NEAR EAST UNIVERSITY

INSTITUTE OF GRADUATE STUDIES

DEPARTMENT OF PETROLEUM AND NATURAL GAS ENGINEERING

ASSESSMENT OF CYCLIC STEAM STIMULATION AND CYCLIC CO_2 STIMULATION FOR HEAVY OIL RECOVERY

MSc. THESIS

Isa Yakubu MUHAMMAD

Nicosia

JUNE, 2022

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Approval

We certify that we have read the thesis submitted by Isa Yakubu MUHAMMAD titled **"Assessment of Cyclic Steam Stimulation and Cyclic CO_2 Stimulation for Heavy Oil Recovery"** and that in our combined opinion it is fully adequate, in scope, and quality, as a thesis for the degree of Master of Applied Sciences.

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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.

ISA YAKUBU MUHAMMAD

21/06/2022

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ISA YAKUBU MUHAMMAD

Abstract

Assessment of Cyclic Steam Stimulation and Cyclic CO_2 Stimulation for Heavy Oil Recovery

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CSS (Cyclic steam stimulation) and CCO_2S (Cyclic CO_2 stimulation) are used in high viscosity reservoirs to decrease the viscosity of the oil and increase mobility. Steam is injected in CSS and CO_2 is injected in CCO_2S. In this research, we investigated the CSS and CCO_2S separately and together.

CSS and CCO_2S applications were tested separately and together in a 13x1x4 radial model to optimize the recovery of heavy oil, having a 20 ˚API gravity with 300 cp viscosity at reservoir conditions. CMG-STARS was used for the simulations. The effects of injecting carbon dioxide and steam into the formation were first examined. Furthermore, the results of a varying number of days for both the injection process and different pressures were assessed The injection fluid, steam, or CO_2 is injected into the well at a specific rate and time. The soak period for both cyclic processes can be viewed as the most important because it is mainly responsible for the initiation of effective drive mechanisms that are responsible for oil production. Overall, both processes would cause an increase in oil swelling, reduction in oil viscosity, and mobilization of residual oil.

CSS, CCO_2S, and combined CSS and CCO_2S were all successful, feasible, and economical for the test reservoir. The combination of CSS and CCO_2S economically produced more than 95 MSTB of oil for the entire field. This accounts for approximately an 8.6% increase in recovery. The best performance was obtained when CO_2 has injected after steam for cycles of steam stimulation alternating CO_2 stimulation. CCO_2S alternating CSS and CCO_2S followed by CSS operations are not favorable and not recommended for the combined process.

***Keywords*:** Steam, CO_2, viscosity reduction, CSS, CCO_2S

Özet

Ağır Petrol Üretiminde Döngüsel Buhar Uygulaması ve Döngüsel CO_2

Uygulamasının Değerlendirilmesi

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Yüksek viskoziteli ağır petrol bulunan rezervuarlarda petrolün viskozitesini azaltmak ve hareket kabiliyetini artırmak için DBU (Döngüsel buhar uyarımı) ve CCO2S (Döngüsel CO2 uyarımı) kullanılmaktadır. Ağır petrol sahasına DBU'da buhar enjeksiyonu yapılarak, DCO2U da ise CO2 enjeksiyonu yapılarak üretim sağlanmaktadır. Bu araştırmada, DBU ve DCO2U ayrı ayrı ve birlikte incelenmiştir.

DBU ve DCO_2U uygulamaları Rezervuar koşullarında 300 cp viskozite ile 20 ˚API yoğunluğuna sahip ağır petrol sahasının optimize edilmesi amacıyla 13x1x4 radyal simülasyon modeli kullanılarak çeşitli senaryolarla test edilmiştir. Simülasyonlar için CMG-STARS kullanılmıştır. İlk olarak formasyona karbondioksit ve buhar enjekte edilmesinin etkileri incelenmiştir. Ayrıca, hem enjeksiyon işlemi hem de farklı basınçlar için değişen gün sayılarının sonuçları değerlendirilmiştir. Enjeksiyon sıvısı, buhar veya CO_2 kuyuya belirli bir hız ve zamanda enjekte edilir. Her iki döngüsel süreç için de ıslatma süresi en önemli olarak görülebilir çünkü esas olarak petrol üretiminden sorumlu olan etkili tahrik mekanizmalarının başlatılmasından sorumludur. Genel olarak, her iki işlem de petrolün genleşmesinde bir artışa, viskozitesinde azalmaya ve kalan petrolün mobilizasyonunu sağlayacaktır.

DBU, DCO_2U ve birleştirilmiş DBU ve DCO_2U, test rezervuarı için başarılı, uygulanabilir ve ekonomik sonuçlar vermiştir. DBU ve DCO_2U kombinasyonu, tüm saha için ekonomik olarak 95 MSTB'den fazla petrol ürettmiştir. Bu, iyileşmede yaklaşık %8,6'lık bir artışa sebep olmuştur. En iyi performans, CO_2 uyarımı dönüşümlü olarak buhar uyarımı döngüleri için buhardan sonra CO_2 enjekte edildiğinde elde edilmiştir. DCO_2U dönüşümlü DBU ve DCO_2U ardından DBU işlemleri uygun değildir ve birleşik işlem için önerilmez.

***Anahtar Kelimeler*:** Buhar, CO_2, viskozite azaltma, CSS, CCO_2S

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List of Abbreviations

API: American Petroleum Institute

CCO_2S: Cyclic CO_2 Stimulation

CMG- STARS: Reservoir Simulator

CO_2: Carbon dioxide

cp: centipoise

CSS: Cyclic Steam Stimulation

CWOR: Cumulative Water Oil Ratio

EOR: Enhanced Oil Recovery

IEA: International energy agency

IOR: Improved Oil Recovery

md: milli-darcy

N_2: Nitrogen

OOIP: Original Oil in Place

OPC: Oilfield Production Consultant

O_2: Oxygen

ϕ: Porosity

S_{or}: Residual Oil Saturation

STB: Stock Tank Barrel

WEO: World Energy Outlook

CHAPTER I

Introduction

The focus of this thesis is on tertiary recovery. EOR, also known as Tertiary Recovery, is the process of extracting crude oil from an oil field that cannot be produced using primary or secondary recovery. EOR can extract 30-60% of a reservoir's oil, whereas primary and secondary recovery can only extract 20-40%. EOR is also known as the process of mobilizing trapped oil that is too viscous to be dispersed effectively by water flooding.

Enhanced Oil Recovery (EOR) Versus Improved Oil recovery (IOR)

The names EOR and IOR have been used interchangeably in the past. Improved oil recovery, or IOR, is a broad term that refers to any way of boosting oil recovery. Infill drilling and horizontal wells, for example, are operational solutions that improve areal and vertical sweep, resulting in improved oil recovery. Enhanced oil recovery, or EOR, is a more technical phrase that can be considered a subset of IOR. EOR reduces oil saturation below the residual oil saturation (S_{or}). The following are the three types of recovery:

1. Primary Recovery
2. Secondary Recovery
3. Tertiary Recovery

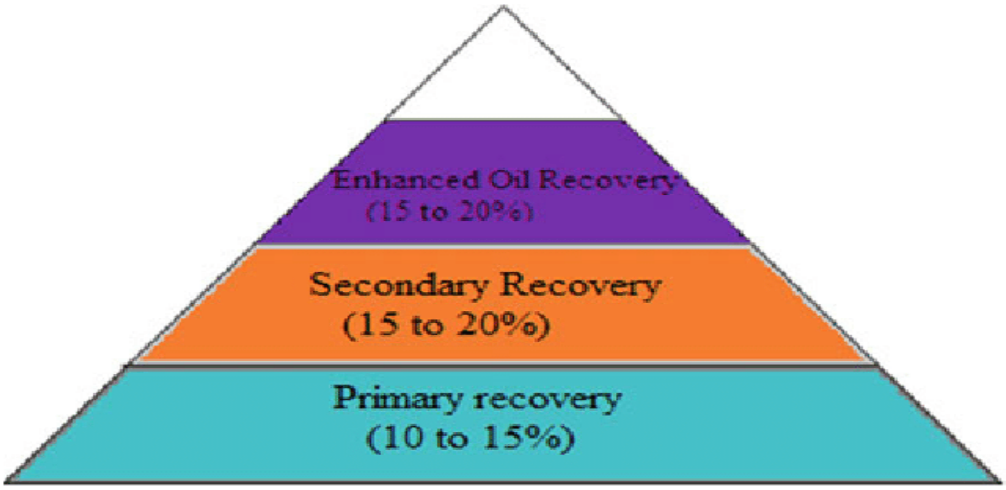

Figure 1.1. *Oil Recovery Percentages (Behera and Sangwai, 2020)*

- **Primary recovery**: The amount of oil generated through primary production is called primary recovery, and it is determined by the field circumstances. A solution gas drive, water drive, gas cap drive, gravity drainage, and rock and fluid expansion are all included. The production of hydrocarbons utilizing the reservoir's natural driving processes alone, without the addition of injected fluids like gas or water, is referred to as primary oil recovery. Due to the paucity of natural drive in most reservoirs, it is usual practice to supplement natural reservoir energy with artificial drive, the most common one which is gas injection or water injection. (Ahmed, 2010).
- **Secondary Recovery:** To produce more oil, the reservoir's pressure must be maintained by injecting another fluid, such as water or gas, into the reservoir to push the oil out. Water is injected into the aquifer and gas is injected into the gas cap in small oil fields, but fluid injection must be dispersed throughout the reservoir in large oil fields.
- **Tertiary Recovery:** Tertiary recovery is the process of extracting oil from the area of the reservoir that has already been swept. It also means improving displacement efficiency (generating oil that remains in the section of the reservoir not swept by displacing fluid) and Improving sweep efficiency (producing oil that remains in the part of the reservoir not swept by displacing fluid)
- **Why EOR?** It is difficult and expensive to gain access to new exploration acreage. There is a considerable amount of oil in found reserves that will not be recovered otherwise. EOR has the potential to make a significant contribution to global oil production in the long run.

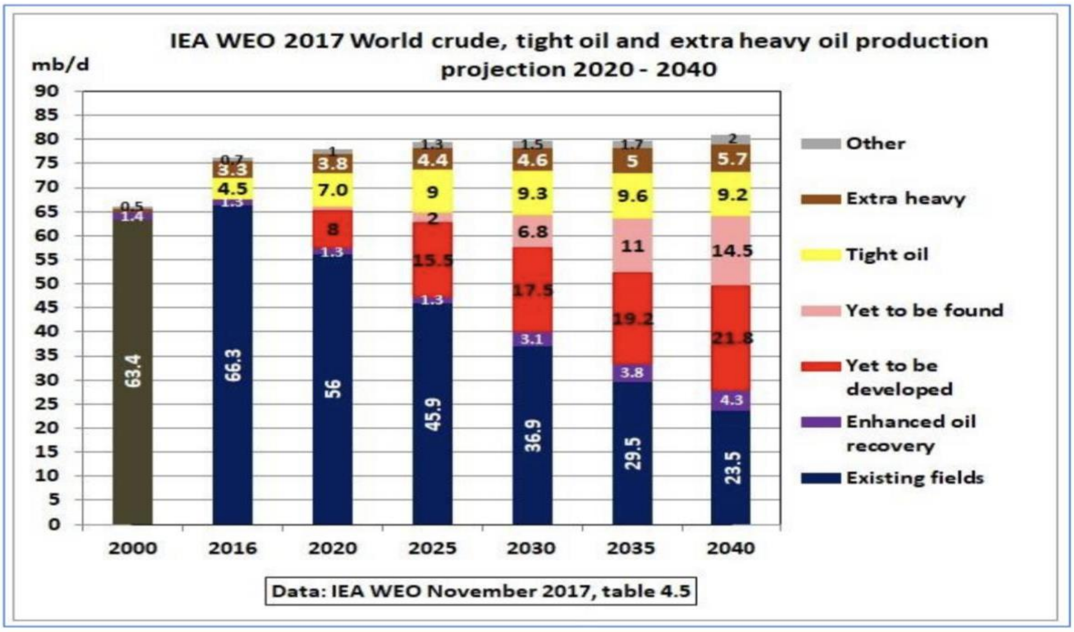

Figure 1.2. *World Crude, Tight Oil, and Extra Heavy Oil Production Projection 2020-2040 (IEA WEO, 2017)*

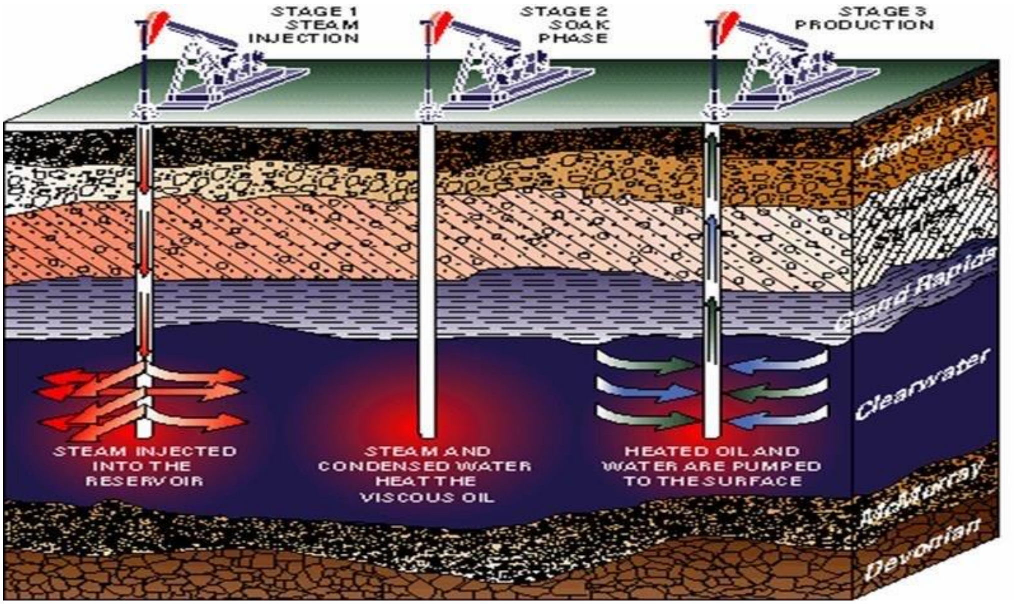

Figure 1.3. *Schematic Diagram of Cyclic Steam Stimulation (Ogiriki et al., 2018)*

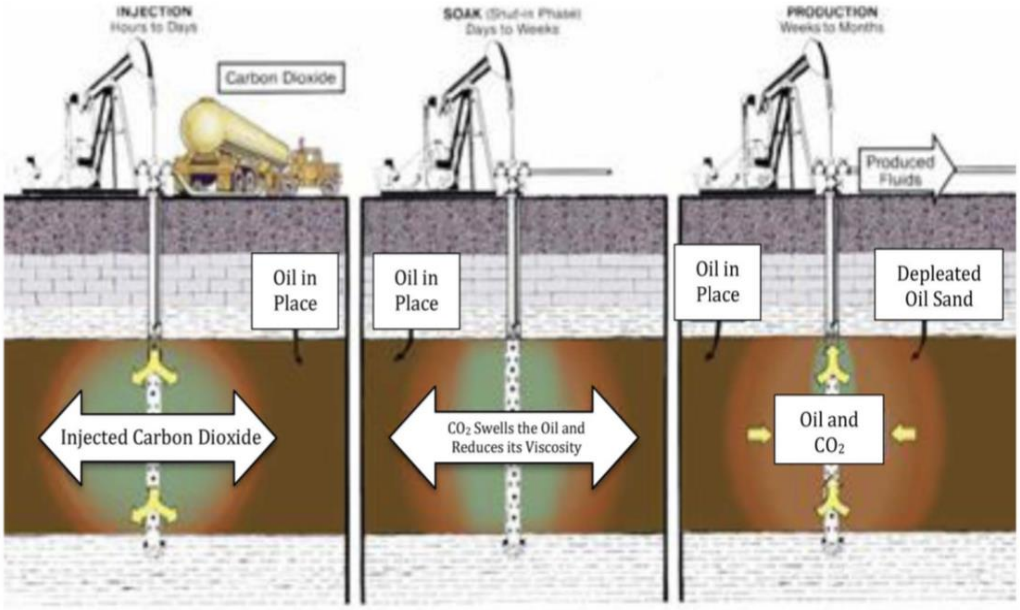

Figure 1.4. *Schematic Diagram of Cyclic CO_2 Stimulation (Bobb and Hosein, 2018)*

So what is being discussed here is the tertiary recovery of oil using steam and CO_2 or solo steam stimulation and solo CO_2 stimulation.

CSS (Cyclic steam stimulation) and CCO_2S (Cyclic CO_2 stimulation) are generally used for low viscosity oils (heavy oils). It is used to decrease the viscosity of the heavy oil and by doing that, the mobility will be increased thereby increasing the production of the oil.

Heavy oil can be classified as crude oil with a viscosity greater than 100 cp or API gravity less than 22.3° (Farouq-Ali et al., 1997).

Statement of Problem

When using EOR (Enhanced Oil Recovery), there are always some obstacles that one has to tackle on the way. There is always a question that begs to be asked; why combine the cyclic steam(CSS) and cyclic CO_2(CCO_2S) if you could use just one of them and still produce oil? The answer is obvious, to produce more oil than is already being produced. And one more factor that is at play here is the steam usage.

It is not economical to use much steam even if it produces more oil because, from the economical point of view, there would not be much profit so the idea of a combined operation is brought up and to be put to test.

Purpose of the Study

The goal of this study was to see if combining the two EOR approaches, CSS and CCO_2S, would be a better alternative for heavy oil recovery from small fields with complex geology than using either CSS or CCO_2S alone. When the study is done, the results are to be compared with an already existing study. Using the CMG (Computer Modelling Group) for the study, the following parameters are to be studied;

1) The length of the injection period.

2) The length of the soaking period.

3) The length of the production period.

4) The number of cycles.

5) The injection pressure.

6) The injection rate.

Research Questions / Hypotheses

When Cyclic Steam Stimulation (CSS) and Cyclic CO_2 Stimulation (CCO_2S) are used together, the outcomes are better than when CSS or CCO_2S are used separately. In addition, there has been relatively little research done on the combination of CCO_2S and CSS. The combination produced more than 95 MSTB for the field in question, according to Bobb and Hosein's (2018) report. As a result, all three methods (combination of CSS and CCO_2S, CSS and CCO_2S) will be shown to be successful, practicable, and cost-effective. As previously indicated, the ideal time, pressure, and injection rate will all be investigated.

Significance of the Study

This research is significant because billions of barrels of heavy oil cannot be produced using conventional methods, necessitating the use of EOR (Enhanced Oil Recovery). According to Bobb and Hosein (2018), Trinidad's oil resources contain more than four billion barrels of heavy oil. If these oil resources are discovered, the country's total oil production might skyrocket. Due to its high viscosity, heavy oil is difficult to produce, and only a small percentage is recovered after primary recovery. As a result, enhanced oil recovery (EOR) processes must be applied to increase heavy oil output.

Limitations

This study is based on only the data collected using the CMG (Computer Modelling Group) STARS. Using the CMG, many data were available from the program. One of the main limitations is that the research on the combination of CSS and CCO_2S is very little. There are studies about CSS or CCO_2S but only very little research was done to investigate the process. So there may not be so much evidence to support this study.

