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College of Petroleum Engineering and Technology
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Study Heavy oil Recovery Techniques (Moga oil Field Case Study)

دراسة تقنيات إستخلاص الخام الثقيل (حقل موقا النفطى)

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

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الاستـــهلال

قال ربنا جل وعلا :

﴿ وَيَسْأَلُونَكَ عَنِ الرُّوحِ قُلِ الرُّوحُ مِنْ أَمْرِ رَبِّي وَمَا أُوتِيتُم مِّنَ الْعِلْمِ إِلَّا قَلِيلًا ﴾ سورة الإسراء الآية رقم (85)

صدق الله العظيم

Dedication

This thesis is dedicated to our **Parents** who taught us that the best kind of knowledge to have is that which is learning for its own sake.

To our supervisor **Eng. Husham Awadelssed Ali** for his guidance and support

To our dear friends who supported us.

To everyone who inspired our creativity…..

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Abstract

This study for Moga oil field which Located in the eastern part of block 6, in Muglad basin located in south west of Sudan.

According to the field under study Moga Sudanese oil field which characterized with low recovery factors and decline in primary production due to low oil gravity (<22 API) and viscosities above 100 CP, therefore the study to find the suitable method to increase the oil recovery efficiency.

The study aimed to implement suitable development methods in Moga oil field to increase the recovery rates, Study the reservoir fluid properties by using CMG software.

To achieve the objectives of this study, the below methodology had been followed:

A deeply Understanding for Moga field properties, CMG software had been studied.

Data collection for Moga oil field (reservoir characteristics, reservoir types, reservoir pressure, temperature, PVT properties of the crude oil, fluid and rock properties and reservoir parameters)

The CMG model has been built for the Moga 26 area (17) wells, all the parameters had been entered to the software then model had been run for Three Cases: Do Nothing Case (DNC), Water injection and Steam injection.

The results obtained from three cases showed that water injection can increase the cumulative oil rate from 14.6 MMSTB to 26 MMSTB compared to DNC, Steam Injection scenario is better and can increase the recovery factor up to 65%

التـــــجريــــــد

تناولت الدراسة حقل موقا الذي يقع في الجزء الشرقي لمربع 6 في حوض المجلد الواقع في الجنوب الغربي لجمهورية السودان. يتصف الخام المنتج من الحقل بارتفاع لزوجته لأكثر من 100 سنتي بواز وانخفاض كثافته النسبية لأقل من 22 درجة مما ادى لهبوط معدل الانتاج الطبيعي ،لذلك هدفت الدراسة لايجاد أنسب الطرق لتحسين كفاءة الاستخلاص ، وكذلك امكانية تنفيذ أفضل الطرق لتطوير حقل موقا من خلال دراسة خواص موائع المكمن باستخدام برنامج CMG للوصول الى أهداف الدراسة، ، تم جمع البيانات (خواص خام الزيت اضافة الى خواص المائع و الصخر و المتغيرات داخل المكمن). ومن ثم تم بناء نموذج حاسوبي خصيصا لحقل موقا 26 الذي يضم عدد 17 بئر انتاج ، حيث تم ادخال جميع المتغيرات للبرنامج ومن ثم تم اجراء النموذج لثلاث حالات ، الأولى بدون اجراء معالجه ،الثانية بحقن الماء ، والأخيرة بحقن البخار.

النتائج المستخلصة من الدراسة بينت ان حقن الماء يزيد معدل الانتاج التراكمى الى 26 مليون برميل مقارنة ب 14.6 في حاله الانتاج بدون حقن , وان حقن البخار هو الافضل بحيث يزيد معدل الانتاج التراكمى الى51 مليون برميل و ان معدل الاستخلاص للحالات الثلاثة %21 في حاله الانتاج بدون حقن,%32 لحقن الماء و %65 بالنسبة للبخار.

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NOMENCLATURE

EOR	:	Enhanced Oil Recovery
IOR	:	Improved Oil Recovery
CSS	:	Cyclic Steam Stimulation
ISC	:	In-Situ Combustion
SAGD	:	Steam Assisted Gravity Drainage
HPAI	:	High Pressure Air Injection
ASP	:	Alkaline-Surfactant-Polymer
VAPEX	:	Vapor Assisted Petroleum Extraction
MEOR	:	Microbial Enhanced Oil Recovery Methods
WAG	:	Water Alternating Gas
MSL	:	Median See Level
FN	:	Fula North
PE	:	Petro Energy
FNE	:	Fula North East
BHP	:	Bottom Hole Pressure
EUR	:	Enhanced Ultimate Recovery
WOR	:	Water Oil Ratio
BTU	:	British Thermal unit
GUI	:	Graphical User Interface
BSIPD	:	Barrel Steam Injected per Day
GOR	:	Gas oil Ratio
MMP	:	Minimum Miscibility Pressure
OOIP	:	Original Oil in Place
BOPD	:	Barrel Oil per Day
BPU	:	Beam Pump Unit
MMSTB	:	Million Stock Tank Barrel
SOR	:	Steam Oil Ratio
HC	:	Hydrocarbon
CP	:	Centipoise
CO2	:	Carbon Dioxide
N2	:	Nitrogen Gas

CONT	:	Continuous
API	:	American Petroleum Institute
DFL	:	Dynamic Fluid Level
CMG	:	Computer Modeling Group LTD.
GEM	:	Generalized Equation of state Model Reservoir Simulator
CMOST	:	Computer Assisted History Matching, Optimization & Uncertainty Assessment Tool
IMEX	:	IMplicit-EXplicit Black Oil Simulator
DTR	:	Development Technical Review
PVT	:	Pressure Volume Temperature
Cum	:	Cumulative Oil
WC	:	Water Cut
AG	:	Abu Gabra Formation
OGMs	:	Oil gathering manifolds
PCP	:	Progressive Cavity Pump

Chapter one: Introduction

1.1General Introduction:

Many of Sudan's large oil field suffers from low recovery factor and decline in primary production due to low oil gravity (< 22 API) and viscosities above 100 cp. Many wells experienced premature water production. As such, Enhanced Oil Recovery Project seem to be the option to improve oil recovery in Sudan.

1.1.1 Development Sequence

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

1.1.1.1 Primary Recovery

Refers to the volume of hydrocarbon produced by the natural energy present in the reservoir and/or artificial lift through a single wellbore, the natural driving mechanisms of primary recovery are outlined as Rock and liquid expansion drive, Depletion drive, Gas cap drive, Water drive, Gravity drainage drive and Combination drive.

The most common primary oil recovery factors range from 20% and 40%, with an average around 34%, while the remainder of hydrocarbon is left behind in the reservoir.

1.1.1.2 Secondary Hydrocarbon Recovery

Once the natural reservoir energy has been depleted and the well oil production rates decline during primary recovery, it is necessary to provide additional energy to the reservoir fluid system to boost or maintain the production level through the application of secondary production methods based on fluid injection Secondary hydrocarbon (oil and/or gas) involves the introduction of artificial energy into the reservoir via one wellbore and production of oil and/or gas from another wellbore, secondary recovery include the immiscible processes of water flooding and gas injection or gas-water combination floods (Laura Romero-Zerón 2012)

1.1.1.3 Tertiary Oil Recovery

Tertiary oil recovery (EOR) methods rely on methods that reduce the viscosity of the oil, to increase output, compared to the natural or induced energy methods of primary and secondary recovery, conventionally tertiary recovery begins when secondary oil recovery is not enough to continue adequate production, but only when the oil can still be extracted profitably. This depends on the cost of the extraction method and the current price of crude oil.

Tertiary oil recovery is defined to include all processes that reduce the viscosity of the oil, increase oil mobility and increase oil recovery beyond primary or secondary recovery processes.

EOR (tertiary oil recovery) is the usual method for heavy-oil recovery and the term EOR is often synonymous with tertiary recovery (G. Speight 2013).

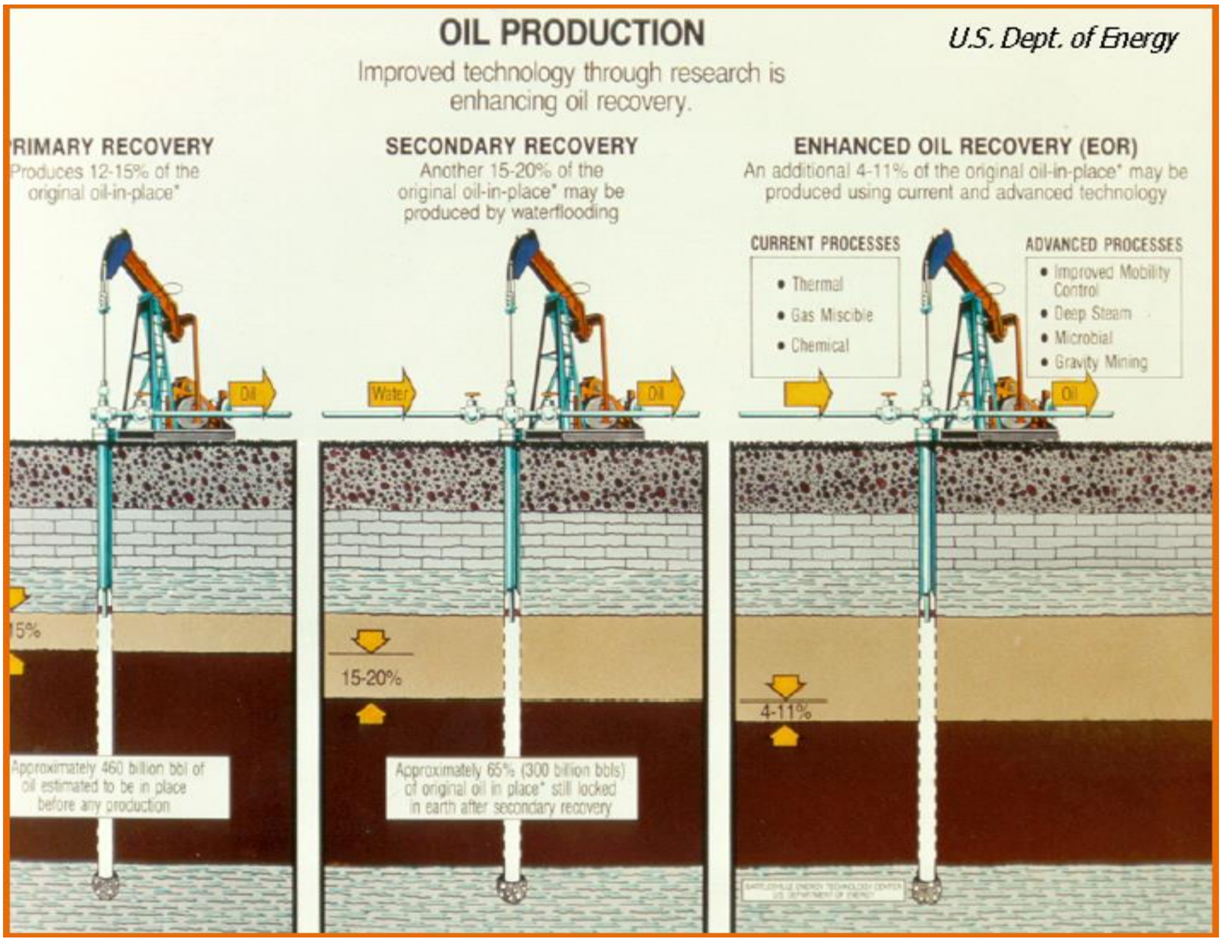

Figure (1.1): - Oil Production Method (James, 2009).

