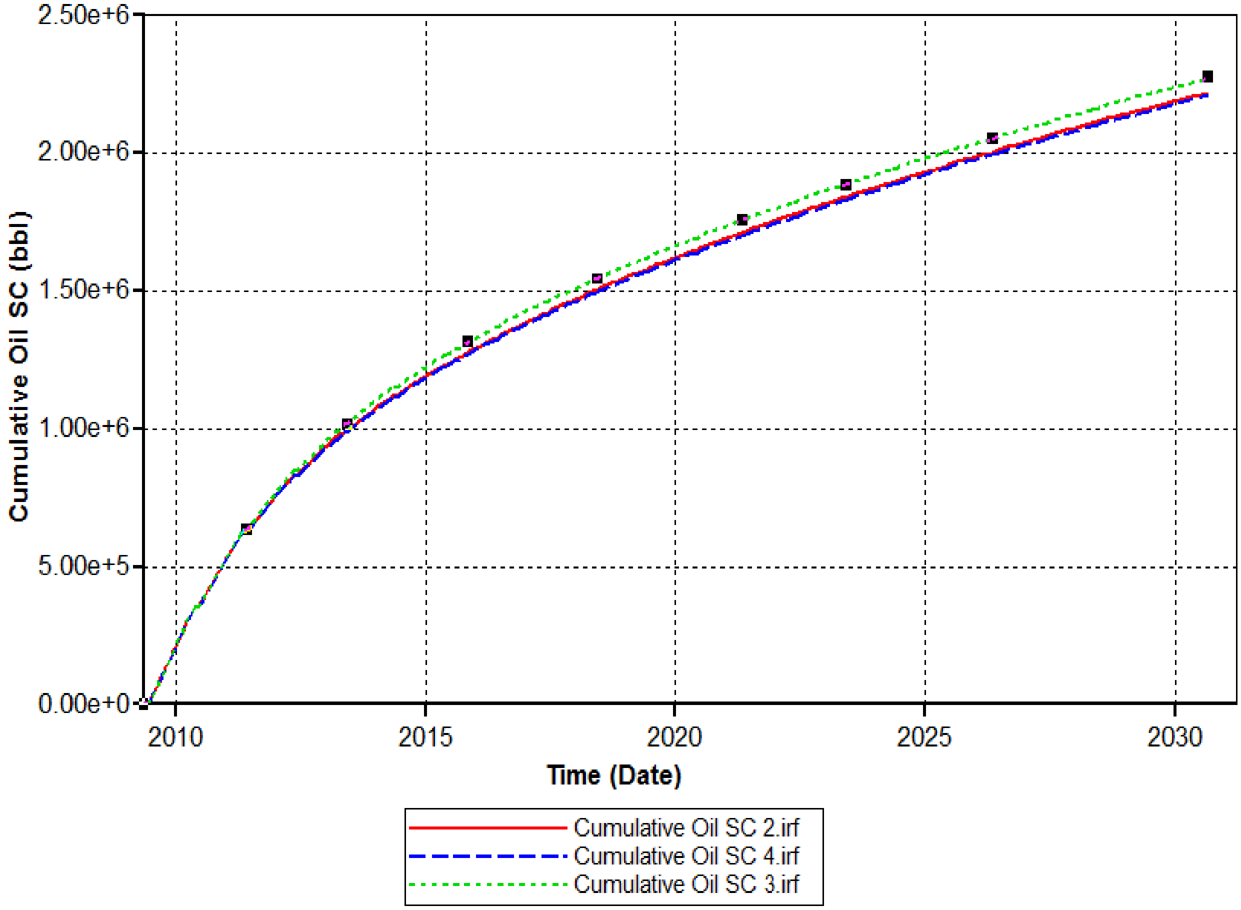

Figure (4.66): Cumulative Oil of Different Soaking Period (2-4) Days for Well-1005.

Table (4.47): Cumulative Oil for Different Soaking Rate between (2-4) Days Well-1005.

No.	Soaking Period (Days)	Cumulative Oil Well-1005 (bbl.)
1	2	2.21975 E6
2	3	2.27255 E6
3	4	2.20932 E6

After build and run all eight models to determine the best soaking period for well-1005 in range (7-20days), after run models and analyzing the data from table (4.47) and figure (4.66) the best soaking period for well-1005 is 3days with (2.27255 E6) cumulative oil.

Soaking Period Sensitivity for Well-1003.