CHAPTER II

Literature Review

Theoretical Framework

Reservoir Characteristics

This research examines and contrasts various simulation scenarios for a 13x1x4 radial model to optimize the oil field. CMG-STARS was used for the simulation. The effects of injecting carbon dioxide and steam into the formation were first discussed. Furthermore, the results of a varying number of days for both the injection process and different pressures were assessed. The original reservoir pressure, porosity percentage (ϕ%), thickness, heat properties, and other reservoir simulation inputs were employed in the study. (Bobb and Hosein, 2018).

There were no data used from other articles. All the data for the components (Oil, Water, and CO_2) are the constant values like the molar mass, density, surface temperature, and surface pressure.

Related Research

According to Wan et al. (2020), the CO_2/steam co-injection process generated higher oil recovery than flue-gas/steam and pure cyclic steam injection processes. The contacted area of the steam with the oil reservoir determines the thermal recovery performance. One reason is that CO_2/steam has a larger cumulative injected enthalpy than flue-gas/steam and pure steam. Another explanation is that, due to their low conductivity, nitrogen or carbon dioxide acts as thermal insulation, reducing heat losses throughout the well-bore.

Enhanced oil recovery (EOR) technology, can help a hydrocarbon reservoir achieve its maximum rate of return (Ersahin et al., 2020). Cyclic steam injection (CSI), a thermal recovery technology aimed at reducing oil viscosity and increasing output in naturally fractured heavy oil reservoirs, is one of the most extensively deployed EOR methodologies. Commercial CSI modeling software, on the other hand, can be difficult to learn and use, as well as time-consuming and expensive.

Zhu et al. (2020), mentioned in their research that, the effective development of reservoirs with edge-bottom water using CSS is critical for petroleum supply. However, as the number of circulation turns grows, the production declines, and the water cut of some CSS wells increases. The basis of targeted treatment techniques is determining the source of the produced water. A new model for distinguishing the source of produced water from Cyclic Steam Stimulation (CSS) wells in edge-bottom water reservoirs are developed in this research. The model evaluates the quality change in injected water and combines classical hydrochemical features analysis and factor analysis.

Zhong et al. (2020) said that a large amount of sludge is produced in the oil production and storage procedures in the Liaohe Oil Field. In most cases, sophisticated chemical treatments are required to successfully cure the sludge, and these surface-treatment techniques are both costly and environmentally hazardous. Water, certain oil components, and solid phases such as mud and fine sand make up the sludge created from the reservoir, and aggregation of the injected sludge components, except for water, could block the empty porosity area. The sludge is buried in the reservoir where it came from.

Dong et al. (2019) claimed that the technology for in-situ is still the most common form of exploitation for heavy oil around the globe. However, in heavy oilfields, most steam-based techniques have reached the end of their useful life. When steam-rock interactions are being considered long-term, it's currently difficult to improve heavy oil in the post-steam injection age.

According to Elwegaa et al. (2019), the impacts of infusing gas temperature on the permeability, porosity, and brittleness indices of the Eagle Ford core samples were also evaluated, according to the authors. thermal shock experiments and CO_2 cyclic gas injection were carried out using an experimental apparatus that was conceived and built. This investigation included 4 outcrop core samples of Eagle Ford Shale. The saturated samples were heated to 180°F before being injected with carbon dioxide at various pressure and temperatures. After five days of production, for each experiment, the oil RF was measured. Additionally, each core sample's porosity, permeability, and ultrasonic velocity were assessed both before and after the experiment.

Wu et al. (2019), said that Heavy oil reserves play an essential role in the world's energy supply. For heavy oil recovery, steam injection is one of the most extensively utilized thermal recovery procedures. However, drawbacks such as low oil recovery, high energy consumption, and substantial greenhouse gas emissions, among others, hampered the technology's use.

After initial production, CO_2 injection is a promising strategy to revitalize shale oil reservoirs (Jia et al., 2019). The authors conducted a thorough analysis of the carbon storage literature and CO_2 injection enhanced oil recovery (EOR) in shales during the last decade in this study. In recent years, advanced models for simulating these processes, including the classic dual continuum model and the embedded discrete fracture model, have been developed in detail (EDFM). On the performance of shale oil recovery, the heterogeneity effect and upscaling algorithm were discussed.

Osma et al. (2019), proposed that the majority of numerical simulations of thermal EOR methods focus on identifying recovery mechanisms with the highest potential to boost oil recovery. In some circumstances, the economic elements of the EOR procedures under consideration are also taken into account. However, many of these studies do not include an assessment of the proposed methods' energy efficiency as a strategy to aid in the selection of viable recovery strategies.

Carbon dioxide (CO_2) injection has lately been used in unconventional shale reservoirs to boost oil recovery (Fakher et al., 2019). CO_2 injection can be done in a variety of ways. Cyclic CO_2 injection is one of the most frequent procedures, especially in unusual reservoirs. The possibility of cyclic CO_2 injection to boost oil recovery from unconventional shale reservoirs, as well as the impact of reservoir thermodynamics, such as pressure and temperature, on the oil recovery potential, are investigated in this study. The tests were carried out in a specifically built vessel that replicated the cyclic CO_2 injection procedure.

According to the authors, shale cores were saturated with crude oil for seven months at a high temperature. After that, the cores were inserted into the huff-n-puff vessel, and the experiment began. Oil recovery was shown to be strongly influenced by pressure and temperature conditions, particularly as the injection cycles advanced.

Bobb and Hosein (2018) stated that due to its high viscosity, heavy oil is difficult to produce. As a result, to boost heavy oil production, enhanced oil recovery (EOR) procedures must be implemented. Cyclic steam stimulation (CSS) and cyclic CO_2 stimulation are two of the most regularly utilized EOR approaches (CCO_2S). However, there was relatively little research on the coupling of these processes, which formed the basis of this work. The combination of two procedures was suggested by Bobb and Hosein (2018).

Yi et al. (2018) insisted that heavy oil is a low-grade oil resource that can alleviate energy crises, but its production is a global challenge. Cyclic steam stimulation is particularly well suited to geologically complicated heavy oil deposits.

Heavy oil reservoirs, on the other hand, face a slew of issues during multicyclic steam stimulation, including decreased reservoir pressure, nonuniform reservoir output, and steam channeling. And helper gas is ideal for resolving issues that arise during the late stages of cyclic steam stimulation. The aiding mechanisms, injection-production optimization, and inventive use of current cyclic steam assisting technologies, such as nitrogen, CO_2, flue gas, and foam, were studied in this study. The advantages and disadvantages of each were then examined. Finally, it was suggested that nitrogen be combined with CO_2 to aid cyclic steam stimulation and that the organic combination of a downhole steam generator, a downhole viscosity lowering unit and nitrogen be the future development direction of assisted cyclic steam stimulation. The research findings serve as a foundation for future technical reserves and innovation.

More than two-thirds of oil discovered around the world remains unrecovered, according to Elbaloula and Musa (2018), and 40–70% of the initial oil is still left in place despite applying standard production techniques, such as primary and secondary recovery procedures. EOR technologies must be implemented to maximize output and recovery from Sudan's oil assets. To ensure optimal selection and execution, these strategies must be thoroughly researched. Sudanese oil fields have six EOR projects. Three thermal EOR projects (two CSS and one steam flooding), two chemical EOR projects, and one gas/N_2 injection project are currently in the execution phase, while the chemical and gas projects are still in the design and evaluation phase.

The CO_2 emissions and energy efficiency of existing steam injection methods were analyzed, as well as sensitivity analysis of numerous contributing factors, according to the authors of this study. To investigate the productivity of steam injection, the CSS process was used as an example.

Zhou et al. (2018), went on to say that, while the thermal approach has shown to be effective and cost-effective in producing heavy oil, it cannot be used in deep reservoirs or reservoirs with thin pay zones because of the high heat loss. As a result, many CO_2 injection procedures are used in heavy oil reservoirs to increase heavy oil output. The CO_2 huff 'n' puff method has shown to be the most effective.

Wu et al. (2017) mentioned that a regression model and calibration curves may be used to forecast the degree of gas breakthrough under various reservoir and development conditions. When the degree of gas breakthrough was moderate or strong, foam plugging was found to be effective in inhibiting gas breakthrough.

An air-assisted cyclic steam stimulation (AACSS) technique has been successfully applied in an ultra-heavy oil reservoir with low reservoir pressure, high water cut, and low oil/steam ratio in its late CSS stage (Wang et al., 2017). The AACSS may greatly boost cyclic oil output, reduce water cut, extend the effective production time, and improve the oil/steam ratio, according to the findings of pilot testing.

In terms of oil recovery, Bao et al. (2017) proved that a vertical well injection – horizontal-well production steam injection gravity drainage (SIGD) procedure is a successful follow-up to vertical well cyclic steam stimulation (CSS). They also said that the SIGD process is less thermally efficient than CSS in terms of thermal efficiency. As a result, SIGD's CO_2 emissions intensity (kgCO_2/m^3 produced oil) is somewhat higher than CSS's.

Cyclic steam stimulation (CSS), has been successful in recovering heavy oil and bitumen (Suranto et al., 2016). The technique, however, is no longer successful after the fifth cycle, as evidenced by the growing cumulative steam-oil ratio. This article recommends that the completion design be changed to increase CSS performance. The perforation gap is separated into two sections: upper and lower (for injection) (for production). Due to heat loss, the injected steam would be condensed in this design. Due to gravity, the steam would then travel to the lower part, where the oil would begin to develop. An interval control valve oversees the injection-production cycle (ICV). The proposed design reduces the CSOR by 30% while increasing cumulative oil production by 3.5 times, according to simulation data. The greater the distance between the production and injection parts, the higher the steam efficiency.

In this paper, the authors Liu et al. (2016) mentioned that a unique hybrid approach is developed for improving ultra-heavy oil recovery in a deep thinly laminated reservoir by combining the injection of the steam procedure with a viscosity reduction and CO_2 injection. Viscosity reducer, physicochemical characterization of ultra-heavy oil, steam multi-system mixtures, and CO_2, is used to investigate enhanced oil recovery mechanisms for hybrid systems.

Alvarez and Han (2013) mentioned that steam flooding is the most commonly performed follow-up procedure following CSI (Cyclic steam injection). One reason is that it makes use of existing well and surface equipment, lowering capital costs. The most significant ground, according to the authors, is because it can sweep any residual oil to a specific production well. Furthermore, CO_2 flooding has only been shown viable in a few regions, and further research is needed to completely develop this approach; additionally, initial investment and CO_2 use directly affect capital costs. Finally, air injection has proven to be effective in some situations, but it is a difficult procedure to simulate and test in the field.

Natural gas hydrates, according to Fitzgerald and Castaldi (2013), constitute a large unconventional natural gas resource and have gotten a lot of interest in the last decade. The use of the gas invasion method to produce hydrates resulted in non-homogeneous hydrate production. Secondary hydrate development was seen in a quasi-repeatable way throughout protracted hydrate formation periods.

The Bohai Offshore Oilfield has abundant heavy oil deposits (Sun et al., 2011). In the past, cold production techniques like ESP were used to recover just a few heavy oil reservoirs, and the production was not economic. The authors also claimed that setting up a conventional steam generator on a production platform for heavy oil production offshore is difficult.

The Oudeh Shiranish reservoir in Syria holds 5.1 billion barrels of crude oil with a 12-16 °API. The principal recovery factor, on the other hand, is anticipated to be only 5 to 7% of the initial oil in place. Waterflood, VAPEX, microbiological treatment, and cyclic steam stimulation (CSS) were all investigated as ways to improve oil recovery. CSS was eventually chosen for a pilot test, according to Li et al. (2010). The CSS pilot began in September 2006 and was discontinued in November 2009. According to the authors, the project grew from two to twenty-four wells.

For Akin et al. (2009), steam injection in naturally fractured rocks has recently piqued interest. The rock is thought to be heated by steam or water, which subsequently undergoes a thermally induced wettability reversal. Hot water can then imbibe spontaneously into the moist rock matrix, leading to excellent oil recovery. Through multi-component thermal simulations, the application of steam injection in an oil-wet cracked carbonate previously flooded with carbon dioxide (CO_2) is examined in this work.

Mohsenzadeh et al. (2009), experiments also revealed that when the continuous steam injection was used instead of cyclic steam injection, more oil was produced during the gravity drainage process. In addition, for both steam injection and gravity drainage methods, the effect of wettability on oil production was examined.

Mago et al. (2005) argued that a constant increase in global energy consumption combined with the decrease of conventional oil resources indicates more aggressive exploitation of heavy oil. With a global base resource surpassing 2.5 trillion barrels, heavy oil is a key source of energy in this century. Reservoir modeling is commonly used to inform management choices and production plans in thermal oil recovery processes. The authors also highlighted that accurate physical property descriptions, notably, oil viscosity, is critical for completing effective modeling studies of fluid flow in reservoirs. In this study, the authors highlight the necessity of these mixing principles and warn reservoir engineers about the importance of employing the various options simulators have built into their platforms to characterize the viscosity of heavy oils.

Most field applications and pilot testing of CO_2 injection are for the miscible drive and are thus limited to light oil reservoirs (Khatib et al., 1981). However, it has long been known that when CO_2 dissolves in heavy oil, it causes the oil to swell and lose viscosity. In the 1950s, core displacement testing revealed that carbonated water may significantly increase the recovery of heavy oil and, in certain situations, light oil. Until recently, bad economics hindered field application, but a field project in southern Arkansas began in 1976. Two techniques have been put to the test in the field. These are "huff-and-puff" CO_2 injections for well stimulation, with either alternate or simultaneous CO_2 and water injections. Both process methods are addressed and, where possible, demonstrated by field test findings from the United States. These were discovered in sandstone reservoirs that contained both light and heavy oils. Several other Pilot or field projects are in the works. In Turkey, a planned field demonstration project of both Processes is summarized in several test regions of a fractured limestone reservoir (oil 9 deg. - 15 deg.). The variety of potential prospective reservoirs is reviewed, as well as a basic economic comparison with steam injection. Heavy oil reserves that are too deep for present steam injection technology and economics are obvious candidates.

CHAPTER III

Methodology

CMG (Computer Modelling Group) was used to create a computer-generated model of the reservoir. Chemical/polymer flooding, thermal applications, steam injection, horizontal wells, dual porosity/permeability, directional permeabilities, flexible grids, fire-flood, and many more possibilities are available in CMG's latest generation advanced processes reservoir simulator, STARS. A radial model of with a grid of 13 x 1 x 4 was used.

The way CSS and CCO_2S work is that there has to be injection, soaking, and then finally, production. The goal is to find the optimal point concerning production and economics. Many simulations had to be run but finally, there were reasonable results.

To create a model on CMG, one can either use a template (on notepad) or use the CMG builder. When using the builder, one has to indicate the units being used that is, field unit or S.I units. Moving forward, it has to be indicated if the reservoir has dual or single porosity and also if its dual or single permeability. The reservoir in this study has single porosity. After indicating the porosity and permeability, the type of reservoir is next (radial or cartesian).

As mentioned earlier, the reservoir in this study is a radial reservoir. The next thing is the dimensions of the reservoirs that is, number of grids in the reservoir. These are the necessary data needed by the CMG to create a model. After the model is created, the other reservoir properties like the number of wells, the injected fluids, pressures, and saturation values can be added. If everything is in place and correct, one can run the simulation. And if there is any mistake, CMG will indicate that there is an error after one has run the simulation.

When using the template on the notepad, one has to use the STARS guide for the keywords on the template. It is almost the same process with the builder but this one is done on the notepad. The keywords are written and the value of the keywords are written after the keyword for example *POR *CON 0.3 meaning a constant porosity of 0.3. After finishing with the template, the process here is the same as the builder. The data is run on STARS and results will be gotten. If there is an error, it means there is a mistake. When the results are gotten, CMG will create other files that can be used to get the results graphs like cumulative oil, CWOR (Cumulative Water Oil Ratio), and many other results. In this study, the template was used to get the results in the next chapter.

Research Design

This research was modeled based on the pattern of descriptive comparative design which means different methods are to be compared and the best/optimal method will be chosen. STARS was created to simulate steam flood, steam cycling, steam-with-additives, dry and wet combustion, and many sorts of chemical additive processes in both field and laboratory scales, utilizing a variety of grid and porosity models. The model is a radial model with the grid of 13×1×4 which was used for the model development meaning 13 grids on the x-axis, 1 grid on the y-axis and 4 grids on the z-axis. STARS was used for creating the model. The model assumes radial flow in the reservoir where flow across the formation is horizontal and fluid moves radially toward the well-bore. The components involved in the reservoir are water, oil, and CO_2. The reservoir properties are stated as follows;

Table 3.1. *Reservoir Model Properties*

Dimensions of the I direction, ft	3 10*10 40 120
Dimension of the J direction, ft	360 (full circle)
Dimensions of the K direction, ft	25 25 20 10
Constant porosity	0.3
Permeability varies across the I direction (PERMI), md	2000 1000 500 200
Permeability of J direction, md	PERMI
Permeability of K direction, md	PERMI/2
Temperature, ˚F	125
API Gravity	20
Depth, ft	55
Viscosity, cp	300

Original Oil in Place (OOIP), STB	7727647.6

10*10 means the value 10 has appeared 10 times.

Participants/Population and Sample

The sample used was a sample from a reference paper in which the results will be compared. The paper is cited as follows; An investigation into the Combination of Cyclic Steam Stimulation and Cyclic CO_2 Stimulation for Heavy Oil Recovery in Trinidad and Tobago, Janos Bobb and Raffie Hosein, The University of the West Indies, 2018.

Data Collection Tools/Materials

The only tool used is the CMG (Computer Modelling Group) for the creation of the model. It was used to run the simulation multiple times using trial and error to find the optimum results.

Data Analysis Procedures

When analyzing the results, some factors have to be considered and they are; Steam usage, cumulative oil produced, the daily oil production rate, and the number of days. All of the factors mentioned above will be further explained in the next chapter.

Study Plan

The research study plan/scope is in three folds:

I) To improve the oil recovery from the studied field. Using CMG- STARS, two injectors were drilled and one producer was. The first injector injects steam and the second injector injects carbon dioxide.

II) The results of this study were derived using the CMG-Stars simulator. This study incorporated data from earlier papers and publications. This study intended to critically evaluate and summarize existing literature on CO_2 and steam injection to maximize oil recovery.

III) The combination of these methodologies will allow for cross-study comparisons and will aid in the discovery of valuable patterns in the combined research data. Following the evaluation of various injection methods and injection days, necessary conclusions will be reached about these approaches' ability to considerably increase oil recovery.

