NEAR EAST UNIVERSITY

INSTITUTE OF GRADUATE STUDIES

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

ASSESSMENT OF CO_2 INJECTION BY MISCIBLE FLOODING AND WAG APPLICATION VIA HORIZONTAL AND VERTICAL WELL CONFIGURATIONS

M.Sc. THESIS

Thompson Clinton UZOR

Nicosia

September, 2022

THOMPSON CLINTON UZOR ASSESSMENT OF CO2 INJECTION BY MISCIBLE FLOODING AND WAG APPLICATION VIA HORIZONTAL AND VERTICAL WELL CONFIGURATIONS MASTER THESIS 2022

NEAR EAST UNIVERSITY

INSTITUTE OF GRADUATE STUDIES

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

ASSESSMENT OF CO_2 INJECTION BY MISCIBLE FLOODING AND WAG APPLICATION VIA HORIZONTAL AND VERTICAL WELL CONFIGURATIONS

M.Sc. THESIS

Thompson Clinton UZOR

Supervisor

Prof. Dr. Cavit ATALAR

Nicosia

September, 2022

Approval

We certify that we have read the thesis submitted by Thompson Clinton UZOR, titled "**Assessment of CO_2 Injection by Miscible Flooding and WAG Application Via Horizontal and Vertical Well Configurations**" and that in combined opinion it is fully adequate, in scope and in quality, as a thesis for the degree of Master of Applied Sciences.

Examining Committee	Name-Surname	Signature
Head of the Committee:	Prof. Dr. Salih SANER	....
Committee Member:	Assoc. Prof. Dr. Huseyin CAMUR	....
Supervisor:	Prof. Dr. Cavit ATALAR	....

Approved by the Head of the Department

13/09/2022

....

Prof. Dr Cavit ATALAR

Head of Department

Approved by the Institute of Graduate Studies

13/09/2022

Prof. Dr. Kemal Hüsnü Can Başer

Head of the Institute

Declaration

I hereby declare that all information, documents, analysis and results in this thesis have been collected and presented according to the academic rules and ethical guidelines of the Institute of Graduate Studies, Near East University. I also declare that as required by these rules and conduct, I have fully cited and referenced information and data that are not original to this study.

Thompson Clinton UZOR

13/09/2022

Acknowledgments

It is always to my pleasure to convey my sincere respect and acknowledgement to my supervisor, Prof. Dr. Cavit Atalar for his immense, and relentless support, and advice, his simulating suggestions and encouragement helped me in all time of fabrication process. I'm so grateful for all his guidance and follow-ups, the time spent proofreading and correcting my mistakes. I would also like to appreciate Prof. Dr. Salih Saner, Assoc. Prof. Dr. Serhat Canbolat, Msc. Palang Moronke Guful, Assoc. Prof. Dr. Huseyin Camur and Dr. Yashar Osgouei for their knowledge and advice imparted.

I am overwhelmed in all humbleness and gratefulness to acknowledge my depth to Msc. Palang Moronke Guful who have played a crucial role to help me put these ideas well above the level of simplicity and into something concrete.

My completion of this project could not have been accomplished without the astounding support of my friends and classmates. I'm immensely obliged to Nwanja James Ikechukwu and Olisa Leonard for their elevating inspiration, valuable conscientious guidance, aspiring motivation, encouragement, invaluably constructive criticism, friendly advice and kind supervision through the course of this endeavour which shaped the work as it shows. Thank you for your truthful illuminating insight.

My heartfelt thanks to my caring, loving and supportive girlfriend Jamestina Humu Kanu: my deepest gratitude. Your encouragement when time got rough are much appreciated and duly noted.

Lastly, I extend my warmth and ineffable gratitude to acknowledge and offer my deepest sense of reverence to my family. Nobody has been more important to me in this pursuit than they have been in always supporting me morally, giving encouragements, enthusiasm, invaluable assistance, endless motivation, prayers, advice, and the fact that without their efforts, I wouldn't accomplish this study.

Thompson Clinton UZOR

Abstract

Assessment of CO_2 Injection by Miscible Flooding and WAG Application Via Horizontal and Vertical Well Configurations

UZOR, Thompson Clinton

Msc, Department of Petroleum and Natural Gas Engineering

August, 2022, 79 pages

CO_2 EOR is one of the most effective methods for enhancing oil recovery because of its high capability in oil recovery. Miscible CO_2 interacts with the oil to produce a miscible slug that can lead to viscous fingering, thereby compromising the macroscopic sweep efficiency of the process. Therefore, the need to increase the macroscopic and microscopic sweep efficiency is required that brings about the introduction of the water alternating gas (WAG) process to stabilize the gas mobility, maintain the reduced oil viscosity and reduces the residual oil saturation.

The area of study used for this project is the shallower Asmari field with Oligocene and Miocene ages, located in southwest of Iran. This study is conducted to compare the process of miscible CO_2 and WAG flooding using horizontal and vertical well configuration for a period of 6 years. A commercial simulator (CMG STAR 2015.10) was used to create a model, which was used for the methodology of this research. The simulated results showed that for the miscible CO_2 flooding, the all-horizontal producer well configuration gave a better results of oil recovery and cumulative oil production, while for the WAG flooding, the scenario with 3 months CO_2 injection, 5 year water injection for the 2-horizontal 2-vertical producer well configurations, gave the best results with oil recovery factor of 53.9% and cumulative oil production of 1.52 MMm^3 when compared to other WAG scenarios and the miscible CO_2 scenarios.

***Keywords**:* Water alternating gas (WAG), miscible CO_2, sweep efficiency, well configuration.

Özet

Yatay ve Dikey Kuyu Konfigürasyonları Üzerinden Misibil Öteleme ve WAG Uygulaması ile CO_2 Enjeksiyonunun Değerlendirilmesi

UZOR, Thompson Clinton

Yüksek Lisans, Petrol ve Doğal Gaz Mühendisliği Bölümü

Ağustos, 2022, 79 sayfa

CO_2 EOR, petrol geri kazanımındaki yüksek kapasitesi nedeniyle petrol geri kazanımını artırmanın en etkili yöntemlerinden biridir. Misibil CO_2, viskoz parmak oluşumuna yol açabilen ve böylece işlemin makroskopik süpürme verimliliğinden ödün veren misibil bir sümüklü böcek üretmek için yağ ile etkileşime girer. Bu nedenle, gaz hareketliliğini stabilize etmek, azaltılmış petrol viskozitesini korumak ve artık petrol doygunluğunu azaltmak için su alternatifli gaz (WAG) işleminin başlatılmasını sağlayan makroskopik ve mikroskobik süpürme verimliliğini artırma ihtiyacı gereklidir.

Bu proje için kullanılan çalışma alanı, İran'ın güneybatısında yer alan Oligosen ve Miyosen yaşlarına sahip daha sığ Asmari sahasıdır. Bu çalışma, 6 yıllık bir süre boyunca yatay ve dikey kuyu konfigürasyonu kullanılarak karışabilir CO_2 ve WAG taşma sürecini karşılaştırmak için yapılmıştır. Bu araştırmanın metodolojisi için kullanılan bir model oluşturmak için ticari bir simülatör (CMG STAR 2015.10) kullanılmıştır. Simüle edilen sonuçlar, karışabilir CO_2 taşması için tüm yatay üretici kuyusu konfigürasyonunun petrol geri kazanımı ve kümülatif petrol üretimi için daha iyi sonuçlar verdiğini, WAG taşması için ise 3 Ay CO_2 Enjeksiyonu, 5 Yıllık Su Enjeksiyonu senaryosunun daha iyi sonuçlar verdiğini göstermiştir. 2-yatay 2-dikey üretici kuyusu Konfigürasyonları, diğer WAG senaryoları ve karışabilir CO_2 senaryoları ile karşılaştırıldığında %53,9 petrol geri kazanım faktörü ve 1,52 MMm3 kümülatif petrol üretimi ile en iyi sonuçları vermiştir.

Anahtar Kelimeler: Su alternatifli gaz (WAG), misibil CO_2, süpürme verimliliği, kuyu konfigürasyonu.

Table of Contents

CHAPTER III

CHAPTER IV

CHAPTER V

List of Tables

List of Figures

List of Abbreviations

ADNOC: Abu Dhabi National Oil Company

Bg: Gas formation Volume Factor

Bo: Oil Formation Volume Factor

CMG: Computer Modelling Group

CO_2: Carbon dioxide Gas

CWI: Carbonated Water Injection

CWOR: Cumulative Water Oil Ratio

DGOC: Gas-Oil Contact Depth

DOE: Department of Energy

Ea: Area Sweep Efficiency

Ed: Microscopic Displacement Efficiency

EOR: Enhanced Oil Recovery

GOC: Water Oil Contact

GOR: Gas Oil Ratio

IFT: Interfacial Tension

K_{ro}: Oil Relative Permeability

K_{rog}: Gas relative permeability

K_{row}: Water relative permeability

MMP: Minimum Miscible Pressure

MRF: Mobility Reduction Factor

N_2: Nitrogen Gas

nWAG: Nanofluid Water Alternating Gas

OOIP: Original Oil in Place

P_c: Capillary Pressure

POVO:	Pore Volume
PVT:	Pressure-Volume Temperature
RF:	Recovery Factor
SAG:	Surfactant Alternating Gas
SCTR:	Sector
Sl:	Liquid Saturation
S_{oi}:	Initial Oil Saturation
S_o:	Oil Saturation
S_{or}:	Residual Oil Saturation
STW:	Surface Water Rate
S_{wr}:	Residual Water Saturation
ULR:	Unconventional Liquid Rich
WAG:	Water Alternating Gas
WOC:	Water Oil Contact

CHAPTER I

Introduction

CO_2 process of enhanced oil recovery is one of the significant methods of oil recovery used worldwide due to its capability of high oil recovery. For miscible flooding, CO_2 mixes with the oil to produce a miscible slug that is less viscous than the initial reservoir oil, and this can result to viscous fingering, which reduces the effectiveness of the macroscopic sweep efficiency of the process. The general method used to enhance the macroscopic sweep efficiency in miscible CO_2 EOR is the water alternating gas (WAG). The Water Alternating Gas (WAG) process is a cyclic process of injecting gas alternatively (for this project CO_2 gas is utilized), alongside water injection, and then repeating this process for different periods.

WAG flooding is required mainly to enhance oil recovery and cumulative oil production, by so doing improving the process of both macroscopic and microscopic sweep efficiency, stabilizing the pressure of the reservoir, reduce the gas mobility, improving the viscosity reduction which occurred as a result of the gas mixture with oil, and reduce the residual oil saturation and effects of the relative permeability hysteresis.

WAG also undergo limitations based on the properties used for the reservoir and the characteristics of the reservoir fluids. In formation with increased water wet which can lead to water blockage causes reduction in oil recovery considerably, most especially in situation with increased water saturations. Therefore, enough CO_2 will not be contacted with oil in lower permeable region due to reduction in capillary pressure. It is however advised that in water wet regions, reduced WAG ratios compared to CO_2 or just continuous CO_2 injections are required.

Problem of Study

CO_2 and water alternating gas (WAG) injection are widely used for enhanced oil recovery processes. However, WAG injection proves to be more efficient method than gas flooding and water flooding for oil recovery and cumulative oil production. To check for the economic evaluation, gas injection like CO_2, N_2 or hydrocarbon gases are expensive operations due to the expense of the gases. Therefore, the implementation of WAG is a preferred method due to the amount of gas injected in the WAG flooding is small compared to the amount of gas injected in continuous gas injection. CO_2 and WAG has been tested and used in a deep and shallow reservoir, onshore, offshore and in different stratigraphy. This study is focused on process of miscible CO_2 and WAG flooding using both vertical and horizontal well configuration.

The study area for this project is located in the southwest of Iran, the said oil field consist of two reservoirs, which are: Gurpi and a shallower Asmari reservoir. The main reservoir used for this project is the Asmari formation with Oligocene and Miocene ages as seen in Figure 1.1. This field being the main focus for the project because it has been a target for high production of oil for commercial consumption. (Fath and Pouranfard, 2014).

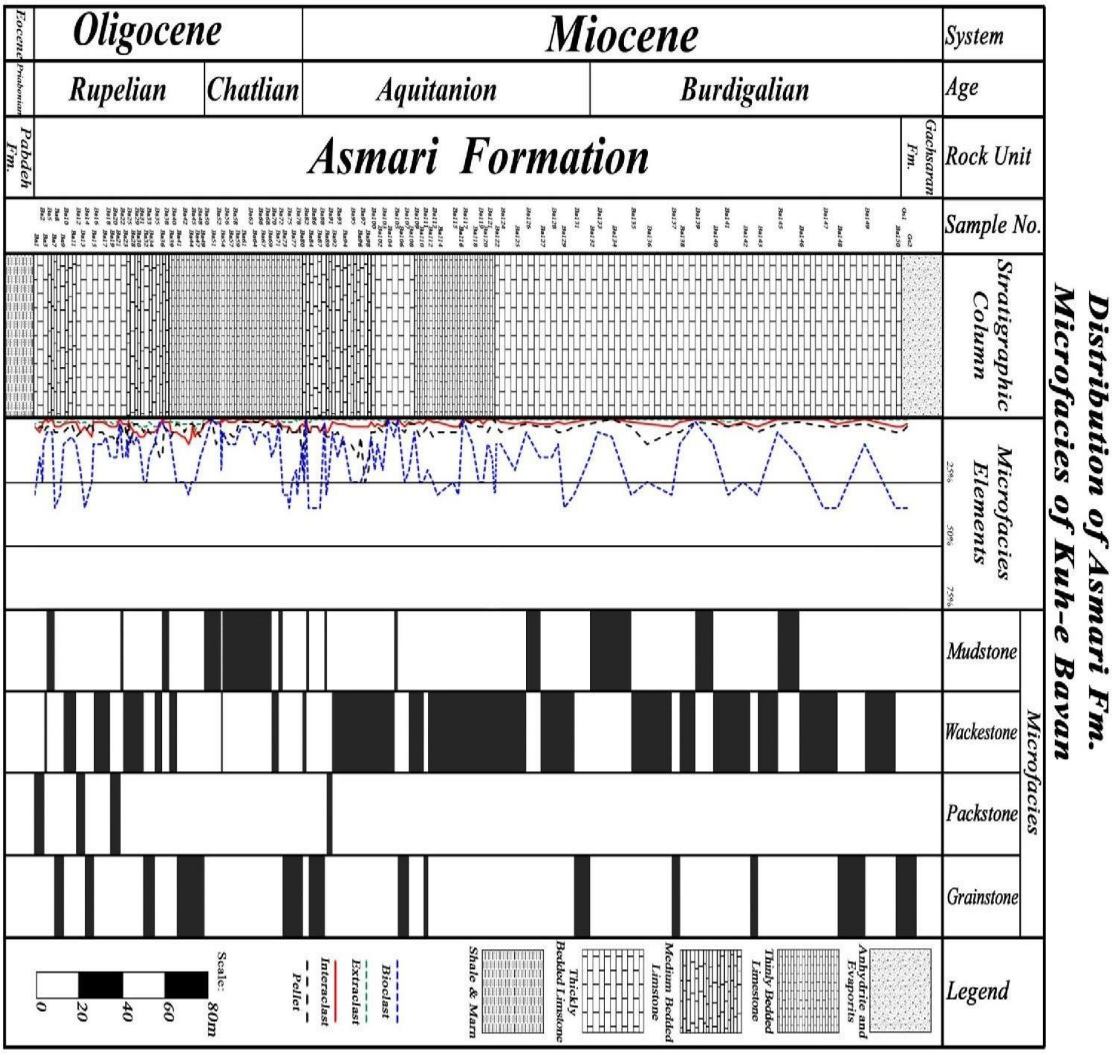


Figure 1.1. *Distribution of Asmari Formation (Fath and Pouranfard, 2014)*

Aim of the Study

The goal of this study is to investigate miscible CO_2 flooding alongside WAG flooding in optimizing the recovery of an oil field using horizontal and vertical well configurations. The main purpose of this project is to check for the flowing achievements:

- How much of field oil efficiency can be attained within 6 years of simulation for both the miscible CO_2 injection and WAG flooding.
- To investigate the amount of cumulative oil production accrued for both scenarios
- To check the cumulative water oil ratio for the WAG flooding scenarios to check which one have minimum usage of water.

Scope of Study

This scope of this study is to check for possible improvement of oil recovery and cumulative oil production using miscible CO_2 injection and WAG flooding, utilizing reservoir properties drafted from the shallower Asmari field that will be used for the reservoir simulation. Through these simulations it is possible to utilize different scenarios with different well configurations and injection period to enhance oilrecovery and cumulative oil production until the best result is met.

Limitation of the Study

The study is only limited to extensive literature research. The reservoir data used for the methodology were all gotten from literature, no laboratory experiment was conducted for this project. It implies therefore, that any variable or data used which have not been published publicly will only have to be estimated realistically to obtain the desired results.

Overview of Study

The following guidelines have been stated below to briefly discuss how this project was carried out:

Chapter 1 is the introductory section that talks about the background of the study, the statement of problem and the importance of the study, the aim and scope of the study which talks about the project focus and what to be achieved, and the limitation of the study was briefly stated.

Chapter 2 includes literature review. A detailed literature study has been discussed in this chapter, which involves subjects related to this project, overview of CO_2 flooding and WAG flooding comparison.

Chapter 3 describes the methodology applied for this study. In this chapter, all the procedures involved to complete this project are discussed and mentioned in detail, starting from the creation and description of the reservoir, component listing of the reservoir, the reservoir rock and fluid data, and the creation of wells with its constraint. Lastly, all the scenarios used for the project were simulated for possible results.

Chapter 4 shows all the results and discussion obtained in this study. The simulation results are all shown and analysed in this chapter.

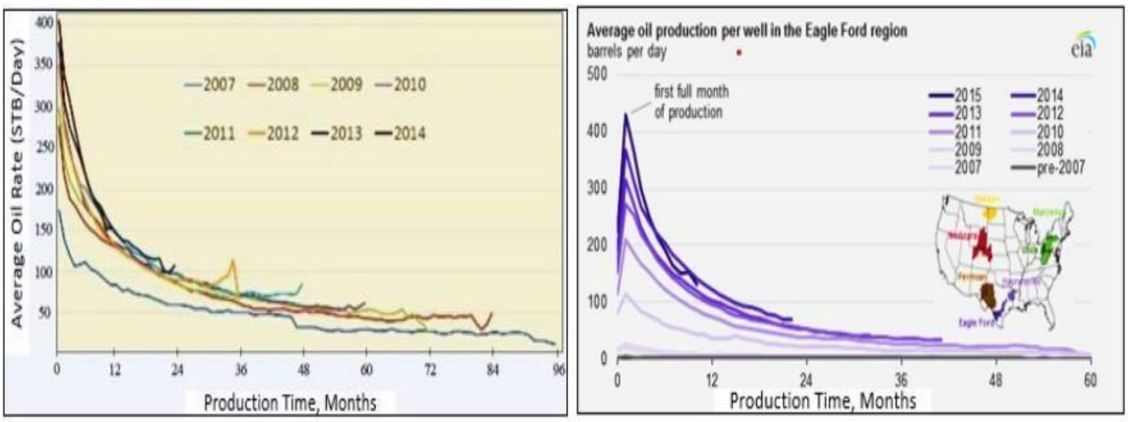
Chapter 5 analyses the conclusions and recommendations. In this chapter, the conclusive remarks are listed in addition to some recommendations for further study.

CHAPTER II
Literature Review

Unconventional Oil Reservoirs

Unconventional reservoir is rich in hydrocarbon for that reason it has been the main target over two decades for oil production and the investment so far has been successful due to high recovery and production of oil. In America, Tight formations like shale have contributed to about 50% in terms of producing oil (Alfarge et al., 2017). Hoffman et al. (2016) confirmed that in the US, about 4 million bbl./day of oil production are gotten from unconventional oil reservoirs. Unconventional LiquidRich (ULR) reservoirs has impacted immensely to all-natural gas increment between the period of 2011 to 2014, and almost 91% to about 93% improvement of oil production in the US (Alfarge et al., 2017).

However, maintaining the hydrocarbon production rate is the principal issue on how to improve the unconventional reservoirs, and this factor can result in a low oil recovery factor. Figure 2.1 explains the trend in these complicated reservoirs for oil production. The producing wells normally begin with excessive production rate; after which a steady decline was shown for the initial 3-5 years periods to the extent of getting levelled up at a very reduced production rate of oil. Yu et al. (2014), concluded that the actual reason for the vast decline is because of the sudden depleted natural fractures phases with low boost from the matrix system, being the most important hydrocarbon source.



A-Bakken Play **B-Eagle Ford Play**

Figure 2.1. *Oil Production Per Well for Unconventional Reservoirs (Alvarez et al., 2016)*

CO_2 Application in Unconventional (Shale) Reservoir

Shale oil reservoir is one of the unconventional reservoirs used for gas technique, it's mostly located in Northern part of America and has been widely applied for the past 10 years. These gases include CO_2, N_2, and some hydrocarbon gases. Most of the researches however, focused more on CO_2 because of its special capabilities. CO_2 easily dissolves in shale oil effortlessly, causes swell of the oil, and reduces the oil viscosity. CO_2 performance in lab experiments have shown great increment in oil recovery from reservoir that contains shale as shown in Figure 2.2. The minimum miscible pressure of CO_2 in these kinds of oil thus has a contented variety between 2400 psi to 3200 psi. Furthermore, it's been mentioned that the oil of those reservoirs has a very reduced acid variety which shows the desire of using CO_2 injection correctly and not having issues of precipitation caused by asphaltenes (Kurtoglu et al., 2014). Most experimental researches has proven that the molecular-diffusion mechanism by CO_2 is beyond the improvement of oil recovery achieved from practical-experiment (Alfarge et al., 2017).

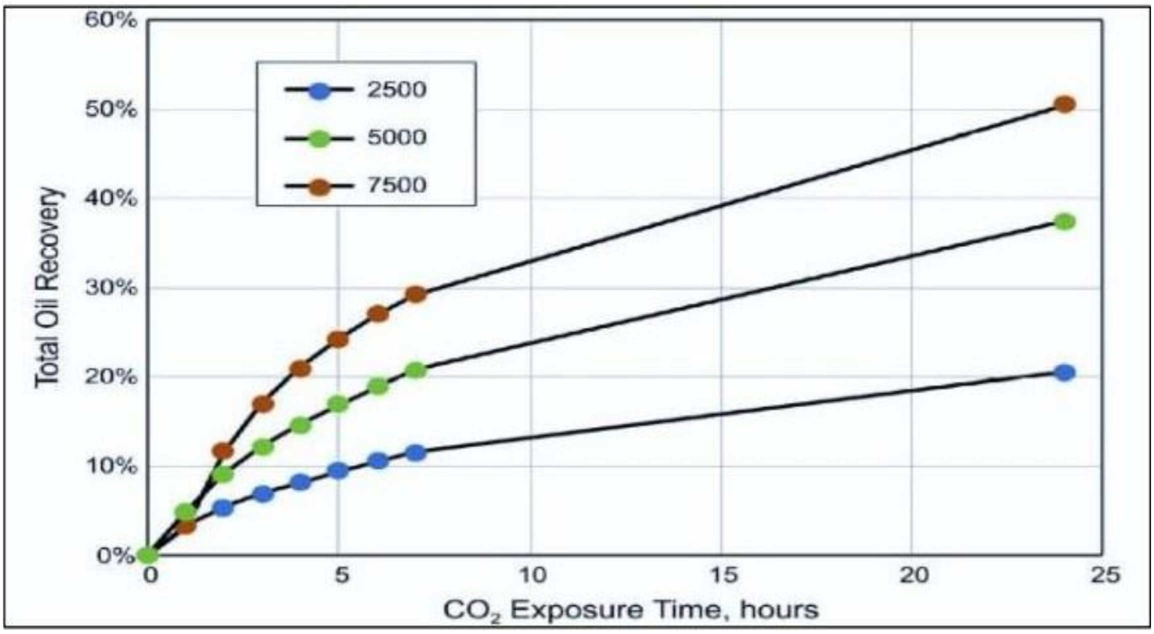


Figure 2.2. *Sample for How Much Oil Recovered Through Natural Cores by CO_2 in Lab Conditions (Hawthorne et al., 2017)*

Background Studies of CO_2 Flooding

Song et al. (2013) carried out practical research in cores from Bakken reservoir to examine the effects of injection of CO_2 alongside water. They were able to show that water flooding recovered more oil than immiscible CO_2 during the Huff-n-Puff process.