This section will determine the best Soaking period of steam for well-1003 all proposed steam Soaking period will be implemented and plotting, the proposed steam Soaking period models are (3-5-10-20) days.

After run the model's figure (4.67) and table (4.48) presenting the difference in cumulative oil for proposed soaking periods.

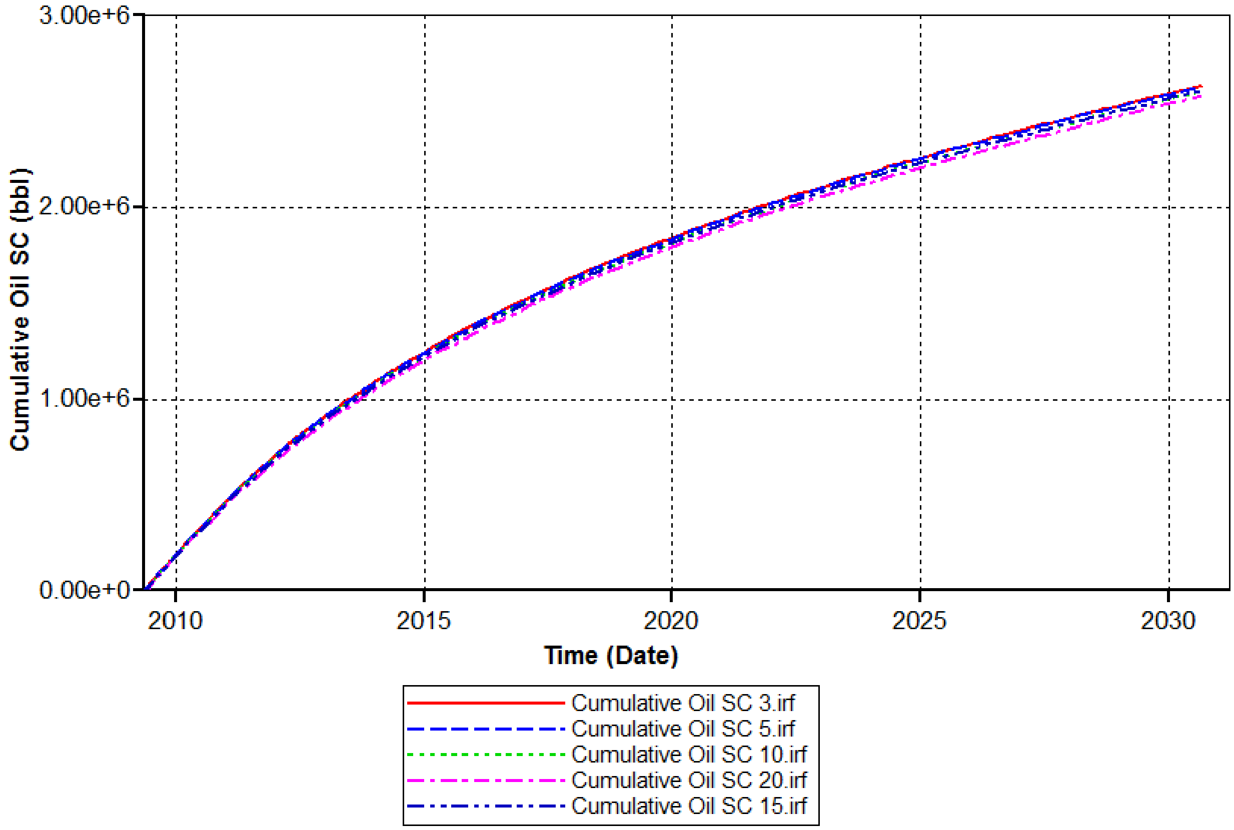

Figure (4.67): Cumulative Oil of Different Soaking Period for Well-1003.

Table (4.48): Cumulative Oil for Different Soaking Period between (3-20) Days Well-1003.

No.	Soaking Period (Days)	Cumulative Oil Well-1003(bbl.)
1	3	2.63412 E6
2	5	2.63011 E6
3	10	2.60748 E6
4	15	2.60835 E6
5	20	2.5816 E6

After build and run five models to detrain the best soaking period for well-1003 in range between (3-20 day), from table (4.48) and figure (4.67) show the highest cumulative oil at 3 days with (2.63412 E6 bbl.), from previous study the highest productivity at 3 days of injection so to be more specific will analyze soaking period greater and less than 3 days of the proposed models.

after run the model's figure (4.68) and table (4.49) presenting the difference in cumulative oil for proposed soaking periods.