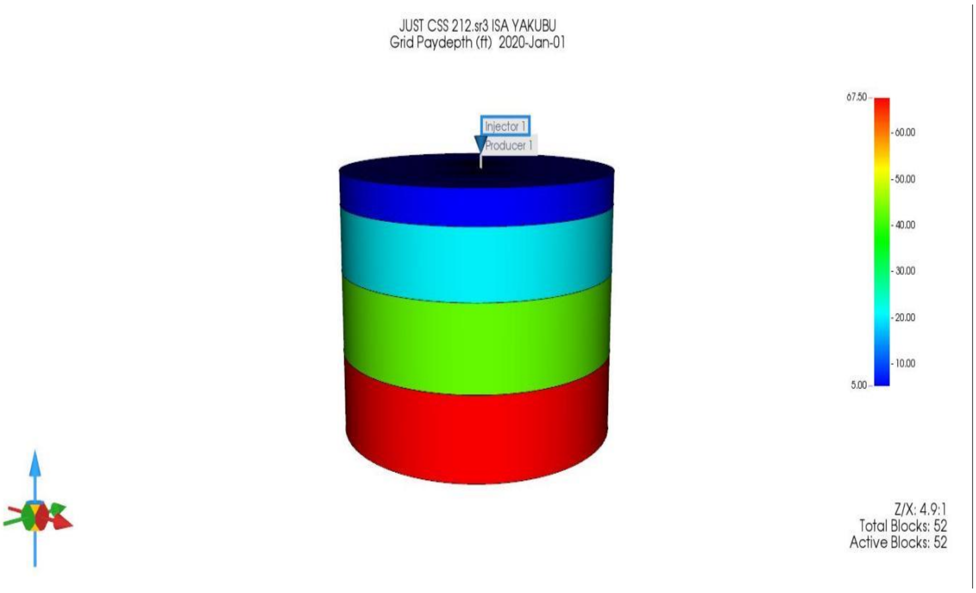

Figure 3.1. *3D View of the Model (CMG STARS 2015)*

CHAPTER IV

Results and Discussions

This chapter presents the findings based on the collected data. After including all the reservoir data on the CMG, the data was run and results were given. We had a goal at the beginning of the research which is choosing the optimized time (injection, soaking, and production), steam oil ratio, and the cumulative oil produced for the combination of the CSS and CCO_2S, CSS alone, and CCO_2S alone.

Different Injection Rates and Different Amounts of Days

For cyclic injection, it deals with injection, soaking, and finally production. And in this study, we are going to test CSS alone, CCO_2S alone then the combination of the two which is our main goal. Many simulations were run and some of the simulations ran in minutes while some in seconds. All the 3 methods (CSS alone, CCO_2S alone, and the combination of the two) are successful but the combination of the two proved to be more successful than using the two methods solo.

To get optimized results, many possibilities were used. For instance, for the injection, soaking, and production time, different amounts of days were used and the optimum one was chosen based on the cumulative oil produced, daily oil produced, WOR, and amount of days (the lesser, the days the better). After running many simulations on the CMG, results were finally gotten, these results gotten from the CMG will be shown below and our results will be organized using different injection rates first (500 injection rate and 750 injection rate) and when the best one is chosen, different pressures will be used to help choose the optimum result. Table 4.1 to 4.9 (Figures A1 to A.24 of Appendix A) shows the results of when 500 injection rate is used while Table 4.10 to 4.18 (Figures B.1 to B.24 of Appendix B) shows the results of when 750 injection rate is used.

Injection Rate of 500 ft^3/day for the CO_2 and 500 bbl/day for the Steam

The tables show the results are gotten when the injection rate of 500ft^3/day for the CO_2 and an injection rate of 500bbl/day for the steam. For almost all of the processes, the CSS proved to be better than the CCO_2S and the combination of CSS and CCO_2S proved to be the better process among the 3 methods. The CSS is better than the CCO_2S because CSS operations are more responsive to the reservoir than

CCO_2S operations. For the test reservoir, this suggests that oil viscosity reduction due to heat transfer may be more effective than oil viscosity reduction due to CO_2 MCM (Multiple Contact Miscibility). As shown in the tables, all the amount of days yielded good results, Table 4.9 (Figures A.22, A.23, and A.24 of Appendix A) has the best results when it comes to oil production but has a high CWOR compared to the others which makes it impossible to be the optimum. Table 4.4 (Figures A.7, A.8, and A.9 of Appendix A), Table 4.8 (Figures A.19, A.20, and A.21 of Appendix A) and Table 7 (Figures A.14, A.15, and A.16 of Appendix A) also gave good results but also have high CWOR and also a high amount of days so now the debate for the optimum remains between Table 4.1 (Figures A.1, A.2 and A.3 of Appendix A) and Table 4.2 (Figures 4.1, 4.2 and 4.3).

Table 4.1. *121 means; 1-month injection, 2 months soaking, and 1-month production (750 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 121	112,605	0.246151	150.4
CCO_2S 121	107,429	0.0120103	143.24
CSS 121	83,710	0.59246	111.6

Table 4.2. *212 meaning; 2 months injection, 1-month soaking, and 2 months production (960 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 212	177,668	0.299496	185.07
CSS 212	139,605	0.760668	145.42
CCO_2S 212	148,625	0.0122374	154.8

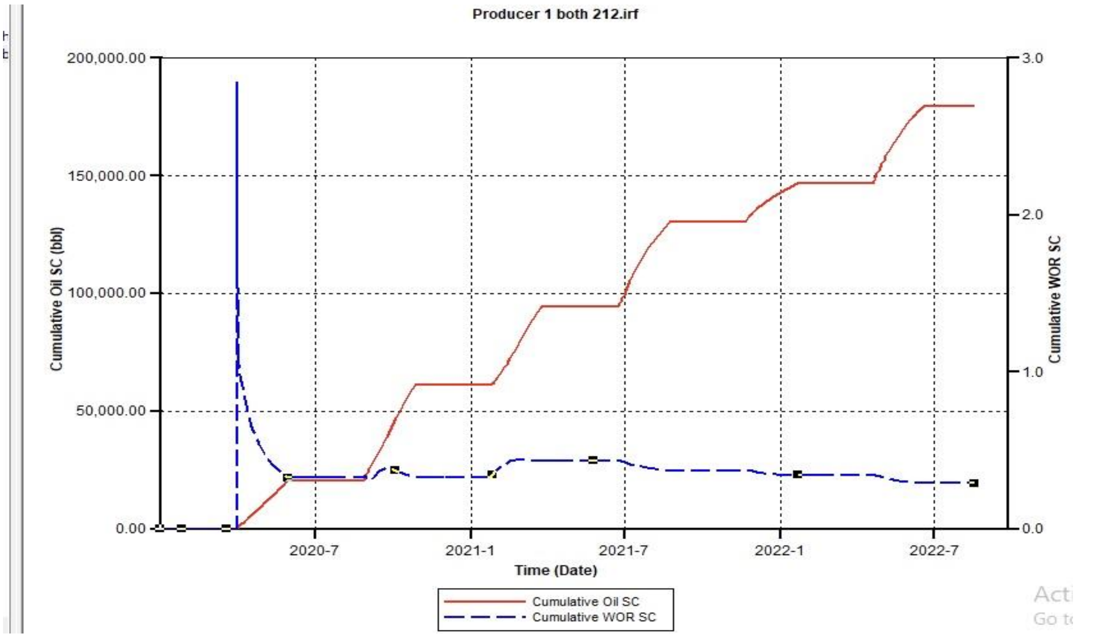

Figure 4.1. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 212 using a 500 Injection Rate*

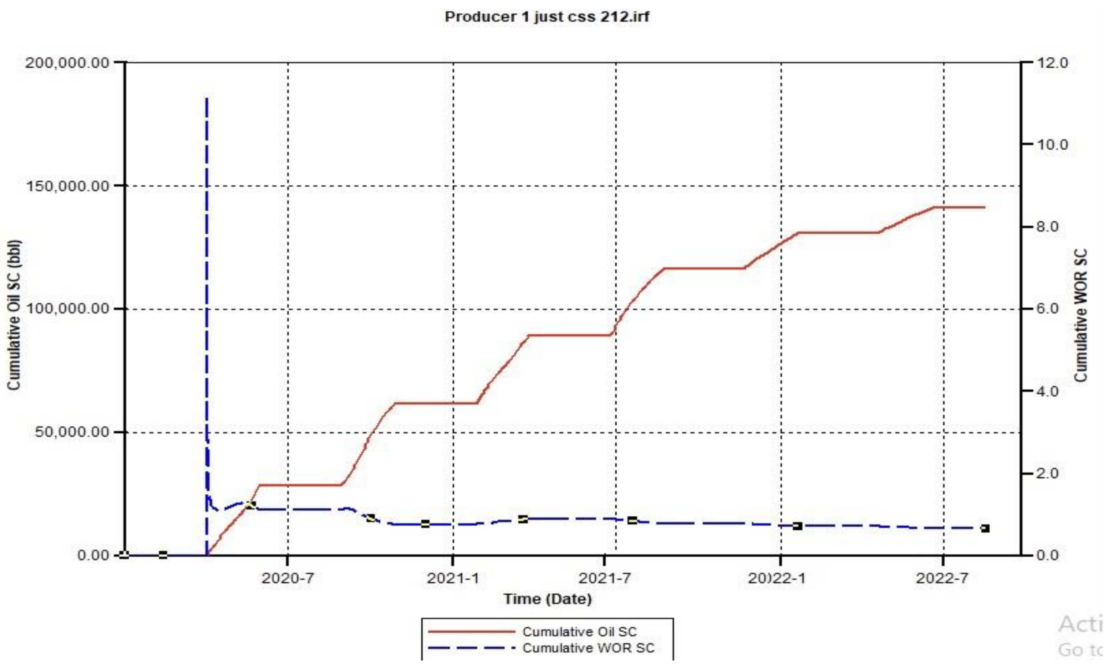

Figure 4.2. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 212 using 500 Injection Rate*

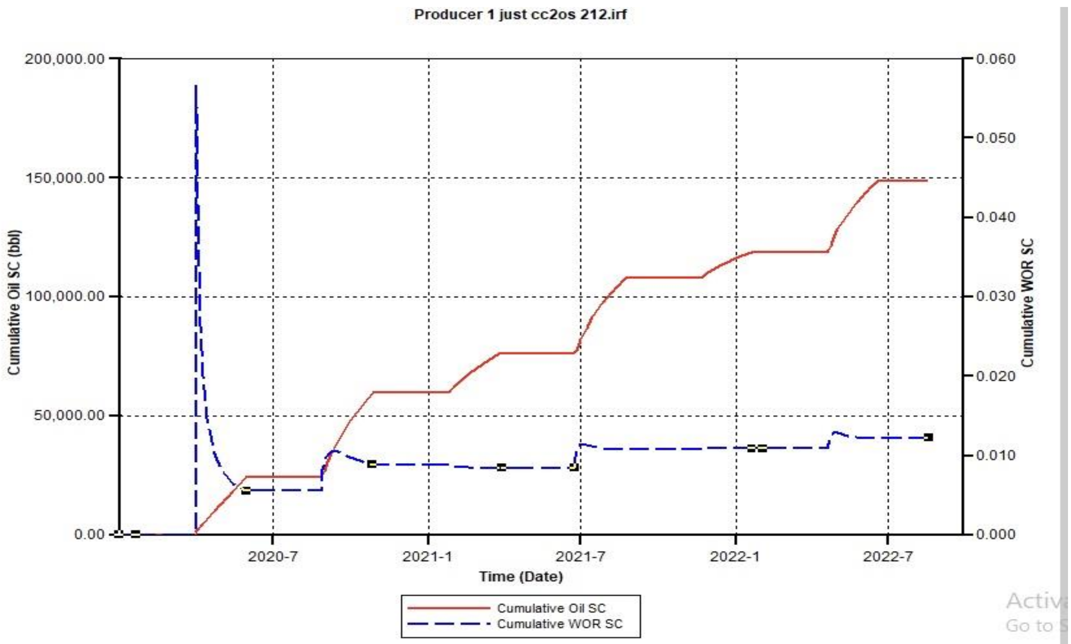

Figure 4.3. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 212 using 500 Injection Rate*

Table 4.3. *222 means; 2 months injection, 2 months soaking, and 2 months production (1140 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 222	177,890	0.29483	156.04
CSS 222	136,919	0.741921	120.1
CCO_2S 222	150,065	0.0117801	131.6

Table 4.4. *313 meaning; 3 months injection, 1-month soaking, and 3 months production (1350 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 313	180,471	0.372268	133.68

CSS 313	169,164	1.03393	125.3
CCO_2S 313	170,980	0.0134011	126.65

Table 4.5. *323 meaning; 3 months injection, 2 months soaking, and 3 months production (1530 days) using a 500 Injection Rate.*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 323	215,314	0.373179	140.7
CSS 323	172,149	0.921829	112.5
CCO_2S 323	171,424	0.0131749	112.04

Table 4.6. *414 means; 4 months injection, 1-month soaking, and 4 months production (1740 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 414	247,969	0.421564	142.51
CSS 414	201,043	1.24912	115.5
CCO_2S 414	184,449	0.0126644	106.01

Table 4.7. *424 means; 4 months injection, 2 months soaking, and 4 months production (1920 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 424	248,151	0.416207	129.25
CSS 424	199,046	1.24237	103.67
CCO_2S 424	185,805	0.0123915	96.77

Table 4.8. *515 meaning; 5 months injection, 1-month soaking, and 5 months production (2100 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 515	275,254	0.467914	131.07
CSS 515	230,897	1.37305	109.95
CCO_2S 515	194,723	0.0125689	92.73

Table 4.9. *525 meaning; 5 months injection, 2 months soaking, and 5 months production (2310 days) using a 500 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 525	280,082	0.449229	121.25
CSS 525	224,924	1.39927	97.37
CCO_2S 525	196,095	0.0121826	84.89

Injection Rate of 750ft³/day for the CO_2 and 750bbl/day for the Steam

It was observed that CSS alternated by CCO_2S is optimum and most effective when the 500 injection rate was used. This may be due to changes in oil viscosity with the degree of CO_2 miscibility (Bobb and Hosein, 2018). Under the same conditions, CO_2 may have a low tendency to be miscible with high viscosity oil but a high tendency to be miscible with low viscosity oil. Oil viscosity may have been lowered in this study due to steam injection, causing CO_2 miscibility to rise. Increased CO_2 miscibility may have lowered oil viscosity, even more, resulting in increased oil mobility and recovery. This has also been stated by the authors in the reference paper. Since the results for the 500 injection rate were gotten, the next injection rate which is the 750 injections will be used to get the results, and then they will be compared.

Therefore, it has been concluded that the well has a high affinity for the combination of CSS and CCO_2S. Followed by the CSS and lastly, CCO_2S.

From Table 4.10 to 4.18 (Figure B.1 to B.24 of Appendix B), there are different amounts of days with different cumulative oil produced but none of them gives a better result than the 212. Even though the tables have a different amount of days, they do share one thing in common that is, the combination of CSS and CCO_2S having the highest cumulative oil produced followed by CSS and lastly, CCO_2S.

The 121 in table 4.10 (Figures B.1, B.2 and B.3 of Appendix B) gives the lowest Cumulative Oil Produced but has the lowest Cumulative Water Oil Ratio (CWOR) so it cannot be optimum. The 515 in Table 4.17 (Figures A.19, A.20 and A.21 of Appendix A) and 525 in Table 4.18 (Figures B.22, B.23 and B.24 of Appendix B), on the other hand, have a very high Cumulative oil produced but they have a high CWOR and a low daily oil produced, also they have a high amount of days which is a disadvantage.

When 222 in Table 4.12 (Figures B.4, B.5 and B.6 of Appendix B) and 313 in Table 4.13 (Figures B.7, B.8 and B.9 of Appendix B) are compared, 313 has every advantage over 222 that could make it the optimum except the fact that it has a higher CWOR than the 222 which keeps 313 out of the scenarios that could be the optimum. Similar to the 500 injection rate, the debate for the optimum remains between 222 and 212.

The 212 in Table 4.11 (Figures 4.4, 4.5 and 4.6) and 222 in Table 4.12 (Figures B.5. B.6, and B.7 of Appendix B) are to be compared and when that is done, it will be found that 212 has every advantage over 222. 212 has higher Cumulative Oil Produced, lower CWOR, higher daily oil produced, and also has lesser days meaning 212 here is optimum. To verify these results, there are graphs in the Appendix that supports all the results tables.

Table 4.10. *121 means; 1-month injection, 2 months soaking, and 1-month production (750 days) using a 750 Injection Rate*

	Cumulative Oil SC	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**

	(bbl)		
CCO_2S & CSS 121	113,227	0.313952	150.97
CCO_2S 121	84,447	0.0128802	112.6
CSS 121	90,917	0.714498	121.22

Table 4.11. *212 meaning; 2 months injection, 1-month soaking, and 2 months production (960 days) using a 750 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 212	181,469	0.439986	189.03
CSS 212	147,437	1.02496	153.58
CCO_2S 212	124,714	0.0131118	129.91

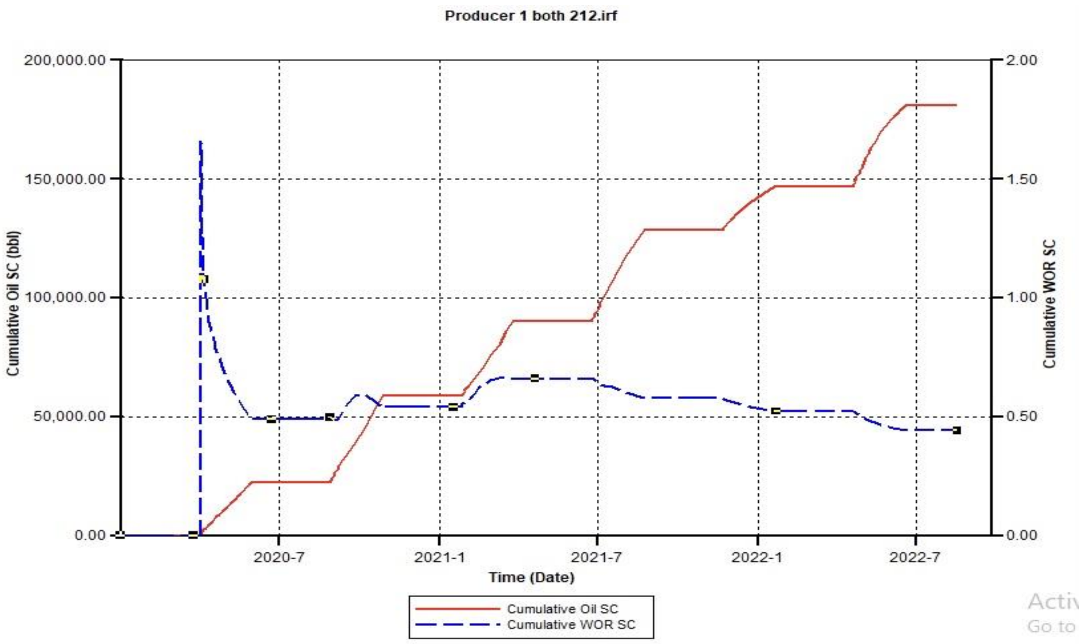

Figure 4.4. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 212 using a 750 Injection Rate*