Miscible CO_2 for same Huff-n-Puff process however, showed better result than water flooding in improving oil recovery. Hawthorne et al. (2013) illustrated beyond the simple mechanism of improving oil recovery by CO_2 injection in Bakken cores. It was concluded that for complicated media, the diffusion mechanism is the best mechanism for CO_2 to improve oil recovery. However, for shale matrix by CO_2, recovering of oil requires enough period of time for exposure with huge contact area. Gamadi et al. (2014) used shale cores from Mancos and Eagle Ford reservoir to check the capability of CO_2 injection when injected into these reservoirs. The results gotten proved that CO_2 injection in cyclic process recovered more oil from shale oil cores between 34% till like 80% though according to the type of shale and their parameters used for the operation. Alharthy et al. (2015) were able to analyze and differentiate the different kinds of gas injection effects such CO_2, C1-C2 mixtures, and N2, on improving the recovery of oil using Bakken cores experimentally. It was also concluded that the injection of C1, C2, C3, and C4, can as well produce almost the same as CO_2 injection may produce, and that is around 90% from numerous Middle Bakken cores and almost 40% from Lower Bakken cores. It was also concluded that for the gases mentioned above to get better oil from shale cores, the counter- current mechanism should be the primary mechanism. In conclusion, CO_2 has shown a very high strength in recovering oil from shale cores during experimental processes (Jin et al.,2016).

Introducing CO_2 and Water Alternating Gas (WAG) as a Methods of Enhancing Oil Recovery

Waterflooding process of oil recovery shortcomings call for tertiary method also known as enhanced oil recovery. Among the techniques normally used in the United States is the miscible CO_2 EOR. The first exceptional commercial-scale CO_2 EOR flood was the SACROC project in Permian Basin, West Texas. As can be seen in Figure 2.3, the unfactored production rate of oil within the SACROC project dramatically expanded by means of a couple of instances after the CO_2 injection began in June 1981. SACROC assignment is still very a hit in both technical and monetary considerations. As of 2014, the United States oil industry was injecting 3.5 BCF/D of CO_2 from natural and industrial assets to help produce 300,000 BOPD of oil from 136 CO_2 EOR projects, wherein carbonate reservoir projects account for more than half. CO_2 flooding has been notably confirmed as an EOR technology and a totally effective procedure for redeveloping positive mature fields with an average incremental of 5% to 15% of Original Oil in Place (OOIP), depending on the reservoir properties and waterflood efficiency in terms of recovery (Duchenne et al.,2014).

Injecting CO_2 with alternating water injection takes advantages of both the CO_2 and water injection processes. The injected CO_2 mainly decreases the oil viscosity while water pushes the mobilized oil vastly to the production well.

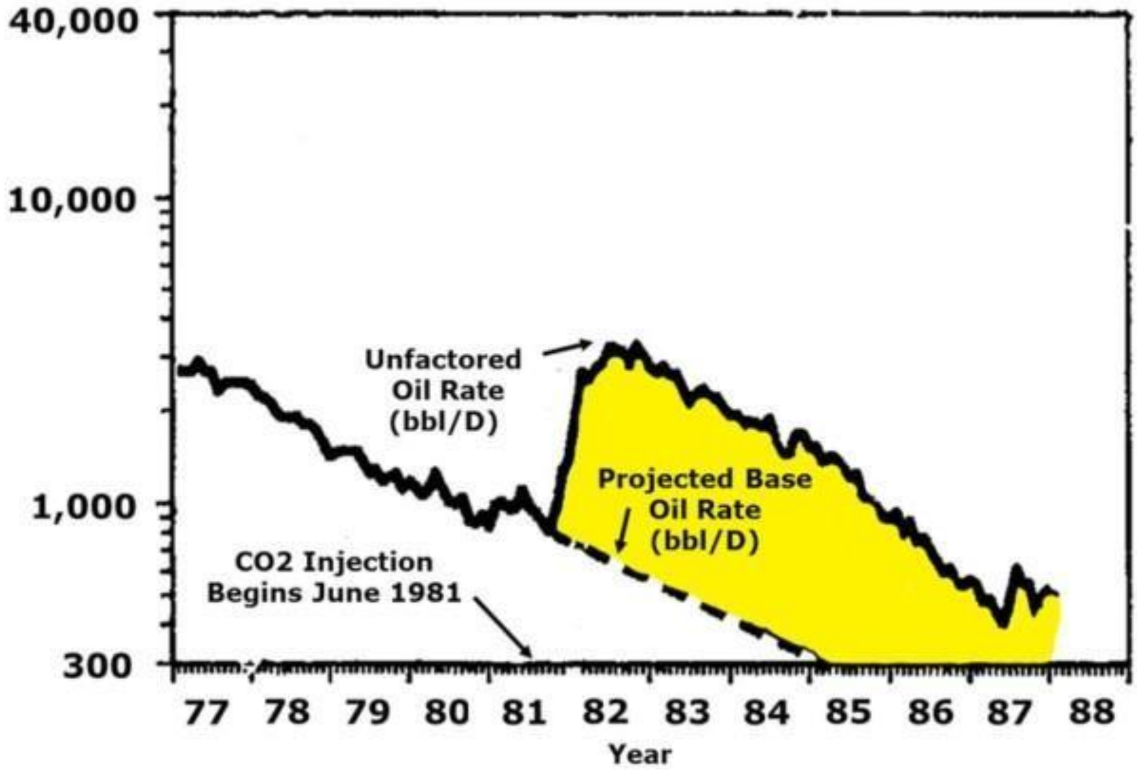


Figure 2.3. *CO_2 injection significantly enhanced oil recovery in SACROC project (Langston,1988)*

Specifically, it is obvious that when gases are injected into the reservoir they tend to act as a non-wetting phase and due to its increased mobility when compared with the oil, it further penetrates in low flow resistant regions and displaces the oil piston-like. However, gas does not displace the whole region, rather it just pass-through high permeability zones. Immediately water is injected alternatively after the CO_2 slug, its mobility is reduced. This happens due to the injected CO_2 as the non-wetting phase occupies the larger pores inside the porous media. The pressure of the water entry into these pores is increased and finally, the injected water is forced to the lower permeability regions. Consequently, the injected water displaces the remaining oil after compressing the CO_2 inside the pores in front of the water slug. Water can also be added to CO_2 and injected as carbonated water. Therefore, CO_2 in this case is more evenly distributed within the reservoir and also lead to CO_2 breakthrough time and an increased sweep efficiency (Derakhshanfar et al., 2012).

Optimizing Miscible CO_2 Injection and WAG Flooding in Carbonate Reservoirs

In recent years, there's been a huge push for anthropogenic CO_2 capture to lessen greenhouse gas emissions. Petro Nova US Department of Energy (DOE) completed the most important carbon capture system project in Texas in 2017. Captured CO_2, purified from the post-combustion flue gas from a coal-fueled energy plant, is used for CO_2 EOR within the West Ranch oil field. Outside of the United States, Saudi Aramco has completed a CO_2 EOR analysis project with 4 producing wells and 4 injection wells inside the Uthmaniyah field. Abu Dhabi National Oil Company (ADNOC) plans to extends its carbon seize program to provide anthropogenic CO_2 sources in maturing oilfields to improve oil recovery rates.

The CO_2-enhanced oil recovery mechanisms have been notably discussed with evidence from related research documents, and its advantages in the reservoir includes oil swelling, reduction in oil viscosity, lowering interfacial tensions, and reducing oil and water density variations. CO_2 displacement can occur via immiscible drive, solution gas drive, first or multiple contact miscible drive methods. This dense or supercritical CO_2 has a feature of high density and viscosity in comparison to other gases, which makes the displacement front greater solid through mitigating gravity segregation and viscous fingering to some degree at some stage in gas injection EOR. Importantly, the pressure calculated for minimum miscibility (MMP) for CO_2 with a given reservoir oil is lower in comparison to light hydrocarbon and N_2injection gases (Johns et al., 2013). If the injected CO_2 meets the miscibility conditions, by creating a miscible flood with the reservoir fluids then the interfacial tension becomes negligible and there's no oil trapped by means of capillary forces. This implies that the remaining oil saturation based on the CO_2 injection may be preferably reduced down to almost zero at some point of miscible CO_2 flooding, increasing the amount of oil recoverable. From an environmental perspective, CO_2 injection permits the geological sequestration of greenhouse gas, specially while the CO_2 utilized is from industrial sources.

Carbonated water injection (CWI), also known as an engineered water-based EOR, is an alternative method of CO_2 EOR. CWI procedure is particularly suitable for certain places wherein there's constrained access to CO_2 resources or offshore fields wherein building recycling facilities producing CO_2or gas injection might be difficult (Mahdavi, 2017). Two crucial features differentiate Carbonated water injection from immiscible or miscible CO_2 flooding. First, the quantity of CO_2 used in carbonated water flooding should not surpassed what is expected to dissolve within the injected water under the conditions of reservoir pressure and temperature. Therefore, there should be no much presence of CO_2 within the reservoir as soon as the flooding starts. Secondly, transfer of mass dominates the process of CO_2 moving among two immiscible phases that consist of water and oil. Therefore, the displacement efficiency of CWI is not well defined by means of minimum miscibility pressure, consequently the improvement of a transition zone is not required of CWI.

The WAG injection has been subjected perfectly to improve the performance of gas injection for sweep efficiency. This is done in particular through the use of the water to control the movement of the displacement phase caused by the gas presence and by so doing stabilizing the process. The WAG injection process combines the effect of gas displacement performance during the gas injection with an upgraded macroscopic sweep by water injection. Despite the improved results of injecting water and gas alternatively, the reduction of oil-gas contact around water decreases the effectiveness of WAG (Mahdavi et al., 2000). Several research have also reviewedthe issues related to a WAG injection process and discussed that the major problem is the water-blockading phenomenon. The water separates the residual oil from coming in contact with the gas. Sometimes inside the reservoir, the produced gas is reinjected into the reservoir or gasoline cap region after gasoline production in the course of the waterflood degree. Gas re-injection is a pressure maintenance program that is employed in a reservoir at the beginning of the production process. Otherwise,introduced after production has commenced. In the field of interest, gas is infused into the gas cap of the reservoir formation to guide the reservoir pressure, thereby increasing the production rate. During the initial gas saturation involvement, there may be a need to analyze the impact of initial gas saturation on CO_2 EOR performance.

Comparison of Reservoir Operation of CO_2 in Different Scenarios at Their Optimum Injection Rates

To investigate immiscible and miscible CO_2 injection with a single porosity system for field oil recovery improvement, which was initiated between south-west of Iran. This particular oil field consist of two reservoirs namely, Gurpi and shallower Asmari reservoir. The actual reservoir used for this field is the Asmari formation (being the only formation producing at larger commercial scale) with Oligocene and Miocene ages which carries seven different zones. The Asmari formation is mainly carbonated production reservoir that is naturally fractured with a porosity 0.089% and a permeability of about and 3.5 md.

At the end of the simulation, the results showed that the natural depletion scenario has average pressure pore volume per sector of 1842 psia while the immiscible CO_2 injection scenario and miscible CO_2 injection scenario are valued at 3054 psia and 5098 psia. Therefore, it is confirmed that the most improved scenario for this reservoir is the miscible CO_2 flooding as a result of its effect in increasing the reservoir pressure as compared to the reduced pressure in immiscible CO_2 injection scenario and the natural depletion scenario. Oil recovery factor (field oil efficiency) has 15.08% of OOIP in the natural depletion scenario, while the immiscible CO_2 with 17,000 Mscf/day injection rate gave an oil recovery factor of 34.48% of OOIP and miscible CO_2 injection (being the best scenario) scenario with an injection rate 30,000 Mscf/day has 36.65% of OOIP.

Comparison of CO_2 and WAG with Nanofluid

The simulation study carried out for this process involves a light oil with increased API gravity (40 °API) from a Neuquén Basin reservoir. The analysis here is to check the different injection scenarios. The use of CO_2 nanofluid, with a backed-up CO_2 and water alternating gas (WAG) injection, gives significant technical improvement. Gas usage problems can be corrected with the aid of the implementing nanofluids with water. The use of WAG flooding alongside CO_2 injection for oil efficiencies are related to continuous CO_2 injection but with expensive operational tools prices for the continuous CO_2 injection. Gas production is low during the utilization of CO_2 based nanofluid and water. The nWAG mixture suggests an outstanding gas control capacity, similar to only CO_2 injection, however with substantially reduced cost.

CHAPTER III
Methodology

This project was done using the numerical simulation modelling method and the particular type used was CMG-STARS software, which is a thermal compositional reservoir simulator, also used for advanced simulation CO_2 and WAG flooding which is a case study for this project. This chapter describes the reservoir description process, the definition of reservoir components, the rock fluid analysis, the fluid contact and initialization, numerical placement, and the creation and completion of the production and injection well, which was used to validate the different scenario processes involved in miscible CO_2 and WAG processes for oil recovery and production.

Reservoir Description

The model was created and run with CMG-STARS 2015.10, for total of 6 years from the 1st of January, 2010 to the 31st of December, 2015. The reservoir fluid is a heavy oil with API gravity of 20.93 °API, and a GOR of 480 Scf/Stb. The reservoir has a pressure 15,500 kPa and temperature of 55.7 ^{o}C. Four producer wells and two injection wells were used for the model. The producer has a producing BHP of 13,000 kPa while the injectors have a maximum BHP of 35,000 kPa for the CO_2 injector and 30,000 kPa for the water injector. The producer wells have a maximum surface oil production rate of 85,000 M^3/day, while the CO_2 injectors have a maximum surface gas injection rate of 850,000 m^3/day and the water injector is 750 Km^3/day. The other reservoir properties used for the simulation model are shown in Table 3.1. To determine the Miscible CO_2, MMP was calculated using the multiple-mixing cell method over a temperature range of 49–82 °C. The predicted MMP at 82 C is 18,900 kPa for CO_2.

The reservoir was created with a cartesian grid type of 25×25×5 Layers with a total grid cell of 3,125. The hydrocarbon-bearing reservoir covers an area of the reservoir has an area of 500m x 500m, the reservoir width was calculated to get the I-block width J-block width for both the I and J directions of the reservoir.

The reservoir was then populated with the petrophysical properties, the reservoir Array properties were defined, and these include the depth to the top of the reservoir of 1073m, a grid thickness of 30m, porosity of 10%, horizontal permeabilities (I and j permeabilities) of 200 md, vertical permeability of 150 md and also a pressure of 24,500 kPa and temperature of 55.7 ^{o}C was given to create a 3D model of the reservoir simulation showing all cells both horizontal and vertical layers as shown in Figure 1. Each colour represents a different layer and depth. Within the reservoir, the two injection wells are centred in the same spot of the reservoir while the four producer wells are positioned at the four flank corners of the reservoir. All the wells were perforated within a range of grid blocks between layers one to five as shown in Figure 3.1.

Table 3.1.

Reservoir Data Used for the Model (Kamashev, 2021)

Properties (Units)	**Values**
Reservoir Area (m^2)	250,000
Reservoir Thickness (m)	30
Vertical Permeability (md)	150
Horizontal Permeability (md)	200
Porosity (%)	10
Reservoir Temperature (^{o}C)	55.7
Reservoir Pressure (kPa)	15500
Reference Depth (m)	1073
API Gravity (^{o}API)	20.93
Water Density (kg/m^3)	997
Oil Saturation (%)	75
Oil Production Rate (m^3/Day)	85000
Minimum Miscible Pressure (kPa)	18900
Gas Injection (m^3/Day)	850000

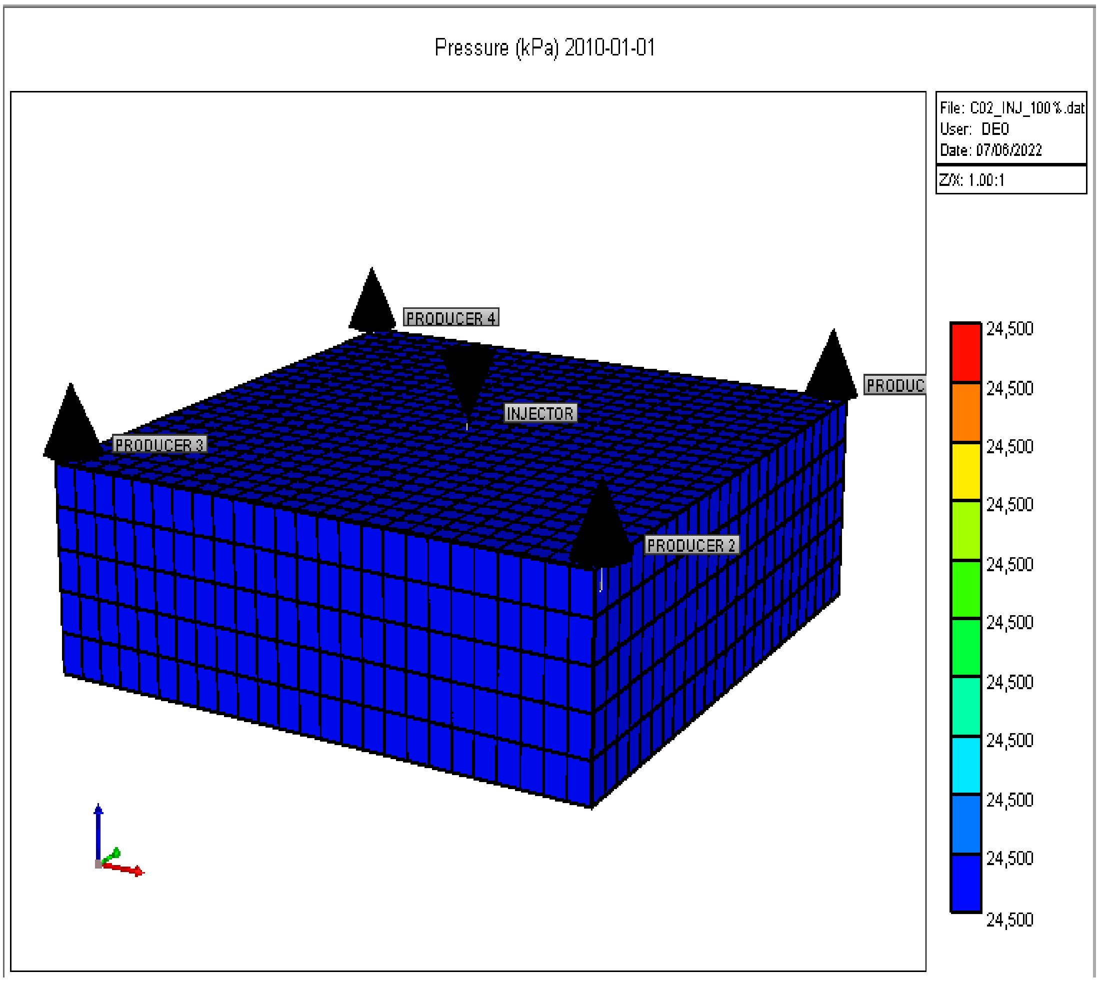


Figure 3.1. *3D Reservoir Model (generated by CMG Builder, 2015)*

Component of the Reservoir

Three components of the reservoir such as CO2, water, and dead oil were defined to create the pressure, volume, and temperature system. Each of the component has their critical pressure, critical temperature and molecular weight values, density of water and 800 g/m^3 density of dead oil was also defined, with their viscosity. The PVT properties of the reservoir such as solution gas-oil ratio, formation volume factor, and viscosity were all defined for the aqueous, oil, and gas phase. Figure 3.2 as seen below, indicates the oil formation volume factor.

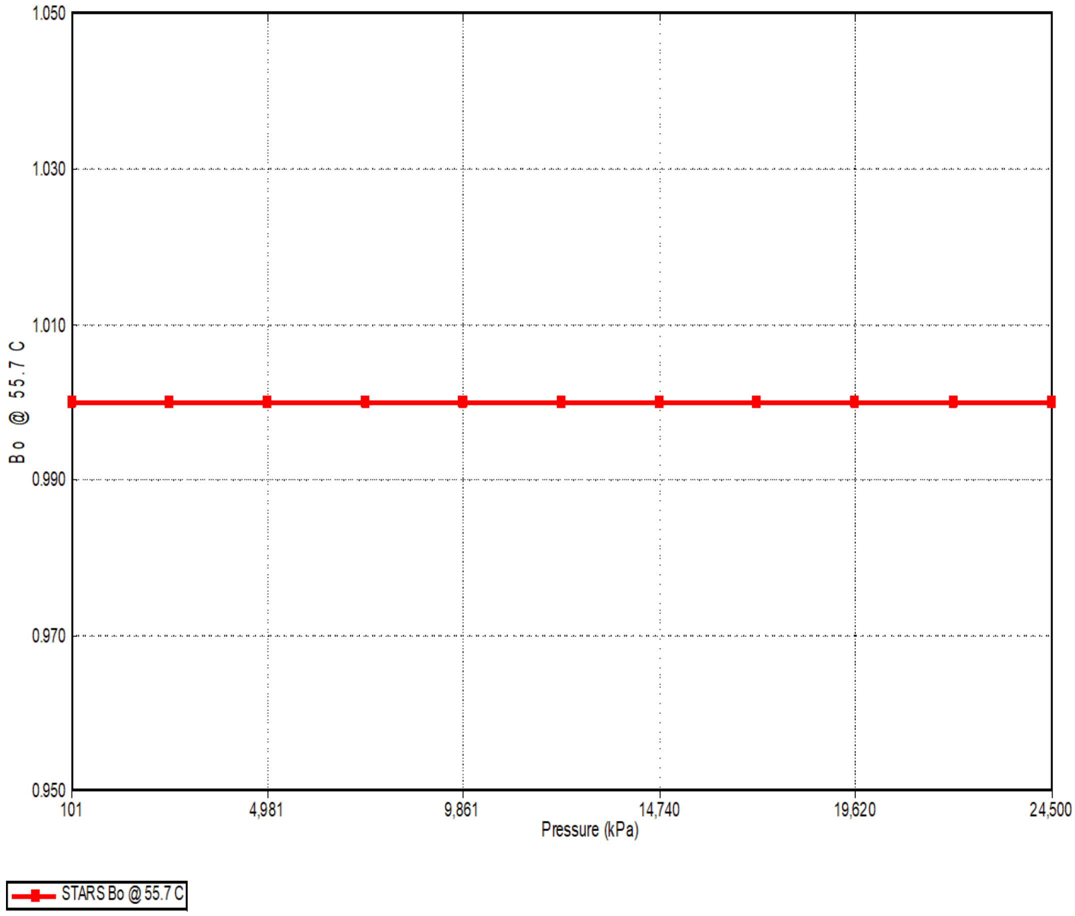


Figure 3.2. *Oil Formation Volume Factor (Bo) versus Pressure (generated by CMG Builder, 2015)*

Rock Fluid Interaction Data

The field referenced to back up this project is located in the southwest of Iran, the oil field has two major reservoir which include the Gurpi and Shallower Asmari reservoir. The main reservoir used is the Asmari formation with Oligocene and Miocene ages because it has been producing oil at large commercial scale. In the rock fluid simulation process, a new rock type, carbonated rock was created and a correlation was used to generate the relative permeability table for both the gas-oil system and the water-oil system. Therefore, the table data gotten from the correlations was then used to plot the relative permeability curves against gas-oil saturation or water-oil saturation.