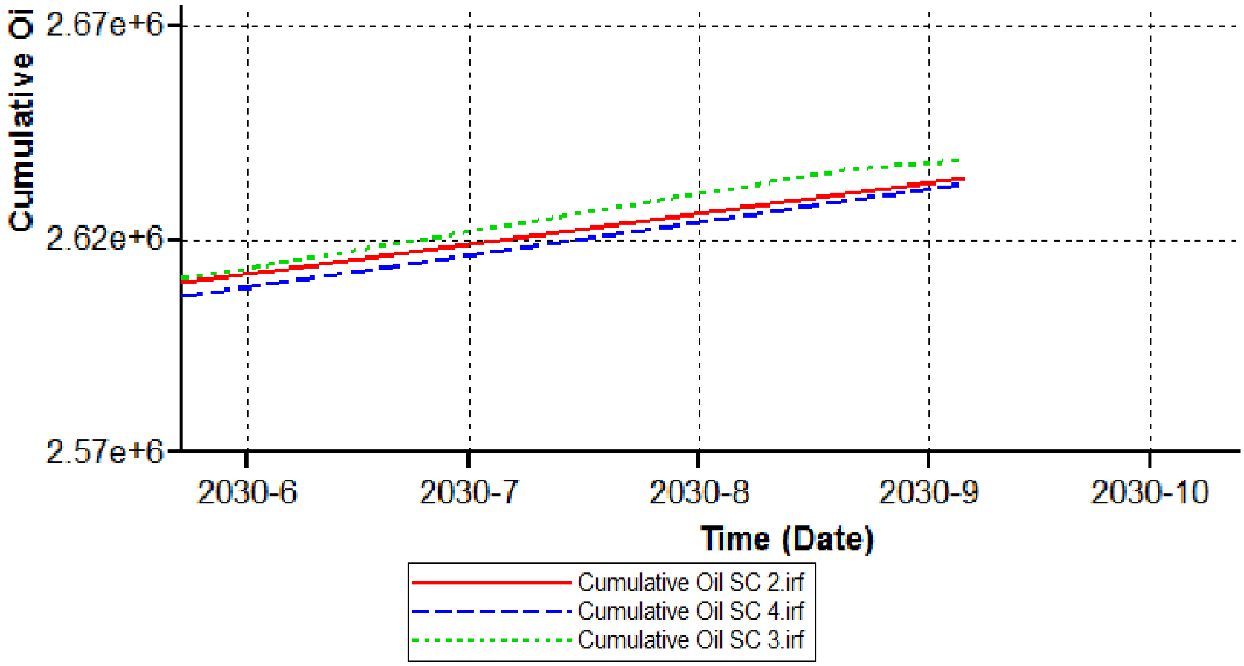

Figure (4.68): Cumulative Oil of Different Soaking Period for Well-1003 (2 to 4) Days.

Table (4.49): Cumulative Oil for Different Soaking Period between (2-4) Well-1003.

No.	Soaking Period (Days)	Cumulative Oil Well-1003 (bbl.)
1	2	2.6297 E6
2	3	2.63412 E6
3	4	2.62824 E6

After build and run all eight models to determine the best soaking period for well-1003 in range (7-20days), after run models and after analyzing the data from table (4.49) and figure (4.68) the best soaking period for well-1003 is 3 days with (2.63412 E6 bbl.) cumulative oil.

after build and run all sixteen previous models to determine best soaking period in range between (3-20 days) (soaking period sensitivity) for well-1005 and well-1003 the best soaking period for well-1005 is 3days with (2.27255 E6) cumulative oil, and the best soaking period for well-1003 is 3 days with (2.63412 E6 bbl.) cumulative oil.

__Final Result for CSS Optimization:__

After build and run all previous study (142 models) the optimum conditions for well-1005 and well-1003 are shows in table (4.50), table (4.51) and figure (4.69) presenting the Cumulative oil, water cut and recovery factor for reservoir.

Table (4.50): Final Result for Well-1005 and Well-1003.

No.	Well name	Well-1005	Well-1003
1	Length Of horizontal section(m)	420	360
2	Direction of horizontal section	North East	North
3	Temperature C	330	230
4	Steam quality %	0.8	0.8
5	Injection rate (M3/day)	250	200
6	Injection period (Days)	28	3
7	Soaking period (Days)	3	3

Table (4.51): Cumulative Oil for Reservoir with CSS.