1.1.2 Enhanced Oil Recovery (EOR):

EOR refers to the recovery of oil through the injection of fluids and energy not normally present in the reservoir the injected fluids must accomplish several objectives as follows**:**

A. Boost the natural energy in the reservoir.
B. Interact with the reservoir rock/oil system to create conditions favorable for residual oil Recovery that include among others:

i. Reduction of the interfacial tension between the displacing fluid and oil
ii. Increase the capillary number
iii. Reduce capillary forces
iv. Increase the drive water viscosity
v. Provide mobility-control
vi. Oil swelling
vii. Oil viscosity reduction
viii. Alteration of the reservoir rock wettability (Laura Romero-Zerón 2012)

1.1.3 Enhanced Oil Recovery Methods Classification:

EOR processes can be classified under three main groups. These are Miscible Gas Injection Processes, Chemical Processes, and Thermal Processes. Under these main groups are specific types of applications of the EOR processes which are named as follows:

A. Miscible Gas Injection Processes

1. Nitrogen injection (N_2)
2. Hydrocarbon (HC) gas injection
3. Carbon dioxide (CO_2) injection
4. Sour gas, flue gas, etc. injection

B. Chemical Processes

1. Polymer flooding
2. Polymer/surfactant flooding
3. Alkali-Surfactant-Polymer (ASP) flooding
4. Microbial

C. Thermal Processes

1. In-Situ Combustion (ISC) or High Pressure Air Injection (HPAI)

2. Steam/Hot water injection
3. Steam Assisted Gravity Drainage (SAGD) (Nnaemeka Ezekwe 2011)

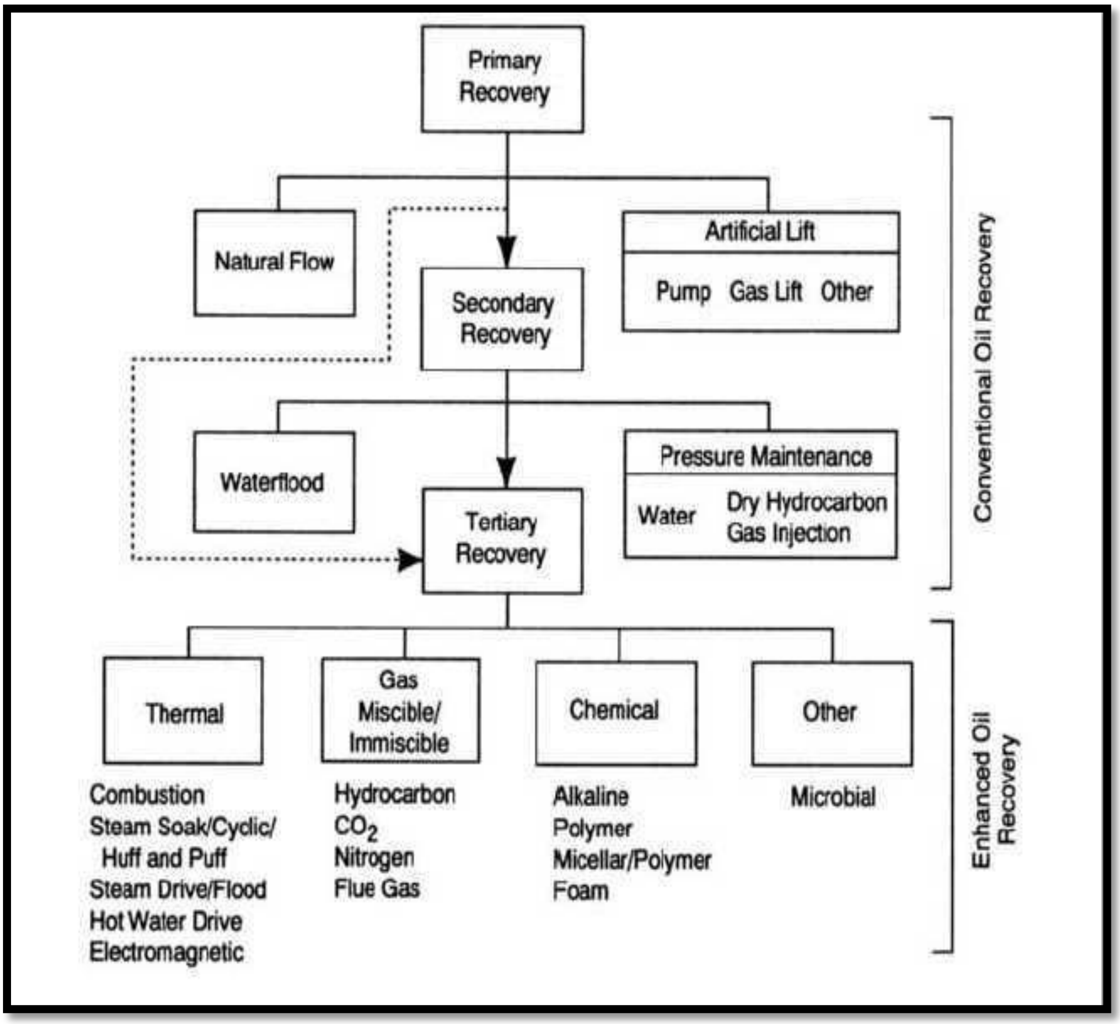

Figure (1.2): - Recovery Mechanisms (OGJ special, 1992).

1.1.4 Heavy Oil

Heavy oil is a type of petroleum that is different from conventional petroleum in so far as it is much more difficult to recover from the subsurface reservoir. It has a much higher viscosity (and lower API less than 20°) than conventional petroleum; Heavy oil is an oil resource that is characterized by high viscosities (i.e. resistance to flow) and high densities compared to conventional oil. Most heavy oil reservoirs originated as conventional oil that formed in deep formations but migrated to the surface region, where they were degraded by bacteria and by weathering and where the lightest hydrocarbons escaped (James 2009).

1.1.4.1 Heavy Oil Classification:

According to the Canadian Center for Energy, heavy crude oil is itself classified into different categories according to specific gravity and viscosity at reservoir conditions:

A) Heavy Oil:

Its type of crude which have API" degree greater than 10, viscosity less than 10,000 CP (10 Pas) and it flows at reservoir conditions.

B) Extra-heavy oil:

The API" degree of which is less than 10 and the in situ level of viscosity is less than 10,000 CP (10 Pas), which means that it has some mobility at reservoir conditions.

C) Natural bitumen:

Often associated with sands, and also referred to as tar sands or oil sands, the API degree of which is less than 10 and the in situ viscosity greater than 10,000 CP (10 Pas); it does not flow at reservoir conditions.

Note that the extra-heavy oil and bitumen have an API" less than 10, which means a specific gravity greater than 1: they are heavier than pure water (Alain 2011).

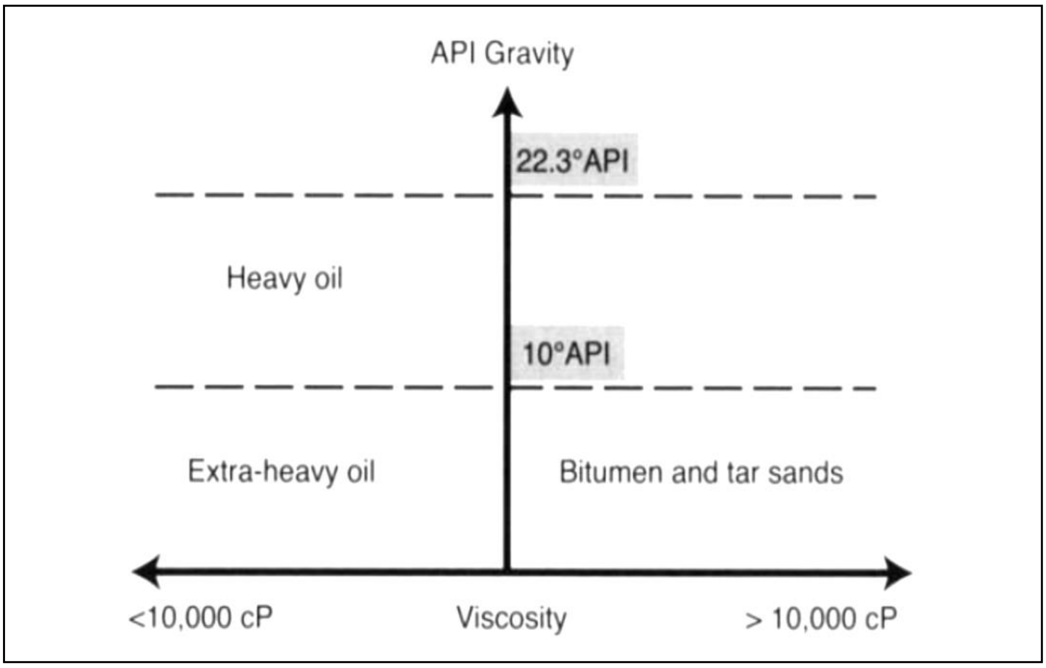

Figure (1.3): - Heavy Oil Classification (Alain, 2011).

1.2 Problem Statement:

According to the field under study Moga Sudanese oil field which characterized with low recovery factors and decline in primary production due to low oil gravity (<22 API) and viscosities above 100 CP, therefore the study to find the suitable method to increase the oil recovery efficiency.

1.3 Objectives:

Study the possibility of implementation a suitable development method in Moga oil field to increase the recovery rates.

1.4 Introduction of Case Study (Moga Oil Field):

Moga Field Located in the eastern part of block 6, 20 km to the north of FN field in Muglad basin located in south west of Sudan (approximately 760 Km from Khartoum MSL 400 m, three reservoirs (Aradeiba, Bentiu & AG) were developed.

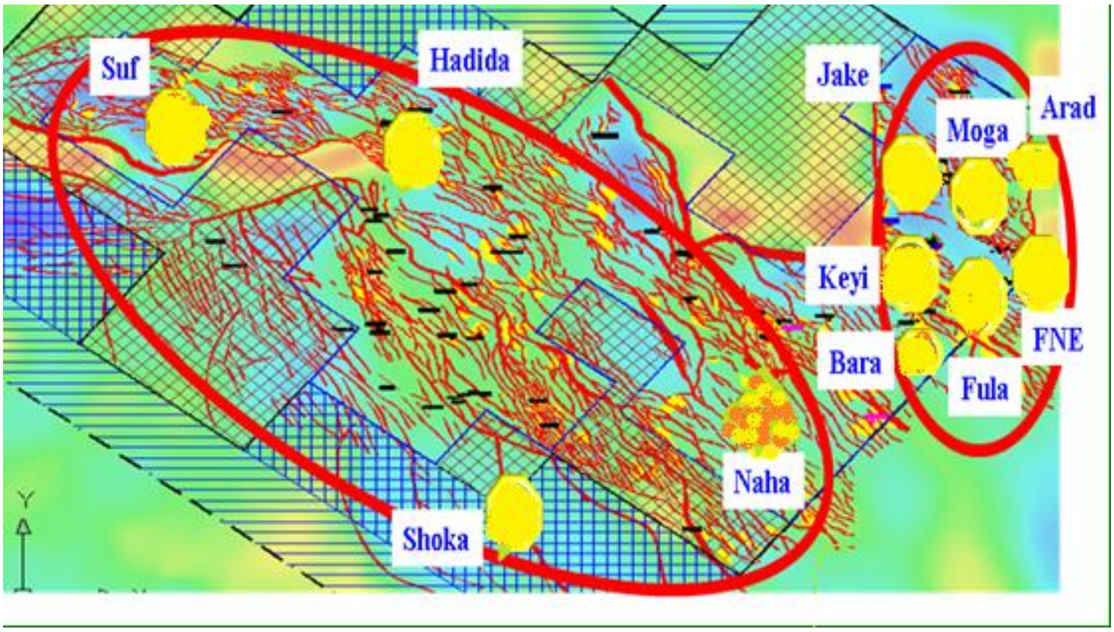

Figure (1.4): - Filed Locations (Husham, 2017).

Moga field produce heavy & light crude, produce light crude from (27) wells gathered in three OGMs (6, 7 and 8) from AG reservoir located in four areas (7, 10, 18 and 33), Heavy crude from (51) wells gathered in five OGMs (1, 2, 3, 4 and 5) located in three main areas (1, 20 and 26).

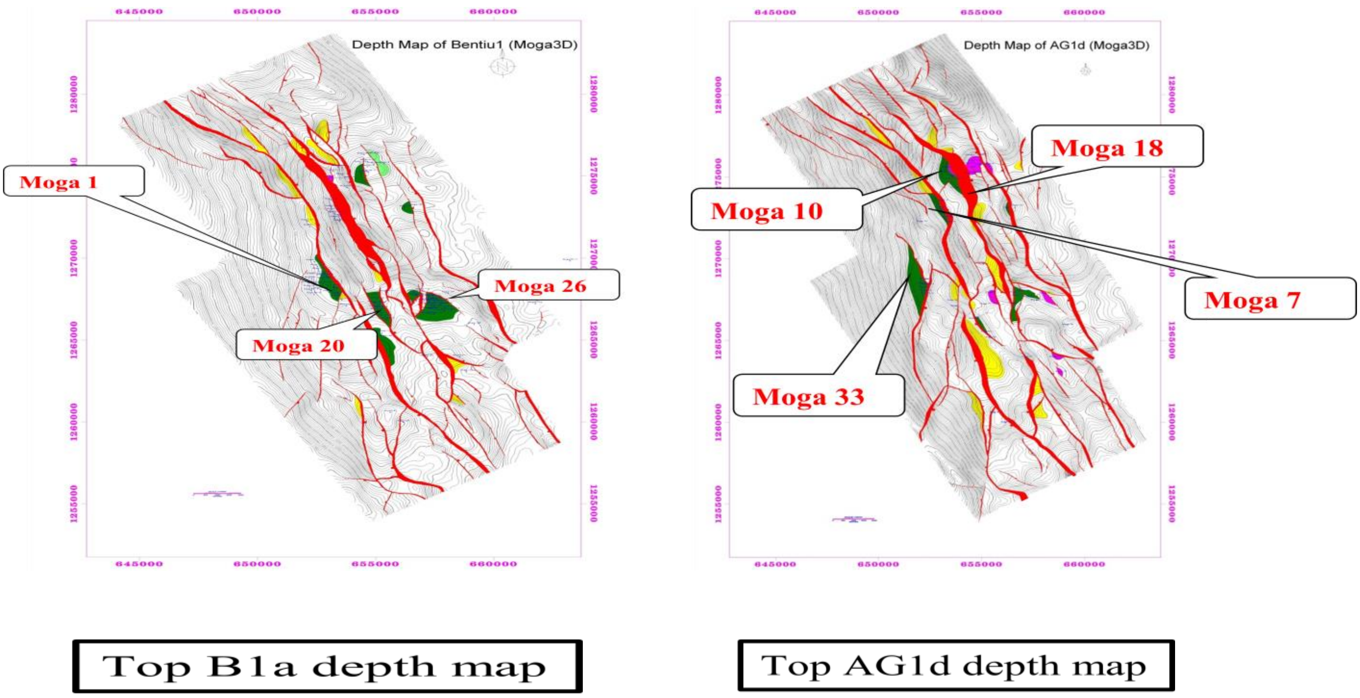

Figure (1.5):-Structure Map of to B1a & AG1d (PE, DTR, 2017).