Relative permeability which is known to be the ratio of the effective permeability of a fluid at a known saturation to the absolute permeability of that fluid at total saturation. For oil-water phase, Figure 3.3 shows that the relative permeability of water (K_{rw}) starts to increase at 0.28 water saturation as denoted by the red colour line and the oil-water relative permeability (k_{row}) reduces over time (decline to zero at 0.68 of S_w) with increasing water saturation as represented in blue colour line. However, for the liquid phase, Figure 3.4 shows the relative permeability curve versus liquid saturation. Based on the plot, the gas's relative permeability reduces over time until it reaches zero at liquid saturation of 0.86. In contrast, the relative permeability of oil-gas (k_{rog}) declines from the initial liquid saturation until 0.64 of its saturation where it starts to increase with an increase in liquid saturation as denoted in the blue colour line.

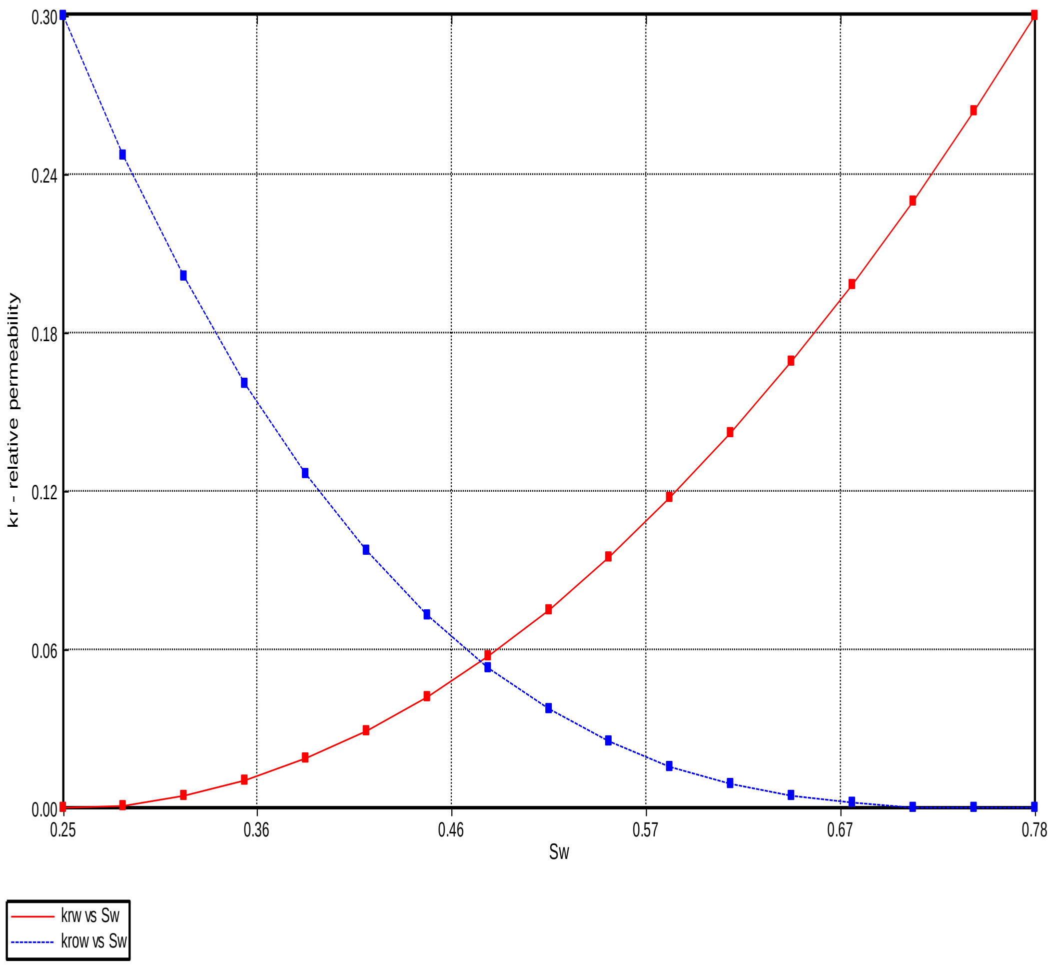


Figure 3.3. *Relative Permeability against Water Saturation (generated by CMG Builder, 2015)*

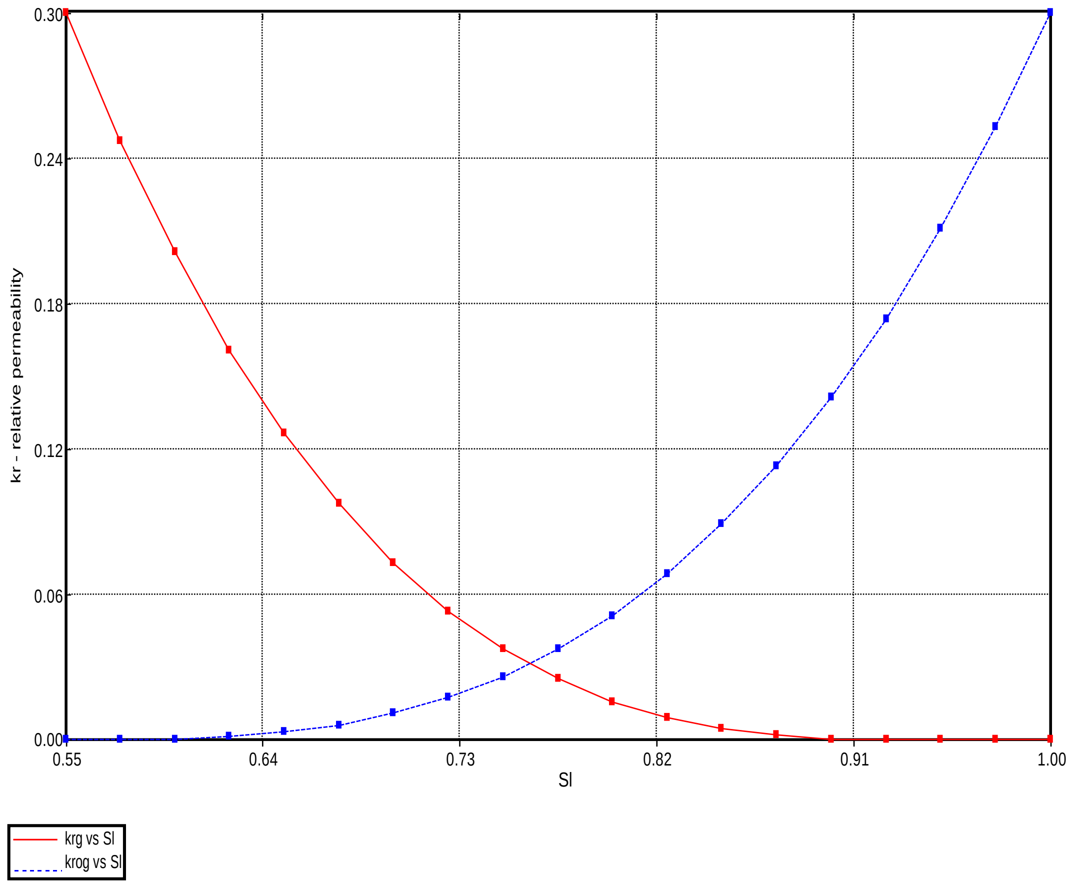


Figure 3.4. *Relative Permeability against Liquid Saturation (generated by CMG Builder, 2015)*

Fluid Contacts and Initialization

For a simulation to be validated, the pre-conditions at the start of the simulation should be known, which include; Reference pressure and phase saturation for the grid cells, Reference Depth, and the contact depths of the fluid, that is OWC depth and GOC depth. For this project, vertical equilibrium calculations were not calculated, therefore, Initial conditions were not defined during the simulation. Also, for the numerical controls, first time step size after well change was specified at 0.01 day for all the simulation validation.

Production and Injection Well Constraints

Under production conditions, a minimum BHP of 13000 kPa and a maximum well oil production rate of 85,000 m^3/Day were used for the four producing wells. For the injectors, maximum bottom-hole pressure of 35,000 kPa and a surface gas rate of 850,000 m3/day was specified for gas (CO_2). An injector 2 on the same spot as gas injector but with surface water rate of 750,000 m^3/day and a maximum BHP OF 30,000 kPa was added. The four producers used for the model were all perforated at the flank of the model and all the layers were all perforated, same goes for the two injection wells in terms of the layer perforation, the injectors were located in between the four producers to allow oil to be recovered and produced efficiently.

The miscible CO_2 simulation has three different well configurations with the same five spots (4 producer wells and 1 injector well) model. The first configuration carries 2 vertical producer wells, 2 horizontal producer wells with an injection well in the middle, the second carries 4 horizontal producer wells and an injection well in the middle, while the last configuration carries 4 vertical producer wells and an injection well in the middle as well.

The first scenario was validated using 100% CO_2, for the 3 well configurations for the simulated period of 6 years. And the results for oil recovery and cumulative oil were compared amongst the well configurations.

Finally, the water alternating gas (WAG) scenario was introduced, whereby another injection well was created in the same spot as the first injector but this time the new injector is carrying 100% water as the injection fluid and the water was injected simultaneously for a period of 5 year after the CO_2 injection periods of 3 months, 6 months and 1 year. That's to say, CO_2 is injected in 3 months after which water is injected alternatively for 5 years. The same process was followed for 6 months CO_2 injection and 1 year CO_2 injection.

CHAPTER IV

Results and Discussion

In this chapter, all the scenario simulation results for the project will be analyzed and discussed. The result of miscible CO_2 was compared against WAG for all the different well configurations to show which has better results in terms of oil recovery factor, cumulative oil, and cumulative water oil ratio (CWOR).

Miscible CO_2 Flooding

This scenario carries 100% CO_2 injection as the injection fluid, results are analyzed for the three well configurations, which includes: the four horizontal producer wells and one vertical injection well; the four vertical producer wells and one vertical injection well; and the two horizontal, two vertical producer wells and one vertical injection well. All the wells have the same well constraints for all the producer wells and the injection well.

2 Horizontal, 2 vertical Well Configuration

This is a scenario of miscible CO_2 with two horizontal, two vertical producer wells, with one injection well positioned in the middle of the model as shown in figure 4.1.

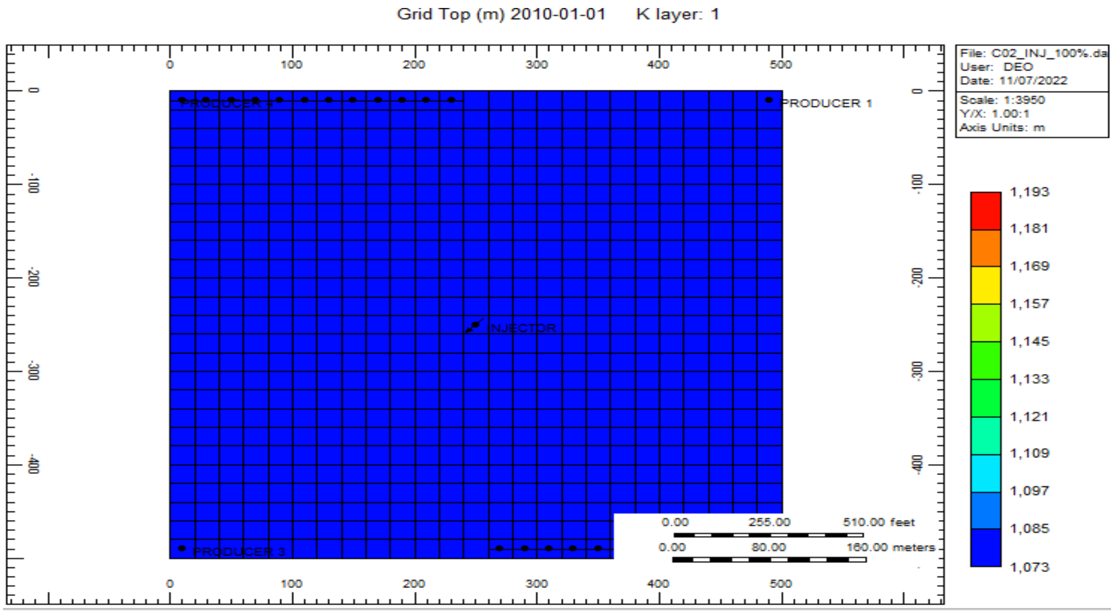


Figure 4.1. *2D Reservoir Model for 2 Horizontal, 2 Vertical Well Configuration (generated by CMG Builder, 2015)*

The results for miscible CO_2 for 2 horizontal 2 vertical producer wells with an injection well was checked using *CMG-STARS* results graph, which showed an improvement in terms of oil recovery and cumulative oil. An oil recovery factor of 35.6% and cumulative oil of 1 MM m^3 was gotten after 6 years of simulation as shown in Figure 4.2 and 4.3.

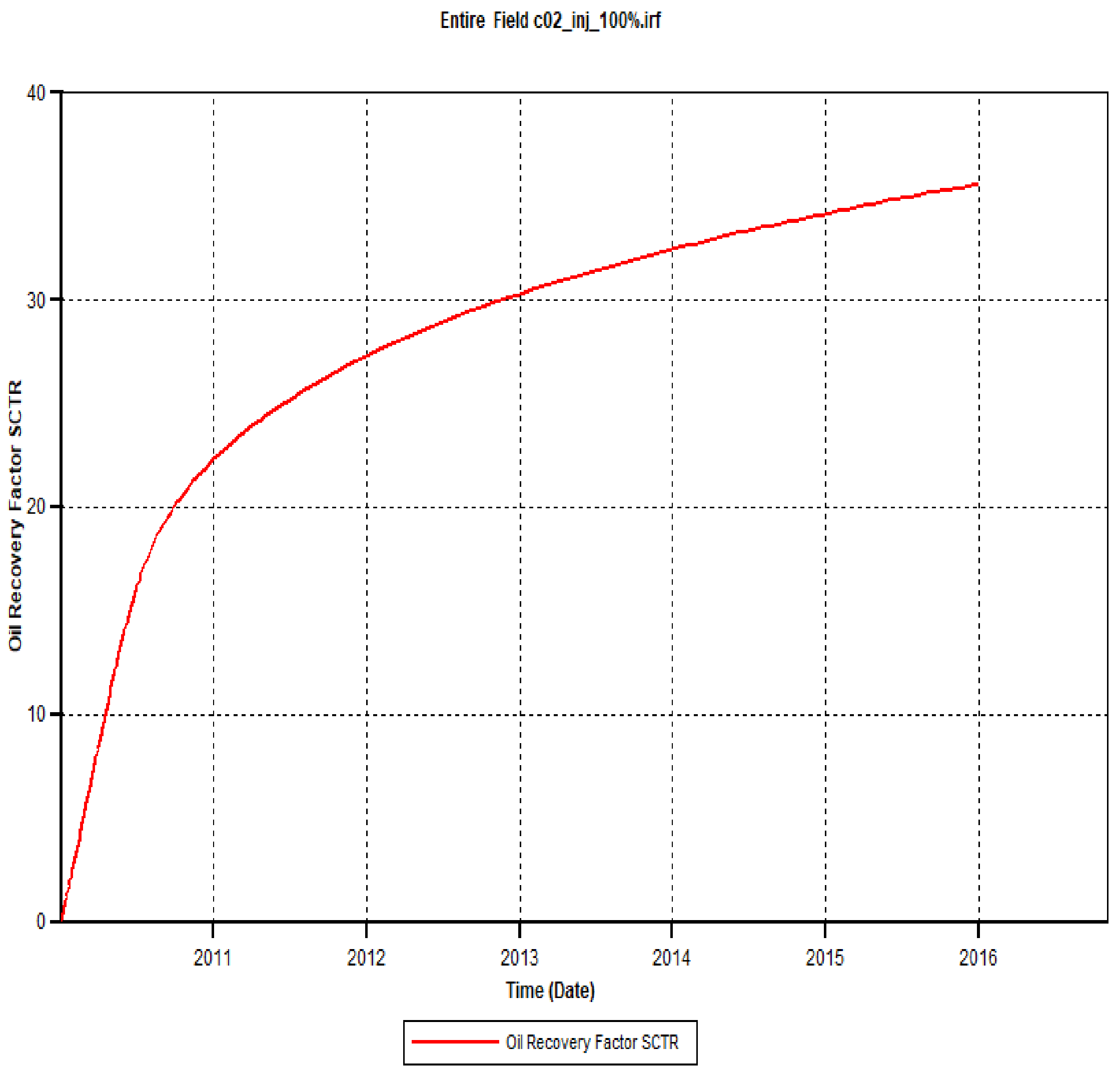


Figure 4.2. *Oil Recovery Factor vs Time for the 2 Horizontal, 2 vertical Well Configuration (generated by CMG Results, 2015)*

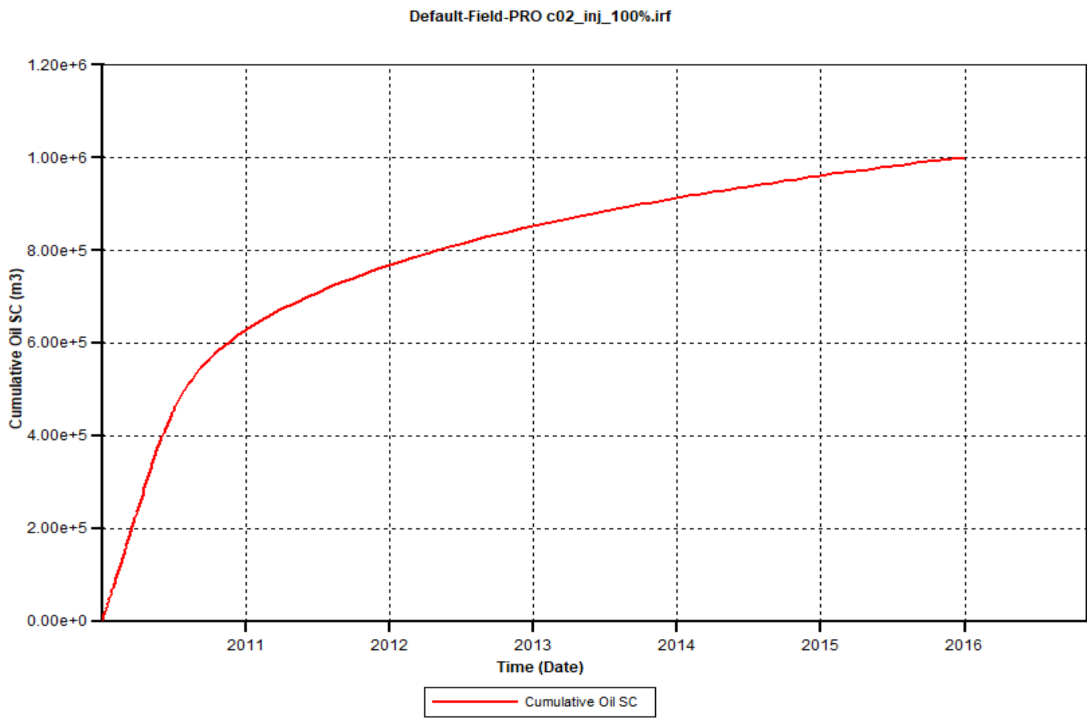


Figure 4.3. *Cumulative Oil vs Time for the 2 Horizontal, 2 vertical Well Configuration (generated by CMG Results, 2015)*

All Horizontal Well Configuration

This is a scenario of miscible CO_2 with all horizontal producer wells, with one injection well positioned in the middle of the model as shown in figure 4.4.

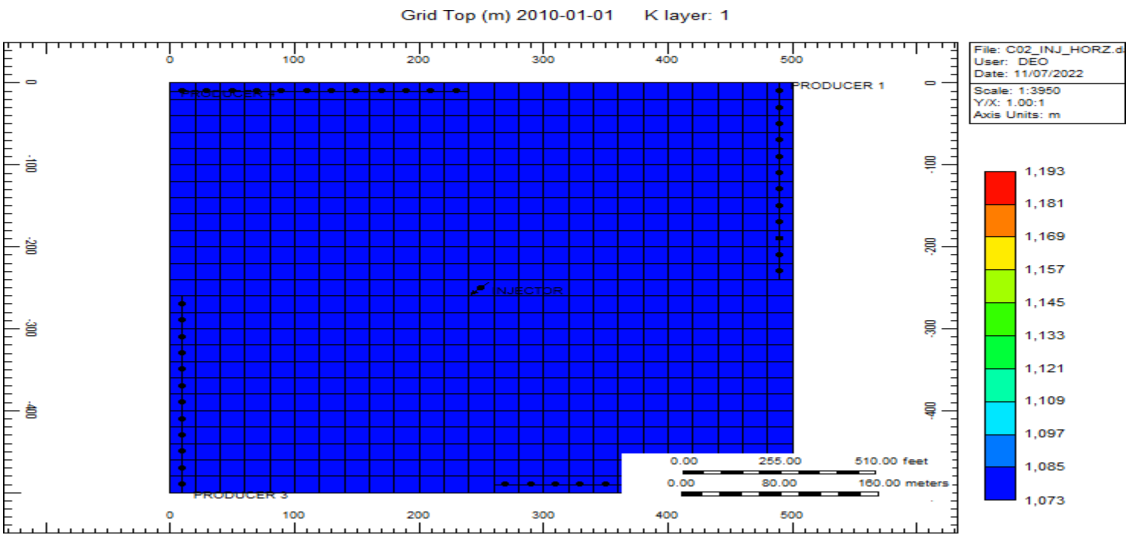


Figure 4.4. *2D Reservoir Model for All Horizontal Well Configuration (generated by CMG Builder, 2015)*

After the combination of horizontal and vertical producer well configuration, the results for all horizontal producer wells with an injection well was checked using *CMG-STARS* results graph, and a better improvement was seen in terms of oil recovery and cumulative oil. An oil recovery factor of 40.6% and cumulative oil of 1.14 MM m^3 was gotten after 6 years of simulation as shown in Figure 4.5 and 4.6.