		Cumulative Oil (bbl.)	W.C(%)	RF (%)
1	Two Horizontal Wells with CSS	3.82938%	91.2369%	32.65%

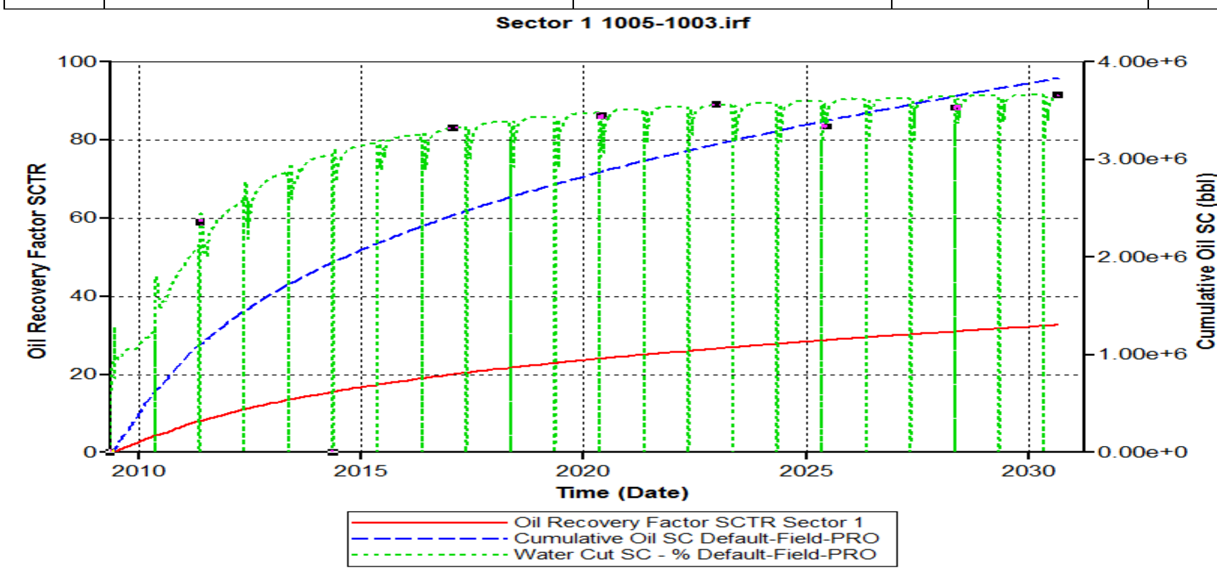

Figure (4.69): Oil Recovery, Cumulative Oil and Water Cut for Reservoir.

After implement CSS optimization on well-1005 and well-1003, found the optimum parameters of well-1005 is more productive than well-1003 with 2.27255 E6 bbl.

From Chang, j. study, published in 2009 which was study horizontal well with CSS with solvent show the oil rat increased by 31% for first cycle, in this study for FNE for horizontal wells with CSS without solvent result show oil rat increased by 15% for first cycle.

Chapter Five

Conclusion and Recommendations

5.1 Conclusions:

- The possibility of improve oil recovery through CSS in horizontal wells in FNE field has been studied.
- The results obtained after the designing models and future prediction till 2030, it has been found that implementation of (CSS) in two horizontal wells with optimum conation will give 8% recovery factor more than to drill 10 CHOPS vertical wells.
- The optimum location for well-1005 and well-1003has been determined.
- Determine the best direction of horizontal section for well-1005 is North East and the best direction of horizontal section for well-1003 is North.
- The optimum length of horizontal section for well -1005 is 420 M and the optimum length of horizontal section for well-1003 is 360M.
- The optimum parameters for CSI which have been found for well-1005 is (temperature 330Co, steam quality 0.8%, injection rate250M3/day, injection period 28 days, soaking period 3days) and for well-1003(temperature 230Co, steam quality 0.8%, injection rate200M3/day, injection period 3 days, soaking period 2days)
- It has been found that well-1005 is more productive than well-1003 with 2.27255 E6 bbl. for well-1005 and 2.6297 E6 bbl. for well-1003
- Oil recovery improved from 24.29% for 10 cold vertical wells to 32.64% by CSS in two horizontals well.

5.2 Recommendations:

- Economic evaluation for drilling horizontal wells in FNE oil field.
- Economic evaluation for CSS in horizontal wells for FNE oil field.
- More study of optimizations injection and production parameter before implement
- Highly recommend for drilling and completion of horizontals well in FNE including CSS after study.

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