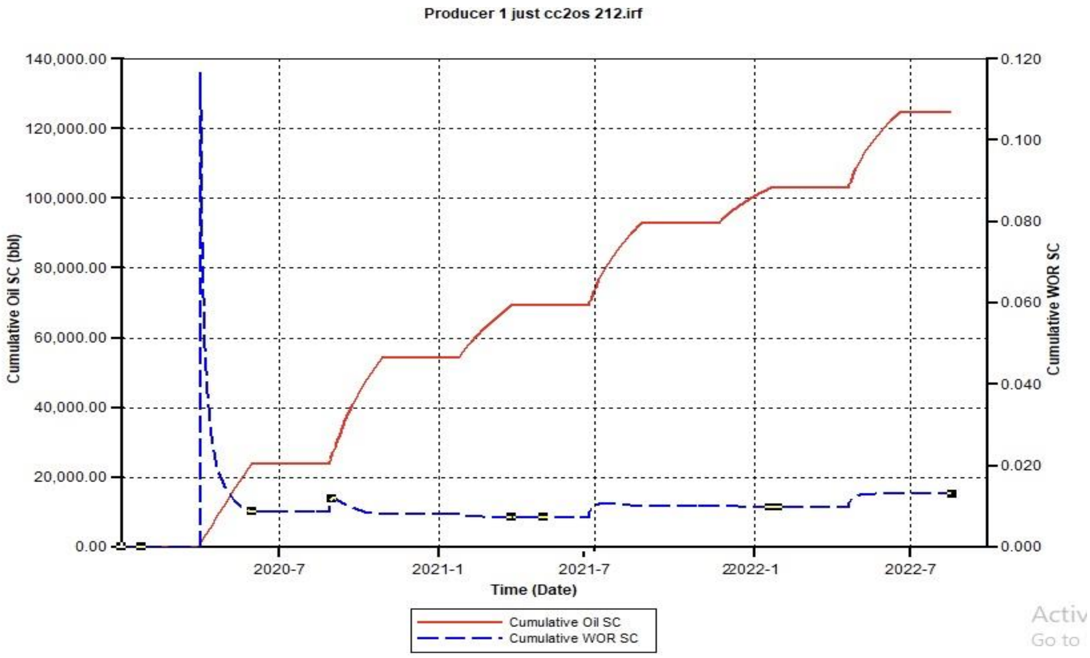

Figure 4.5. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for* CCO_2S *212 using 750 Injection Rate*

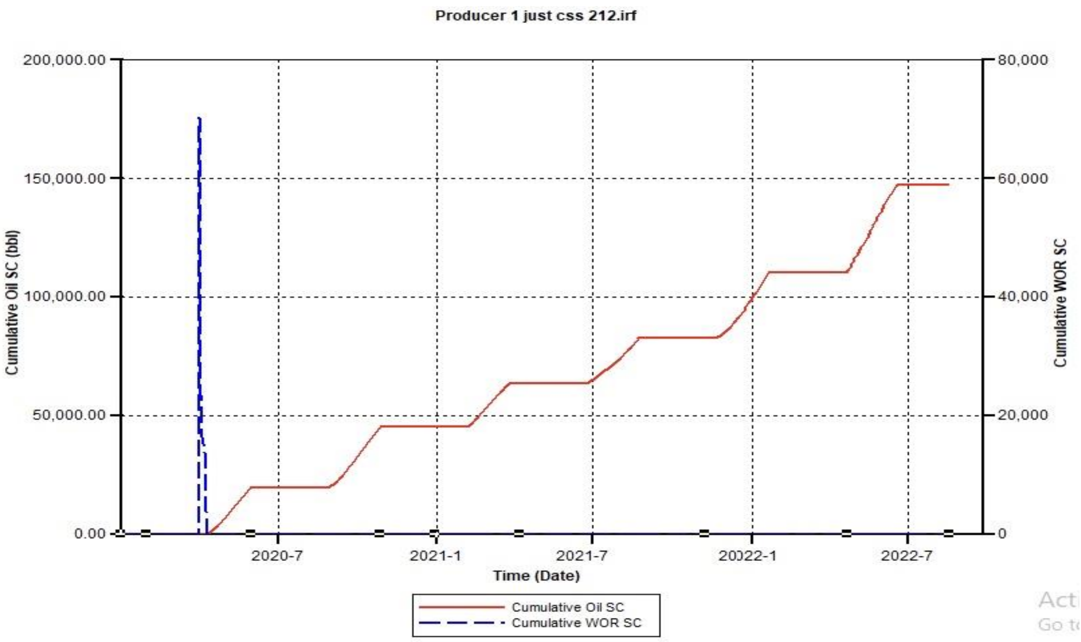

Figure 4.6. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 212 using 750 Injection Rate*

Table 4.12. *222 means; 2 months injection, 2 months soaking, and 2 months production (1140 days) using a 750 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 222	179,118	0.449456	157.12
CSS 222	150,937	0.97038	132.40
CCO_2S 222	125,631	0.0128799	110.20

Table 4.13. *313 meaning; 3 months injection, 1-month soaking, and 3 months production (1350 days) using a 750 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 313	224,600	0.535676	166.37
CSS 313	186,340	1.33602	138.03
CCO_2S 313	142,200	0.0156743	105.33

Table 4.14. *323 meaning; 3 months injection, 2 months soaking, and 3 months production (1530 days) using a 750 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 323	229,901	0.515349	150.26
CSS 323	189,462	1.28724	123.83
CCO_2S 323	142,130	0.0153522	92.9

Table 4.15. *414 means; 4 months of injection, 1-month soaking, and 4 months of production (1740 days) using a 750 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**

CCO_2S & CSS 414	258,937	0.611269	148.8
CSS 414	213,059	1.64048	122.45
CCO_2S 414	152,235	0.0164012	87.5

Table 4.16. *424 meaning; 4 months injection, 2 months soaking, and 4 months production (1920 days) using a 750 Injection Rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 424	266,331	0.577082	138.71
CSS 424	213,897	1.62002	111.4
CCO_2S 424	153,940	0.0157121	80.18

Table 4.17. *515 means; 5 months injection, 1-month soaking, and 5 months production (2100 days) using a 750 injection rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 515	289,594	0.681113	137.9
CSS 515	245,453	1.79943	116.88
CCO_2S 515	158,598	0.0189176	75.52

Table 4.18. *525 meaning; 5 months injection, 2 months soaking, and 5 months production (2310 days) using a 750 injection rate*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS	292,936	0.66362	126.8

525			
CSS 525	228,263	1.97023	98.82
CCO_2S 525	161,368	0.0206057	69.85

Optimized Injection Rate and Pressure for the CCO_2S and CSS

According to the results, the 500 injection rate (500ft^3/day for the CO_2 and 500bbl/day for the steam) proved to be better than the 750 injection rate (750ft^3/day for the CO_2 and 750bbl/day for the steam) so the injection rate that will be used to choose the optimum will be the 500 injection rate. The cumulative oil production increases as the number of days increases. High production is also our goal but it is not necessarily the optimum. Because there are some factors to consider as it was mentioned earlier like the number of days, CWOR, and the daily production rate. For an optimum result, a low number of days, lower CWOR, and high daily oil production are needed. As stated earlier, after the results using different injections are gotten and the optimum is chosen, different pressures will be used to choose the final optimum.

As 212 (2 months injection, 1 month soaking, and 2 months production) had a low CWOR, high production, fewer days (960), and a very strong daily production rate, indicating that it was the best case for the application. Because 212 is the optimum, Figures 4.19 and 4.20 employed different pressures of 750psi and 1000psi respectively to determine the optimum pressure. When comparing Tables 4.19 and 4.20, 1000psi produces more cumulative oil, has a lower CWOR, and produces more daily oil than 750psi. In addition, the 1000psi produced significantly less water than the 750psi. Because both have the same number of days, the number of days is not taken into account. The ideal pressure is 1000psi, based on the criteria described.

Like it was stated earlier, after choosing the optimum, different pressures will be used to choose a more optimum result will be chosen. Since the 212 with 500 injection rate (500ft^3/day for the CO_2 and 500bbl/day for the steam) was chosen, 750psi and 1000psi pressures will be used to see different results and from there, the better results will be chosen.

It has been our intention all along that the results of this study will be compared to the reference paper used in conducting this research. However, the results of the reference paper were that the reservoir had more affinity for the CSS hence CSS is the best and optimum method. But the result in this study is slightly different because the author of the reference paper used a Cartesian model while a radial model was used for this study. The radial model gives better results because it expands and shrinks like a circle or sphere giving it the ability to provide good results.

One more observation is that when CO_2 is involved, there is some irregularity in the graphs, which means the cycles are not equal as seen in Figures 4.7, 4.8, 4.11 and 4.12. This may be because of CO_2 depressurization.

From the results, the best performance was when steam is injected first then followed by CO_2. In a similar study by (Luo and Cheng, 2005), the same observation was made. This may be due to changes in oil viscosity with the degree of CO_2 miscibility (Bobb and Hosein, 2018). Under the same conditions, CO_2 may have a high tendency to be miscible with low viscosity oil but a low tendency to be miscible with high viscosity oil. Oil viscosity may have been lowered in this study due to the injection of steam, causing the miscibility of CO_2 to rise. Increased CO_2 miscibility may have lowered oil viscosity, even more, resulting in increased oil mobility and recovery.

Table 4.19. *Results using the 750psi Bottom-hole Pressure*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 212	214,515	0.164428	223.45
CSS 212	150,042	1.33576	156.29
CCO_2S 212	138,295	0.0131821	144.06

CCO_2S 212 here has a Cumulative Water SC of 1879.23 bbl as shown in Figure 4.11.

Table 4.20. *Results using the 1000psi Bottom-hole Pressure*

	Cumulative Oil SC (bbl)	**Cumulative Water Oil Ratio (CWOR)**	**Daily Prod. Rate (bbl/day)**
CCO_2S & CSS 212	217,525	0.163325	226.59
CSS 212	151,070	1.04838	157.4
CCO_2S 212	148,625	0.0122374	154.8

CCO_2S 212 here has a Cumulative Water SC of 1762.97 bbl as shown in Figure 4.12.

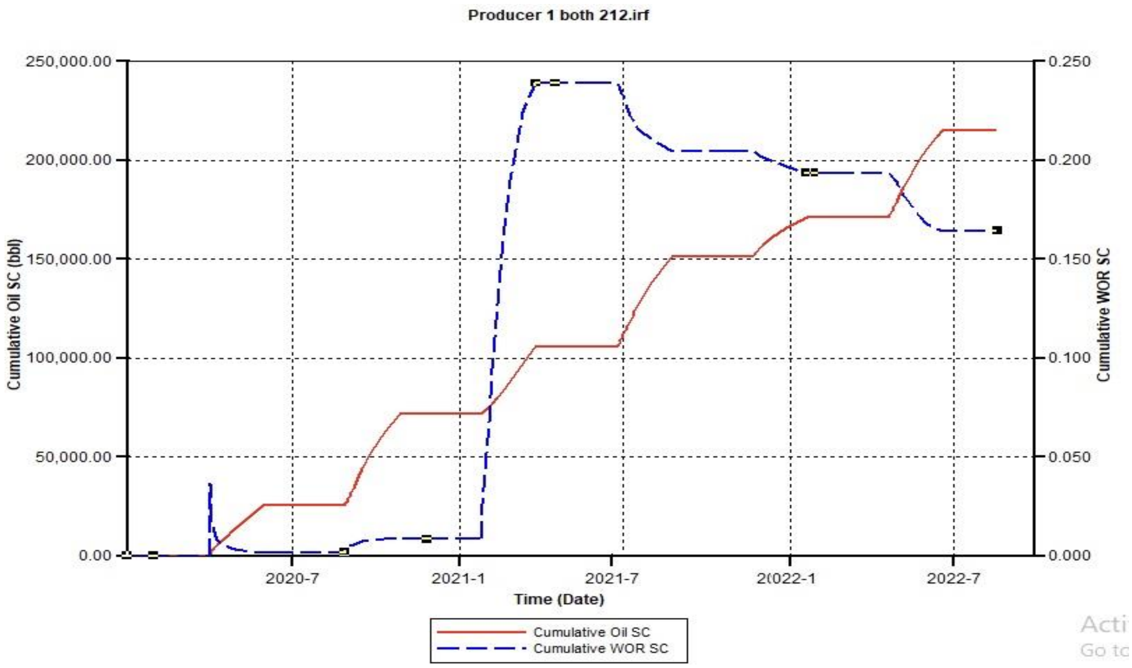

Figure 4.7. *Cumulative Oil Produced and Water Oil Ratio (WOR) for the combination of CSS and CCO_2S using 750 psi Pressure*

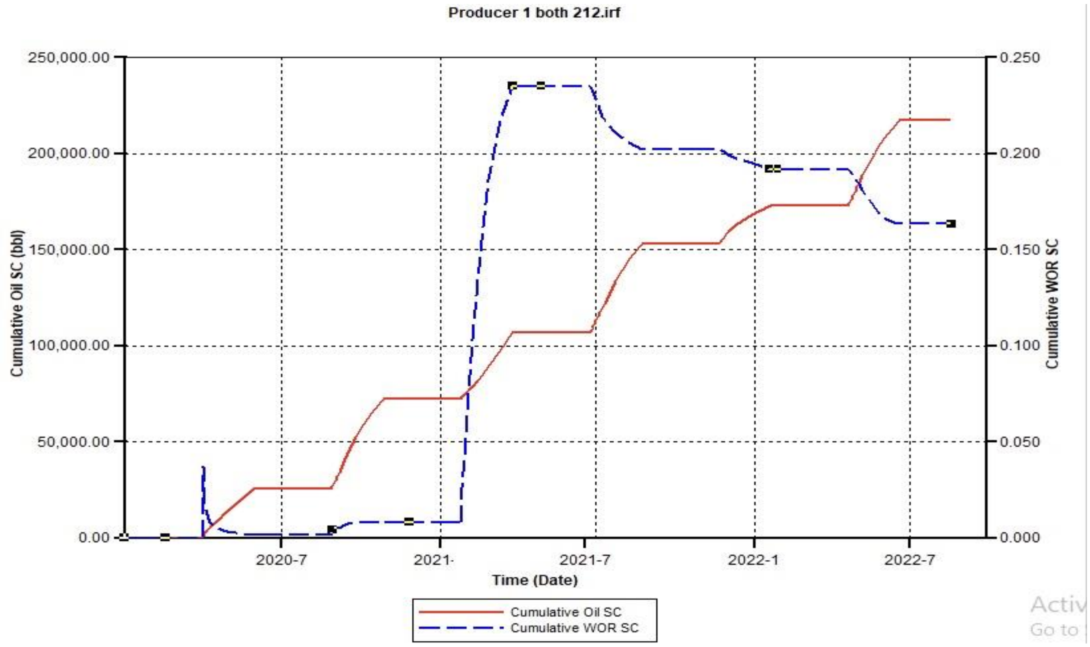

Figure 4.8. *Cumulative Oil Produced and Water Oil Ratio (WOR) for the combination of CSS and CCO_2S using 1000 psi Pressure*

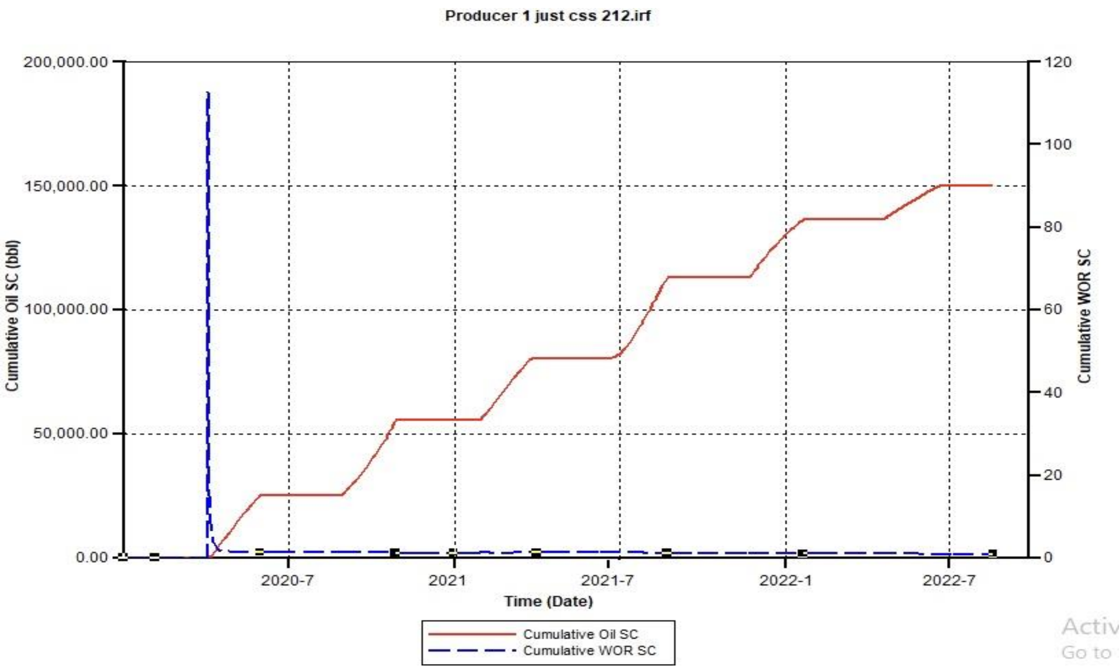

Figure 4.9. *Cumulative Oil Produced and Water Oil Ratio (WOR) for the CSS using 750 psi Pressure*

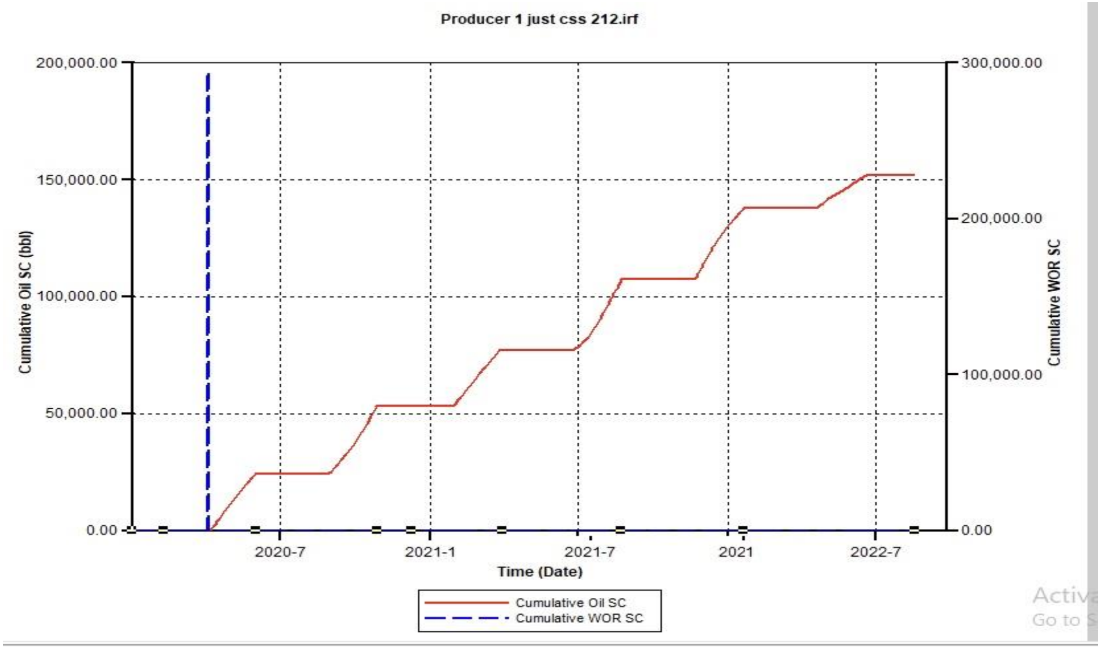

Figure 4.10. *Cumulative Oil Produced and Water Oil Ratio (WOR) for the CSS using 1000 psi Pressure*