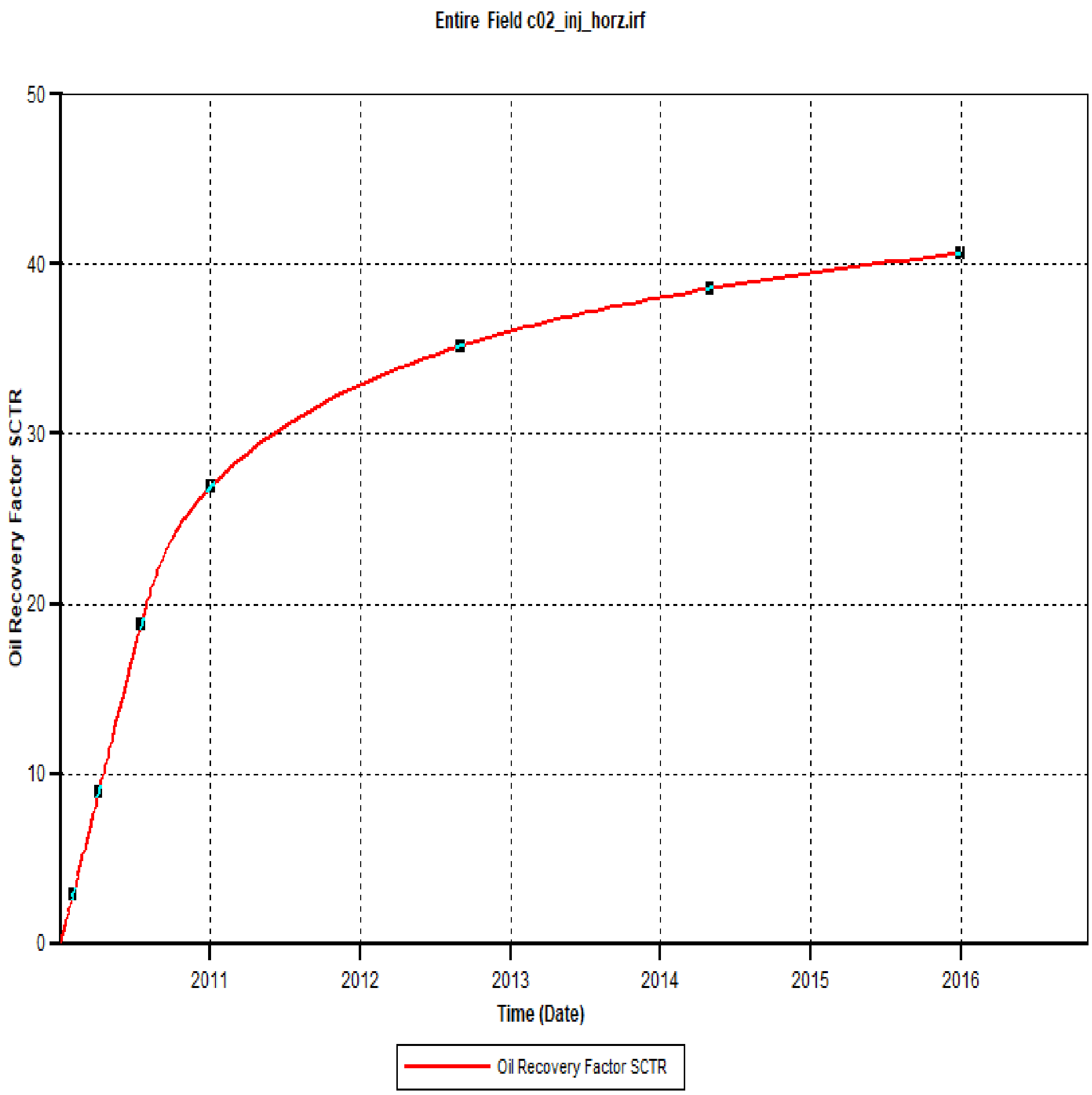


Figure 4.5. *Oil Recovery Factor vs Time for the All-Horizontal Well Configuration (generated by CMG Results, 2015)*

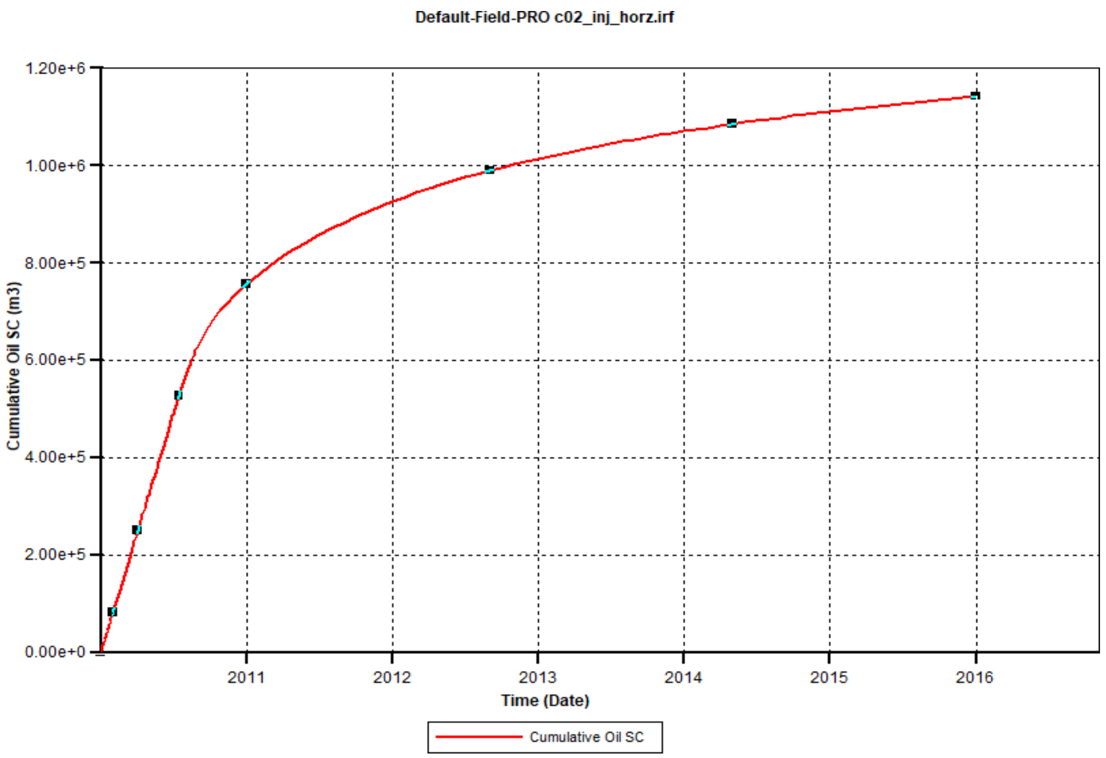


Figure 4.6. *Cumulative Oil vs Time for the All-Horizontal Well Configuration (generated by CMG Results, 2015)*

All Vertical Well Configuration

This is a scenario of miscible CO_2 with all vertical producer wells, with one injection well positioned in the middle of the model as shown in figure 4.7.

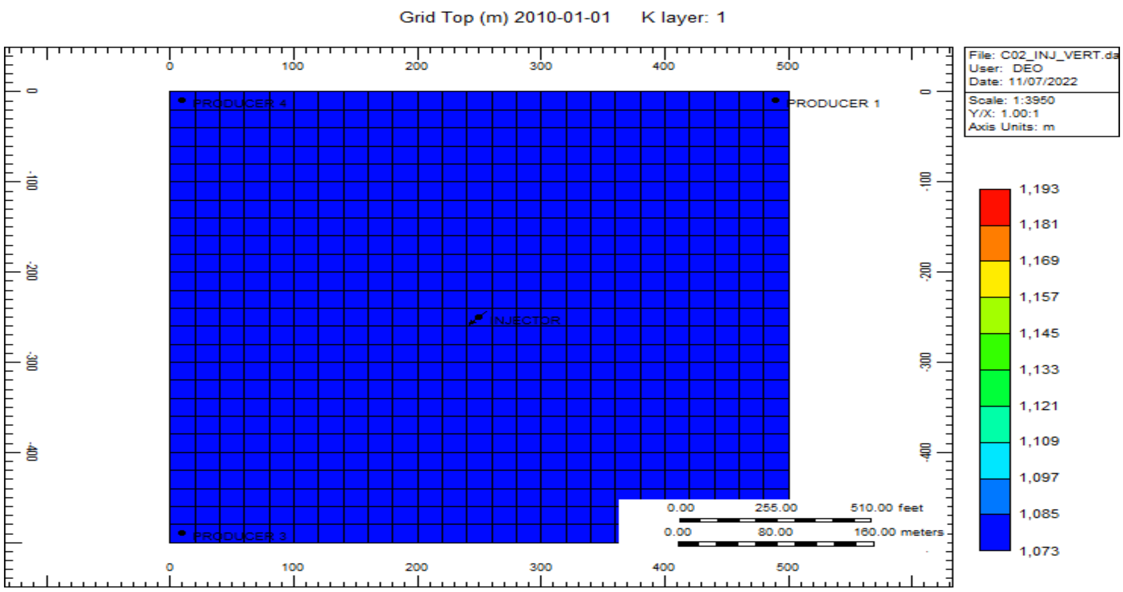


Figure 4.7. *2D Reservoir Model for All Vertical Well Configuration (generated by CMG Builder, 2015)*

The results for the all-vertical producer wells with an injection well using *CMG-STARS* results graph showed a decrease in oil recovery and cumulative oil when compared with the all-horizontal producer well and the 2 vertical, 2 horizontal producer wells. An oil recovery factor of 26.7% and cumulative oil of 751,911 m^3 was achieved after 6 years of simulation as shown in Figure 4.8 and 4.9.

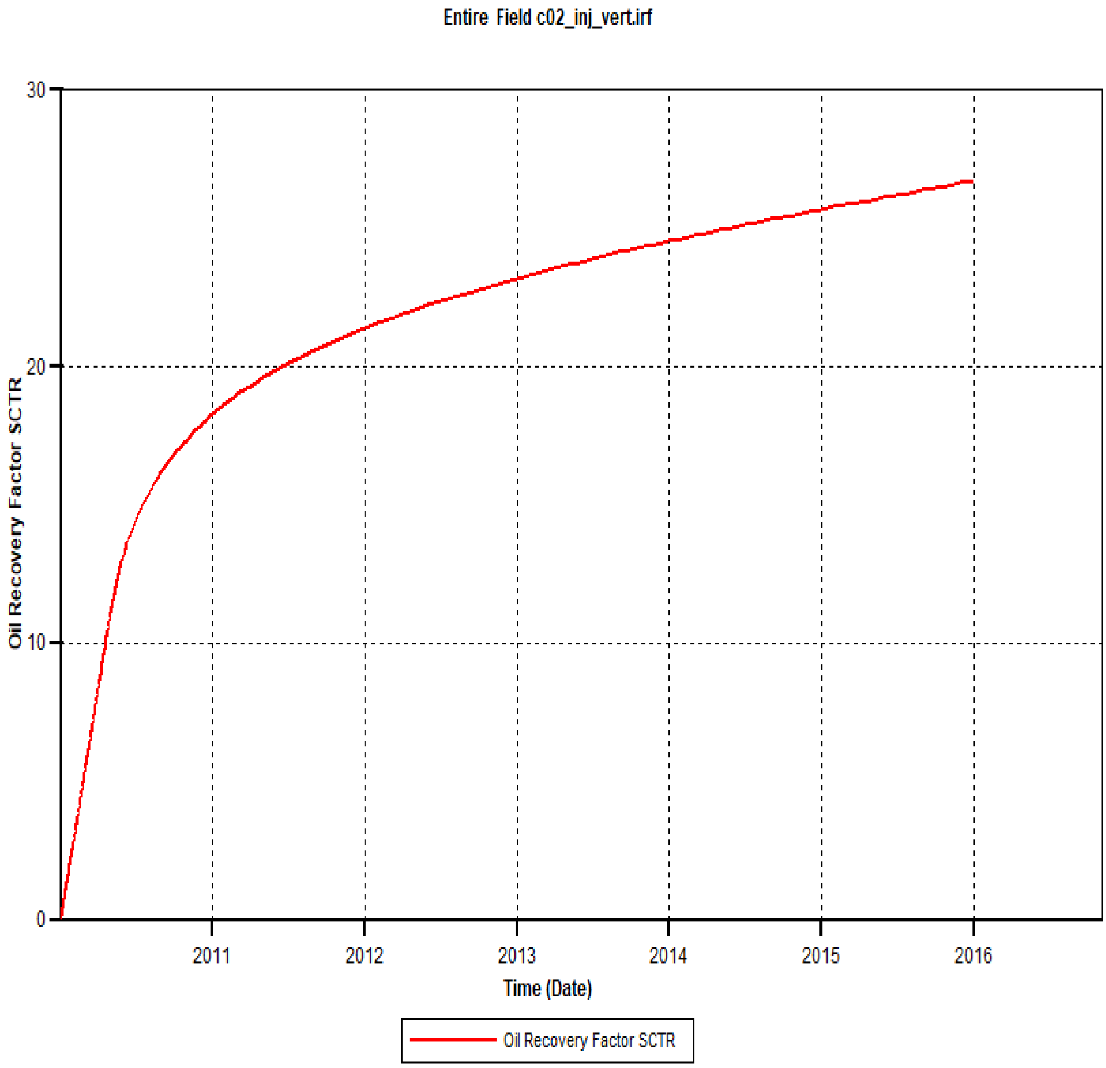


Figure 4.8. *Oil Recovery Factor vs Time for the All-Vertical Well Configuration (generated by CMG Results, 2015)*

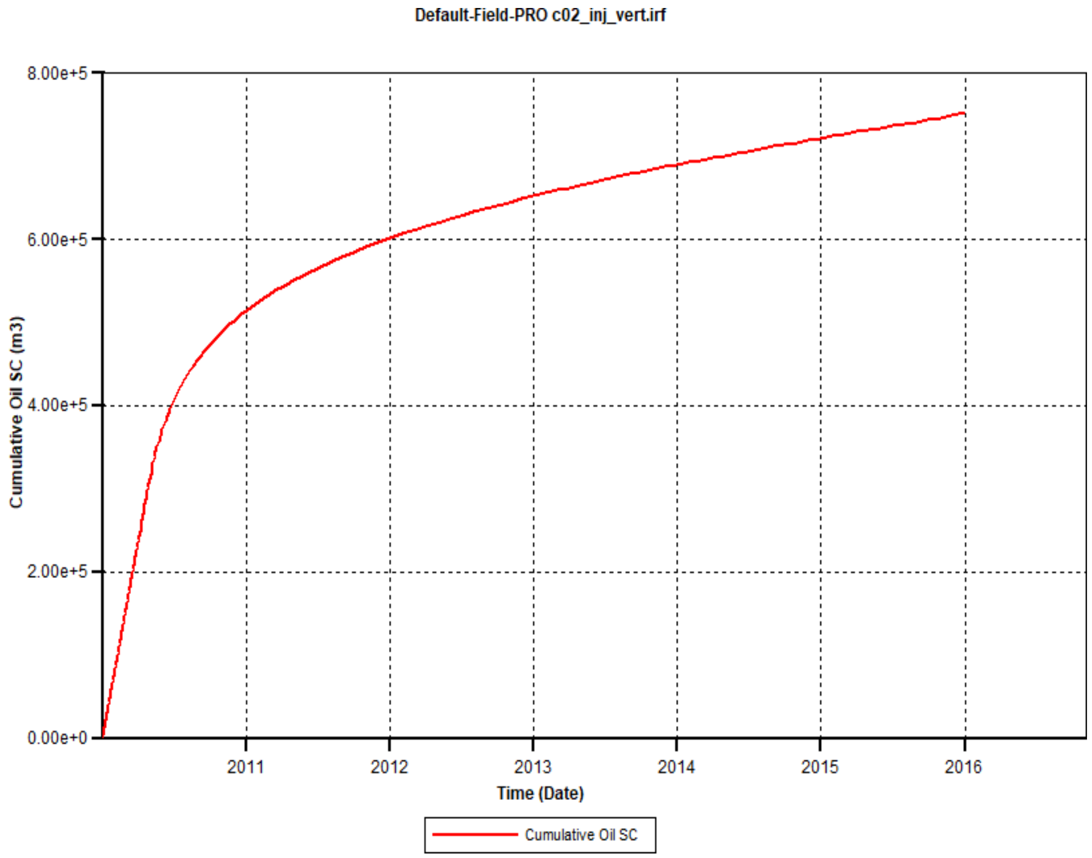


Figure 4.9. *Cumulative Oil vs Time for the All-Vertical Well Configuration (generated by CMG Results, 2015)*

Comparison of Miscible Scenarios with Literature Review

From literature for miscible CO_2 flooding, the BHP for all of production wells was 1900 psia. And also, the total production rate for production wells was 18,000 stb/day. In order to find the optimum injection rate CO_2 was injected at different rates of 12,000, 16,000, 20,000, 24,000, 27,000, 30,000, ,000 and 36,000 Mscf/day. The miscible CO_2 injection scenario with the best result in the literature review as shown in Figure 4.10 with an injection rate 30,000 Mscf/day has oil recovery factor of 36.65% of OOIP, while for this project, the best miscible CO_2 scenario with the all horizontal well configuration as shown in Figure 4.5 has an oil recovery of 40.6% which indicated that a better result was achieved from this project as compared to results from literature.

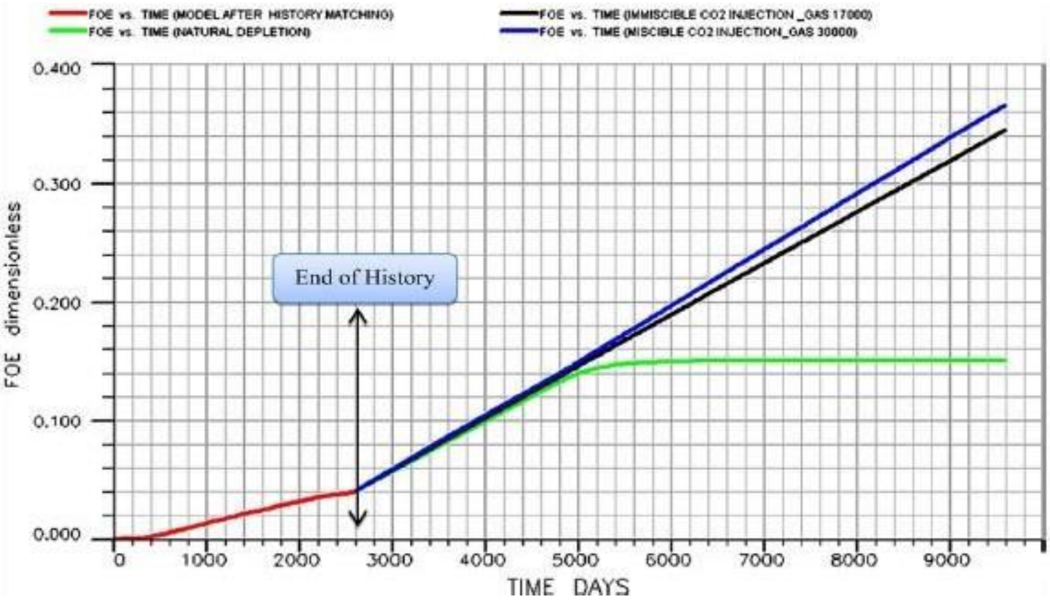


Figure 4.10 *Comparison of field oil efficiency values in natural depletion, immiscible and miscible CO_2 injection scenarios (Fath and Pouranfard, 2014)*

Water Alternating Gas (WAG) Flooding

The water alternating gas scenario combines the injection of CO_2 for a period of 3 months, 6 months and 1 year with a water injection period of 5 years. Their simulation results were analyzed for the three different well configurations with the same well constraints for both the producer wells and the injection wells. The results for the water alternating gas (WAG) flooding for the different time interval are analyzed in the following sub-sections.

WAG for All Horizontal Well Configuration

This WAG scenario was simulated for 3 months CO_2 with an alternating 5 years water injection, 6 months CO_2 with an alternating 5 years water injection, and 1 year CO_2 with an alternating 5 years water injection, their results were checked for oil recovery factor, cumulative oil production and cumulative water oil ratio (CWOR). The 3 months CO_2 with an alternating 5 years water injection has the highest oil recovery factor of 52.9 % and cumulative oil production 1.49 MM m^3, while the 1year CO_2 with an alternating 5 years water injection had less water usage with a CWOR of 2.54%. Results are shown in Figure 4.11, 4.12 and 4.13.

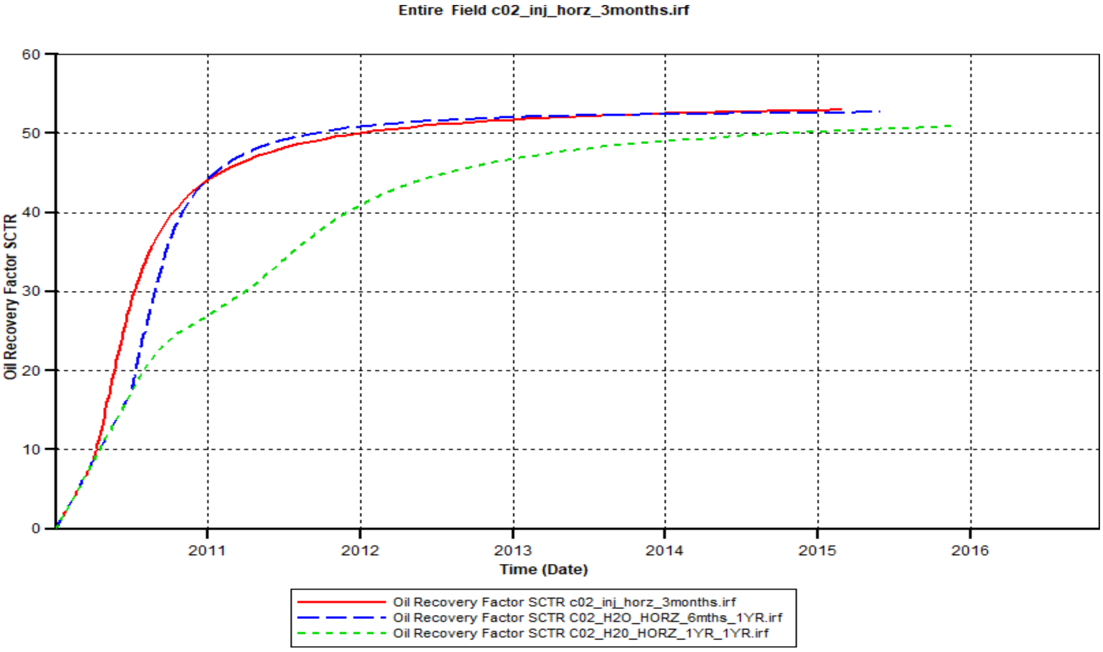


Figure 4.11**.** *Oil Recovery Factor vs Time for the WAG-All Horizontal WellConfiguration (generated by CMG Results, 2015)*

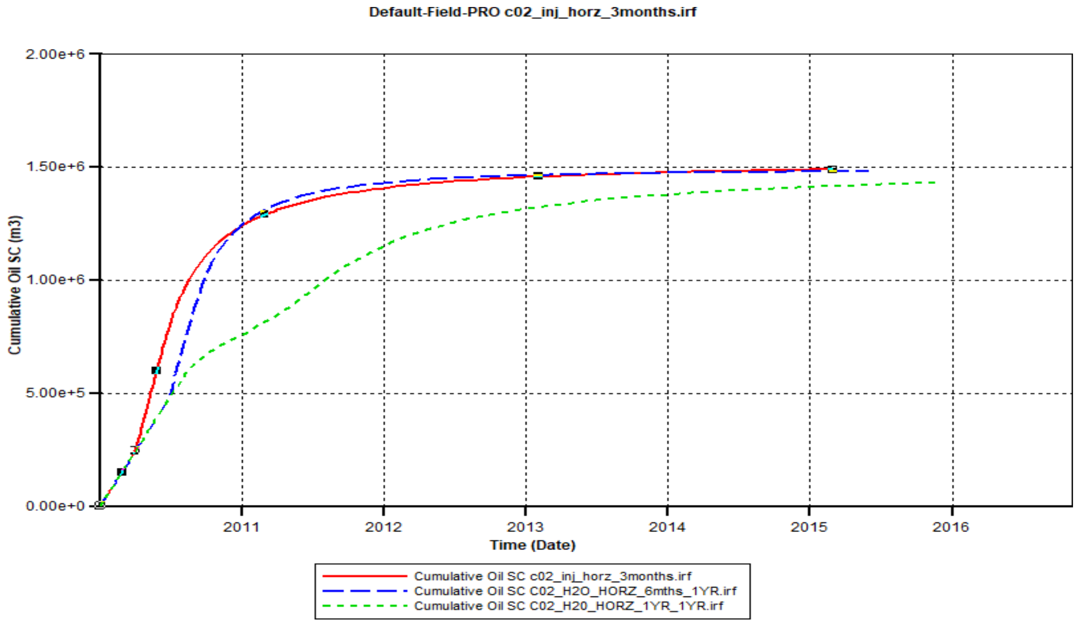


Figure 4.12. *Cumulative Oil vs Time for the WAG-All Horizontal Well Configuration (generated by CMG Result,2015.10)*

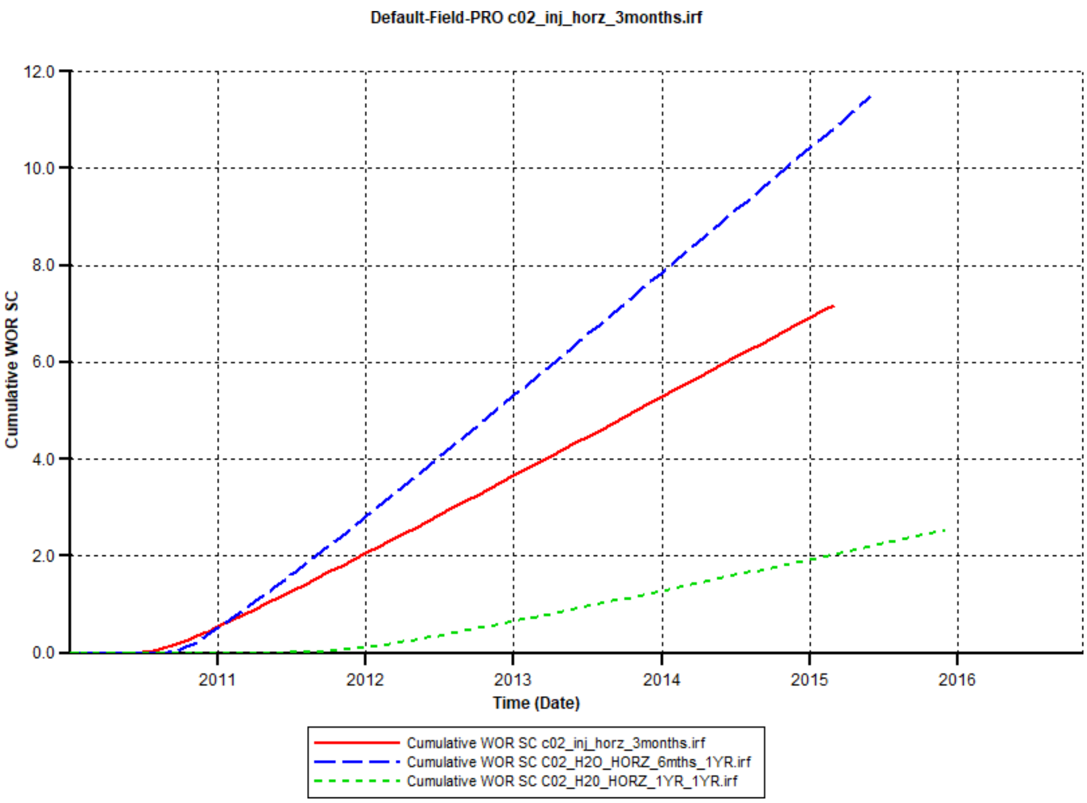


Figure 4.13. *Cumulative Water Oil Ratio vs Time for the WAG-All Horizontal Well Configuration (generated by CMG Results, 2015)*

WAG for 2 Horizontal 2 Vertical Well Configuration

This WAG scenario was also simulated for 3 months CO_2 with an alternating 5 years water injection, 6 months CO_2 with an alternating 5 years water injection, and 1 year CO_2 with an alternating 5 years water injection, their results were checked for oil recovery factor, cumulative oil production and cumulative water oil ratio (CWOR). The 3 months CO_2 with an alternating 5 years water injection has the highest oil recovery factor of 53.9 % and cumulative oil production 1.52 MM m3, while the 6 months CO_2 with an alternating 5 years water injection had less water usage with a CWOR of 6.7%. Results are shown in Figure 4.14, 4.15 and 4.16.