Moga-26 Area:

Start Production Apr. 2006 Produced from Bentiu with strong bottom aquifer and viscous oil (412 cp @ res temp), All wells producing with PCP.

By May.31, 2016 the wells (total/ active): (17/16) daily oil rate is 1222 STB/D, Liquid rate is 4875 STB/D, and WC is 75%, cum oil 10.7 MMSTB.

WC increase rapidly due to unfavorable mobility ratio of heavy oil.

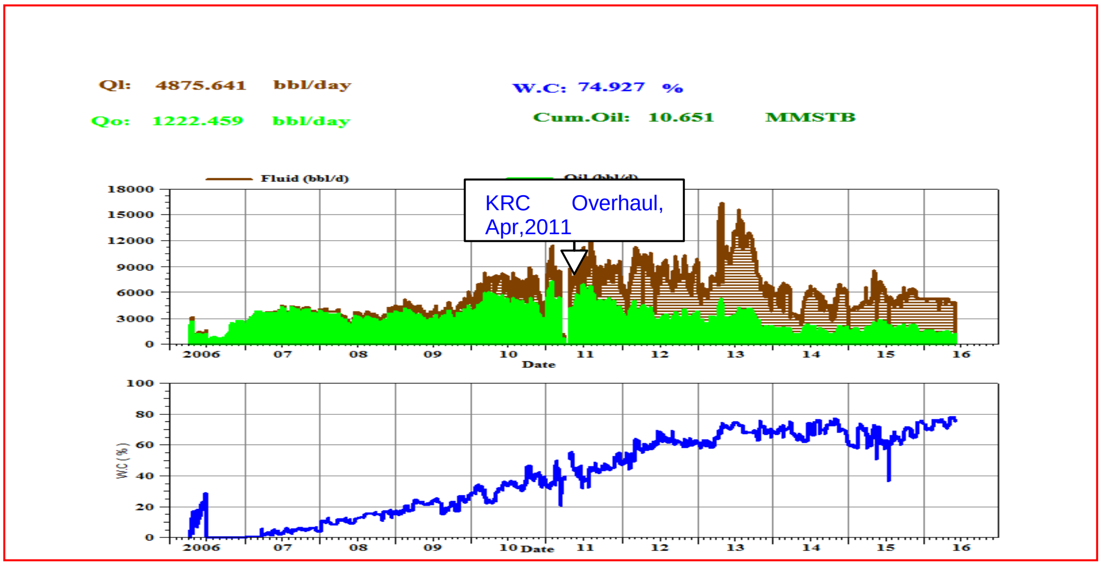

Figure (1.6): - Cum oil, WC, oil and liquid rate for Moga-26 Area (PE, DTR, 2017).

Moga-20 Area:

Start Production Apr. 2006 Produced from Bentiu with strong bottom aquifer and viscous oil (491 cp @ res temp), all wells producing with PCP.

By May.31, 2016 wells (total/active): (9/9) daily oil rate is 644 STB/D, Liquid rate is 1441 STB/D, and WC is 55%, Cum oil 3.9 MMSTB.

WC increase rapidly due to unfavorable mobility ratio of heavy oil

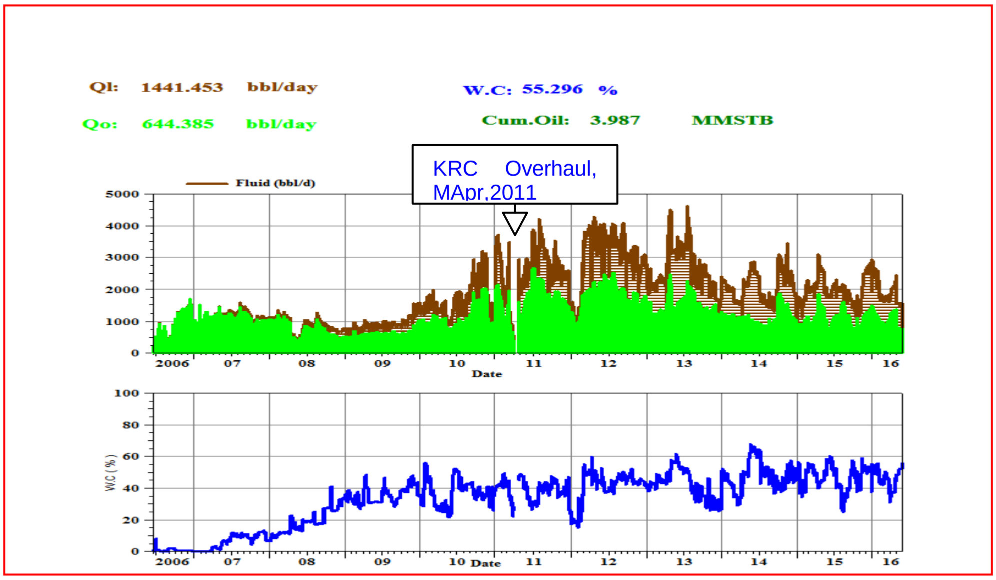

Figure (1.7): - Cum Oil, WC, Oil and Liquid Rate for Moga-20 Area (PE, DTR, 2017).

Moga-1 Area:

Start Production Jun. 2008 Produced from Bentiu and Aradeiba, Bentiu has strong bottom aquifer which indicated by stable DFL, while Aradeiba is associated with weak aquifer, all wells producing with PCP.

By May.31st, 2016, the wells (total/ active), (18/17), daily oil rate is 1276 STB/D, Liquid rate is 2828STB/D, WC is 55% and Cum oil 3.9 MMSTB.

WC increase rapidly due to unfavorable mobility ratio of heavy oil

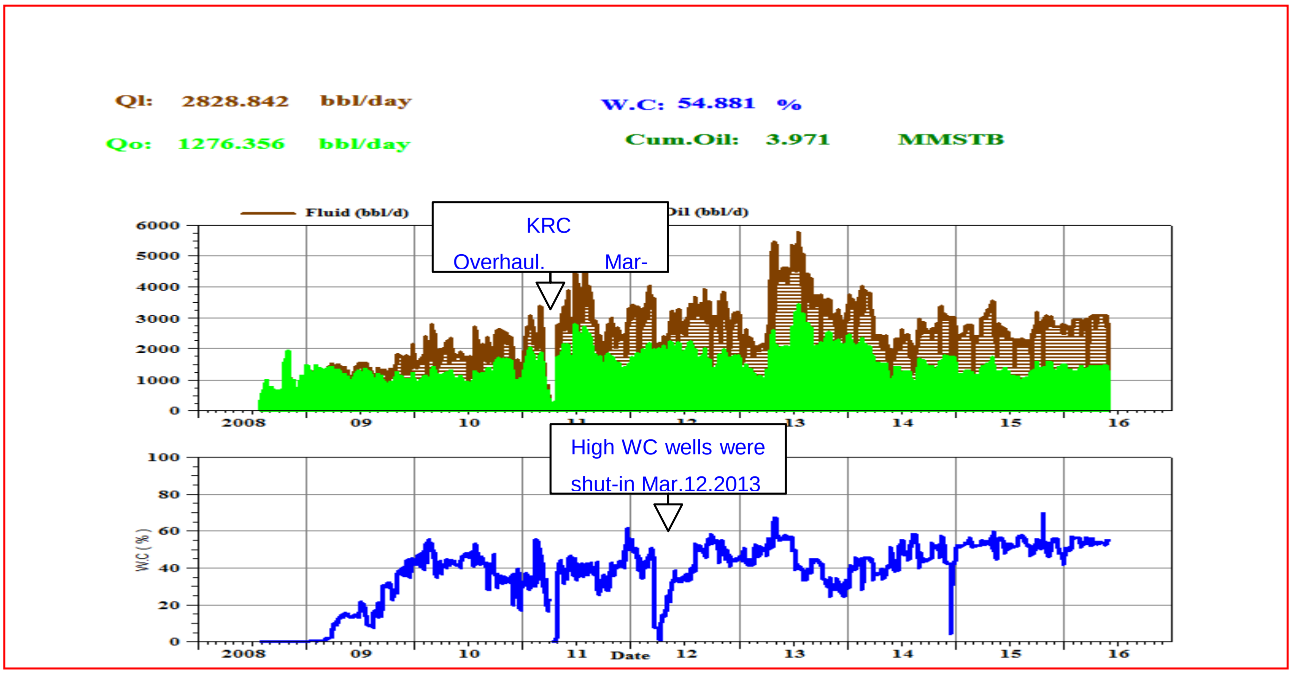

Figure (1.8): - Cum oil, WC, oil and liquid rate for Moga-1 Area (PE, DTR, 2017).

1.5 Thesis Outlines:

In this thesis Chapter one include the general introduction, problem statement, Objective of the study and introduction to case study. Chapter two is theoretical background of heavy oil production and the literature review, while chapter three is illustrating the methodology of optimum methods suitable to reduce viscosity using CMG software. Chapter four is project results and discussion of the work and Chapter five is the conclusion and recommendations.

Chapter (2) Theoretical Background & Literature Review

2.1Theoretical Background:

There are several methods for heavy oil recovery, these methods range from recovery due to reservoir energy (i.e., the oil flows from the well hole without assistance) to enhanced recovery methods in which considerable energy must be added to the reservoir to produce heavy oil.

Although some heavy-oil reservoirs yield oil by primary and secondary recovery methods), it is more traditional in terms of heavy-oil recovery to apply thermal oil recovery techniques of which steam injection is the most popular.

Heavy-oil recovery efforts include thermal methods (steam floods, cyclic steam stimulation, steam-assisted gravity drainage (SAGD)) as well as non-thermal methods (cold flow with sand production, cyclic solvent process, vapor-assisted petroleum extraction (VAPEX)).

2.1.1 Primary Recovery (Cold production):

Produce heavy oil by primary recovery methods (cold production), dependent upon the fluidity of the heavy oil which, in turn, is dependent upon the reservoir temperature, the term cold production refers to the use of operating techniques and specialized pumping equipment to aggressively produce heavy-oil reservoirs without applying heat.

In summary, the recovery from primary production in heavy-oil reservoirs may be as high as 20% but is often lower. At the conclusion of primary production, therefore, there is still a significant amount of oil in place in the reservoir, and the reservoirs have been stripped of their natural energy. In order to recover additional oil, the reservoir energy has to be replenished, and then oil has to be displaced to production wells.

2.1.2 Secondary Recovery:

When dealing with heavy-oil reservoirs, 90% or more of the original oil in place can be left in the reservoir after attempts at primary or cold production ,Secondary oil recovery uses various techniques to aid in recovering oil from depleted or low-pressure reservoirs, Pumps and other secondary recovery techniques increase the reservoir's pressure by water injection (water flooding), natural gas injection (gas flooding), and gas lift, which injects air, carbon dioxide, or some other gas into the reservoir.

2.1.3 Tertiary Recovery:

EOR (tertiary oil recovery) is the usual method for heavy-oil recovery and the term EOR is often synonymous with tertiary recovery, its include thermal and Non-thermal methods:

2.1.3.1 Non-thermal Methods:

a) Alkaline Flooding:
b) Carbon Dioxide Flooding
c) Cyclic Carbon Dioxide Stimulation:
d) Polymer Flooding:
e) Micellar Polymer Flooding**:**

2.1.3.2 Thermal Recovery Methods:

Thermal recovery involves heating up the reservoir, thereby lowering the heavy oil's viscosity and enabling the oil to flow to the wellbore. The application of thermal recovery methods to heavy oil production focuses on reducing the viscosity of the oil and increasing the mobility to move the oil to a production well, The thermal recovery processes used today fall into two classes: processes in which a hot fluid such as steam is injected into the reservoir and processes in which heat is generated within the reservoir itself, such as the combustion processes.