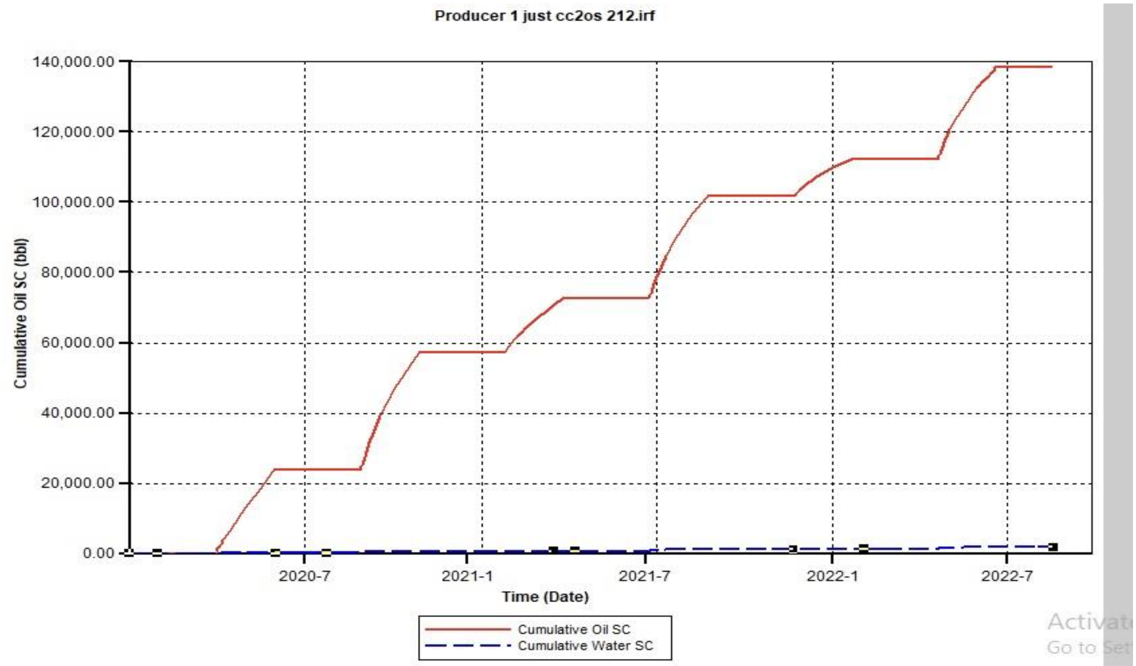

Figure 4.11. *Cumulative Oil Produced and Cumulative Water SC for the CCO_2S using 750psi Pressure*

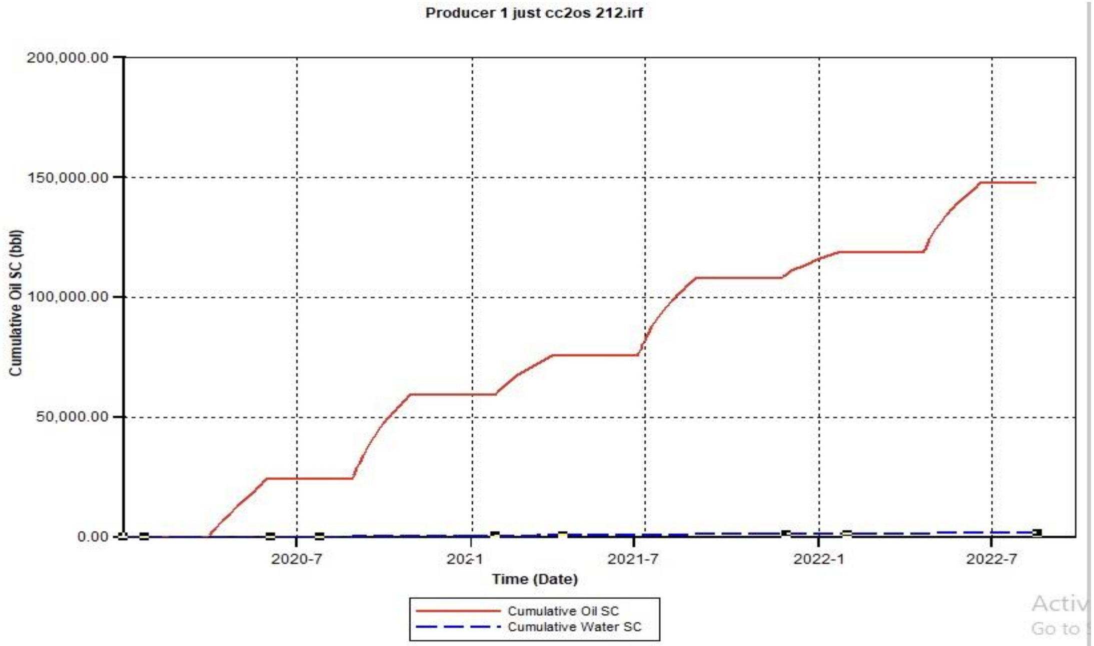

Figure 4.12. *Cumulative Oil Produced and Cumulative Water SC for the CCO_2S using 1000 psi Pressure*

CHAPTER V

Conclusions and Recommendations

Conclusions

This chapter presents conclusions based on the research findings in the previous chapter. As mentioned in the results and discussions, the 500 injection rate (500ft^3/day for the CO_2 and 500bbl/day for the steam) proved to be better than the 750 injection rate (750ft^3/day for the CO_2 and 750bbl/day for the steam).

The 525 may be the best from the production perspective however from an economic perspective the steam oil ratio is still high and the daily oil produced is lower which is not optimum.

The 222 (2 months injection, 2 months soaking, and 2 months production) had a reasonable CWOR, and a lesser amount of days (1140 days), with a high daily production rate.

The 212 (2 months injection, 1-month soaking, and 2 months production) had a low CWOR, a high production, a lesser amount of days (960 days) and it also had a very good daily production rate showing the optimum case for the application.

The application of different pressures such as 750 psi and 1000 psi at the optimum scenario, 212 showed that; 1000psi had the higher cumulative oil produced, lesser CWOR, and higher daily oil produced than the 750psi. Moreover, the 1000psi produced less water than the 750psi.

After all the optimization, the optimum is 212 (2 months injection, 1-month soaking, and 2 months production) with a 500 injection rate(500ft^3/day for the CO_2 and 500bbl/day for the steam) and 1000psi bottom-hole pressure.

CSS, CCO_2S, and combined CSS and CCO_2S were all successful, feasible, and economical for the test reservoir. The combination of CSS and CCO_2S economically produced more than 95 MSTB of oil for the entire field. This accounts for approximately an 8.6% increase in recovery.

Recommendation

It is recommended that further research is conducted because there are plenty of studies about CSS alone and CCO_2S alone but there are only a few studies on the combination of the CSS and CCO_2S.

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Appendices

Appendix A: Graphs for 500 injection rate

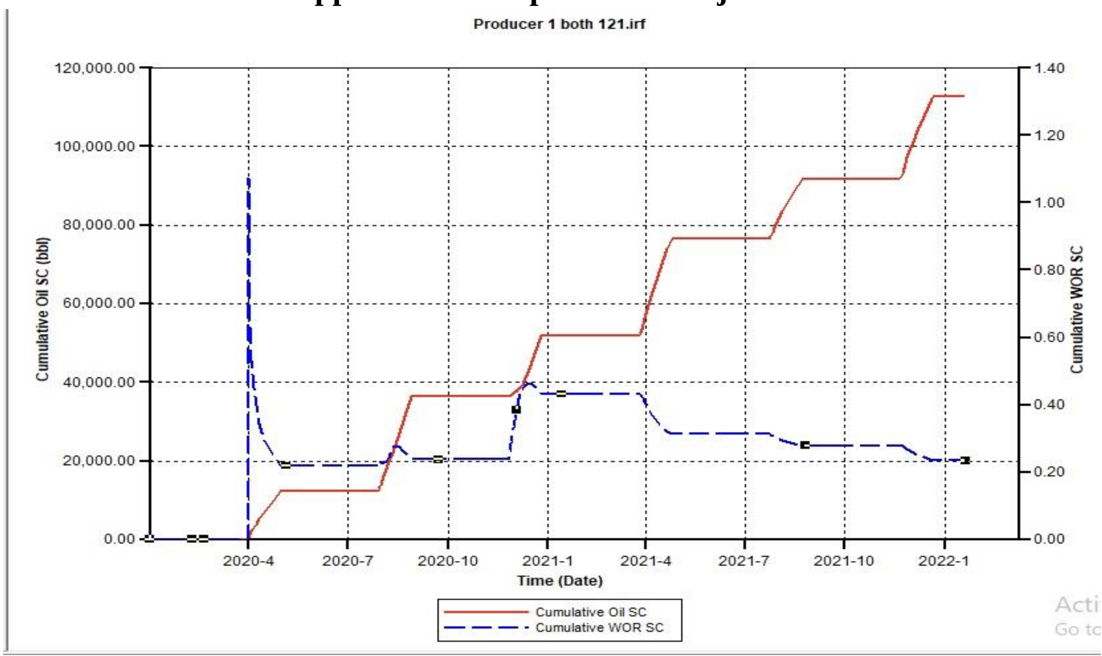


Figure A.1. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 121 using a 500 Injection Rate*

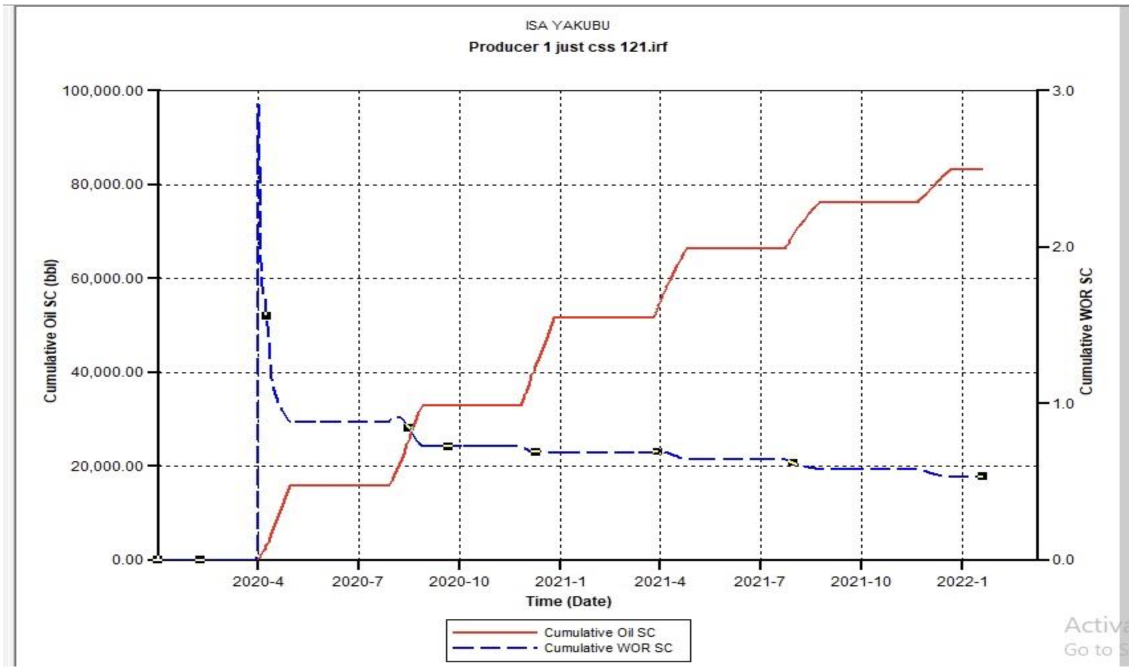


Figure A.2. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 121 using a 500 Injection Rate*

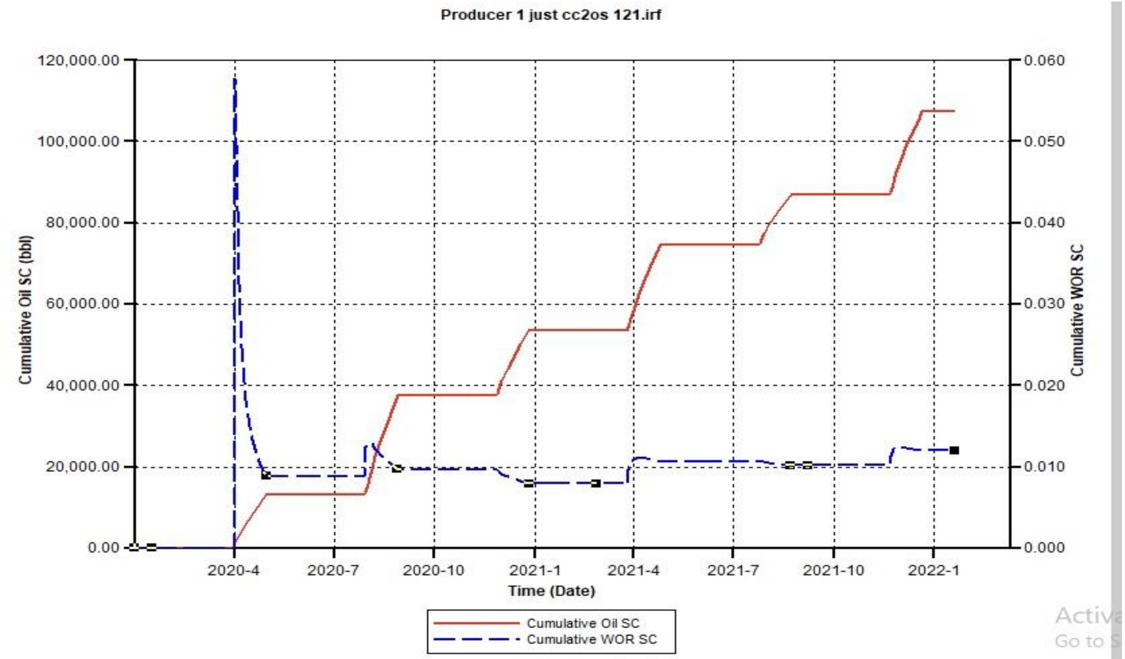


Figure A.3. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO$_2$S 121 using a 500 Injection Rate*

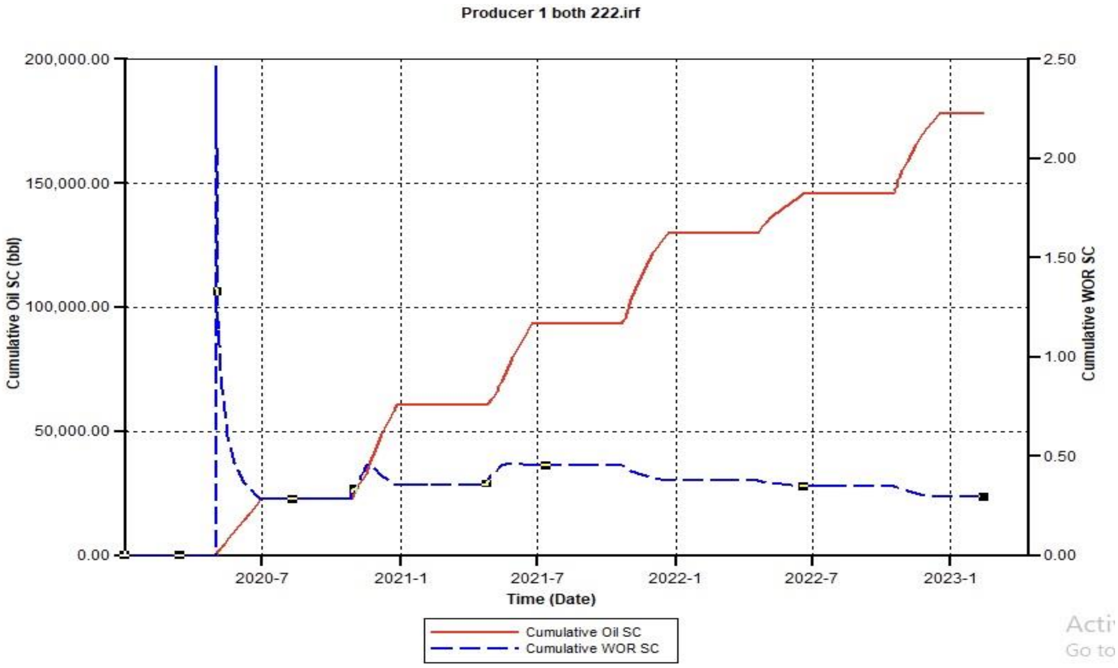


Figure A.4. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO$_2$S 222 using a 500 Injection Rate*

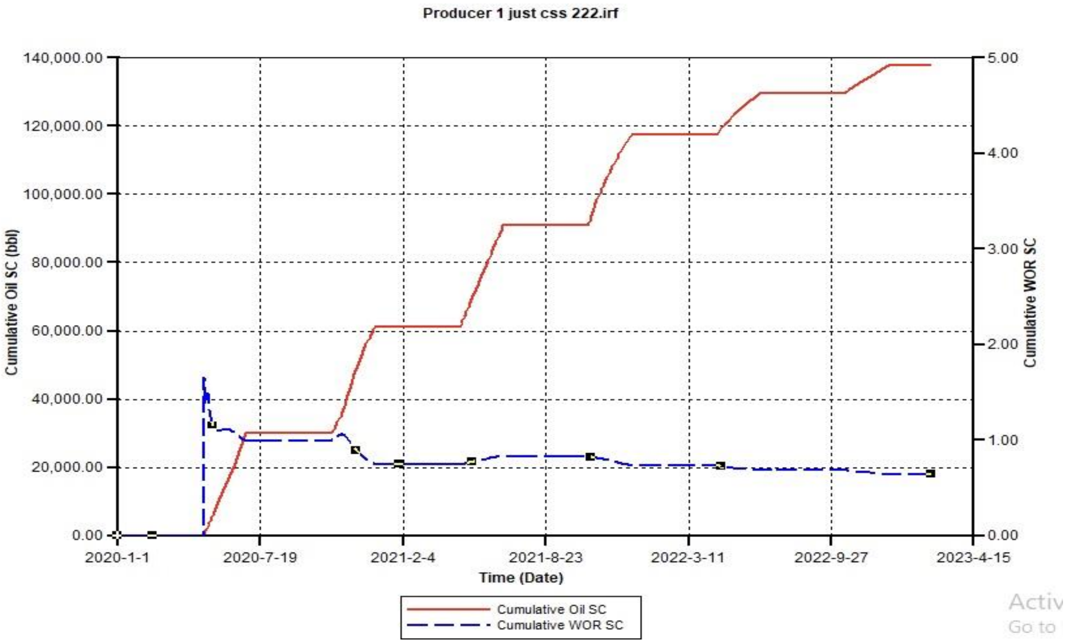
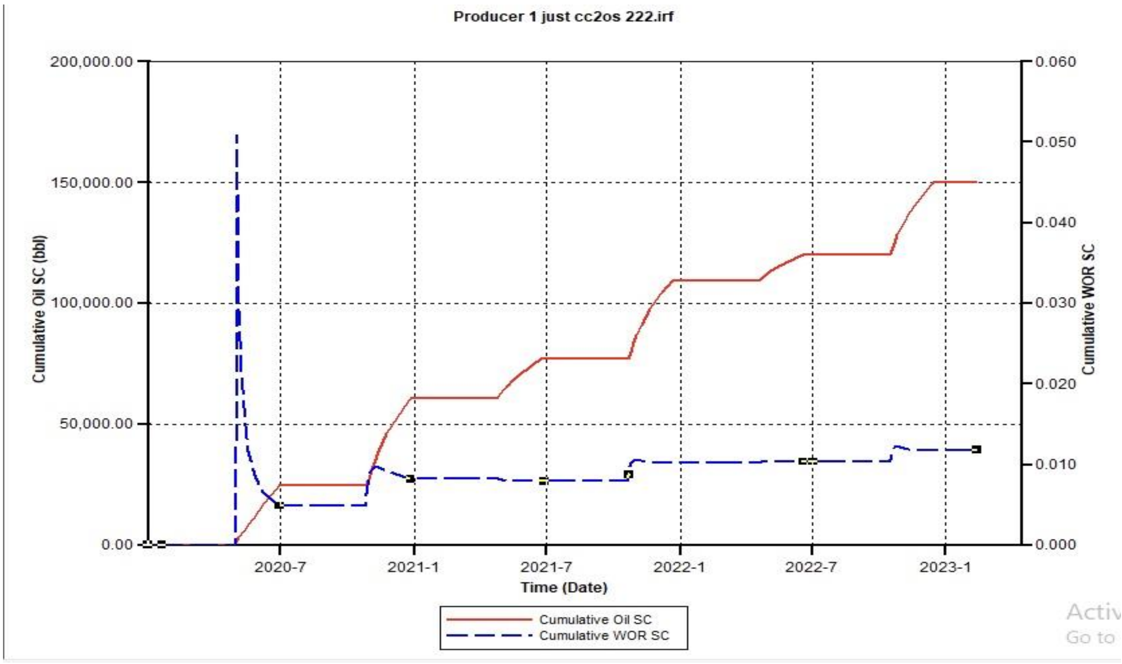