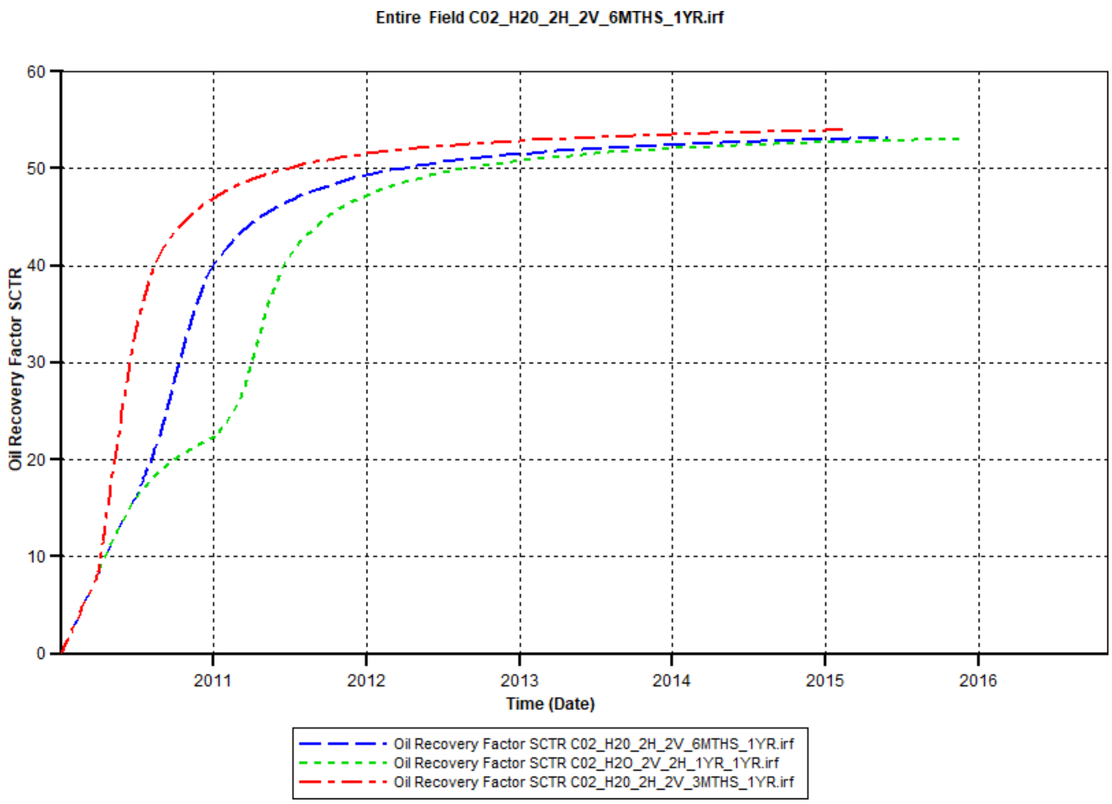


Figure 4.14. *Oil Recovery Factor vs Time for the WAG-2 Horizontal 2 Vertical Well Configuration (generated by CMG Results, 2015)*

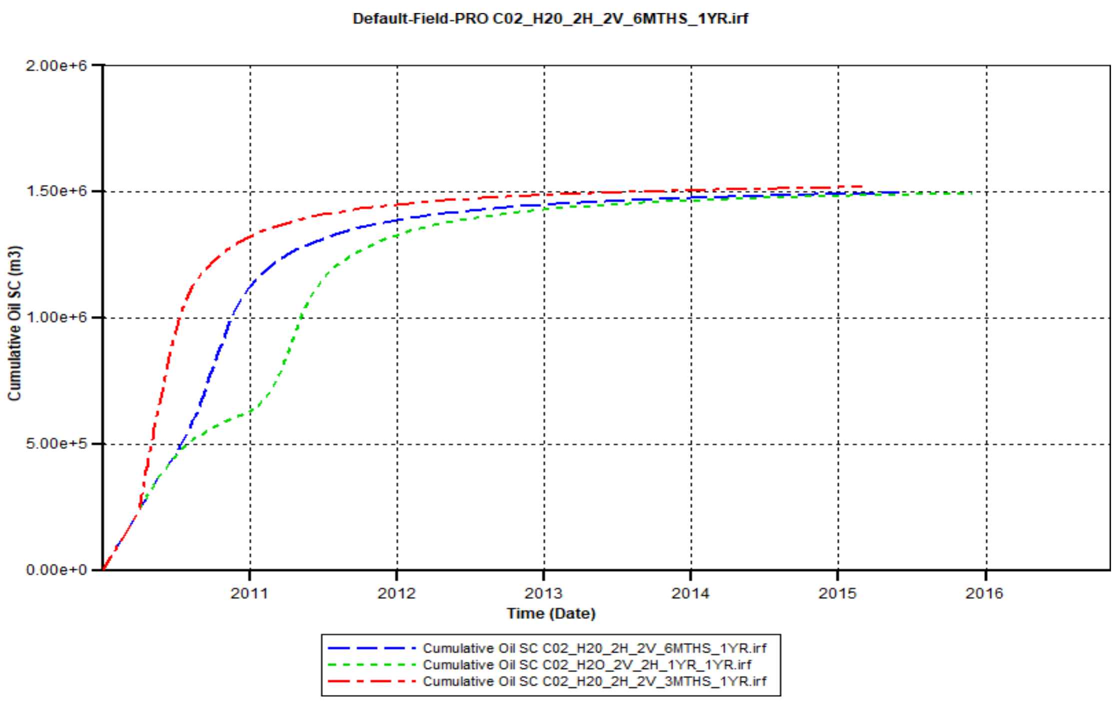


Figure 4.15. *Cumulative Oil vs Time for the WAG-2 Horizontal 2 Vertical Well Configuration (generated by CMG Results, 2015)*

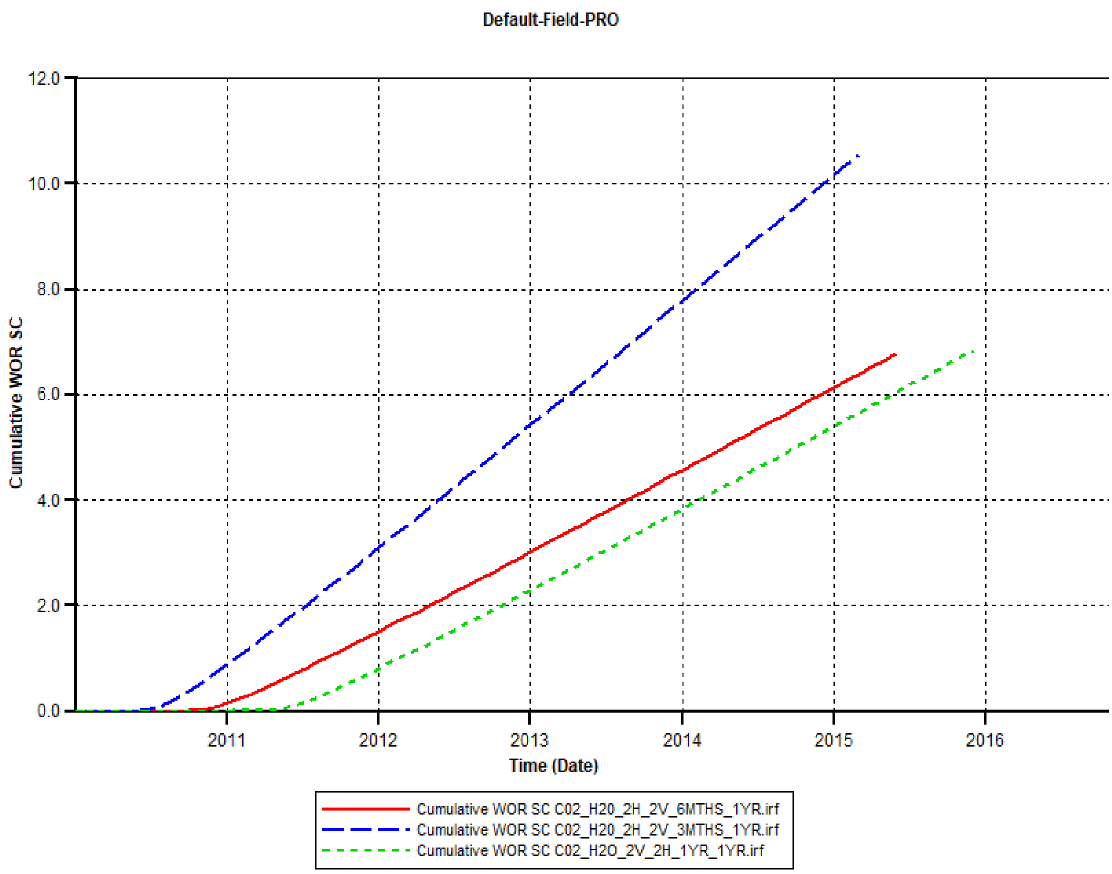


Figure 4.16. *Cumulative Water Oil Ratio vs Time for the WAG-2 Horizontal 2 Vertical Well Configuration (generated by CMG Results, 2015)*

WAG for All Vertical Well Configuration

This WAG scenario was also simulated for 3 months CO_2 with an alternating 5 years water injection, 6 months CO_2 with an alternating 5 years water injection, and 1 year CO_2 with an alternating 5 years water injection, their results were checked for oil recovery factor, cumulative oil production and cumulative water oil ratio (CWOR). It showed that the 3-period interval of CO_2 and water injection have the same oil recovery factor of 51.2 % and cumulative oil production 1.44 MM m^3, while the 3 months CO_2 with an alternating 5 years water injection had less water usage with a CWOR of 2.01%. Results are shown in Figure 4.17, 4.18 and 4.19.

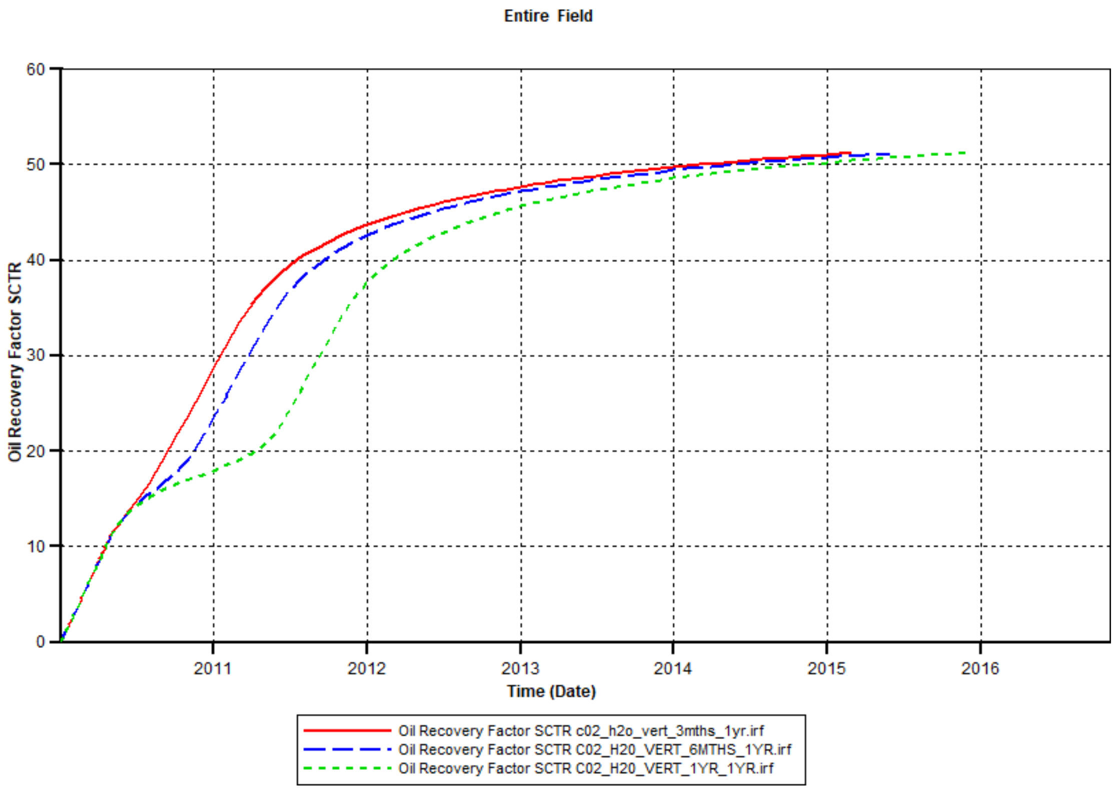


Figure 4.17. *Oil Recovery Factor vs Time for the WAG-All Vertical Well Configuration (generated by CMG Results, 2015)*

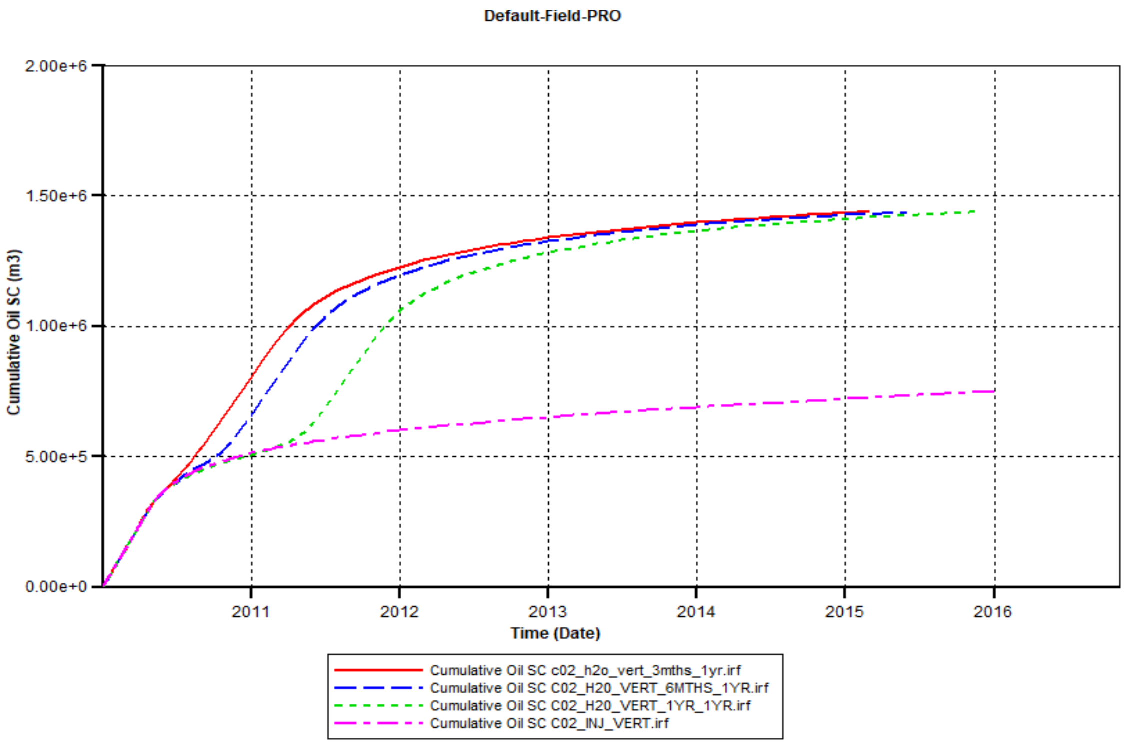


Figure 4.18. *Cumulative Oil vs Time for the WAG-All Vertical Well Configuration (generated by CMG Results, 2015)*

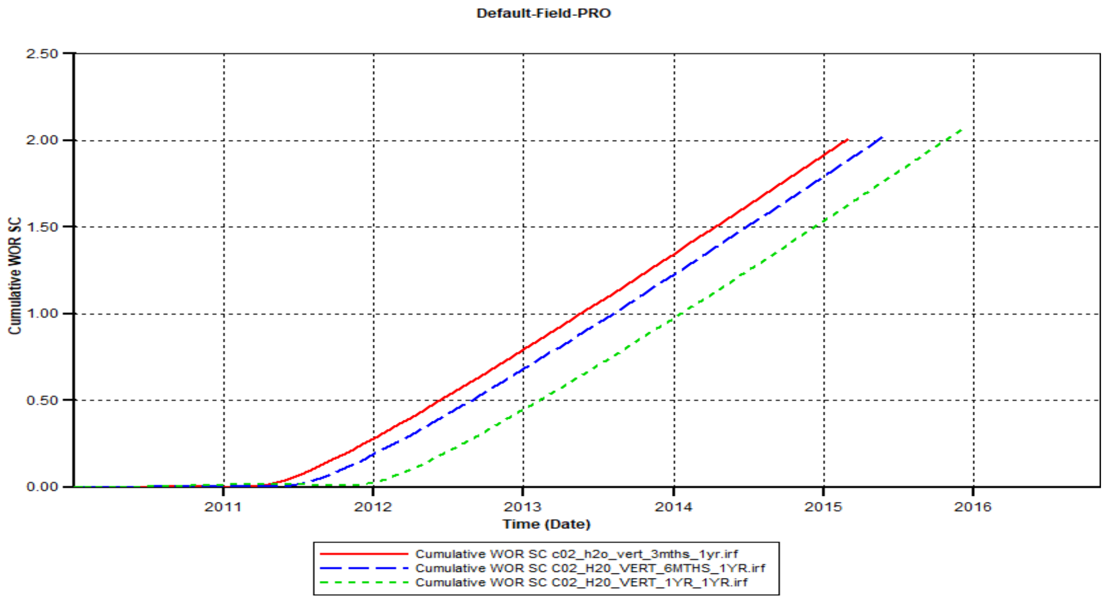


Figure 4.19**.** *Cumulative Water Oil Ratio vs Time for the WAG-All Vertical Well Configuration (generated by CMG Results, 2015)*

Comparison of WAG Scenarios with Literature Review

As seen in figure 4.20, literature review shows that other project on WAG scenario has an oil recovery factor of 53.5%, while the best scenario for WAG scenario for this project with 3 months CO_2 injection and 5 years water injection for the 2 horizontal 2 vertical well configuration achieved 53.9% of oil recovery which is a little better when compared to literature result.

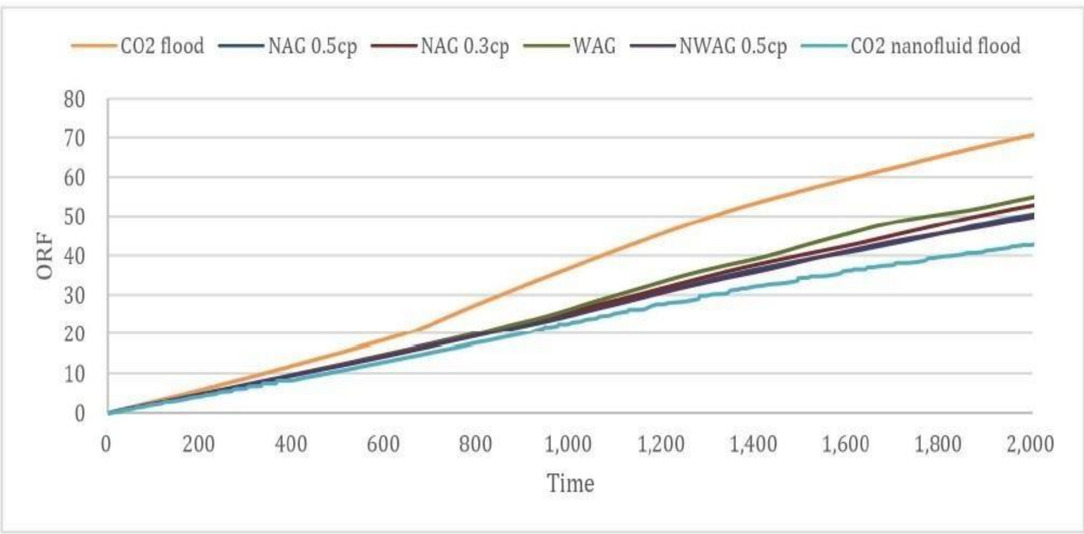


Figure 4.20. *Oil Recovery Factor for CO_2 and WAG with Nanofluid (Galo and Erdman, 2017).*

Comparison of Miscible CO_2 Flooding Against WAG Flooding

Effect of Well Configurations

The 2 horizontal 2 vertical well configuration for water alternating gas (WAG) had the best impact for oil recovery with oil recovery factor of 53.9% and cumulative oil production of 1.52 MMm^3 when compared with other WAG scenarios and miscible CO_2, as shown in Figure 4.21 and 4.22. The miscible CO_2 for the all-horizontal producer well configurations have the best result with oil recovery of 40.6% and cumulative oil production of 1.14 MMm^3 for miscible CO_2 flooding scenarios, but when compared with WAG scenarios, it has the least oil recovery and cumulative as shown in Figure 4.21, 4.22.

Effect of CO2 and WAG

The WAG scenarios show better improvement both in oil recovery and cumulative production oil as compared to CO2 injection. The 3 months CO2 injection and 5-year water injection of WAG had the best oil recovery factor of 53.9% and cumulative oil of 1.52e+6 m^3 (see Figure 4.19 and 4.20), as compared to miscible CO_2 flooding for the all-horizontal well configuration with highest oil recovery of 40.6% and cumulative oil production of 1.14e+6 m3 as shown in Figures 4.23 and 4.24.