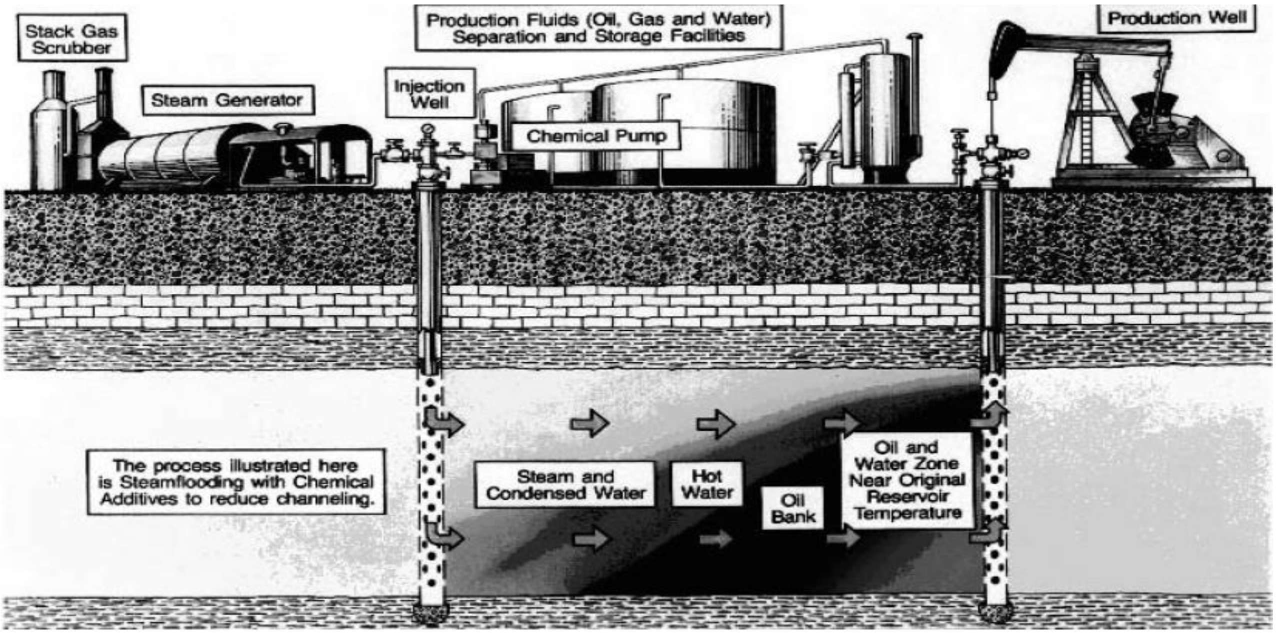

Figure (2.1): - Oil Recovery by Thermal Methods (James, 2009).

a) Fluid Injection:

Hot-fluid injection processes are those processes in which preheated fluids are injected into a relatively cold reservoir. The injected fluids are usually heated at the surface, Fluids range from water (both liquid and vapor) and air to others such as natural gas, carbon dioxide, exhaust gases, and even solvents.

b) Steam Injection:

Steam processes are most often applied in reservoirs containing viscous oils and tars, in steam stimulation processes, heat and drive energy are supplied in the form of steam injected through wells into the heavy oil reservoir, the concept behind the steam-based processes is generally viscosity reduction so that the heavy oil can flow to the production well.

c) Steam Flooding (steam drive):

Steam can be injected into one or more wells with production coming from other wells (steam drive). This technique is very effective in heavy oil formations but has found little success during application to heavy oil reservoirs because of the difficulty in connecting injection and production wells.

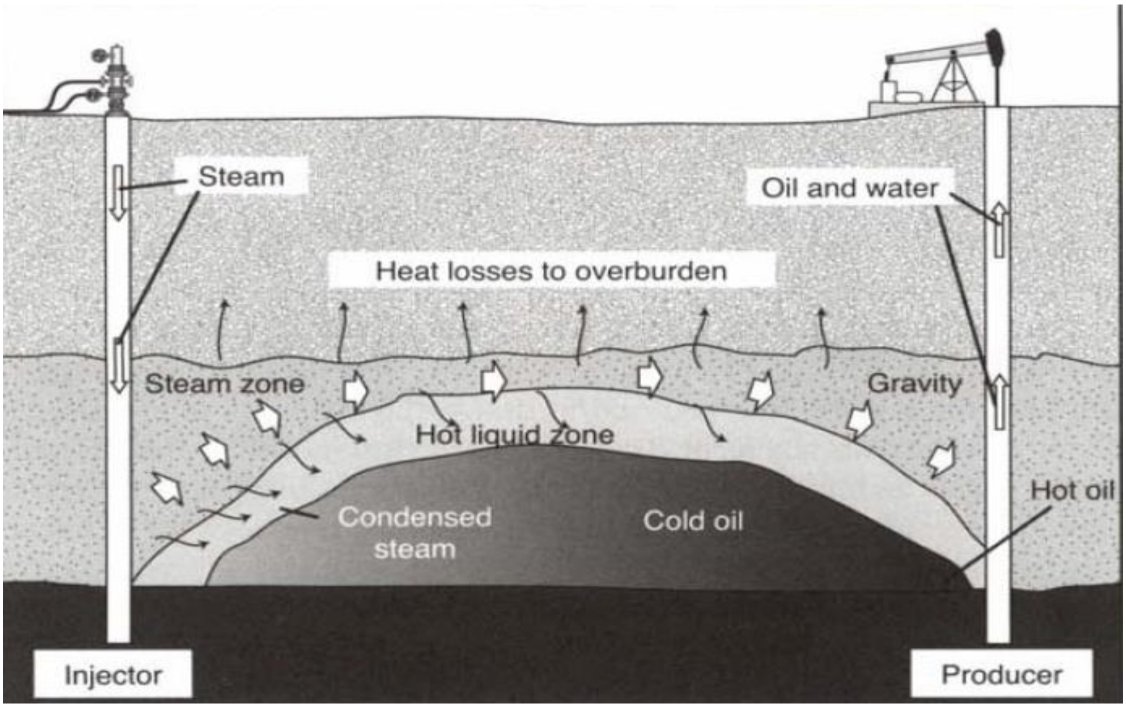

Figure (2.2): - Schematic Cross-Section of Continuous Steam Injection (Vogel JV, 19821).

d) ***Cyclic Steam Injection:***

Cyclic steam injection (or cyclic steam stimulation) is the alternating injection of steam and production of oil with condensed steam from the same well or wells.

Cyclic steam stimulation is often the preferred method for production in heavy oil reservoirs that can contain high-pressure steam without fracturing the overburden. The minimum depth for applying cyclic steam stimulation is on the order of 1,000 ft, depending upon the type and structure of the overlying formations, there are three phases in cyclic steam stimulation. First, high-temperature, high-pressure steam is injected for up to 1 month. Second, the formation is allowed to soak for 1 or 2 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 uneconomic rates, which may take up to 1 year. Then the cycle is repeated, as many as 15 times, until production can no longer be recovered, artificial lift is required to bring the heavy oil to surface, typical recovery factors for cyclic steam stimulation are (20-35) % with SOR of (3-5.22). Steam flood processes may follow cyclic steam stimulation *e) **Combustion Process:***

This process is sometimes started by lowering a heater or igniter into an injection well. Air is then injected down the well, and the heater is operated until ignition is accomplished. After heating the surrounding rock, the heater is withdrawn, but air injection is continued to maintain the advancing combustion front. Water is sometimes injected simultaneously or alternately with air, creating steam which contributes to better heat utilization and reduced air requirements.

*f) **Steam-Assisted Gravity Drainage (SAGD):***

This method involves drilling two parallel horizontal wells, one above the other, along the reservoir itself. The top well is used to introduce hot steam into the oil sands. As the heavy oil thins and separates from the sand, gravity causes it to drain into the lower well, from where it is pumped to the surface for processing Even though the injection and production wells can be very close (between 15 and 25 ft), the mechanism causes the steam-saturated zone (known as the steam chamber) to rise to the top of the reservoir, expand gradually sideways, and eventually allow, drainage from a very large area. The method is claimed to significantly improve heavy oil recovery by between 50% and 60% of the OOIP and is therefore more efficient than most other thermal recovery methods.

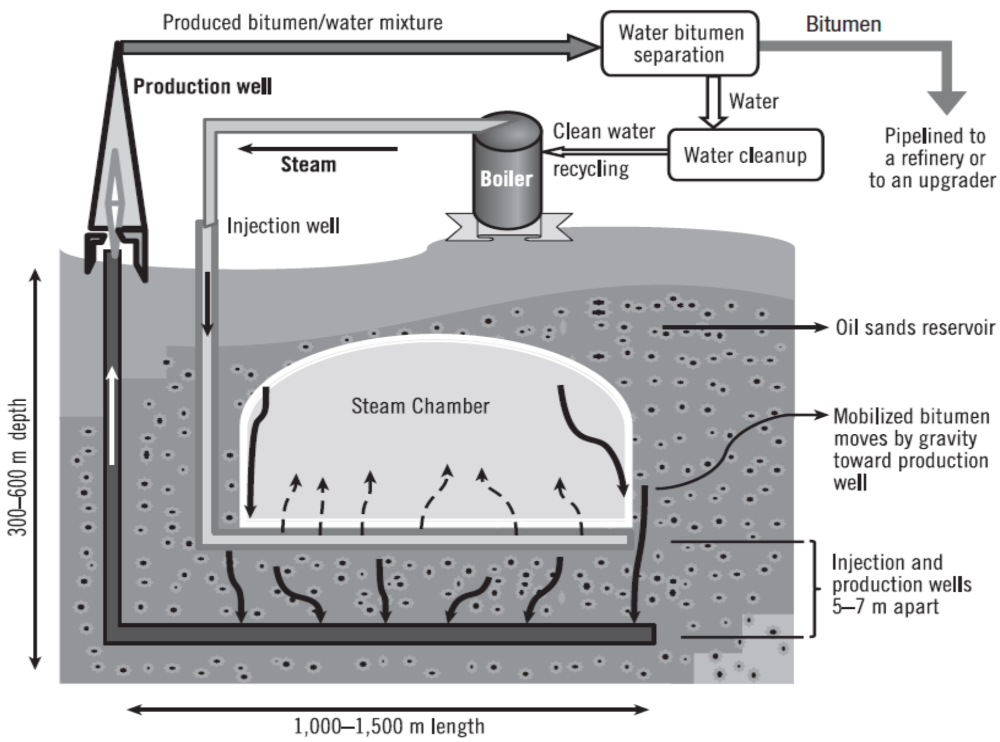

Figure (2.3): - Cross-sectional view of the SAGD concept (K. Banerjee, 2012).

2.1.3.3 Other Methods:

Horizontal Well Technology:

Long horizontal wells with several multilateral branches have been used widely in the development of the heavy oils of Venezuela, where production rates as high as (2,000-2,500) barrels/day, this technology can only achieve (8-15) % recovery and only from the best high-permeability zones.

2.2 Literature Review

Patrick Shuler, et all (2010) presents an evaluation of different chemical agents that can reduce dramatically the apparent viscosity of a heavy crude oil or a thick emulsion. The focus of this study is on methods to improve the production of heavy oils and very viscous emulsions such as are found in California, Canada, and Venezuela. This study identified several surfactant-demulsifier formulations that can reduce the viscosity of such heavy fluids by as much as 3 orders of magnitude, a novel torque viscosity measurement device provides an accurate and convenient method to determine the viscosity of emulsions over a wide range of temperatures, shear rates, and mixture viscosities. Aqueous surfactant/demulsifier formulations identified in this study can reduce dramatically the viscosity of heavy oils and their emulsions, and its effective will vary, depending on the crude oil being treated.

Abdalla Elhag Suliman,et all (2011): illustrate that a considerable number of Enhanced Oil Recovery (EOR) techniques have been assessed in order to recommend suitable EOR development project for the Thar Jath field, , three most promising techniques; ASP, steam flood/CSS and in-situ combustion were developed to optimize pattern spacing, injection rates and pressures for each technique, Comprehensive screening study confirming that feasibility of EOR in the Thar Jath field and recommending Steam Injection (CSS) as preferred EOR technique, The injection scheme for TJ-1 Lower BEN CSS pilot comprise 3 cycles of 30 days injection, 10 days soaking and up to 180 days production, At least two cycles, and a minimum of 13 months in the Upper BEN CSS pilot are completed before any definite “proof of concept”, or pilot failure, is considered.

Raj Deo Tewari1 et.all (2011**):** provided Case Study about implementation and evaluation of Cyclic Steam Stimulation in heavy oil field of Sudan (FNE) Fula North East field is a medium size heavy oil field at shallow depth of 550-600m, eight wells selected spread over the field encompassing varying reservoir characteristics for understanding the efficacy of the process, steam injection and soaking periods were optimized for 6-10 and 3-5 days respectively. And average heated radius varies 8.5-18.30 m, Cyclic steam stimulation (CSS) increased the oil rate 400-600 bopd more than 3 times of the average cold production which is around 125-150 bopd. Performance results of all the steam stimulated wells suggest a good success of the pilot in terms of improvement in oil rate.