Figure A.5. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 222 using a 500 Injection Rate*



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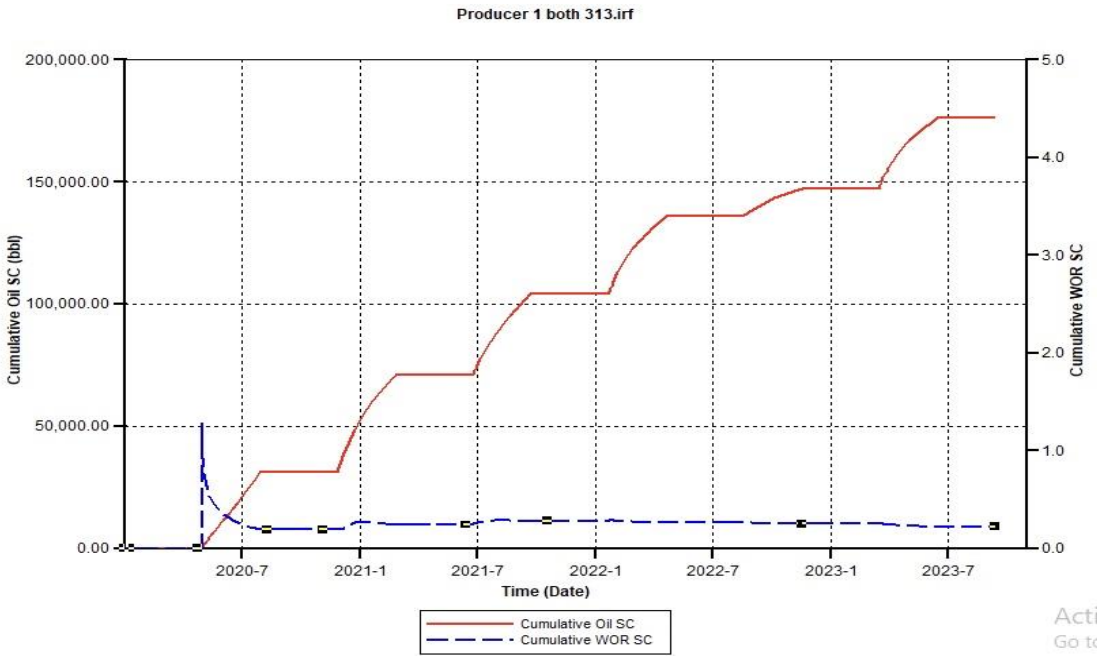

Figure A.7. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 313 using a 500 Injection Rate*

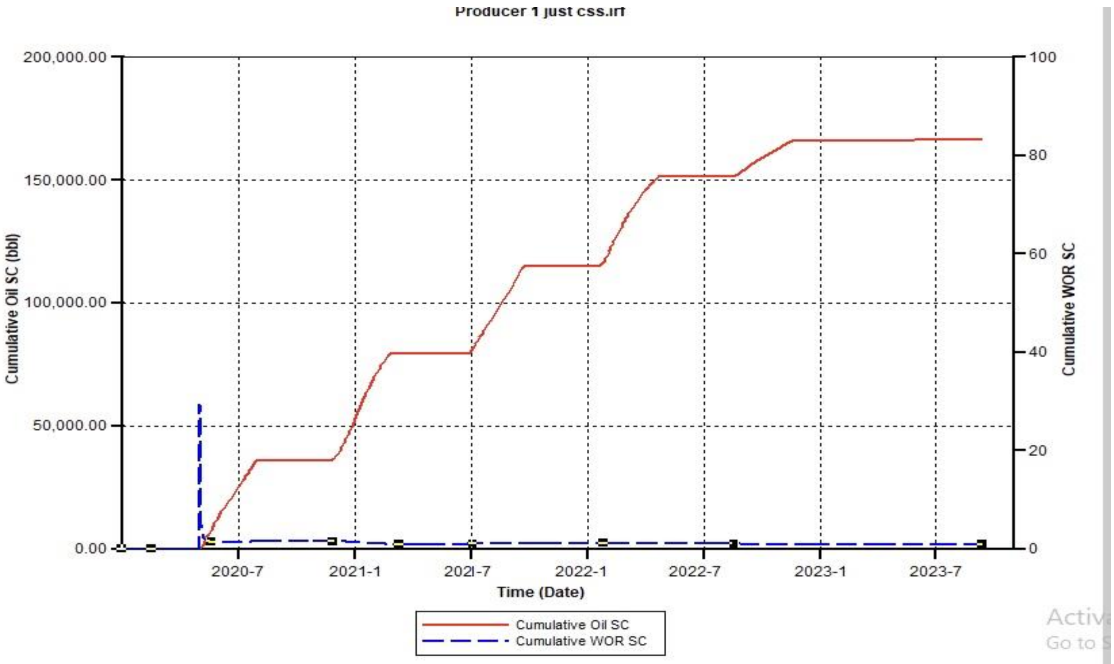

Figure A.8. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 313 using a 500 Injection Rate*

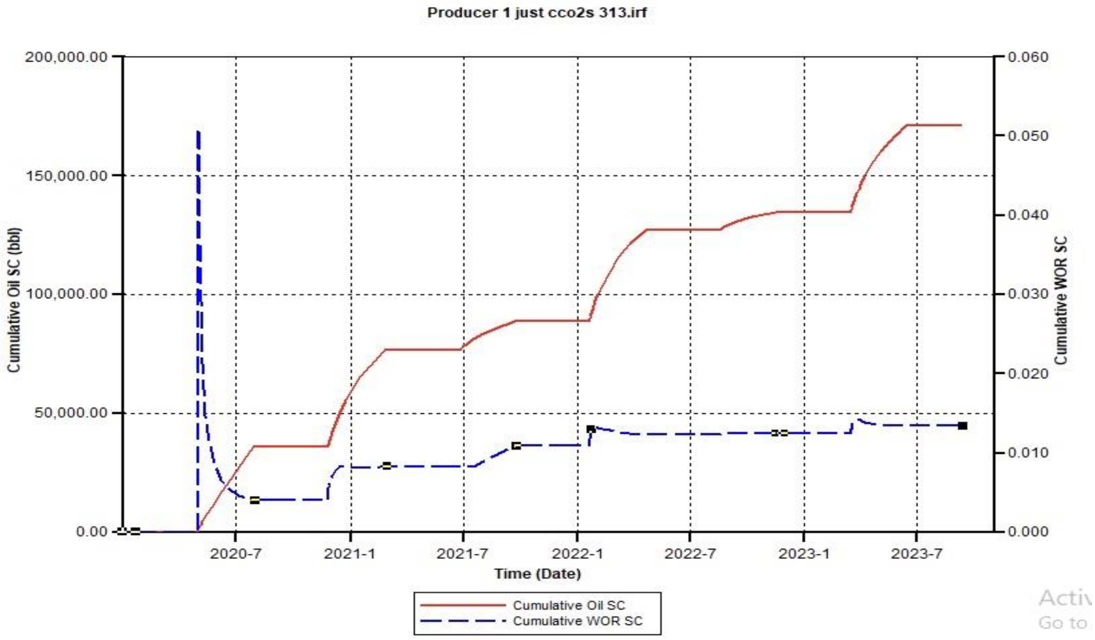

Figure A.9. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 313 using 500 Injection Rate*

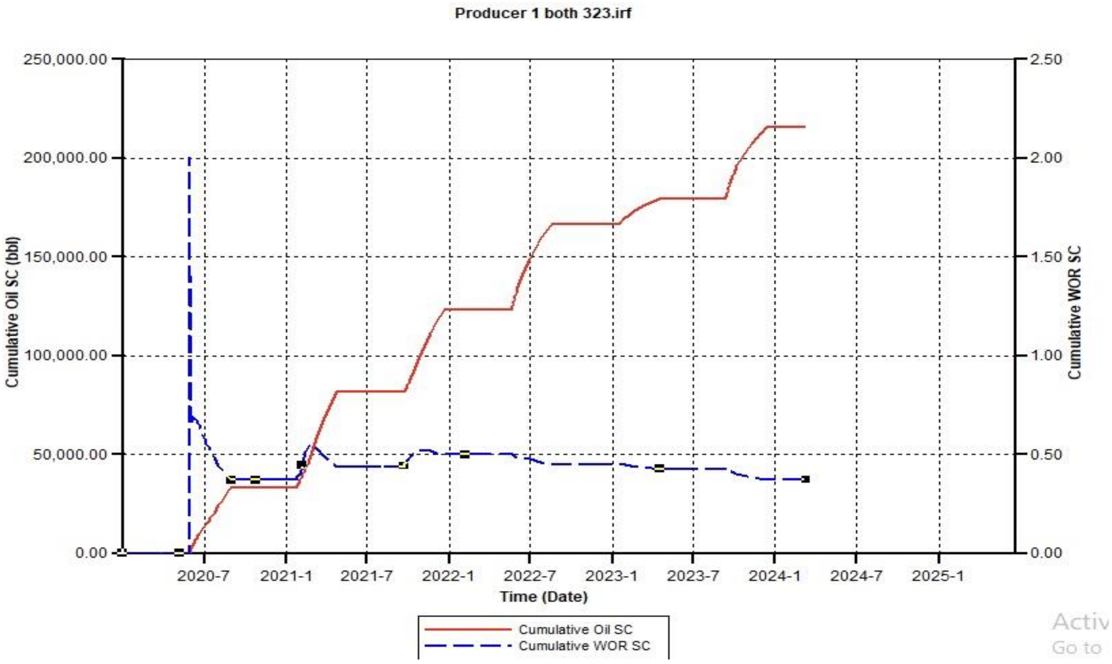

Figure A.10. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 323 using a 500 Injection Rate*

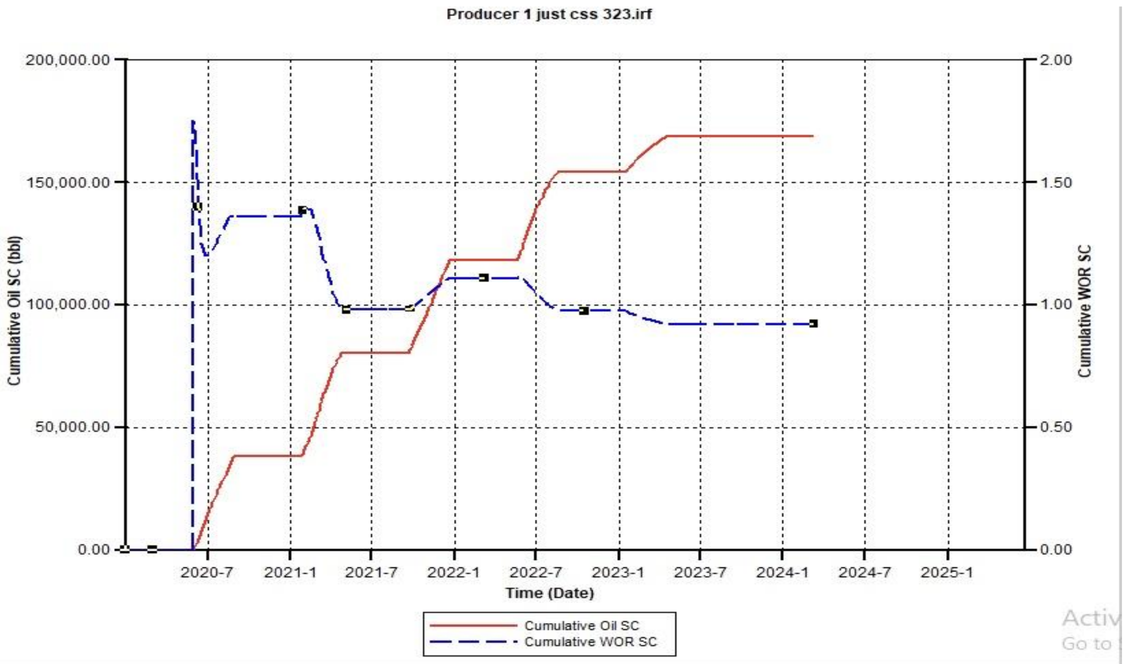

Figure A.11. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 323 using 500 Injection Rate*

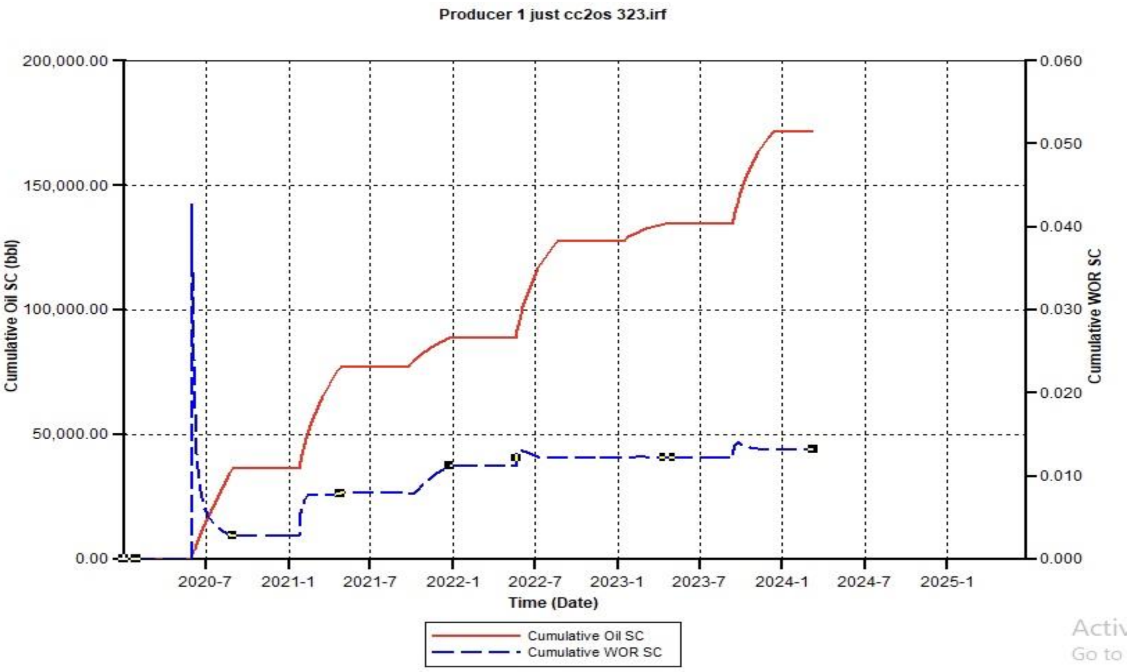

Figure A.12. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 323 using 500 Injection Rate*

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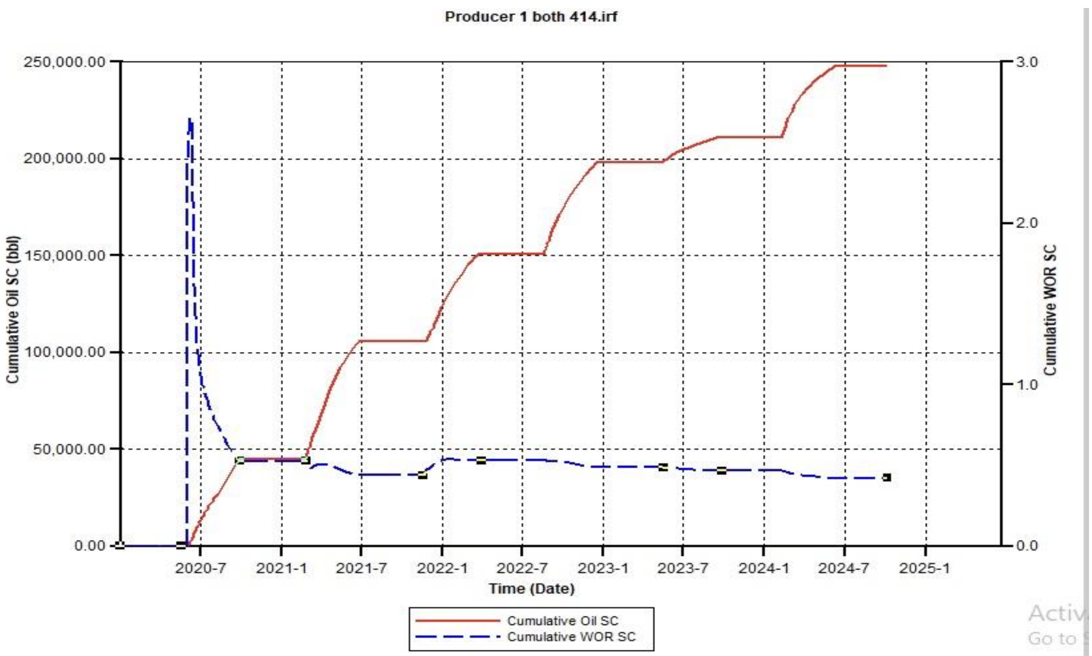

Figure A.13. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 414 using a 500 Injection Rate*