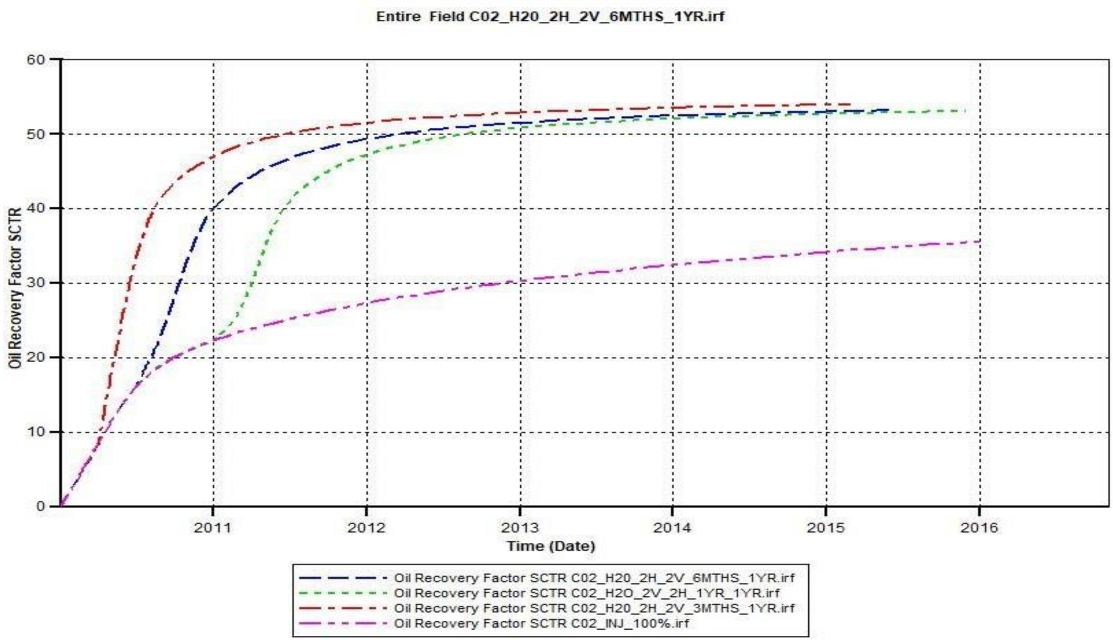


Figure 4.21. *Oil Recovery Factor vs Time for all Scenarios with the 2 Horizontal 2 Vertical Well Configuration (generated by CMG Results, 2015)*

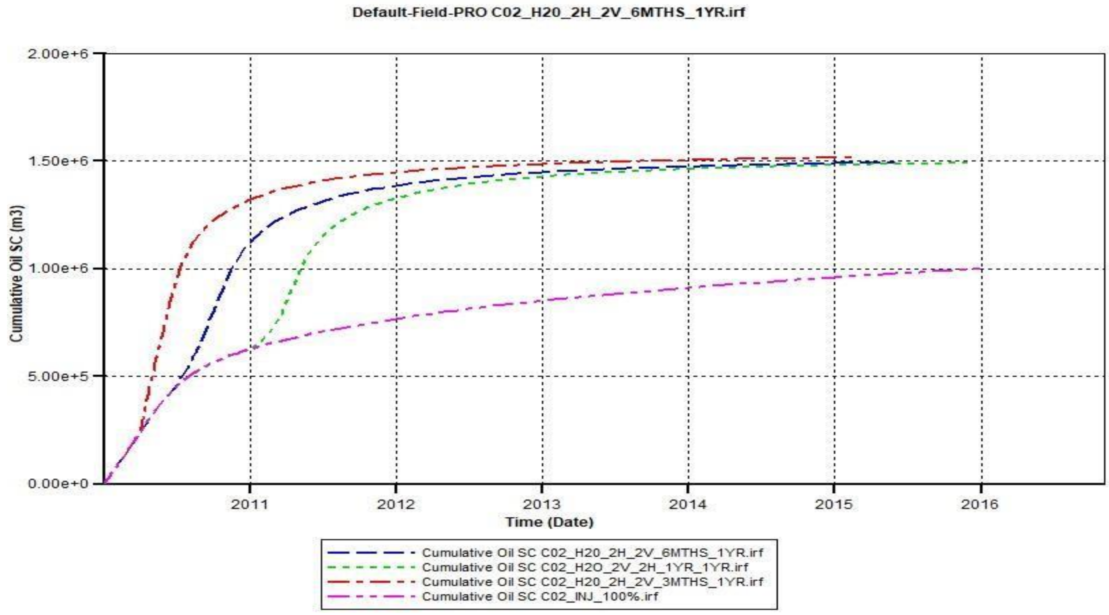


Figure 4.22. *Cumulative Oil vs Time for all Scenarios with the 2 Horizontal 2 Vertical Well Configuration (generated by CMG Results, 2015)*

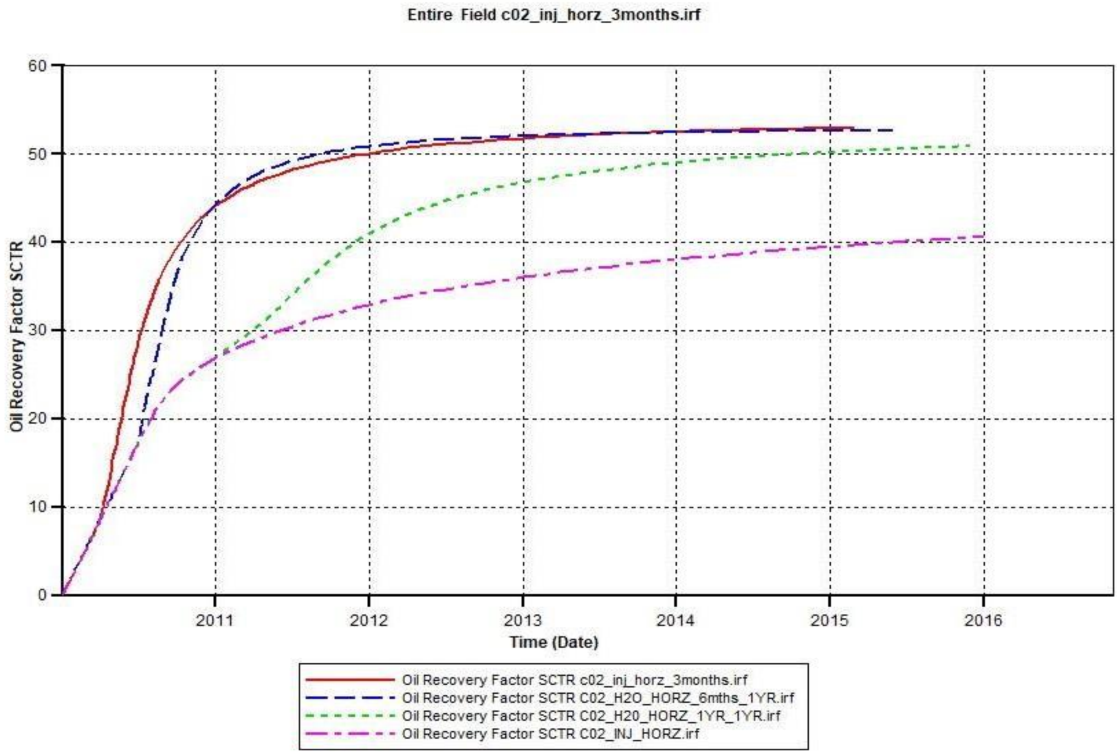


Figure 4.23. *Oil Recovery Factor vs Time for all Scenarios with the All-Horizontal Well Configuration (generated by CMG Results, 2015).*

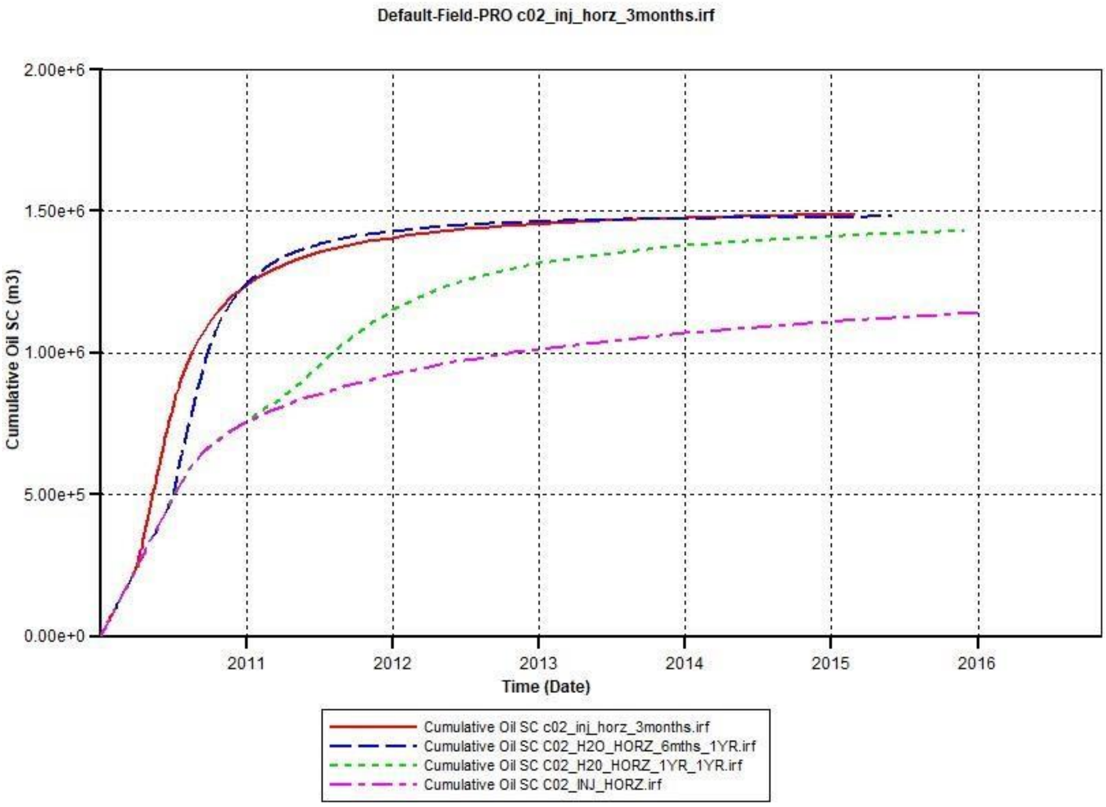


Figure 4.24**.** Cumulative *Oil vs Time for the All-Horizontal Well Configuration (generated by CMG Results, 2015)*

All results for the whole scenarios are tabulated in Table 4.1.

Table 4.1.

Analysis of Miscible CO_2 Scenarios Against WAG Scenarios (generated from CMG Results, 2015)

Scenario Case	**Oil Recovery Factor %**	**Cumulative Oil Production (MMSTB)**	**Cumulative Water Oil Ratio (%)**
CO_2 & WAG for all Horizontal Well Configuration			
100% CO_2 Injection for 6 years	40.6	1.14	
3 Months CO_2 Injection, 5 Year Water Injection	52.9	1.49	7.2
6 Months CO_2 Injection, 5 Year Water Injection	52.6	1.48	11.5
1 Year CO_2 Injection, 5 Year Water Injection	50.8	1.43	2.54
CO_2 & WAG for All Vertical Well Configuration			
100% CO_2 Injection for 6 Years	26.7	0.75	
3 Months CO_2 Injection, 5 Year Water Injection	51.2	1.44	2.01

6 Months CO_2 Injection, 5 Year Water Injection	51.2	1.44	2.03
1 year CO_2 Injection, 5 Year Water Injection	51.2	1.44	2.1
CO_2 & WAG for 2 Horizontal, 2 Vertical Well Configuration			
100% CO_2 Injection for 6 years	35.6	1.0	
3 Months CO_2 Injection, 5 Year Water Injection	53.9	1.52	10.5
6 Months CO_2 Injection, 5 Year Water Injection	53.2	1.49	6.7
1 Year CO_2 Injection, 5 Year Water Injection	53.1	1.49	6.8

CHAPTER V

Conclusions and Recommendations

Conclusions

- This study aims to examine the recovery factor, cumulative oil and cumulative water oil ratio for Miscible CO_2 and water alternating gas (WAG) flooding using horizontal and vertical well configurations and this simulation was backed up by reservoir properties from shallower Asmari reservoir.
- Miscible CO_2 flooding was simulated for 6 years with 3 different well configurations that indicated that the all-horizontal producers well configuration have the best oil recovery factor 40.6% and cumulative oil production of 1.14 MMm^3.
- WAG scenarios were also simulated for the 3 different well configuration, where water was injected simultaneously within 5-year period intervals after 3 months, 6 months, and 1 year of CO_2 injection period. WAG gave better results than Miscible CO_2, for oil recovery factor and cumulative oil production. The WAG scenario with 3 months CO_2 injection and 5 years water injection for both vertical and horizontal producer well configuration gave the best result with oil recovery of factor of 53.9% and cumulative oil production of 1.52 MMm^3.
- The WAG scenario with 3 months CO_2 injection and 5 years water injection for all vertical producer well configuration has the least water usage with 2.01% of cumulative water oil ratio (CWOR)

Recommendations

WAG flooding with horizontal and vertical wells is strongly recommended for future oil recovery because of its significance in EOR and economic viability.

In high water wet formations, especially with high saturation, water blockage can cause decrease in the oil recovery. Therefore, oil in lower permeable region may not be contacted by the CO_2 rich phase due to an insufficient capillary pressure. Therefore, in water wet regions, reduced WAG ratios to CO_2 or continuous CO_2 injection are recommended.

References

Aghdam KA, Ghorashi SS (2017). Critical parameters affecting Water Alternating Gas (WAG) injection in an Iranian fractured reservoir. J Pet Sci Techno l7(3):3–14.

Alfarge, D., Wei, M., and Bai, B., (2017). IOR Methods in Unconventional Reservoirs of North America: Comprehensive Review. SPE-185640-MS.

Alharthy, N., Teklu, T., Kazemi, H. et al. (2015). Enhanced Oil Recovery in LiquidRich Shale Reservoirs: Laboratory to Field. Society of Petroleum Engineers. DOI: 10.2118/175034MS.

Alvarez, J.O. and Schechter, D.S. (2016). Altering Wettability in Bakken Shale by Surfactant Additives and Potential of Improving Oil Recovery During Injection of Completion Fluids. Society of Petroleum Engineers. http:10.2118/SPE-179688-MS.

Bachu, S. and Adams, J. J. (2003). Sequestration of CO2 in geological media in response to climate change: capacity of deep saline aquifers to sequester CO2 in solution. Energy Conversion and Management 44 (20): 3151-3175. http:// www.sciencedirect.com/science/article/pii/S0196890403001018.

Bhatia J, Srivastava JP, Sharma A, Sangwai JS (2014) Production performance of water alternate gas injection techniques for enhanced oil recovery: effect of WAG ratio, number of WAG cycles and the type of injection gas. Int J Oil Gas Coal Technol 7(2):132. https://doi.org/10.1504/ijogc t.2014.05932 3

Clark, A. J., (2009). Determination of Recovery Factor in the Bakken Formation, Mountrail County, ND. Society of Petroleum Engineers. doi:10.2118/133719-STU.

Dong, C., & Hoffman, B. T. (2013). Modeling Gas Injection into Shale Oil Reservoirs in the Sanish Field, North Dakota. Society of Petroleum Engineers. doi:10.1190/URTEC2013-185Energy Information Administration (EIA), (2015).

Derakhshanfar, M., Nasehi, M., (2012). Simulation Study of CO_2-assisted Waterflooding for Enhanced Heavy Oil Recovery and Geological Storage SPE, IPAC- CO_2 Research Inc., K. Asghari, SPE, Husky Energy Inc.

Duchenne, S., Puyou G., Cordelier, P., et al., (2014) "Laboratory Investigation of Miscible CO_2 WAG Injection Efficiency in Carbonate", SPE-169658-MS.

Fath, H., A., Pouranfard, A., A., (2014). Evaluation of miscible and immiscible CO_2 injection in one of the Iranian oil fields, Egypt. J. Petrol. http://dx.doi.org/10.1016/j.ejpe.2014.08.002

Gallo, G., Erdmann, E., Instituto Tecnológico de Buenos Aires (2017). Simulation of Viscosity Enhanced CO_2 Nanofluid Alternating Gas in Light Oil Reservoirs, SPE-185607-MS.

Gamadi, T. D., Sheng, J. J., Soliman, M. Y., Menouar, H., Watson, M. C., & Emadibaladehi, H. (2014). An Experimental Study of Cyclic CO_2 Injection to Improve Shale Oil Recovery. Society of Petroleum Engineers. doi:10.2118/169142-MS,

Goodrich, J.H.: (1980). "Review and Analysis: Past and Ongoing Carbon Dioxide Injection Field Tests," paper SPE 8832, presented at the Sixth Biennial SPE-DOE Symposium onimproved Oil Recovery of the Society of Petroleum Engineers of AIME at Tulsa, Oklahoma.

Haddadnia, Ali, Mohsen Zirrahi, Hassan Hassanzadeh, and Jalal Abedi. (2017). Solubility and thermo-physical properties measurement of CO_2 - and N_2-Athabasca bitumen systems. Jounral of Petroleum Science and Engineering 277-283. https://doi.org/10.1016/j.petrol.2017.04.035.

Hamdi, Zakaria, and Mariyamni Awang. (2014). CO_2 Minimum Miscibility Pressure Determination of Pure Hydrocarbons in Different Temperatures Using Slimtube Simulations. Research Journal of Applied Sciences, Engineering and Technology 7 (15): 3159-63. https://doi.org/10.19026/rjaset.7.655.

Hamdi, Zakaria, and Mariyamni Awang. (2016). Effect of Low-Temperature CO_2 Injection in High-Temperature Oil Reservoirs Using Slimtube Experiment. Jurnal Teknologi 78 (6-6). https://doi.org/10.11113/jt.v78.9018.

Hawthorne et al., (2017). Measured Crude Oil MMPs with Pure and Mixed CO_2, Methane, and Ethane, and Their Relevance to Enhanced Oil Recovery from Middle Bakken and Bakken Shales. SPE-185072-MS paper was prepared for presentation at the SPE Unconventional Resources Conference held in Calgary, Alberta, Canada, 15-16.

Hawthorne, S. B., Gorecki, C. D., Sorensen, J. A., Steadman, E. N., Harju, J. A., & Melzer, S. (2013). Hydrocarbon Mobilization Mechanisms from Upper, Middle, and Lower Bakken Reservoir Rocks Exposed to CO. Society of Petroleum Engineers.

Hoffman, B. T., and Evans J., (2016). Improved Oil Recovery IOR Pilot Projects in the Bakken Formation. SPE-180270-MS.

Jin, L., Sorensen, J.A., Hawthorne, S.B., Smith, S.A., Bosshart, N.W., Burton Kelly, M.E., Miller, D.J., Grabanski, C.B., and Harju, J.A., (2016). Improving oil transportability using CO_2 in the Bakken System—a laboratorial investigation: Proceedings of the SPE International Conference & Exhibition on Formation Damage Control, SPE 178948, Lafayette, Louisiana, February 24–26.

Johns, Y., Mitsuishi, H., Takagi, S., Okabe, H., Nguyen Hai An, Nguyen Manh Hung, Phan Ngoc Trung and Ueda, Y., (2009). Comprehensive CO_2-EOR Study –Study on Applicability of CO2-EOR to Rang Dong Field –Part I Laboratory Study, Petro Vietnam Journal Vol. 6.

Kane, A. V. (1979). Performance Review of a Large-Scale CO2-WAG Enhanced Recovery Project, SACROC Unit KellySnyder Field. Journal of Petroleum Technology 31 (02): 217-231. 10.2118/7091-PA.

Kawahara, Y., Mitsuishi, H., Takagi, S., Okabe, H., Nguyen Hai An, Nguyen Manh Hung, Phan Ngoc Trung and Ueda, Y., (2009). Comprehensive CO_2 -EOR Study –Study on Applicability of CO2-EOR to Rang Dong Field –Part I Laboratory Study, Petro Vietnam Journal Vol. 6.

Kamashev, A., Amanbek, Y., (2021). Reservoir Simulation of CO_2 Storage Using Compositional Flow Model for Geological Formations, Department of Mathematics, School of Sciences and Humanities, Nazarbayev University, Nur-Sultan 010000.

Kurtoglu, B., Kazemi, H., Rosen, R., Mickelson, W., & Kosanke, T. (2014). A Rock and Fluid Study of Middle Bakken Formation: Key to Enhanced Oil Recovery.Society of Petroleum Engineers. doi:10.2118/171668-MS.

Klins, Mark A., and S.M. Farouq Ali. (1982). Heavy Oil Production by carbon dioxide injection. The Journal of Canadian Petroleum Technology 21(5): 64-72. PETSOC-82-05-06. https://doi.org/10.2118/82-05-06.

Langston M V, Hoadley S F, Young D N, (2016) "Definitive CO_2 flooding response in the SACROC unit", SPE 17321, 1988. Pu, H., and Li, Y., Novel Capillarity Quantification Method in IOR Process in Bakken Shale Oil Reservoirs. SPE-179533-MS.

Mahdavi, S., James, L.A., (2017). "Investigation of Waterflooding and Carbonated Water Injection (CWI) in a Fractured Porous Media", SCA2017-058, paper presented at the International Symposium of the Society of Core Analysts held in Vienna, Austria.

Pruess, K., Xu, T., Apps, J. et al. (2003). Numerical Modeling of Aquifer Disposal of CO_{2+*}. SPE Journal 8 (01): 49-60.10.2118/83695-PA.

Ramanathan, R., Shehata, A.M., and Nasr-El-Din, H.A. (2015). Water-Alternating-0O2 Injection Process - Does Modifying the Salinity of Injected Brine Improve Oil Recovery? Presented at the Offshore Technology Conference Brazil, Rio de Janeiro, Brazil, 27-29 October. OTC-26253-MS. 10.4043/26253-MS.

Ramanathan, R., Shehata, A.M., and Nasr-El-Din, H.A. (2016). Effect of Rock Aging on Oil Recovery during WaterAlterating-0O2 Injection Process: An Interfacial Tension, Contact Angle, Coreflood, and CT Scan Study. Presented at the SPE Improved Oil Recovery Conference, Tulsa, Oklahoma, 11-13 April. SPE-179674-MS. 10.2118/179674-MS.

Shoaib, S., & Hoffman, B. T. (2009). CO_2 Flooding the Elm Coulee Field. Society of Petroleum Engineers. doi:10.2118/123176-MS.

Song, C., & Yang, D. (2013). Performance Evaluation of CO_2 Huff-n-Puff Processes in Tight Oil Formations. Society of Petroleum Engineers. doi:10.2118/167217-MS.

Teletzke, G.F, Wattenbarger, R.C. and Wilkinson J.R., (2010). Enhanced Oil Recovery Pilot Testing Best Practices, SPE-118055-PA

Wang, X., Luo, P., Er, V., & Huang, S.-S. S. (2010). Assessment of CO_2 Flooding Potential for Bakken Formation, Saskatchewan. Society of Petroleum Engineers. doi: 10.2118/137728-MS.

Xu, T., & Hoffman, T. (2013). Hydraulic Fracture Orientation for Miscible Gas Injection EOR in Unconventional Oil Reservoirs. Society of Petroleum Engineers. doi:10.1190/URTEC2013-189

Yu et al., (2016). Experimental Evaluation of Shale Oil Recovery from Eagle Ford Core Samples by Nitrogen Gas Flooding. SPE-179547-MS Paper presented at the SPE Improved Oil Recovery Conference held in Tulsa, Oklahoma, USA, 11–13 April 2016.

Yu, W., Lashgari, H., & Sepehrnoori, K. (2014). Simulation Study of CO_2 Huff-n-Puff Process in Bakken Tight OilReservoirs. Society of Petroleum Engineers. doi:10.2118/169575 MS.