R.R. Ibatullin, et all (2012) illustrate that more than 450 heavy oil fields and deposits have been identified in the Republic of Tatarstan with oil-in-places ranging between 1.4 and 7.0 billion tons, according to different estimates. Considering high viscosity of heavy oil, thermal recovery methods seem the right solution for development of shallow heavy oil fields. Heavy oil was produced through vertical wells, and different thermal recovery techniques were tested, including in-situ combustion, steam and gas mixture injection, and cyclic steam stimulation. The shift from conventional vertical wells to SAGD horizontal well pairs led to an order-of-magnitude increase

Eric Delamaide, et all (2015) discuss the challenges and potential solutions for Enhanced Oil Recovery in heavy oil reservoirs with bottom aquifer, the study reviewed field cases of EOR experience with bottom aquifer for chemical as well as thermal processes (SAGD, steam injection as well as In Situ Combustion). Steam assisted Gravity Drainage (SAGD) appears to be the most adapted because controlling the steam chamber pressure allows preventing the inflow of water or conversely the loss of oil to the water zone. In Situ Combustion appears to be a potential solution but the process has seen few successes and field extensions even without bottom water.

Chemical EOR has been applied extensively but mostly in lighter oil, although its use in heavy oil has been gaining in importance these past few in production rates.

Ayman R. Al-Nakhli, et.all (2016) Illustrated a new thermochemical research program reduce oil viscosity to improve well productivity and the overall reservoir depletion efficiency for heavy oil and tar launched by Saudi Arabia, Saudi Aramco it enabling in-situ steam generation by chemical reaction (EXO-Clean) to mobilize the low API crude oil or tar reserves, the technology depend on generate steam in situ rather than conventional steam injection methods, Moreover, the method can be applied to produce deep heavy oil reservoirs that cannot be produced with traditional steam injection method, Based on the BTU delivered from the reaction, 1 bbl of the reaction is equivalent to 1.82 bbl of Steam Injected per Day (BSIPD) at given above conditions The oil production when chemicals are used for in-situ steam generation, increases about double of production compared to super quality-steam flooding.

Hassan Al Saadiet, et.all In, 2016 provides an alternative method to improve production and recovery of heavy oil, especially in the Middle East and clarify The current technologies for reducing viscosity are Steam injection and Miscible Gas (hydrocarbon or carbon dioxide) injection, however both steam and miscible gas has technical and economic limitations so that an alternative technology is required to extend beyond them. The research program was conducted simulate reservoir behavior by implementing mixture viscosity sensitivity performance test imbibitions tube test and core flood test. The tests are implemented using actual reservoir oil, water and rock. The result of viscosity reduction is able to reduce oil viscosity from more than 376 cp at reservoir temperature to less than 10 cp mixture viscosities at temperature between 60 and 90° C. For comparison, steam injection is able to reduce viscosity of heavy oil to become less than 10 cp, but requires a temperature of 350° C instead of 60 to 90°.

Husham Elbaloula et.all (2016): designed a model to simulate steam flooding of heavy oil reservoir in FNE oil field in which the reservoir is shallow and thin , six different cases at different well spacing were investigated and compared with the base case, the numerical thermal simulator was used to simulate the data from the present steam flooding experiments. The result showed that converting of Cyclic Steam Stimulation (CSS) to steam flooding after the third cycle could improve the recovery factor of the field up to 43 ~ 50.1%, while CSS only can increase the recovery percent of the suggested well groups by 32.5 - 34.2% of the studied sector model which makes it more attractive method as development Case for FNE oil field.

Husham and Tagwa (2017): illustrate and analyze the performance of CSS phase's implementation starting from the first pilot up to full field scale through different stages, and analysis for the CSS performance implementation including the injection parameters in FNE field .The result showed that the CSS is very successful and the average oil rate is almost 1.6 times compared to cold production, the CSS only can increase the recovery percent from 32.5 - 34.2% which makes it more attractive method as development Case for FNE oil field

All previous studies of block 6 were been for FNE, FN Oil Field, while this the first study for Moga oil field illustrate Moga formation types, crude oil types and reservoirs rock/fluid properties, this study trying to find suitable methods to enhance Moga heavy oil recovery.

Chapter Three: Methodology

3.1 Introduction

To achieve the objectives of this study, the below methodology had been followed:

1. A deeply Understanding for Moga field properties: (reservoir characteristics, reservoir types, reservoir pressure & temperature, PVT properties of the crude oil, fluid properties, rock properties, reservoir parameters).
2. CMG software had been studied.
3. Data collection
4. CMG sector model for Moga field data.
5. The model had been built for the Moga model data

CMG software is a group of software's specialized in reservoir simulation it's consisting of:

a) Builder
b) GEM - Compositional & Unconventional Oil & Gas Reservoir Simulator
c) IMEX - Three-Phase, Black-Oil Reservoir Simulator
d) STARS (thermal simulator)
e) Win Prop (model generator)
f) CMOST (optimization software)
g) RESULTS - Visualization & Analysis

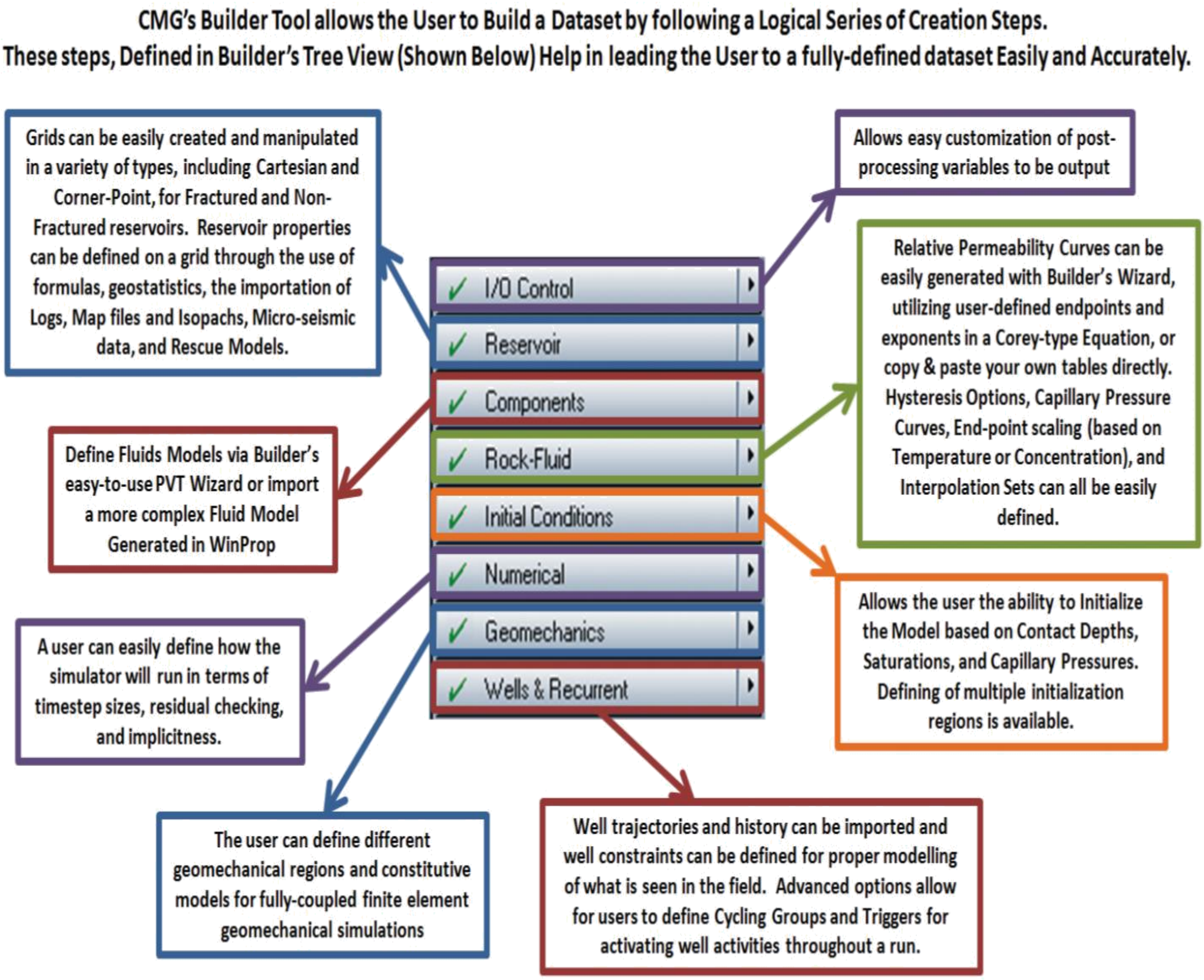

Figure (3.1): - CMG builder user interface.

Advantages:

1. Easily and effectively visualize and analyze simulator output data.
2. Make fast and informed decisions about improving recovery and performance for a well or a field.
3. Real-time updating of results as simulation progresses.
4. Repeat plot facility for wells and groups to rapidly generate plots for analysis.
5. Complete integration of production and property profile plotting with 3D environment.
6. Output to 3D geological software to complete the seismic to-simulation-and-back workflow.

3.2 Building Simulation Model:

The Model has been built for Three cases (DNC, Water Injection &Steam Injection), then the Model Run for each one and the result shown in the below chapter.

Chapter Four: Results and Discussion

4.1 Introduction

Moga Field Production Performance

Great Moga Start Production since Apr-2006, By May-31- 2016: daily oil rate is 5630 STB/D, liquid rate is 13772 MSTB/D, and WC is 59 %, cumulative oil production 30.7MMSTB/D and contributes about 12.5% of PE total daily oil production.

All HC wells produce with PCP and Different production technology were adopted for LC wells:

1. 4 wells produce naturally
2. 3 wells produce with gas lift
3. 8 wells produce with PCP
4. 1 well produce with BPU

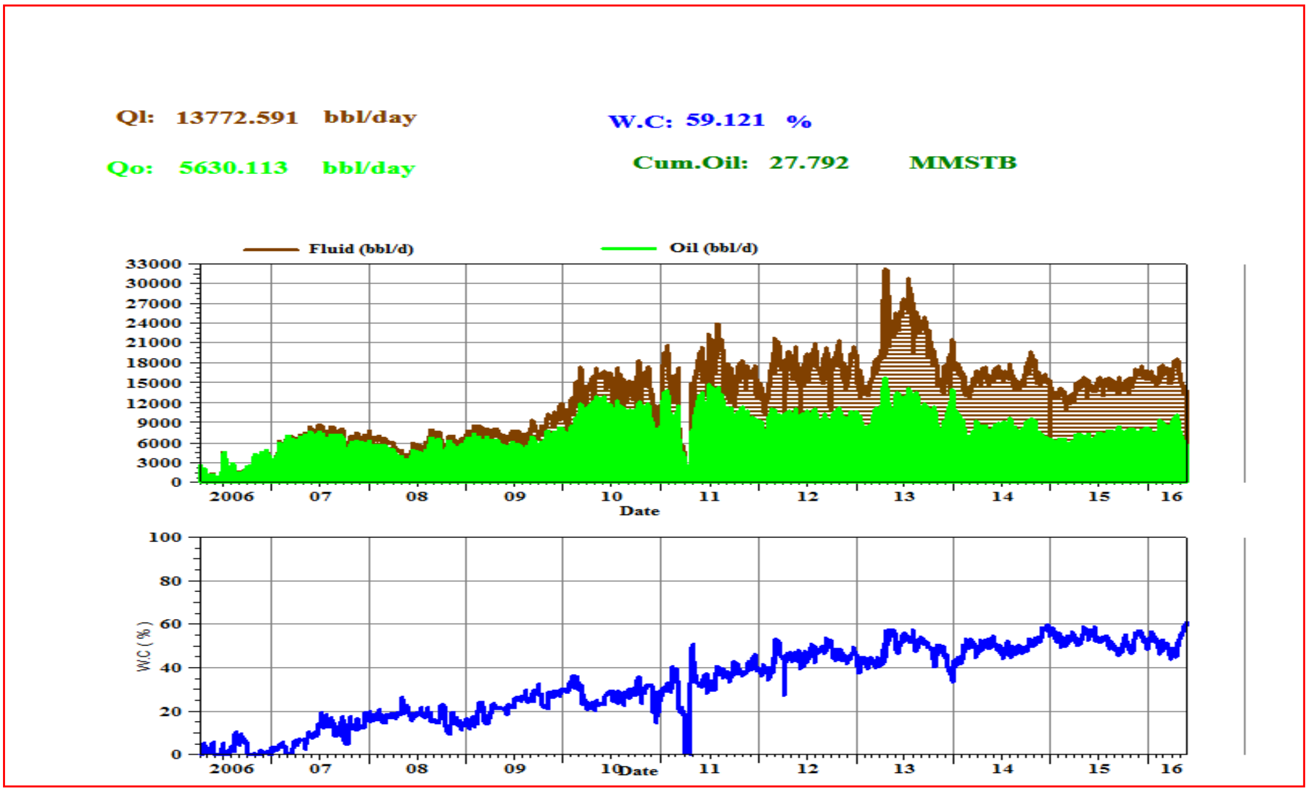

Figure (4.1): - Cum Oil, WC, Oil and Liquid Rate for Great Moga (PE, DTR, 2017).