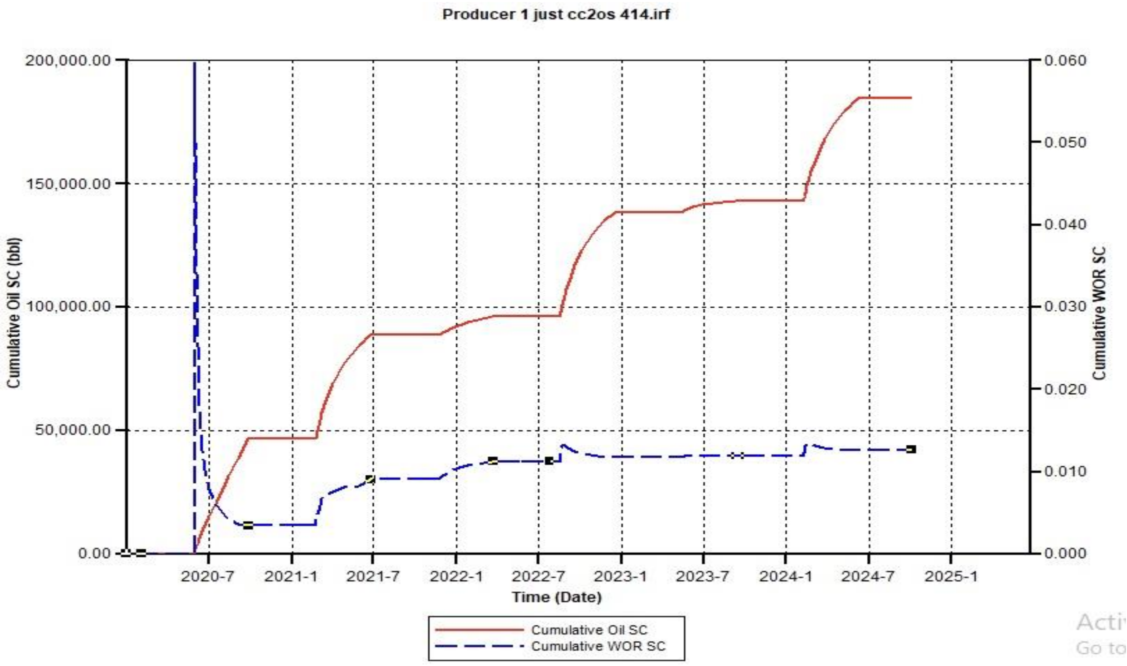

Figure A.14. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 414 using a 500 Injection Rate*

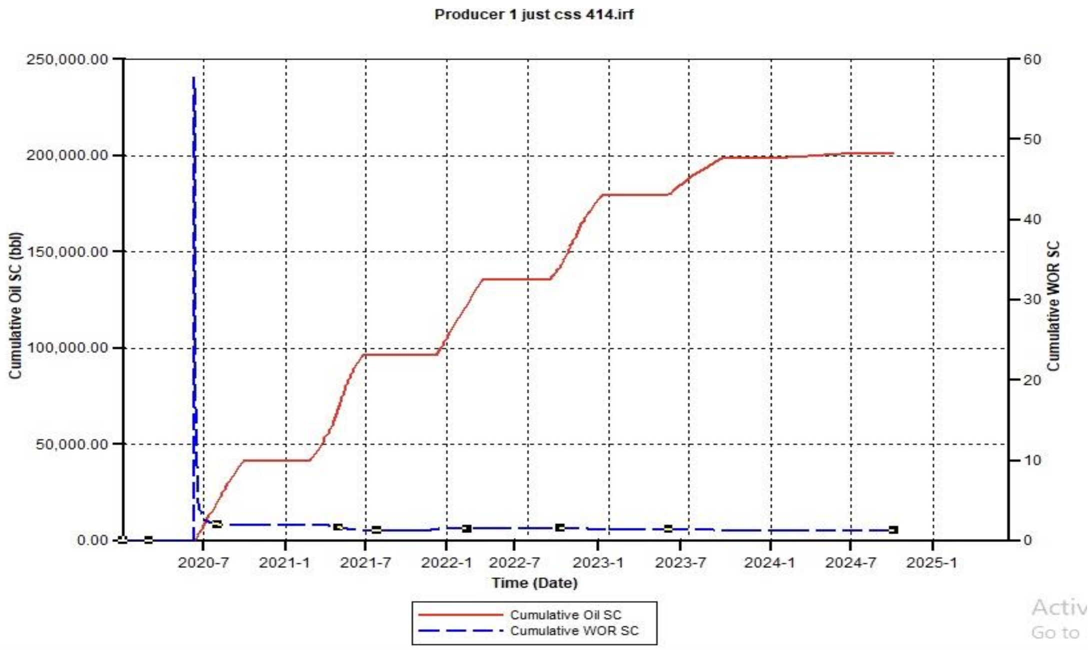

Figure A.15. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 414 using a 500 Injection Rate*

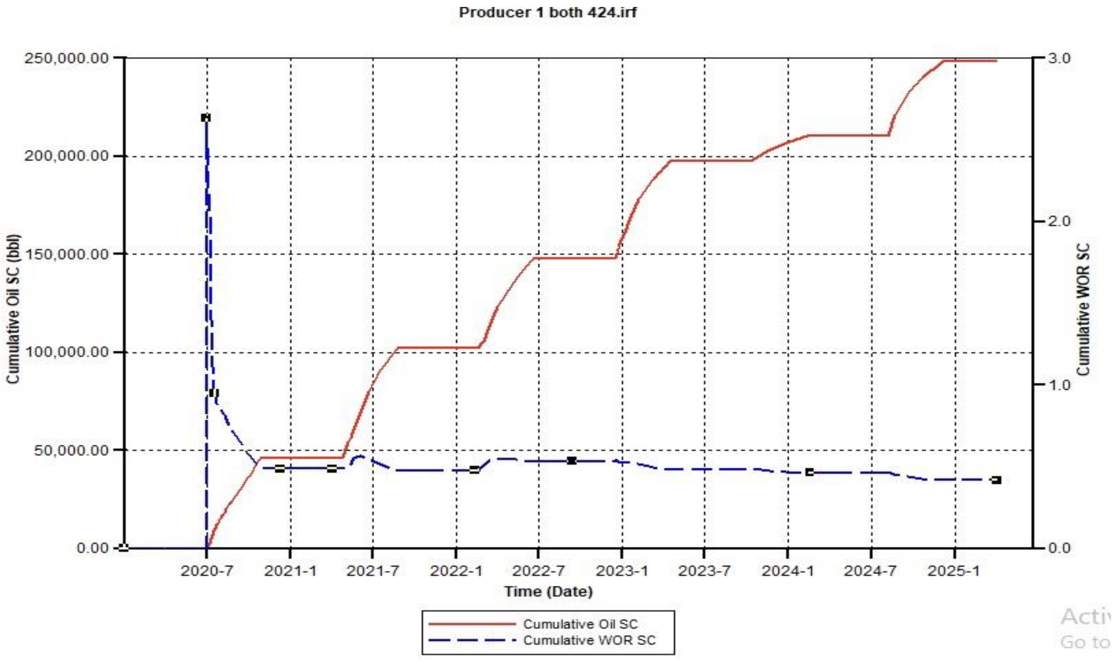

Figure A.16. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 414 using a 500 Injection Rate*

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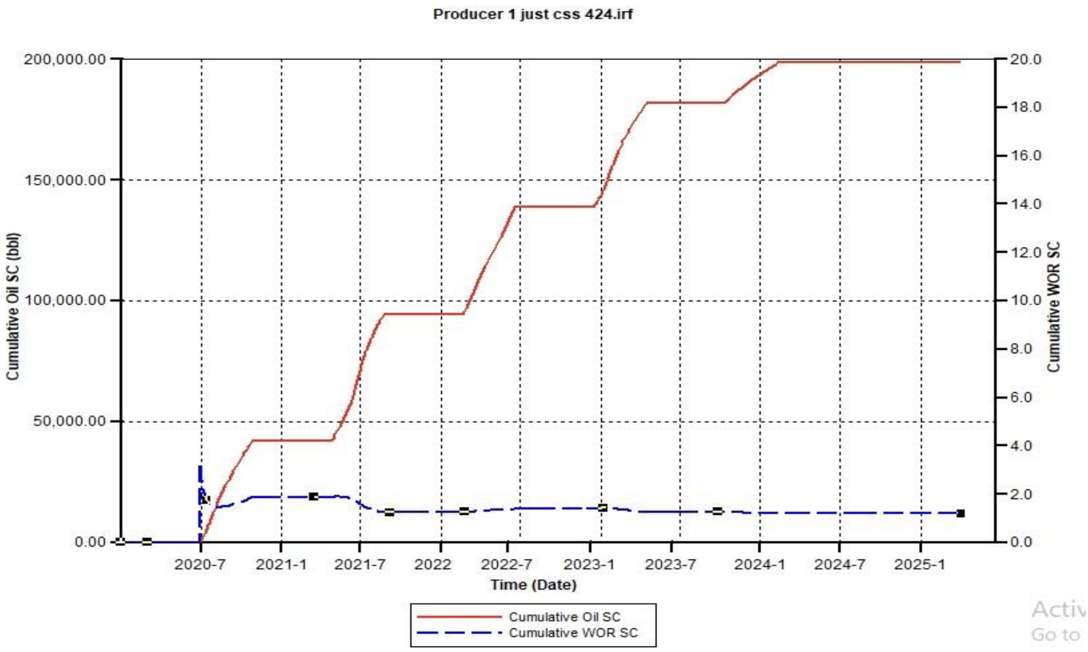


Figure A.17. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 424 using a 500 Injection Rate*

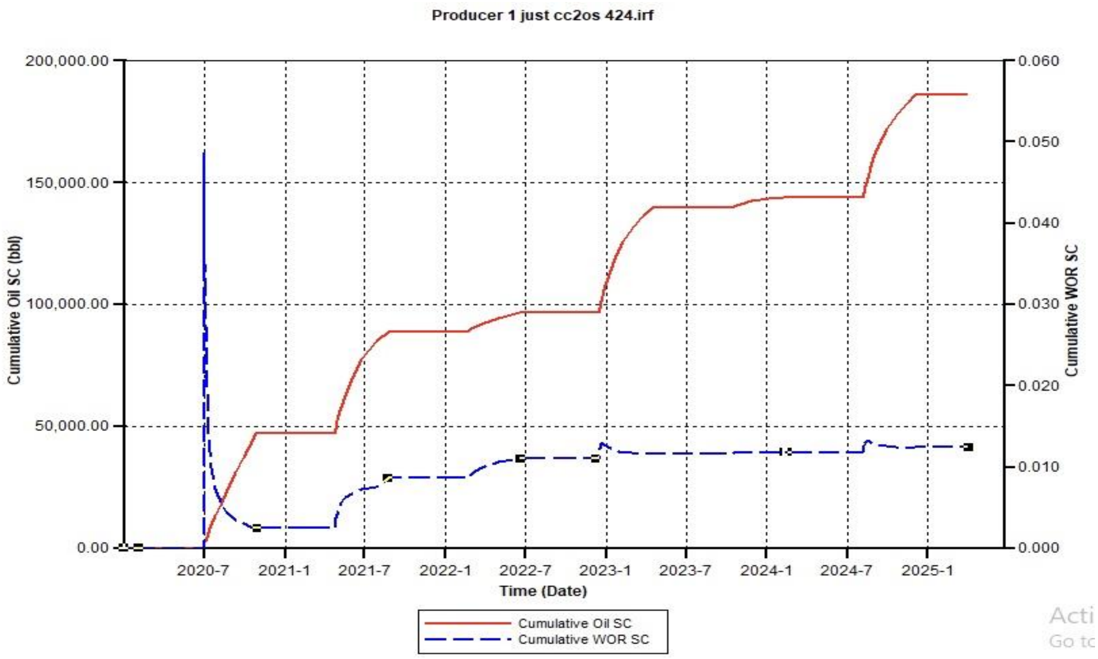


Figure A.18. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 424 using 500 Injection Rate*

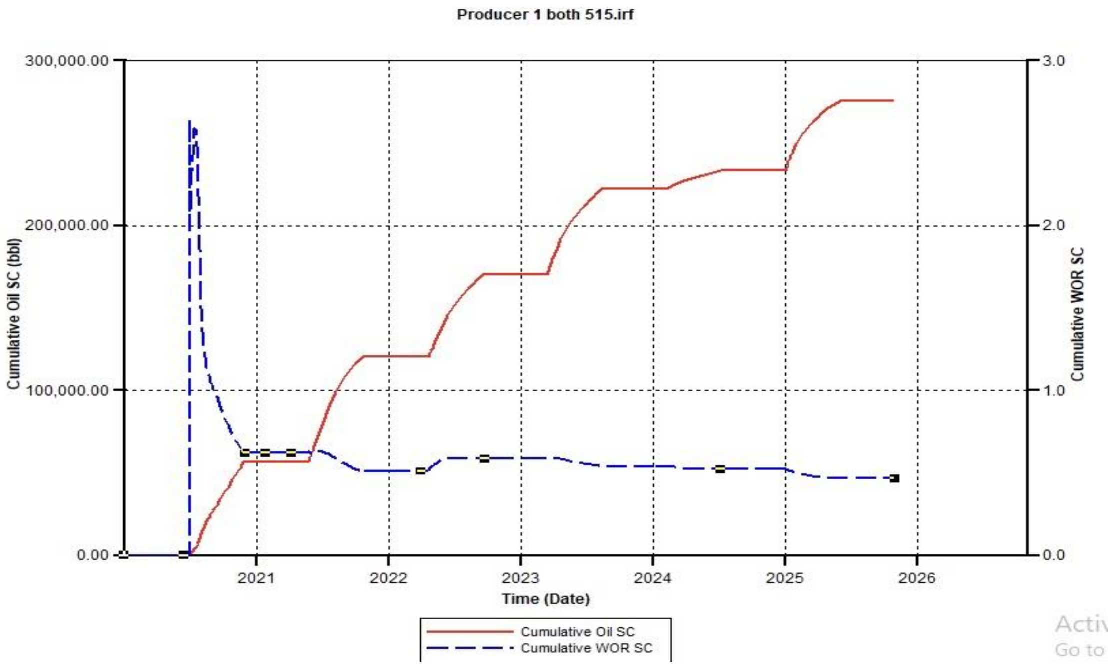


Figure A.19. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 515 using a 500 Injection Rate*

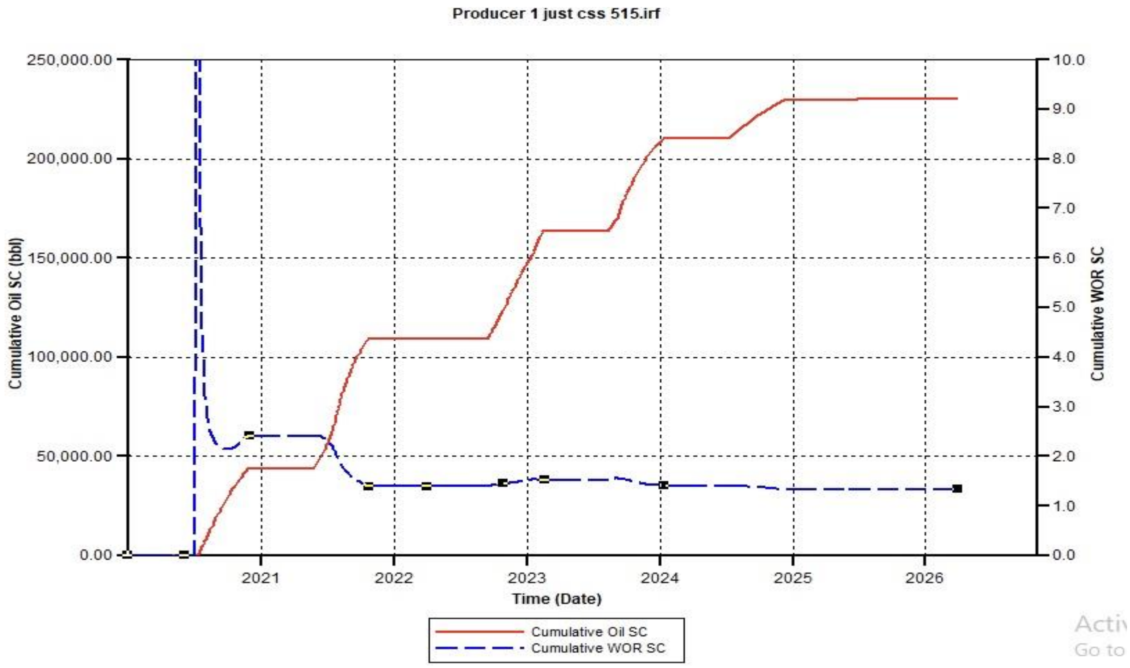


Figure A.20. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 515 using a 500 Injection Rate*

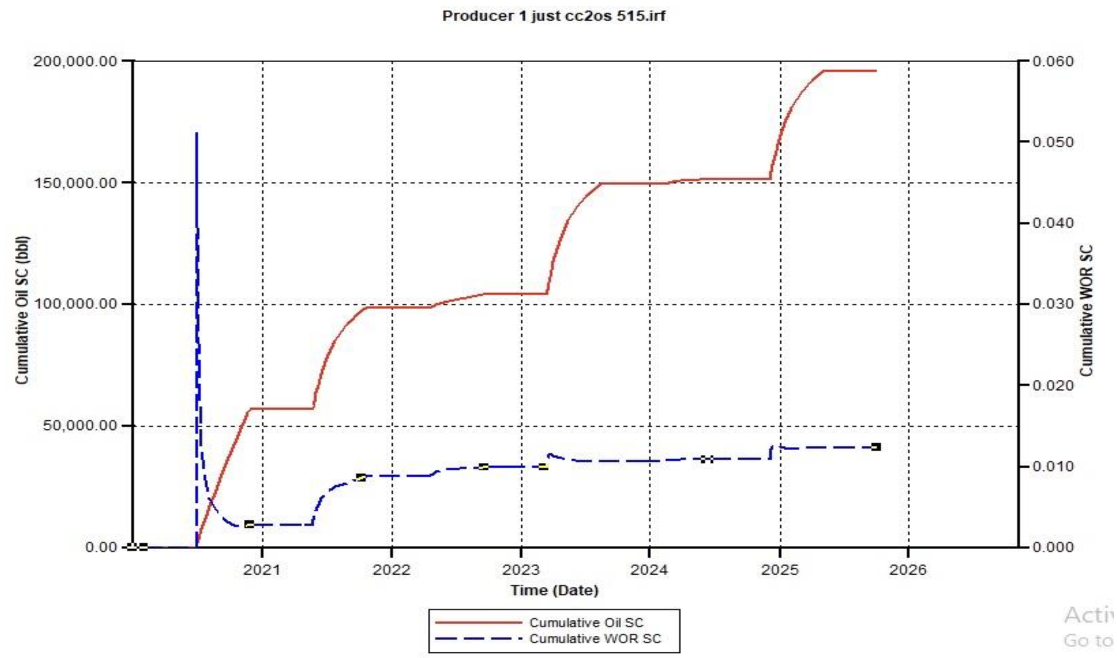


Figure A.21. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 515 using 500 Injection Rate*