Zhang, K., (2016). Experimental and Numerical Investigation of Oil Recovery from Bakken Formation by Miscible CO_2 Injection. Paper SPE 184486 presented at the SPE International Student Paper Contest at the SPE Annual Technical Conference and Exhibition held in Dubai, UAE, 26-28 September 2016.

Zhong Z, Liu S, Carr TR, Takbiri-Borujeni A, Kazemi M, Fu Q (2019). Numerical simulation of Water-Alternating-Gas process for optimizing EOR and carbon storage. Energy Procedia 158:6079–6086. https ://doi.org/10.1016/j.egypr o.2019.01.507

Zhu, P., Balhoff, M. T., & Mohanty, K. K. (2015). Simulation of Fracture-to-Fracture Gas Injection in an Oil-Rich Shale. Society of Petroleum Engineers. doi:10.2118/175131-MSSPE-180270-MS17.

Appendices

Appendix A

WAG (3 Months CO_2 Injection, 5 Year Water Injection) Flooding CMG-STARS Data with 2 Horizontal 2 Vertical Producer Well Configurations

```
INUNIT FIELD
WSRF WELL 1
WSRF GRID TIME
WSRF SECTOR TIME
OUTSRF GRID PRES SG SO SW TEMP
OUTSRF WELL LAYER NONE
WPRN GRID 0
OUTPRN GRID NONE
OUTPRN RES NONE

** Distance units: ft
RESULTS XOFFSET          0.0000
RESULTS YOFFSET          0.0000

** (DEGREES)
** (DEGREES)
** (DEGREES)
** (DEGREES)
** (DEGREES)
RESULTS ROTATION          0.0000 ** (DEGREES)
RESULTS AXES-DIRECTIONS 1.0 -1.0 1.0

**
**********************************************************************
*******
** Definition of fundamental cartesian grid
**
**********************************************************************
*******
GRID VARI 24 12 9
KDIR DOWN
DI IVAR
24*1296.9
DJ JVAR
12*2593.8
DK ALL
 2016*22.2002 576*22.2998
DTOP
 288*7100
** 0 = null block, 1 = active block
NULL CON           1
PERMI CON          150
POR CON        0.2
PERMK CON        133.5
```

```
** 0 = pinched block, 1 = active block
PINCHOUTARRAY CON            1
PERMJ CON          150
END-GRID
** Model and number of components
** Model and number of components
** Model and number of components
MODEL 4 4 4 2
COMPNAME 'Water' 'Surfact' 'Dead_Oil' 'Soln_Gas'
CMM
0 299.41 213.547 25.8188
PCRIT
0 0 0 653.339
TCRIT
0 0 0 -29.6738
KV1
0.0 0.0 0.0 45900.8
KV2
0.0 0.0 0.0 0.00186747
KV3
0.0 0.0 0.0 4.59498
KV4
0.0 0.0 0.0 -1583.98
KV5
0.0 0.0 0.0 -446.782
PRSR 14.6488
TEMR 140
PSURF 14.6488
TSURF 62.33
MASSDEN
68.4931 236.694 53.5476 21.7427
CP
2.82708e-006 2.82708e-006 1.06333e-005 1.06333e-005
CT1
0.000206059 0.000206059 0.000352778 0.000352778
AVG
0 0 0 2.83096e-005
BVG
0 0 0 1
VISCTABLE
**      temp
        37    1.80551    1.80551  1081.24   6.76293 ** Live oil visc (P=2155) =
86.806
        50    1.43604    1.43604   869.715    7.0522 ** Live oil visc (P=2155) =
79.4399
        70    1.07359    1.07359  635.133   7.43441 ** Live oil visc (P=2155) =
69.626
       140   0.516363   0.516363  635.133   7.43441 ** Live oil visc (P=2155) =
69.626
       212   0.309803   0.309803   90.3334   2.85621  ** Live oil visc (P=2155) =
16.2277
```

```
        284    0.21457    0.21457     21.68  1.41749  ** Live oil visc (P=2155) =
5.58848
        356   0.169027   0.169027   7.47066  0.839805  ** Live oil visc (P=2155) =
2.52103
        428   0.138837   0.138837   3.32496  0.564033  ** Live oil visc (P=2155) =
1.37666
        500   0.117754   0.117754    1.7801  0.414747  ** Live oil visc (P=2155) =
0.862951
        572  0.0999595  0.0999595   1.09166  0.325996  ** Live oil visc (P=2155) =
0.59869
        644  0.0875591  0.0875591  0.740959  0.269332  ** Live oil visc (P=2155) =
0.448065
        716  0.0776075  0.0776075  0.543138  0.231091  ** Live oil visc (P=2155) =
0.355177
        788  0.0695055  0.0695055  0.422366  0.204126  ** Live oil visc (P=2155) =
0.294258
        860  0.0627602  0.0627602  0.343889   0.18443  ** Live oil visc (P=2155) =
0.252305
        932   0.057057   0.057057  0.290286  0.169623  ** Live oil visc (P=2155) =
0.222252
       1004  0.0521719  0.0521719  0.252163  0.158223  ** Live oil visc (P=2155) =
0.20002
       1076  0.0479405  0.0479405  0.224135  0.149269  ** Live oil visc (P=2155) =
0.183131
       1148  0.0442399  0.0442399  0.202954  0.142116  ** Live oil visc (P=2155) =
0.170011
       1220   0.040976   0.040976  0.186572  0.136319  ** Live oil visc (P=2155) =
0.159626
       1292   0.038076   0.038076  0.173653  0.13156  ** Live oil visc (P=2155) =
0.151273
       1364  0.0354821  0.0354821  0.163292  0.127612  ** Live oil visc (P=2155) =
0.144459
       1436  0.0331483  0.0331483  0.154862  0.124304  ** Live oil visc (P=2155) =
0.138835
       1508  0.0310374  0.0310374  0.147917  0.121508  ** Live oil visc (P=2155) =
0.134142
VSMIXCOMP 'Soln_Gas'
VSMIXENDP 0.00797116 0.51
VSMIXFUNC 0.00797116 0.0761352 0.136785 0.191817 0.242731 0.290437
0.335853 0.379797 0.422786 0.465378 0.508075
ROCKFLUID
RPT 1 WATWET
INTCOMP 'Surfact' WATER
IFTTABLE
**  Composition of component/phase  Interfacial tension
                         0                  30
                     0.001                   1
INTLIN
FMMOB 0.1
KRINTRP 1
DTRAPW 1
```

DTRAPN 1
** Sw krw krow
SWT

0.3	0	1
0.31875	0.000717474	0.878906
0.3375	0.0028699	0.765625
0.35625	0.00645727	0.660156
0.375	0.0114796	0.5625
0.39375	0.0179369	0.472656
0.4125	0.0258291	0.390625
0.43125	0.0351563	0.316406
0.45	0.0459184	0.25
0.46875	0.0581154	0.191406
0.4875	0.0717474	0.140625
0.50625	0.0868144	0.0976563
0.525	0.103316	0.0625
0.54375	0.121253	0.0351563
0.5625	0.140625	0.015625
0.58125	0.161432	0.00390625
0.6	0.183673	0
0.8	0.510204	0
1	1	0

** Sl krg krog
SLT

0.3	0.3	0
0.525	0.128254	0
0.75	0.0284024	0
0.7625	0.024963	0.0025
0.775	0.0217456	0.01
0.7875	0.01875	0.0225
0.8	0.0159763	0.04
0.8125	0.0134246	0.0625
0.825	0.0110947	0.09
0.8375	0.00898669	0.1225
0.85	0.00710059	0.16
0.8625	0.00543639	0.2025
0.875	0.00399408	0.25
0.8875	0.00277367	0.3025
0.9	0.00177515	0.36
0.9125	0.000998521	0.4225
0.925	0.000443787	0.49
0.9375	0.000110947	0.5625
0.95	0	0.64
0.975	0	0.81
1	0	1

KRINTRP 2
DTRAPW 0.909091
DTRAPN 0.909091

```
**       Sw          krw        krow
SWT
        0.3           0           1
     0.31875  0.000717474    0.878906
      0.3375    0.0028699    0.765625
     0.35625   0.00645727    0.660156
       0.375    0.0114796      0.5625
     0.39375    0.0179369    0.472656
      0.4125    0.0258291    0.390625
     0.43125    0.0351563    0.316406
        0.45    0.0459184        0.25
     0.46875    0.0581154    0.191406
      0.4875    0.0717474    0.140625
     0.50625    0.0868144   0.0976563
       0.525     0.103316      0.0625
     0.54375     0.121253   0.0351563
      0.5625     0.140625    0.015625
     0.58125    `0.161432 0.00390625
         0.6     0.183673           0
         0.8     0.510204           0
           1            1           0


**       Sl          krg      krog

SLT
         0.3          0.3         0
       0.525     0.128254         0
        0.75    0.0284024         0
      0.7625     0.024963    0.0025
       0.775    0.0217456      0.01
      0.7875      0.01875    0.0225
         0.8    0.0159763      0.04
      0.8125    0.0134246    0.0625
       0.825    0.0110947      0.09
      0.8375   0.00898669    0.1225
        0.85   0.00710059      0.16
      0.8625   0.00543639    0.2025
       0.875   0.00399408      0.25
      0.8875   0.00277367    0.3025
         0.9   0.00177515      0.36
      0.9125  0.000998521    0.4225
       0.925  0.000443787      0.49
      0.9375  0.000110947    0.5625
        0.95            0      0.64
       0.975            0      0.81
           1            0         1
KRWIRO 0.909091
KRGCW 0.909091
ADSCOMP 'Surfact' WATER
```

```
ADSTABLE
**    Mole Fraction Adsorbed moles per unit pore volume
**    Mole Fraction Adsorbed moles per unit pore volume
              0                        0
   6.024164656e-005              0.0004573024163
ADMAXT 0.000457302
BSOIRW CON        0.4
INTERP_ENDS ON
INITIAL
VERTICAL DEPTH_AVE

INITREGION 1
REFDEPTH 7100
DWOC 7250
DGOC 7100
REFPRES 3840
SO CON        0.7
MFRAC_WAT 'Water' CON          1
MFRAC_OIL 'Soln_Gas' CON    0.497041
MFRAC_OIL 'Dead_Oil' CON    0.502959
NUMERICAL
RUN
DATE 2010 1 1
DTWELL 0.01
**
WELL 'PRODUCER'
PRODUCER 'PRODUCER'
OPERATE MIN BHP 32.0 CONT
OPERATE  MAX  STO  10000.0  CONT
**        rad geofac wfrac skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'PRODUCER'
** UBA           ff         Status Connection
   7 6 1        1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   7 6 2        1.0 OPEN     FLOW-TO  1
   7 6 3        1.0  OPEN    FLOW-TO  2
   7 6 4        1.0  OPEN    FLOW-TO  3
   7 6 5        1.0  OPEN    FLOW-TO  4
   7 6 6        1.0  OPEN    FLOW-TO  5
   7 6 7        1.0  OPEN    FLOW-TO  6
   7 6 8        1.0  OPEN    FLOW-TO  7
   7 6 9        1.0  OPEN    FLOW-TO  8
**
WELL  'INJECTOR- 1'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR- 1'
INCOMP  WATER  0.5 0.5  0.0  0.0
TINJW  100.0
OPERATE MAX BHP 12000.0 CONT
OPERATE  MAX  STG  1000000.0  CONT
**        rad geofac wfrac skin
GEOMETRY  K  0.28  0.249  1.0  0.0
```

```
    PERF     GEOA  'INJECTOR- 1'
** UBA          ff         Status  Connection
   2 2 1        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   2 2 2        1.0  OPEN    FLOW-FROM  1
   2 2 3        1.0  OPEN    FLOW-FROM  2
   2 2 4        1.0  OPEN    FLOW-FROM  3
   2 2 5        1.0  OPEN    FLOW-FROM  4
   2 2 6        1.0  OPEN    FLOW-FROM  5
   2 2 7        1.0  OPEN    FLOW-FROM  6
   2 2 8        1.0  OPEN    FLOW-FROM  7
   2 2 9        1.0  OPEN    FLOW-FROM  8
**
WELL  'INJECTOR- 2'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR- 2'
INCOMP  WATER  0.5 0.5  0.0  0.0
TINJW  100.0
OPERATE MAX BHP 12000.0 CONT
OPERATE  MAX  STG  1000000.0  CONT
**         rad geofac wfrac skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'INJECTOR- 2'
** UBA           ff         Status  Connection
   22 2 1       1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   22 2 2       1.0  OPEN    FLOW-FROM  1
   22 2 3       1.0  OPEN    FLOW-FROM  2
   22 2 4       1.0  OPEN    FLOW-FROM  3
   22 2 5       1.0  OPEN    FLOW-FROM  4
   22 2 6       1.0  OPEN    FLOW-FROM  5
   22 2 7       1.0  OPEN    FLOW-FROM  6
   22 2 8       1.0  OPEN    FLOW-FROM  7
   22 2 9       1.0  OPEN    FLOW-FROM  8
**
**
WELL  'INJECTOR-3'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR-3'
INCOMP  WATER  0.5 0.5  0.0  0.0
TINJW  100.0
OPERATE MAX BHP 12000.0 CONT
OPERATE  MAX  STG  1000000.0  CONT
**         rad geofac wfrac skin
GEOMETRY  K  0.28  0.249  1.0  0.0
    PERF     GEOA  'INJECTOR-3'
** UBA           ff         Status  Connection
   21 9 1       1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   21 9 2       1.0  OPEN    FLOW-FROM  1
   21 9 3       1.0  OPEN    FLOW-FROM  2
   21 9 4       1.0  OPEN    FLOW-FROM  3
   21 9 5       1.0  OPEN    FLOW-FROM  4
   21 9 6       1.0  OPEN    FLOW-FROM  5
   21 9 7       1.0  OPEN    FLOW-FROM  6
   21 9 8       1.0  OPEN    FLOW-FROM  7
```

```
   21 9 9        1.0  OPEN    FLOW-FROM  8
**
**
WELL  'INJECTOR-4'
INJECTOR MOBWEIGHT EXPLICIT 'INJECTOR-4'
INCOMP  WATER  0.5 0.5  0.0  0.0
TINJW  100.0
OPERATE MAX BHP 12000.0 CONT
OPERATE  MAX  STG  1000000.0  CONT
**         rad geofac wfrac skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'INJECTOR-4'
** UBA            ff         Status  Connection
   4 9 1        1.0  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   4 9 2        1.0  OPEN    FLOW-FROM  1
   4 9 3        1.0  OPEN    FLOW-FROM  2
   4 9 4        1.0  OPEN    FLOW-FROM  3
   4 9 5        1.0  OPEN    FLOW-FROM  4
   4 9 6        1.0  OPEN    FLOW-FROM  5
   4 9 7        1.0  OPEN    FLOW-FROM  6
   4 9 8        1.0  OPEN    FLOW-FROM  7
   4 9 9        1.0  OPEN    FLOW-FROM  8
**
WELL  'PRODUCER 2'
PRODUCER 'PRODUCER  2'
OPERATE MIN BHP 32.0 CONT
OPERATE  MAX  STO  10000.0  CONT
**         rad geofac wfrac skin
GEOMETRY  K  0.28  0.249  1.0  0.0
     PERF     GEOA  'PRODUCER 2'
** UBA            ff         Status  Connection
   19 6 1        1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
   19 6 2        1.0  OPEN    FLOW-TO  1
   19 6 3        1.0  OPEN    FLOW-TO  2
   19 6 4        1.0  OPEN    FLOW-TO  3
   19 6 5        1.0  OPEN    FLOW-TO  4
   19 6 6        1.0  OPEN    FLOW-TO  5
   19 6 7        1.0  OPEN    FLOW-TO  6
   19 6 8        1.0  OPEN    FLOW-TO  7
   19 6 9        1.0  OPEN    FLOW-TO  8
DATE 2010 2  1.00000
DATE 2010 3  1.00000
DATE 2010 4  1.00000
DATE 2010 5  1.00000
DATE 2010 6  1.00000
DATE 2010 7  1.00000
DATE 2010 8  1.00000
DATE 2010 9  1.00000
DATE 2010 10  1.00000
DATE 2010 11  1.00000
DATE 2010 12  1.00000
```

DATE 2011 1 1.00000
DATE 2011 2 1.00000
DATE 2011 3 1.00000
DATE 2011 4 1.00000
DATE 2011 5 1.00000
DATE 2011 6 1.00000
DATE 2011 7 1.00000
DATE 2011 8 1.00000
DATE 2011 9 1.00000
DATE 2011 10 1.00000
DATE 2011 11 1.00000
DATE 2011 12 1.00000
DATE 2012 1 1.00000
DATE 2012 2 1.00000
DATE 2012 3 1.00000
DATE 2012 4 1.00000
DATE 2012 5 1.00000
DATE 2012 6 1.00000
DATE 2012 7 1.00000
DATE 2012 8 1.00000
DATE 2012 9 1.00000
DATE 2012 10 1.00000
DATE 2012 11 1.00000
DATE 2012 12 1.00000
DATE 2013 1 1.00000
DATE 2013 2 1.00000
DATE 2013 3 1.00000
DATE 2013 4 1.00000
DATE 2013 5 1.00000
DATE 2013 6 1.00000
DATE 2013 7 1.00000
DATE 2013 8 1.00000
DATE 2013 9 1.00000
DATE 2013 10 1.00000
DATE 2013 11 1.00000
DATE 2013 12 1.00000
DATE 2014 1 1.00000
DATE 2014 2 1.00000
DATE 2014 3 1.00000
DATE 2014 4 1.00000
DATE 2014 5 1.00000
DATE 2014 6 1.00000
DATE 2014 7 1.00000
DATE 2014 8 1.00000
DATE 2014 9 1.00000
DATE 2014 10 1.00000
DATE 2014 11 1.00000
DATE 2014 12 1.00000
DATE 2015 1 1.00000
DATE 2015 2 1.00000
DATE 2015 3 1.00000

DATE 2015 4 1.00000
DATE 2015 5 1.00000
DATE 2015 6 1.00000
DATE 2015 7 1.00000
DATE 2015 8 1.00000
DATE 2015 9 1.00000
DATE 2015 10 1.00000
DATE 2015 11 1.00000
DATE 2015 12 1.00000
DATE 2016 1 1.00000
DATE 2016 2 1.00000
DATE 2016 3 1.00000
DATE 2016 4 1.00000
DATE 2016 5 1.00000
DATE 2016 6 1.00000
DATE 2016 7 1.00000
DATE 2016 8 1.00000
DATE 2016 9 1.00000
DATE 2016 10 1.00000
DATE 2016 11 1.00000
DATE 2016 12 1.00000
DATE 2017 1 1.00000
DATE 2017 2 1.00000
DATE 2017 3 1.00000
DATE 2017 4 1.00000
DATE 2017 5 1.00000
DATE 2017 6 1.00000
DATE 2017 7 1.00000
DATE 2017 8 1.00000
DATE 2017 9 1.00000
DATE 2017 10 1.00000
DATE 2017 11 1.00000
DATE 2017 12 1.00000
DATE 2018 1 1.00000
DATE 2018 2 1.00000
DATE 2018 3 1.00000
DATE 2018 4 1.00000
DATE 2018 5 1.00000
DATE 2018 6 1.00000
DATE 2018 7 1.00000
DATE 2018 8 1.00000
DATE 2018 9 1.00000
DATE 2018 10 1.00000
DATE 2018 11 1.00000
DATE 2018 12 1.00000
DATE 2019 1 1.00000
DATE 2019 2 1.00000
DATE 2019 3 1.00000
DATE 2019 4 1.00000
DATE 2019 5 1.00000
DATE 2019 6 1.00000

DATE 2019 7 1.00000
DATE 2019 8 1.00000
DATE 2019 9 1.00000
DATE 2019 10 1.00000
DATE 2019 11 1.00000
DATE 2019 12 1.00000
DATE 2020 1 1.00000
DATE 2020 2 1.00000
DATE 2020 3 1.00000
DATE 2020 4 1.00000
DATE 2020 5 1.00000
DATE 2020 6 1.00000
DATE 2020 7 1.00000
DATE 2020 8 1.00000
DATE 2020 9 1.00000
DATE 2020 10 1.00000
DATE 2020 11 1.00000
DATE 2020 12 1.00000
DATE 2021 1 1.00000
DATE 2021 2 1.00000
DATE 2021 3 1.00000
DATE 2021 4 1.00000
DATE 2021 5 1.00000
DATE 2021 6 1.00000
DATE 2021 7 1.00000
DATE 2021 8 1.00000
DATE 2021 9 1.00000
DATE 2021 10 1.00000
DATE 2021 11 1.00000
DATE 2021 12 1.00000
DATE 2022 1 1.00000
DATE 2022 2 1.00000
STOP
RESULTS PVTIMEX VISCREGION 1
RESULTS PVTIMEX PVTREGION 1 FALSE
RESULTS PVTIMEX TABLECOLS P RS BO BG VISO VISG DENOIL DENGAS CO
RESULTS PVTIMEX TABLE 101.325 0.790495 1.03671 1.147 621.844 0.0110236 850.382 0.949657 4.35113e-006
RESULTS PVTIMEX TABLE 1085.12 4.90752 1.04627 0.104287 517.025 0.0112062 846.898 10.4448 4.35113e-006
RESULTS PVTIMEX TABLE 2068.91 9.83239 1.058 0.0532138 431.088 0.0114665 842.579 20.4694 4.35113e-006
RESULTS PVTIMEX TABLE 3052.7 15.2348 1.0712 0.03506 365.429 0.0117889 837.69 31.0683 4.35113e-006
RESULTS PVTIMEX TABLE 4036.49 20.9903 1.0856 0.0257603 315.143 0.0121741 832.353 42.2843 4.35113e-006
RESULTS PVTIMEX TABLE 5020.29 27.0303 1.10106 0.0201147 276.001 0.0126266 826.641 54.1523 4.35113e-006
RESULTS PVTIMEX TABLE 6004.08 33.3104 1.11748 0.0163328 244.956 0.0131533 820.616 66.6914 4.35113e-006

RESULTS PVTIMEX TABLE 6987.84 39.7996 1.13479 0.0136338 219.885 0.0137616 814.327 79.8937 4.35113e-006
RESULTS PVTIMEX TABLE 7971.65 46.4743 1.15293 0.0116237 199.301 0.0144588 807.821 93.7097 4.35113e-006
RESULTS PVTIMEX TABLE 8955.46 53.3165 1.17185 0.0100822 182.151 0.0152497 801.138 108.037 4.35113e-006
RESULTS PVTIMEX TABLE 9939.27 60.3117 1.19152 0.00887626 167.675 0.0161358 794.307 122.716 3.99498e-006
RESULTS PVTIMEX TABLE 10923 67.4479 1.21189 0.00791978 155.313 0.0171133 787.371 137.536 3.53335e-006
RESULTS PVTIMEX TABLE 11906.8 74.7149 1.23294 0.00715365 144.647 0.0181732 780.348 152.266 3.15856e-006
RESULTS PVTIMEX TABLE 12890.6 82.1042 1.25465 0.00653501 135.361 0.0193021 773.26 166.68 2.84893e-006
RESULTS PVTIMEX TABLE 13874.4 89.6086 1.27698 0.00603165 127.208 0.0204843 766.14 180.59 2.58934e-006
RESULTS PVTIMEX TABLE 14858.2 97.2213 1.29992 0.00561883 120 0.0217033 758.998 193.858 2.36894e-006
RESULTS PVTIMEX TABLE 16023.4 106.37 1.29667 0.00522097 120 0.0231739 760.898 208.631 2.14778e-006
RESULTS PVTIMEX TABLE 17188.6 115.656 1.29401 0.00489942 120 0.0246526 762.467 222.324 1.96078e-006
RESULTS PVTIMEX TABLE 18353.8 125.069 1.29179 0.00463617 120 0.0261218 763.776 234.947 1.80083e-006
RESULTS PVTIMEX TABLE 19519.1 134.605 1.28992 0.00441804 120 0.0275684 764.88 246.547 1.66265e-006
RESULTS PVTIMEX TABLE 20684.3 144.257 1.28834 0.00423518 120 0.0289833 765.818 257.192 1.54223e-006
RESULTS PVTIMEX TABLEDO 2.77778 420
RESULTS PVTIMEX TABLEDO 10 340
RESULTS PVTIMEX TABLEDO 21.1111 250
RESULTS PVTIMEX TRES 60
RESULTS PVTIMEX BPP 15
RESULTS PVTIMEX BWI 1.00519
RESULTS PVTIMEX DENSITYWATER 1108.96
RESULTS PVTIMEX VISCOSITYWATER 0.516363
RESULTS PVTIMEX WATERCVW 0
RESULTS PVTIMEX DENSITYOIL 880.738
RESULTS PVTIMEX GASGRAVITY 0.891225
RESULTS PVTIMEX WATERCOMP 4.10033e-007
RESULTS PVTIMEX REFPW 26475.9
RESULTS PVTIMEX CVO 0
RESULTS PVTIMEX RATIODEADPVT 2.46428
RESULTS PVTIMEX VISCPRESSURE 101.3
RESULTS PVTIMEX COMPOSITION 2 0.502959 0.497041
RESULTS PVTIMEX KVALUETEMP FALSE 400 -99999 0 0.264
RESULTS PVTIMEX END
RESULTS PVTIMEX VISCREGION 1
RESULTS PVTIMEX PVTREGION 1 FALSE
RESULTS PVTIMEX TABLECOLS P RS BO BG VISO VISG DENOIL DENGAS CO