Table (4.1): - Reservoir Properties for Moga (PE, DTR, 2017)

Parameters	Moga26	Moga20	Moga1		Moga6	Moga25	Moga4
Formation	Bentiu	Bentiu	Bentiu	Aradeiba	Bentiu	Aradeiba	Aradeiba
Depth, m	790	760	877	840	907.6	707	743
Initial reservoir Pressure,psi	855	795	1055	814	1006		989.5
Temperature, C^o	52	52.5	53.5	51.85	59	46	51
Porosity, %	37.6	15.2	26.9	30	23.1	31.6	26
Permeability md	3908	200	3777	309	46.4~187.3	156.73	99
Oil gravity, API	20	20.7	17.7	17.75	20.88		18.4
Viscosity @ Res Tem, cp	413	491	901	569	319		569
FVF, RB/STB	1.0162	1.0013	1.001	1.01			1.01
OOIP	$79*10^6$ STB						

4.1.1 Moga Heavy Production Performance (2015-2016)

Since Jun. 2015: daily oil production decrease from 5331 STB/D to 3276 STB/D, WC increased from 62% to 67%.

The main reason for oil production decline is the oil price crisis which results in suspension of development activities.

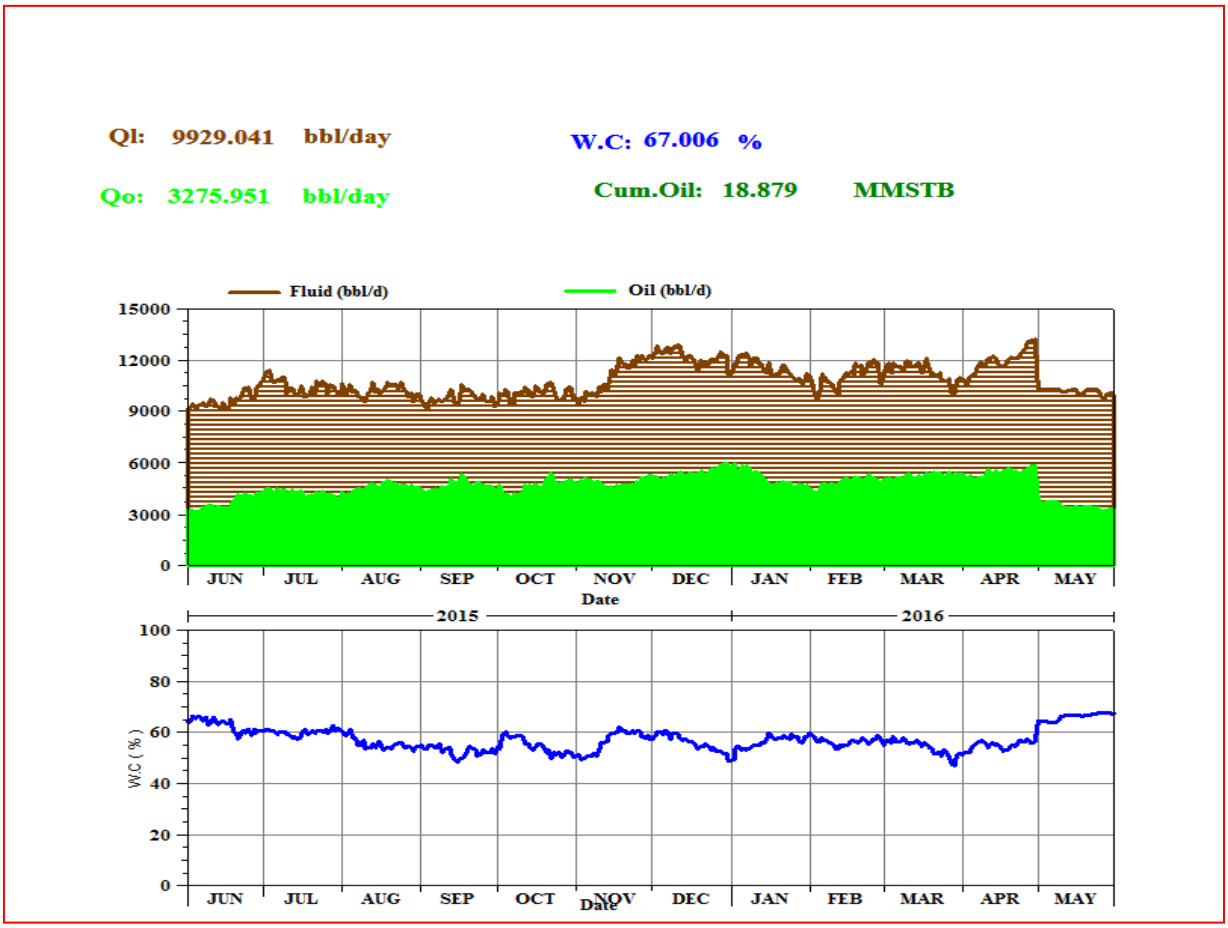

Figure (4.2): - Moga Heavy Production Performance (2015-2016) (PE, DTR, 2017).

4.2 Modeling

The model had been built for Moga-26 area Bentiu formation its consists from 17 well the parameters had been entered to the software and run with different Case, the first Case build by using IMEX and Convert the simulator from IMEX to STARS for the other Cases

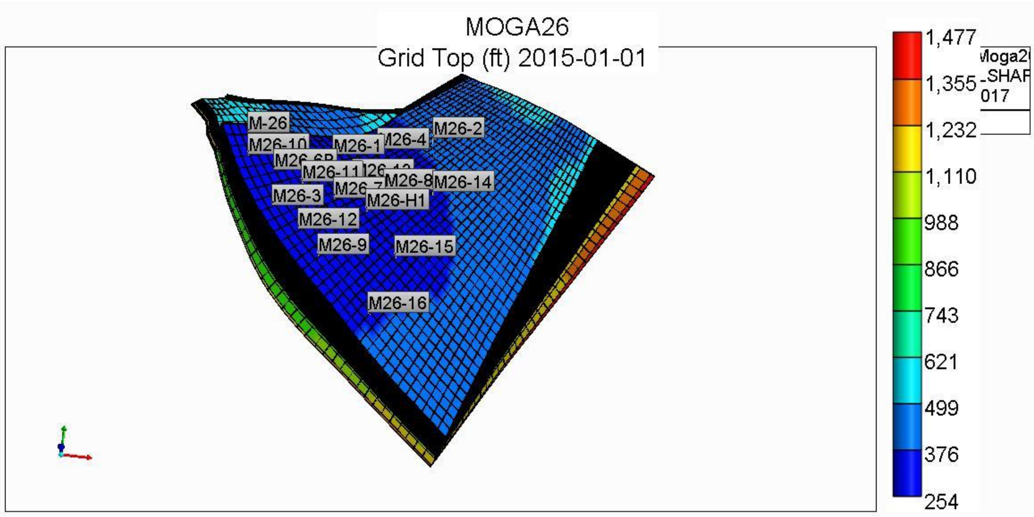

Figure (4.3): - Well Distribution in the Reservoir.

The permeability in the reservoir ranged from 100 up to 82,313 as shown in the below figure.

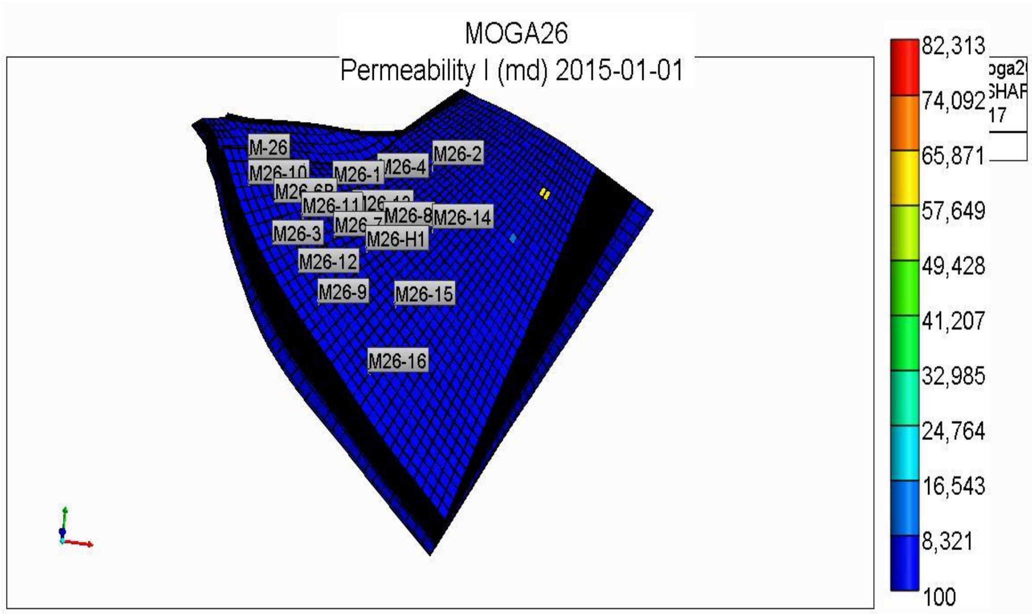

Figure (4.4): - Permeability Distribution in the Reservoir.

The porosity distribution in the reservoir ranged from (0.0 – 0.4) as shown in the below model view.

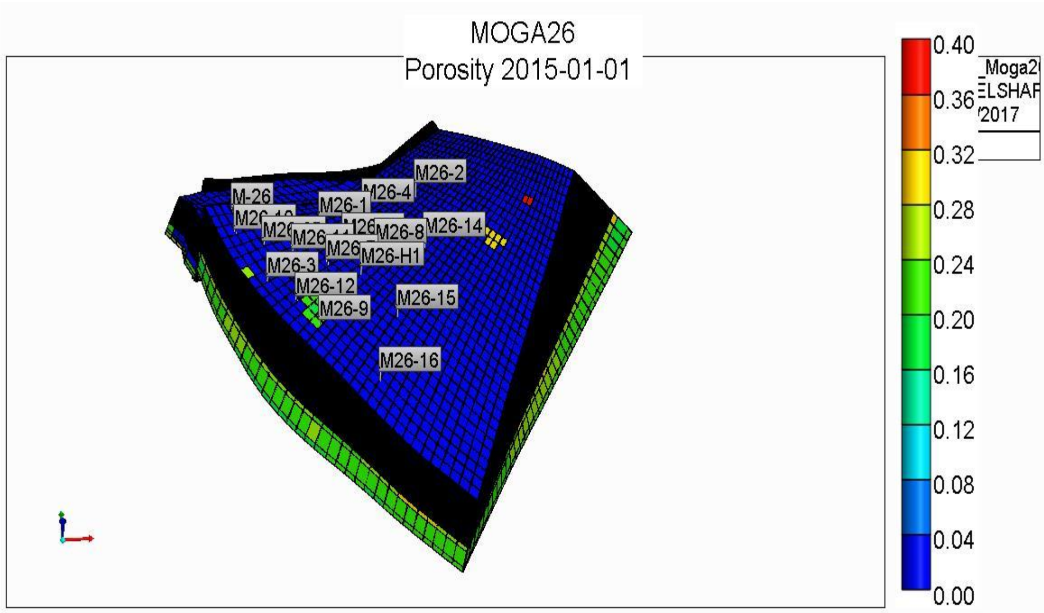

Figure (4.5): - Porosity Distribution in the Reservoir.

The CMG model had been built for the Moga 26 area (17) wells, all the parameters had been entered to the software then model had been run for three Cases:

1. Do Nothing Case (DNC)
2. Water injection
3. Steam injection

4.2.1 Do Nothing Case (DNC):

After the model build run as DNC and result as follow

4.2.1.1 Oil Rate

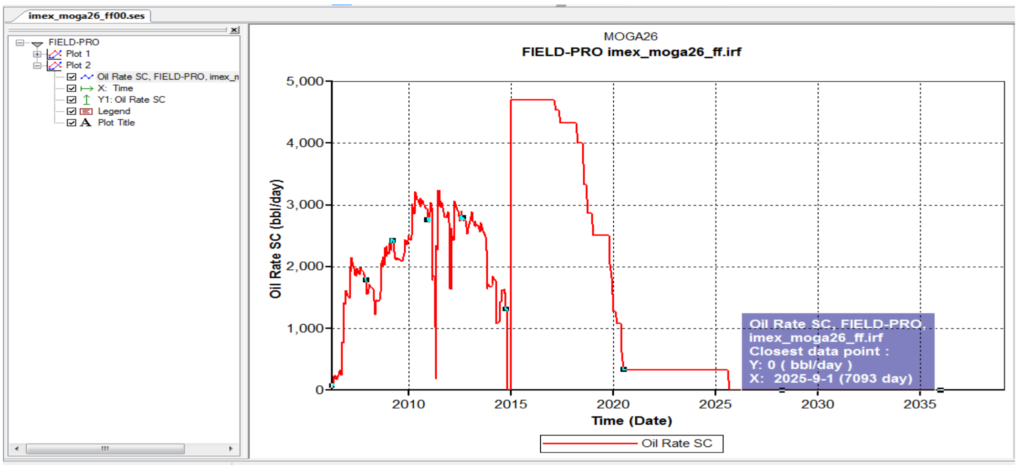

Figure (4.6): -.DNC Oil Rate.

The oil rate start with 74 (bbl/d) on 2006 and increase up to 4697.8 (bbl/d) on Jan 2015 then decreased to 332 (bbl/d) on 2025, the rate on Sep 2025 decreased to zero.

4.2.1.2 Cumulative oil Production

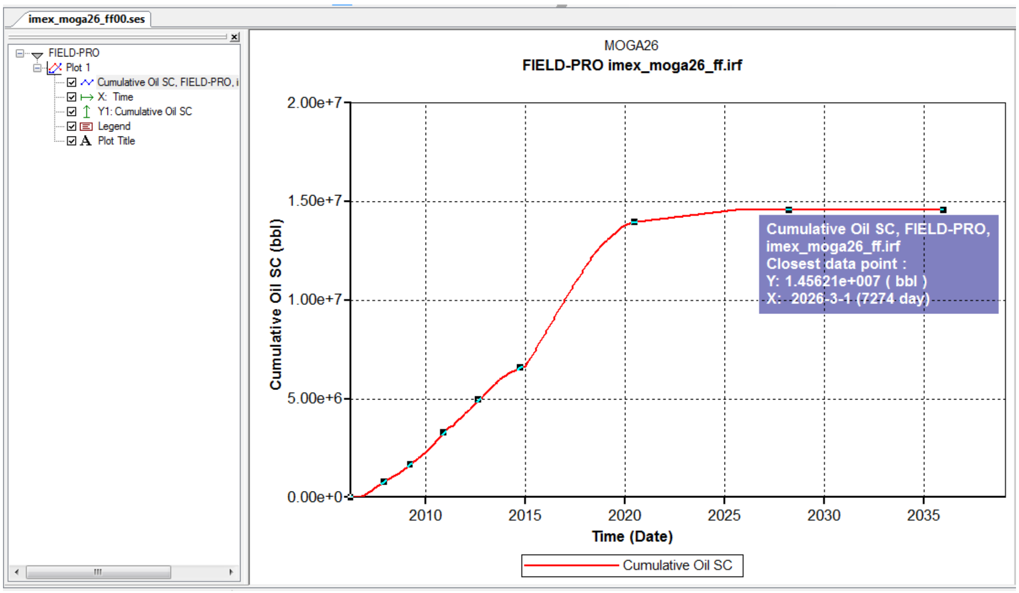

Figure (4.7): - DNC Cumulative Oil.

The cumulative oil on Jan 2015 was 6.60686e+006 up to 1.45621e+007 (bbl) on Aug 2025 and remain constant due to no production after this date.

4.2.1.3 Water Cut %

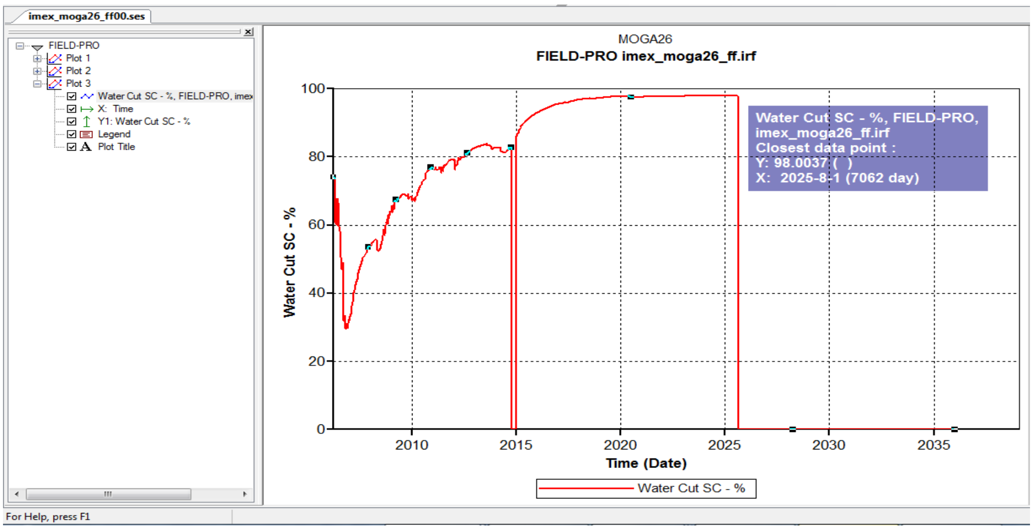

Figure (4.8): - DNC Water Cut.

The water cut on 2006 was 32% increased to 82% on 2015 and continuously increase to 98% on 2025

4.2.1.4 Oil Recovery

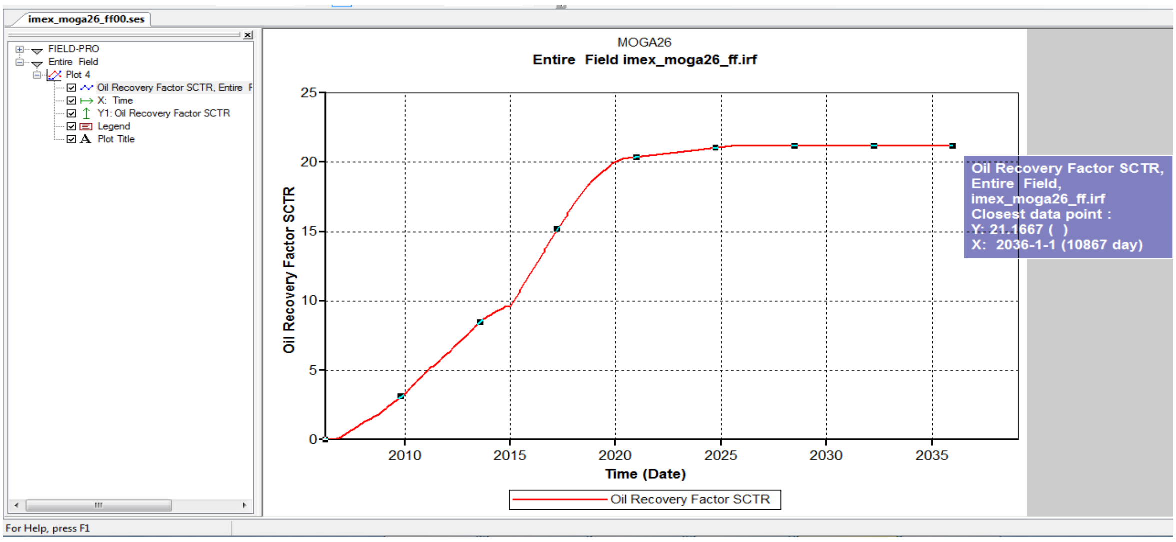

Figure (4.9) :-DNC Oil Recovery Factor.

The oil recovery factor on 2015 was 9.5, increased up to 21.2 on 2025

4.2.1.5 Combination

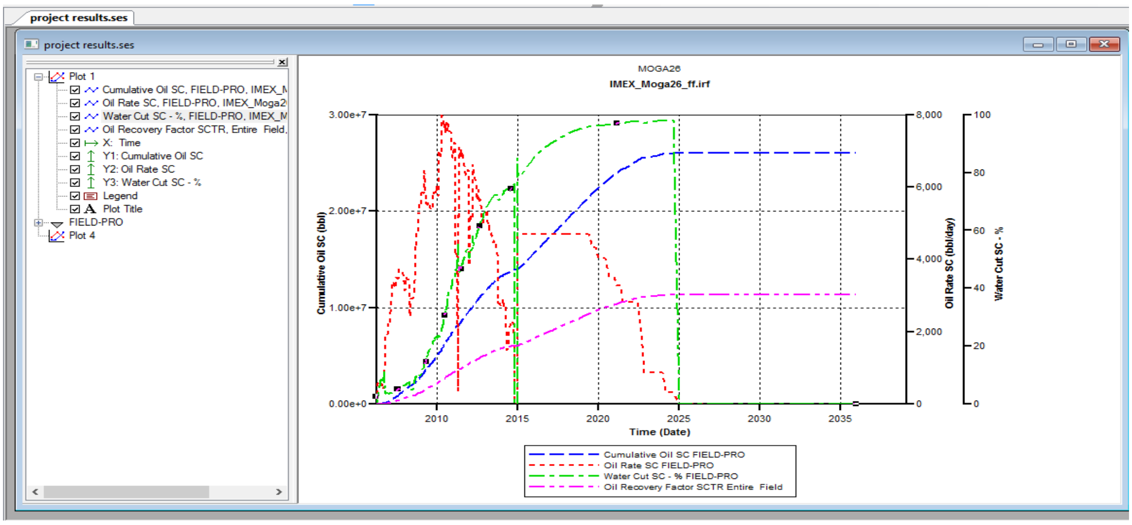

Figure (4.10): - DNC Combination Result.

The figure showed that combination of cumulative oil, oil rate, WC and recovery factor.

Table (4.2): - DNC Production Data.

DNC Production Data				
Date	Cum Oil	OIL Rate(bbl/d)	WC %	RF
1-Jan-2015	6.2154e+006	4697.8	82.556	9.5980
1-Aug-2025	1.4562e+007	0	98	21.1667
1-Jan-2036	1.4562e+007	0	0	21.1667

4.2.2 Water Injection:

The simulator converted from IMEX to START then select well to convert from producer to injector, run the model and the result as below.

4.2.2.1 Cumulative Oil

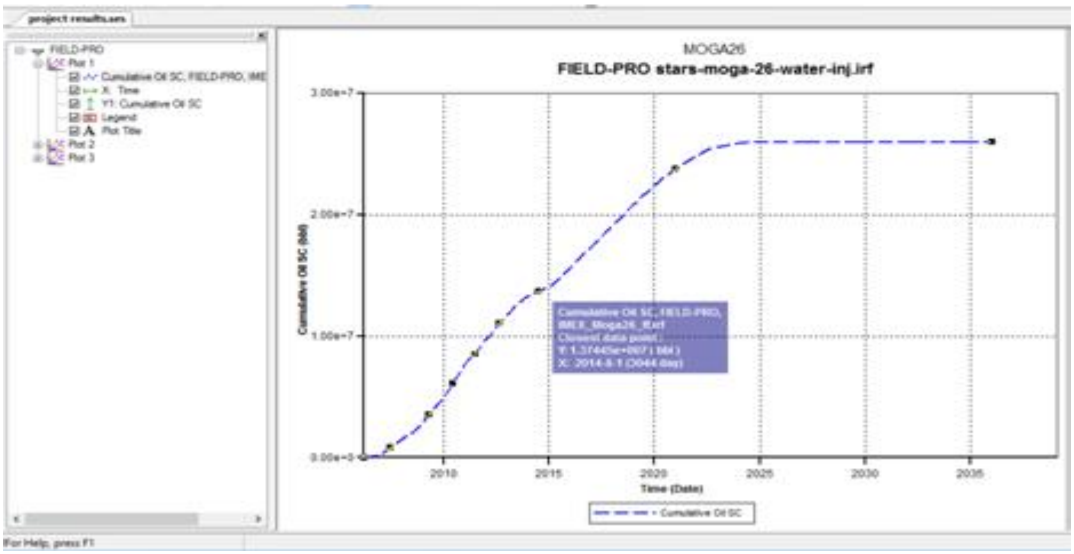

Figure (4.11): - Water Injection Case Cumulative Oil.

The cumulative oil on Jan 2015 was 137445e+007up to 259793e+007 (bbl) on 2036 and remain constant due to no production after this date.

4.2.2.2 Water injection case recovery factor calculation:

RF=NP/N

Where:

RF: Recovery Factor

NP: Cumulative oil produced, STB N: Initial (original) oil-in-place, STB

RF= 259793e+007/ (79*10^6) RF= 1.37445e+007/ (79*10^6)

The oil recovery factor on 2015 was 17.4 %, increased up to 32.9 % on 2036.

4.2.2.3 Oil Rate

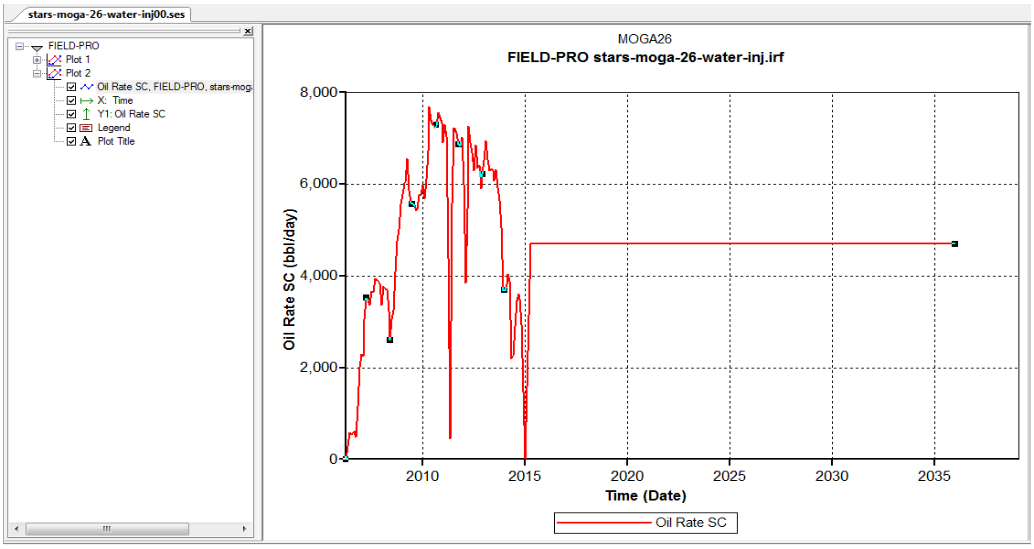

Figure (4.12): -Water Injection Case Oil Rate.