RESULTS PVTIMEX TABLE 101.325 0.790495 1.03671 1.147 621.844 0.0110236 850.382 0.949657 4.35113e-006
RESULTS PVTIMEX TABLE 1085.12 4.90752 1.04627 0.104287 517.025 0.0112062 846.898 10.4448 4.35113e-006
RESULTS PVTIMEX TABLE 2068.91 9.83239 1.058 0.0532138 431.088 0.0114665 842.579 20.4694 4.35113e-006
RESULTS PVTIMEX TABLE 3052.7 15.2348 1.0712 0.03506 365.429 0.0117889 837.69 31.0683 4.35113e-006
RESULTS PVTIMEX TABLE 4036.49 20.9903 1.0856 0.0257603 315.143 0.0121741 832.353 42.2843 4.35113e-006
RESULTS PVTIMEX TABLE 5020.29 27.0303 1.10106 0.0201147 276.001 0.0126266 826.641 54.1523 4.35113e-006
RESULTS PVTIMEX TABLE 6004.08 33.3104 1.11748 0.0163328 244.956 0.0131533 820.616 66.6914 4.35113e-006
RESULTS PVTIMEX TABLE 6987.84 39.7996 1.13479 0.0136338 219.885 0.0137616 814.327 79.8937 4.35113e-006
RESULTS PVTIMEX TABLE 7971.65 46.4743 1.15293 0.0116237 199.301 0.0144588 807.821 93.7097 4.35113e-006
RESULTS PVTIMEX TABLE 8955.46 53.3165 1.17185 0.0100822 182.151 0.0152497 801.138 108.037 4.35113e-006
RESULTS PVTIMEX TABLE 9939.27 60.3117 1.19152 0.00887626 167.675 0.0161358 794.307 122.716 3.99498e-006
RESULTS PVTIMEX TABLE 10923 67.4479 1.21189 0.00791978 155.313 0.0171133 787.371 137.536 3.53335e-006
RESULTS PVTIMEX TABLE 11906.8 74.7149 1.23294 0.00715365 144.647 0.0181732 780.348 152.266 3.15856e-006
RESULTS PVTIMEX TABLE 12890.6 82.1042 1.25465 0.00653501 135.361 0.0193021 773.26 166.68 2.84893e-006
RESULTS PVTIMEX TABLE 13874.4 89.6086 1.27698 0.00603165 127.208 0.0204843 766.14 180.59 2.58934e-006
RESULTS PVTIMEX TABLE 14858.2 97.2213 1.29992 0.00561883 120 0.0217033 758.998 193.858 2.36894e-006
RESULTS PVTIMEX TABLE 16023.4 106.37 1.29667 0.00522097 120 0.0231739 760.898 208.631 2.14778e-006
RESULTS PVTIMEX TABLE 17188.6 115.656 1.29401 0.00489942 120 0.0246526 762.467 222.324 1.96078e-006
RESULTS PVTIMEX TABLE 18353.8 125.069 1.29179 0.00463617 120 0.0261218 763.776 234.947 1.80083e-006
RESULTS PVTIMEX TABLE 19519.1 134.605 1.28992 0.00441804 120 0.0275684 764.88 246.547 1.66265e-006
RESULTS PVTIMEX TABLE 20684.3 144.257 1.28834 0.00423518 120 0.0289833 765.818 257.192 1.54223e-006
RESULTS PVTIMEX TABLEDO 2.77778 420
RESULTS PVTIMEX TABLEDO 10 340
RESULTS PVTIMEX TABLEDO 21.1111 250
RESULTS PVTIMEX TRES 60
RESULTS PVTIMEX BPP 15
RESULTS PVTIMEX BWI 1.00519
RESULTS PVTIMEX DENSITYWATER 1108.96
RESULTS PVTIMEX VISCOSITYWATER 0.516363
RESULTS PVTIMEX WATERCVW 0

RESULTS PVTIMEX DENSITYOIL 880.738
RESULTS PVTIMEX GASGRAVITY 0.891225
RESULTS PVTIMEX WATERCOMP 4.10033e-007
RESULTS PVTIMEX REFPW 26475.9
RESULTS PVTIMEX CVO 0
RESULTS PVTIMEX RATIODEADPVT 2.46428
RESULTS PVTIMEX VISCPRESSURE 101.3
RESULTS PVTIMEX COMPOSITION 2 0.502959 0.497041
RESULTS PVTIMEX KVALUETEMP FALSE 400 -99999 0 0.264
RESULTS PVTIMEX END
RESULTS PROCESSWIZ PROCESS 2
RESULTS PROCESSWIZ FOAMYOILMODEL -1
RESULTS PROCESSWIZ SGC 0.15
RESULTS PROCESSWIZ KRGCW 0.0001
RESULTS PROCESSWIZ COALESCENCE -14503.6 FALSE
RESULTS PROCESSWIZ BUBBLEPT -14503.6
RESULTS PROCESSWIZ MINPRESSURE -14503.6 FALSE
RESULTS PROCESSWIZ NUMSETSFOAMY 2
RESULTS PROCESSWIZ PRODTIME 2207
RESULTS PROCESSWIZ FOAMYREACTIONS 0.00244676 0.453104 0.000453104 0.00453104 4.53104e-005
RESULTS PROCESSWIZ VELOCITYFOAMY TRUE
RESULTS PROCESSWIZ CHEMMODEL 7
RESULTS PROCESSWIZ CHEMDATA1 TRUE FALSE TRUE TRUE FALSE 0 3 FALSE FALSE
RESULTS PROCESSWIZ CHEMDATA2 0.075 -99999 -99999 -99999 0 5 0.9 180 139.244 0 0
RESULTS PROCESSWIZ CHEMDATA3 2.65 0 0.1 0.1 40 0.1
RESULTS PROCESSWIZ FOAMDATA FALSE FALSE TRUE 80 3840 140 1.386 0.693 693 13.86 0 0.02 0.35
RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.4 0 1 0.1 20 0.2 40 0.3 45 0.4 48 0.5 49 0.6 15 0.7 10 0.8 5 0.9 2 1 0.02
RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.6 0 1 0.1 160 0.2 170 0.3 180 0.4 205 0.5 210 0.6 220 0.7 150 0.8 48 0.9 20 1 15
RESULTS PROCESSWIZ TABLEFOAMVISC 0 0.8 0 1 0.1 235 0.2 255 0.3 345 0.4 380 0.5 415 0.6 335 0.7 255 0.8 180 0.9 125 1 40
RESULTS PROCESSWIZ FOAMVISCWEIGHT 1 0.1 0.4 1
RESULTS PROCESSWIZ TABLEIFT 0 18.2
RESULTS PROCESSWIZ TABLEIFT 0.05 0.5
RESULTS PROCESSWIZ TABLEIFT 0.1 0.028
RESULTS PROCESSWIZ TABLEIFT 0.2 0.028
RESULTS PROCESSWIZ TABLEIFT 0.4 0.0057
RESULTS PROCESSWIZ TABLEIFT 0.6 0.00121
RESULTS PROCESSWIZ TABLEIFT 0.8 0.00037
RESULTS PROCESSWIZ TABLEIFT 1 0.5
RESULTS PROCESSWIZ IFTSURFACTANT TRUE 8
RESULTS PROCESSWIZ SURFACTCONC 0 0.05
RESULTS PROCESSWIZ TABLEIFTS 0 23.4
RESULTS PROCESSWIZ TABLEIFTS 0.5 5.163
RESULTS PROCESSWIZ TABLEIFTS 0.75 4.356
RESULTS PROCESSWIZ TABLEIFTS 1 3.715

RESULTS PROCESSWIZ TABLEIFTS 1.25 4.102
RESULTS PROCESSWIZ TABLEIFTS 1.5 3.805
RESULTS PROCESSWIZ TABLEIFTS 1.75 3.521
RESULTS PROCESSWIZ TABLEIFTS 2 2.953
RESULTS PROCESSWIZ TABLEIFTS 0 0.17
RESULTS PROCESSWIZ TABLEIFTS 0.5 0.011
RESULTS PROCESSWIZ TABLEIFTS 0.75 0.005
RESULTS PROCESSWIZ TABLEIFTS 1 0.007
RESULTS PROCESSWIZ TABLEIFTS 1.25 0.007
RESULTS PROCESSWIZ TABLEIFTS 1.5 0.056
RESULTS PROCESSWIZ TABLEIFTS 1.75 0.097
RESULTS PROCESSWIZ TABLEIFTS 2 0.098
RESULTS PROCESSWIZ IFTSURFACTANTSALINITY TRUE 8
RESULTS PROCESSWIZ SURFACTSALINITYCONC 0 0.05
RESULTS PROCESSWIZ TABLEIFTSSALINITY 0 23.4
RESULTS PROCESSWIZ TABLEIFTSSALINITY 15000 5.163
RESULTS PROCESSWIZ TABLEIFTSSALINITY 22500 4.356
RESULTS PROCESSWIZ TABLEIFTSSALINITY 30000 3.715
RESULTS PROCESSWIZ TABLEIFTSSALINITY 37500 4.102
RESULTS PROCESSWIZ TABLEIFTSSALINITY 45000 3.805
RESULTS PROCESSWIZ TABLEIFTSSALINITY 52500 3.521
RESULTS PROCESSWIZ TABLEIFTSSALINITY 60000 2.953
RESULTS PROCESSWIZ TABLEIFTSSALINITY 0 0.17
RESULTS PROCESSWIZ TABLEIFTSSALINITY 15000 0.011
RESULTS PROCESSWIZ TABLEIFTSSALINITY 22500 0.005
RESULTS PROCESSWIZ TABLEIFTSSALINITY 30000 0.007
RESULTS PROCESSWIZ TABLEIFTSSALINITY 37500 0.007
RESULTS PROCESSWIZ TABLEIFTSSALINITY 45000 0.056
RESULTS PROCESSWIZ TABLEIFTSSALINITY 52500 0.097
RESULTS PROCESSWIZ TABLEIFTSSALINITY 60000 0.098
RESULTS PROCESSWIZ ADSORPTION TRUE TRUE FALSE TRUE 2 TRUE
RESULTS PROCESSWIZ ADSPOR 0.2494 0.2494 0.2494
RESULTS PROCESSWIZ ADSSURF 0 0
RESULTS PROCESSWIZ ADSSURF 0.1 27.5
RESULTS PROCESSWIZ ADSALK 0 0
RESULTS PROCESSWIZ ADSALK 0.1 50
RESULTS PROCESSWIZ ADSPOLYMER 0 0
RESULTS PROCESSWIZ ADSPOLYMER 0.1 50
RESULTS PROCESSWIZ ALKALINECONC 0 0.3 0.6
RESULTS PROCESSWIZ ADSSURF2 0 0
RESULTS PROCESSWIZ ADSSURF2 0.1 27.5
RESULTS PROCESSWIZ ADSSURF2 0 0
RESULTS PROCESSWIZ ADSSURF2 0.1 39.5
RESULTS PROCESSWIZ ADSSURF2 0 0
RESULTS PROCESSWIZ ADSSURF2 0.1 51
RESULTS PROCESSWIZ SALINITYPPM 0 30000 60000
RESULTS PROCESSWIZ ADSSURF3 0 0
RESULTS PROCESSWIZ ADSSURF3 0.1 27.5
RESULTS PROCESSWIZ ADSSURF3 0 0
RESULTS PROCESSWIZ ADSSURF3 0.1 39.5
RESULTS PROCESSWIZ ADSSURF3 0 0

RESULTS PROCESSWIZ ADSSURF3 0.1 51
RESULTS PROCESSWIZ VELOCITY 0.0328084
RESULTS PROCESSWIZ SALINITY 1000
RESULTS PROCESSWIZ COMPPOLY 0 0.03 0.05 0.075
RESULTS PROCESSWIZ POLYVISC 0.516363 3.5 5.2 10.8
RESULTS PROCESSWIZ COMPSALINITY 0 0.03 0.05 0.075
RESULTS PROCESSWIZ SALINITYVISC 0.516363 3.5 5.2 10.8
RESULTS PROCESSWIZ SALINITY_INITIAL -99999
RESULTS PROCESSWIZ FINES 10000 8000 240 15000 500 50 10 5000 0.0001 6.5839e+019 FALSE
RESULTS PROCESSWIZ LSWI 50 0.00614738 0.556808 0 2 2 'Ca-X2'
RESULTS PROCESSWIZ LSWIREACT FALSE FALSE FALSE FALSE TRUE TRUE TRUE FALSE FALSE FALSE FALSE FALSE FALSE 0.9999
RESULTS PROCESSWIZ LSWIREACTAQ
RESULTS PROCESSWIZ LSWIREACTMIN
RESULTS PROCESSWIZ LSWIREACTAQMINTEQ
RESULTS PROCESSWIZ LSWIREACTMINMINTEQ
RESULTS PROCESSWIZ LSWIRPT 0.6 0.7
RESULTS PROCESSWIZ LSWIRPTCHG TRUE 0.001 2 4
RESULTS PROCESSWIZ LSWIAQINJ
RESULTS PROCESSWIZ LSWIAQINIT
RESULTS PROCESSWIZ LSWIMIN
RESULTS PROCESSWIZ ISCMODEL -1 FALSE TRUE FALSE FALSE FALSE FALSE FALSE
RESULTS PROCESSWIZ ISCDATA 4.29923 120.238 1.52043e+008 1.58801e+008 0.065 0.708108 0.065 0.708108
RESULTS PROCESSWIZ REACTO2 0 0 1 0
RESULTS PROCESSWIZ BURN 0 0 1 1
RESULTS PROCESSWIZ CRACK 0 0 1 0
RESULTS PROCESSWIZ COMPNAMES
RESULTS PROCESSWIZ BLOCKAGE FALSE 4
RESULTS PROCESSWIZ END
RESULTS RELPERMCORR NUMROCKTYPE 1
RESULTS RELPERMCORR CORRVALS 0.3 0.3 0 0.4 0 0.45 0 0.05
RESULTS RELPERMCORR CORRVALS 1 1 0.3 -99999 2 2 2 2
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999
RESULTS RELPERMCORR NOSWC false
RESULTS RELPERMCORR CALINDEX 0
RESULTS RELPERMCORR STOP
RESULTS RELPERMCORR NUMROCKTYPE 1
RESULTS RELPERMCORR NUMISET 2
RESULTS RELPERMCORR CORRVALS 0.3 0.3 0 0.4 0 0.45 0 0.05
RESULTS RELPERMCORR CORRVALS 1 1 0.3 -99999 2 2 2 2
RESULTS RELPERMCORR CORRVALS_HONARPOUR -99999 -99999 -99999 -99999 -99999 -99999 -99999 -99999
RESULTS RELPERMCORR NOSWC false
RESULTS RELPERMCORR CALINDEX 0
RESULTS RELPERMCORR STOP

RESULTS SPEC 'Oil Saturation'

```
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.809
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Irreducible Oil Sat W-O ST'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.202
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Irreducible Oil Sat W-O ST'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.3
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Oil Saturation'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.65
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Irreducible Oil Sat W-O ST'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.5
RESULTS SPEC SPECKEEPMOD 'YES'
```

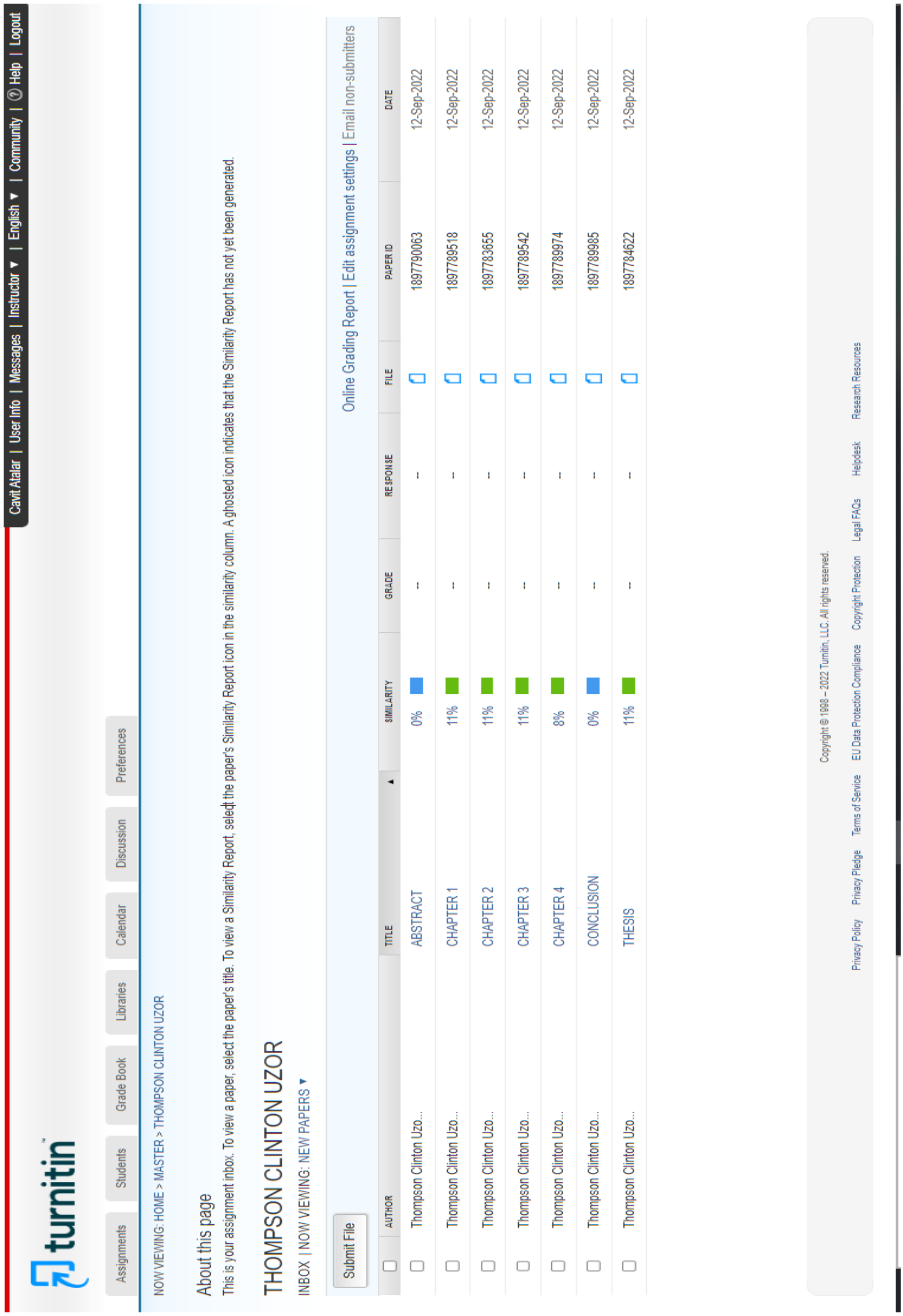
```
RESULTS SPEC STOP


RESULTS SPEC 'Irreducible Oil Sat W-O ST'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.45
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Oil Saturation'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.8
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Irreducible Oil Sat W-O ST'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.4
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Porosity'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.2
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Permeability I'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
```

```
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 150
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Permeability J'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 150
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Permeability K'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 133.5
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Oil Saturation'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'All Layers (Whole Grid)'
RESULTS SPEC REGIONTYPE 'REGION_WHOLEGRID'
RESULTS SPEC LAYERNUMB 0
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 0.7
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Grid Thickness'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 2 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 2
RESULTS SPEC PORTYPE 1
```

```
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 3 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 3
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 4 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 4
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 5 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 5
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 6 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 6
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 7 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 7
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.2
RESULTS SPEC REGION 'Layer 8 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 8
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.3
RESULTS SPEC REGION 'Layer 9 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 9
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 22.3
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP


RESULTS SPEC 'Grid Top'
RESULTS SPEC SPECNOTCALCVAL -99999
RESULTS SPEC REGION 'Layer 1 - Whole layer'
RESULTS SPEC REGIONTYPE 'REGION_LAYER'
RESULTS SPEC LAYERNUMB 1
RESULTS SPEC PORTYPE 1
RESULTS SPEC CON 7100
RESULTS SPEC SPECKEEPMOD 'YES'
RESULTS SPEC STOP
.
.
```

Appendix B

Turnitin Similarity Report



turnitin

Cavit Atalar | User Info | Messages | Instructor ▾ | English ▾ | Community | Help | Logout

Assignments | Students | Grade Book | Libraries | Calendar | Discussion | Preferences

NOW VIEWING: HOME > MASTER > THOMPSON CLINTON UZOR

About this page

This is your assignment inbox. To view a paper, select the paper's title. To view a Similarity Report, select the paper's Similarity Report icon in the similarity column. A ghosted icon indicates that the Similarity Report has not yet been generated.

THOMPSON CLINTON UZOR

INBOX | NOW VIEWING: NEW PAPERS ▾

Submit File

Online Grading Report | Edit assignment settings | Email non-submitters

AUTHOR	TITLE	SIMILARITY	GRADE	RESPONSE	FILE	PAPER ID	DATE
Thompson Clinton Uzo...	ABSTRACT	0%	--	--		1897790063	12-Sep-2022
Thompson Clinton Uzo...	CHAPTER 1	11%	--	--		1897789518	12-Sep-2022
Thompson Clinton Uzo...	CHAPTER 2	11%	--	--		1897783655	12-Sep-2022
Thompson Clinton Uzo...	CHAPTER 3	11%	--	--		1897789542	12-Sep-2022
Thompson Clinton Uzo...	CHAPTER 4	8%	--	--		1897789974	12-Sep-2022
Thompson Clinton Uzo...	CONCLUSION	0%	--	--		1897789985	12-Sep-2022
Thompson Clinton Uzo...	THESIS	11%	--	--		1897784622	12-Sep-2022

Appendix C

Ethical Approval Letter

YAKIN DOĞU ÜNİVERSİTESİ
ETHICAL APPROVAL DOCUMENT

Date: 13/09/2022

To the **Institute of Graduate Studies**

The research project titled "**ASSESSMENT OF CO_2 INJECTION BY MISCIBLE FLOODING AND WAG APPLICATION VIA HORIZONTAL AND VERTICAL WELL CONFIGURATIONS**'' has been evaluated. Since the researcher will not collect primary data from humans, animals, plants or earth, this project does not need through the ethics committee.

Title: Prof. Dr.

Name Surname: Cavit ATALAR

Signature:

Role in the Research Project: Supervisor