The oil rate increased and reach the maximum rate 7687.88 (bbl/d) on May-2010 and the rate decreased to 4697.8 (bbl/d) on Jan 2015 and the rate sable until Sep 2036.

4.2.2.4 Water Cut %

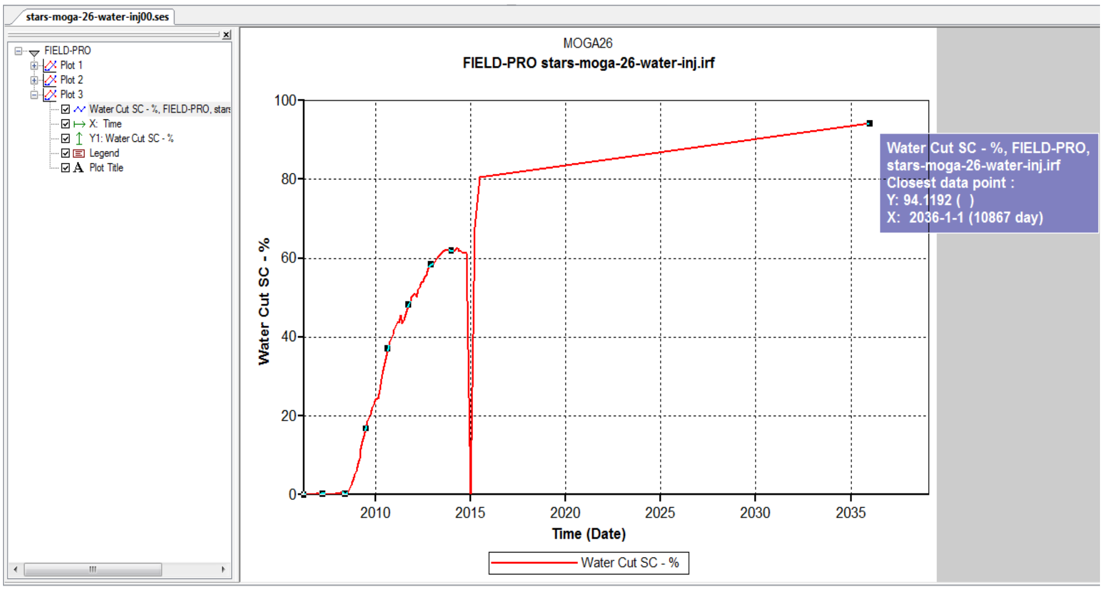

Figure (4.13): -Water Injection Case Water Cut.

The water cut increased to 67.8 % on 2015 and continuously increase to 94.1% on 2036.

Table (4.3): - Water Injection Production Data.

Water Injection Production Data				
Date	Cum Oil	Oil Rate(bbl/d)	WC %	RF
1-Jan-2015	1.37445e+007	4697.8	67.8	17.4 %
1-Jan-2036	259793e+007	4697.8	94.1	32.9 %

4.2.3 Steam Injection:

The model has been built by the same steps that used to build the water injection model but the different between the two models that the injected fluid temperature in the steam model is about (482 F) while the water injection temperature (100 F), and the steam quality is 0.75.

4.2.3.1 Cumulative Oil SC

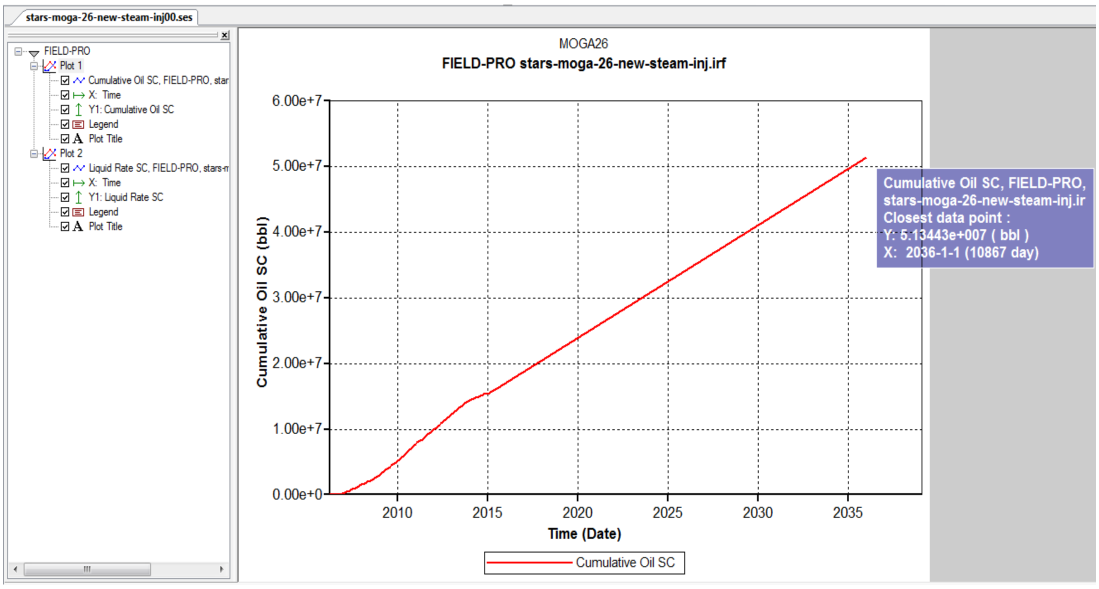

Figure (4.14): -Steam Injection Case Cumulative Oil.

The cumulative oil on Jan 2015 was 1.4697.8e+007 increased to 5.13443e +007 (bbl) on Jan 2036.

4.2.3.2 Oil Rate

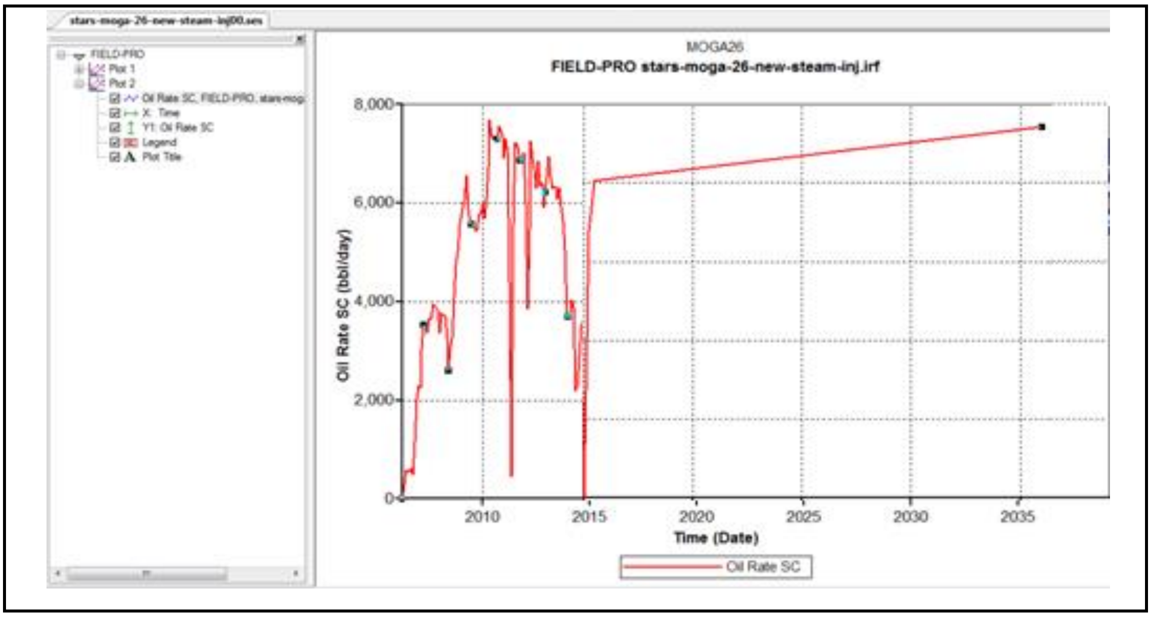

Figure (4.15): - Steam Injection Case Oil Rate.

The oil rate on Jan 2015 was 6230.8 (bbl/d) and the rate increased to 6710.2 (bbl/d) on 2036.

4.2.3.3 Water Cut %

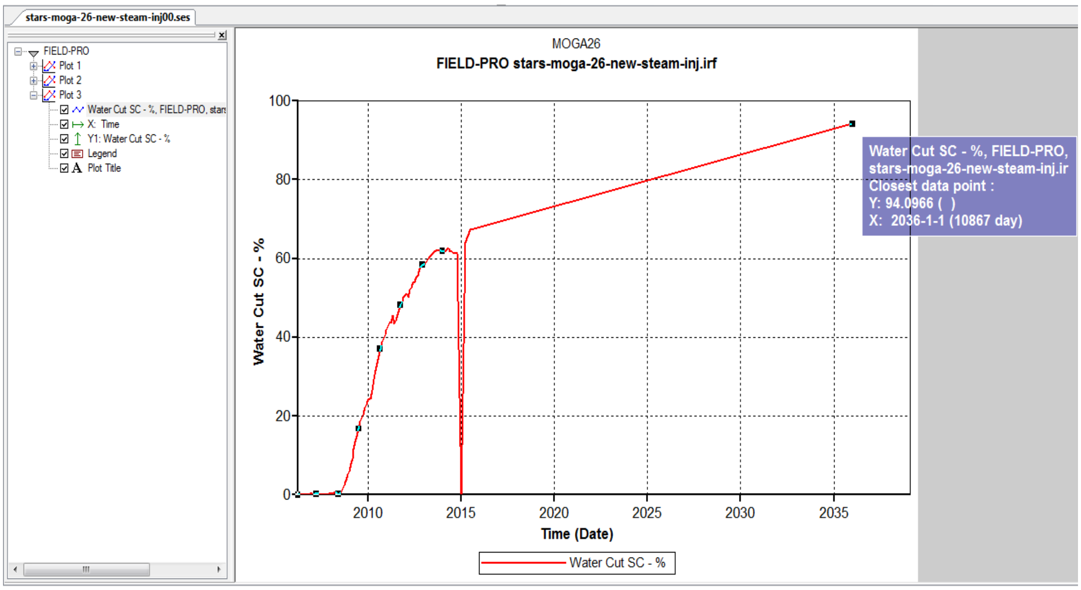

Figure (4.16): - Steam Injection Case Water Cut.

The water cut increased to 64.1 % on 2015 and continuously increase to 94.0 % on 2036.

4.2.3.4 Steam injection case recovery factor calculation:

RF=NP/N

Where:

RF: Recovery Factor

NP: Cumulative oil produced, STB N: Initial (original) oil-in-place, STB

RF= 5.13443e +007/ (79*10^6) RF= 1.46978e+007/ (79*10^6)

The oil recovery factor on 2015 was 18.6 % increased up to 65 % on 2036.

Table (4.4): - Steam Injection Production Data.

Steam Injection Production Data				
Date	Cum Oil	OIL Rate(bbl/d)	WC %	RF
1-Jan-2015	1.46978e+007	6230.8	64.1	18.6%
1-Jan-2036	5.13443e +007	6710.2	94.0	65 %

Table (4.5): - Combination Production Data.

Scenario	Date	Cum Oil (bbl)	OIL Rate(bbl/d)	WC %	RF %
DNC	1-Jan-2015	6.2154e+006	4697.8	82.556	9.5980
	1-Jan-2025	1.4562e+007	0	98	21.1667
	1-Jan-2015	1.37445e+007	4697.8	67.8	17.4
Water Injection	1-Jan-2036	2.59793e+007	4697.8	94.1	32.9
Steam Injection	1-Jan-2015	1.46978e+007	6230.8	64.1	18.6
	1-Jan-2036	5.13443e +007	6710.2	94.0	65

Chapter Five: Conclusion and Recommendations

5.1 Conclusion

1. Moga Heavy Production Performance has been reviewed and studied.
2. Dynamic model for Moga Oil Field has been build using advanced EOR simulator to understand the production performance and propose the suitable method for the field.
3. The results showed that water injection can increase the cumulative oil rate from 14.6 MMSTB to 26 MMSTB compared to DNC.
4. The final results showed that Steam Injection scenario is better and can increase the recovery factor up to 65%.

5.2 Recommendations.

1. Detail study is highly recommended for Steam Injection Parameters.
2. Economic Evaluation should be done for optimum scenario before implementation.
3. It's highly recommended to study the required injection equipment's and surface facility as well.

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