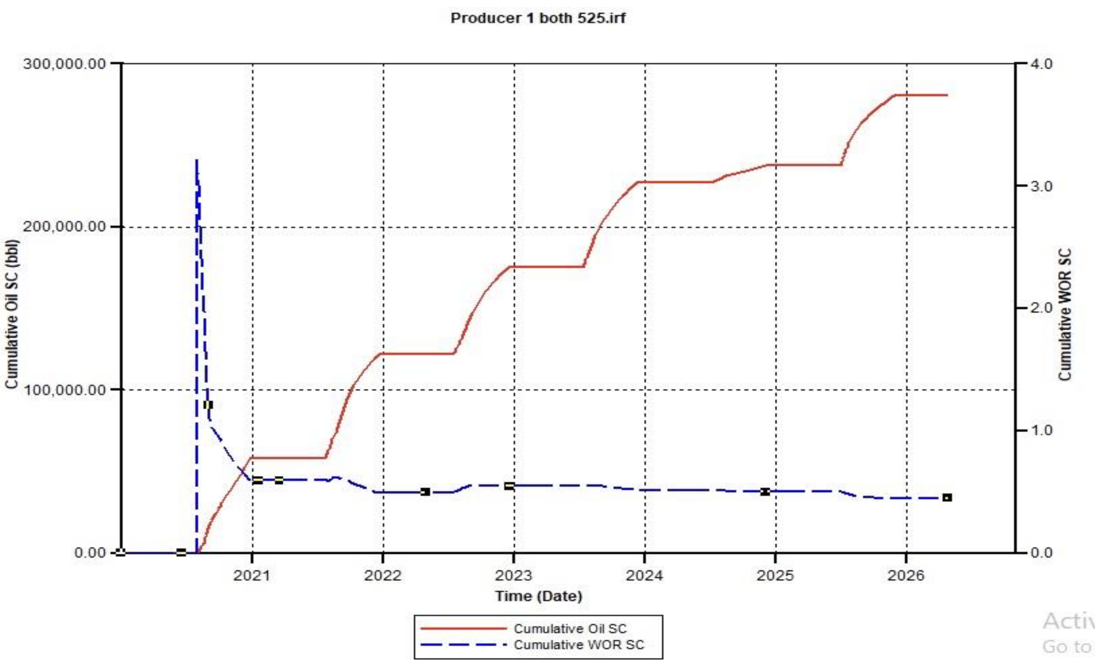


Figure A.22. ***Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 525 using a 500*** *Injection Rate*

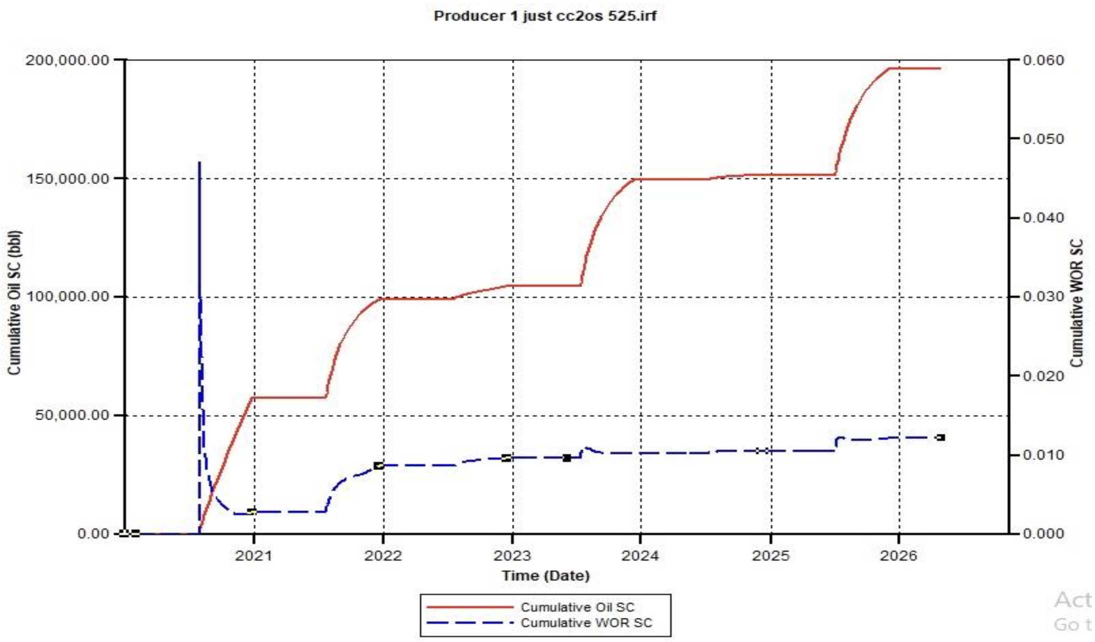


Figure A.23. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 525 using 500 Injection Rate*

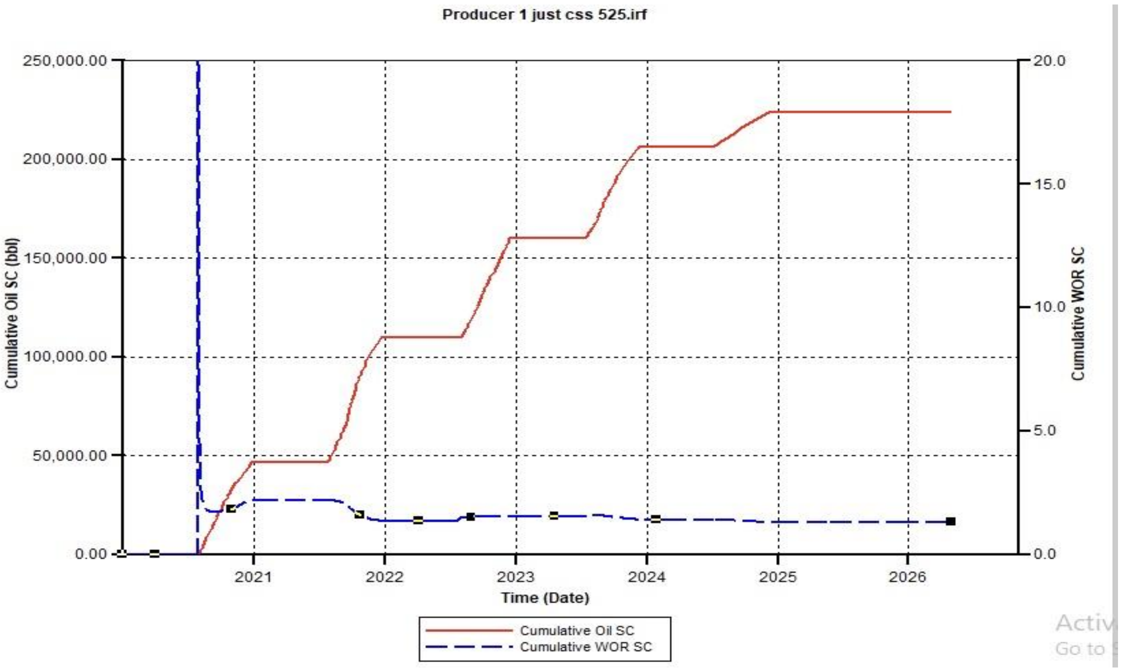


Figure A.24. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 525 using a 500 Injection Rate*

Appendix B: Graphs for 750 injection rate

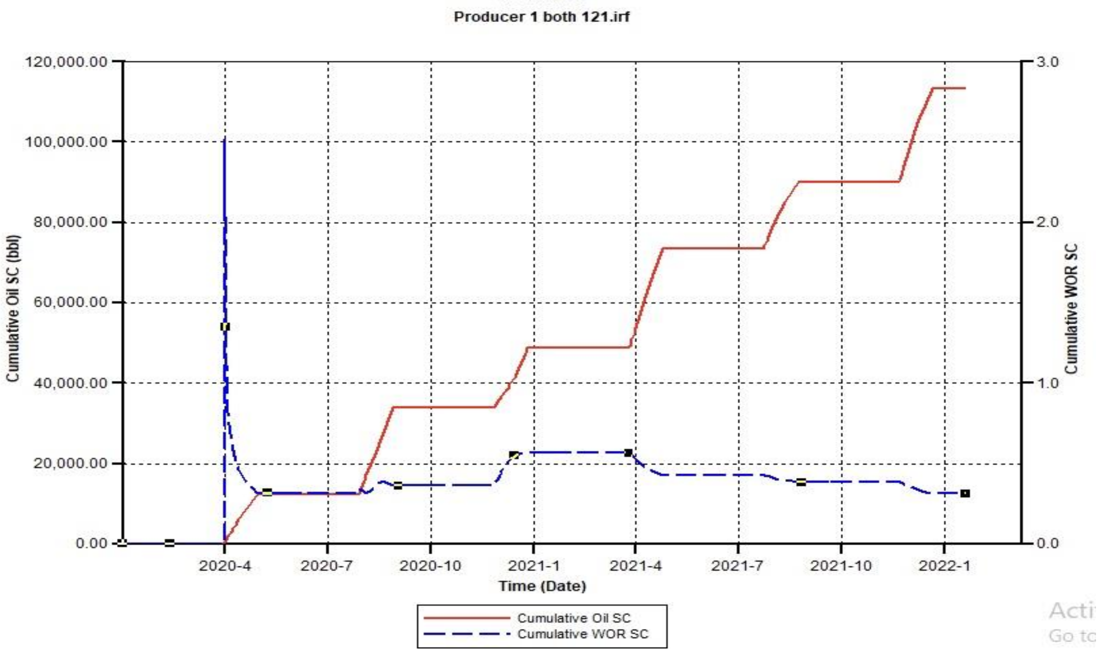


Figure B.1. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 121 using a 750 Injection Rate*

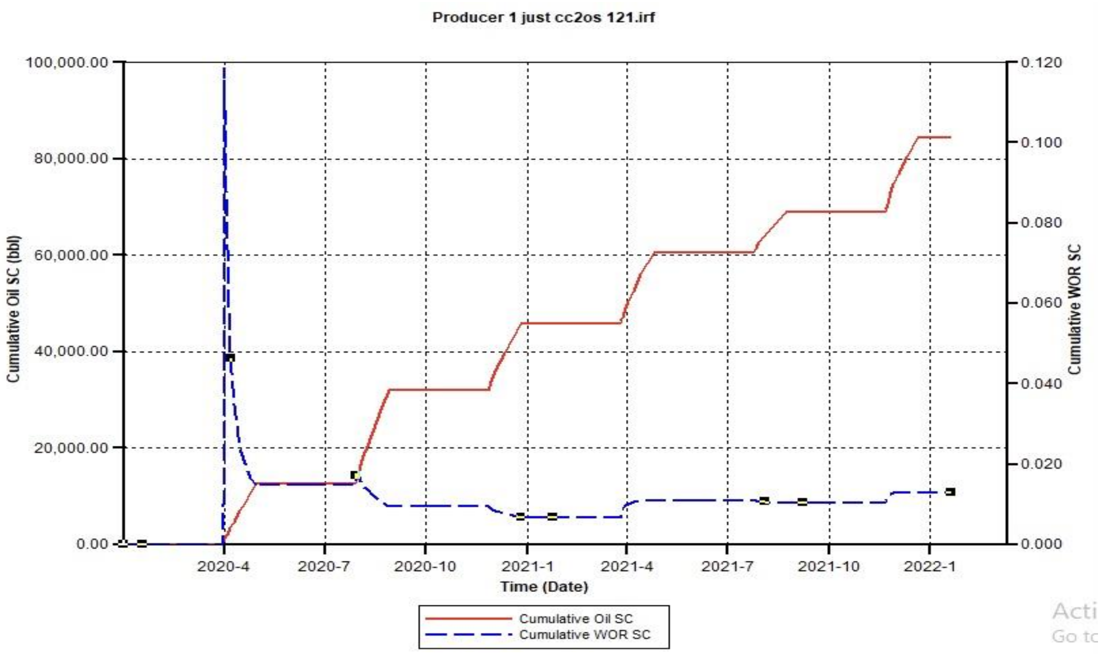


Figure B.2. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 121 using 750 Injection Rate*

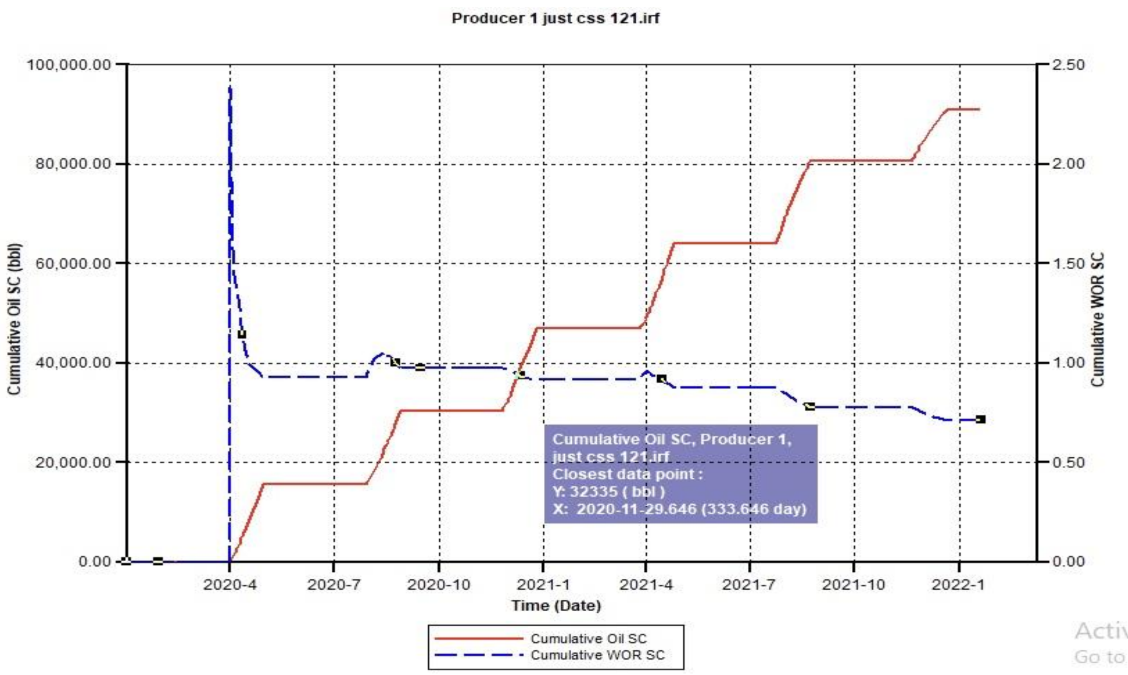


Figure B.3. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 121 using a 750 Injection Rate*

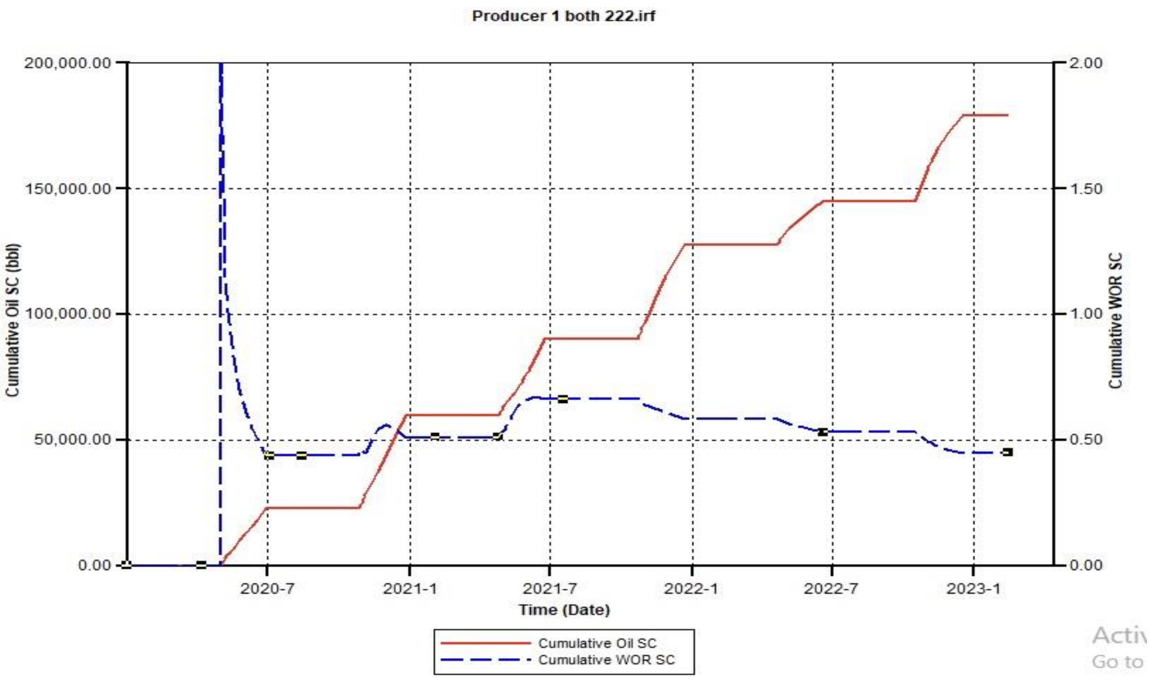


Figure B.4. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO₂S 222 using a 750 Injection Rate*

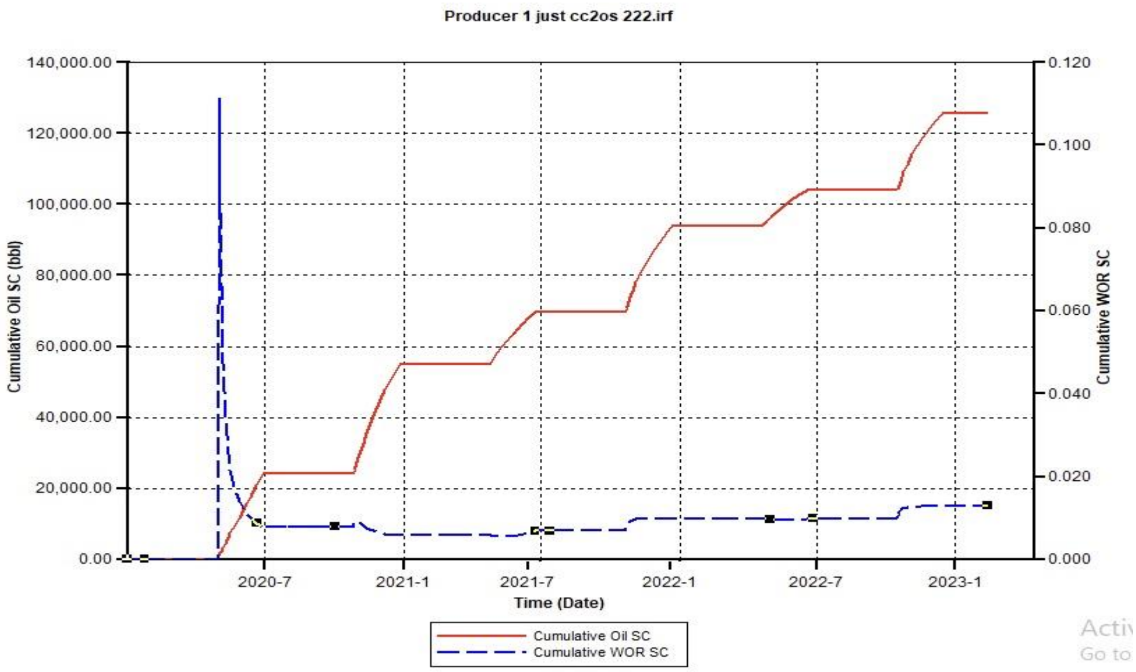
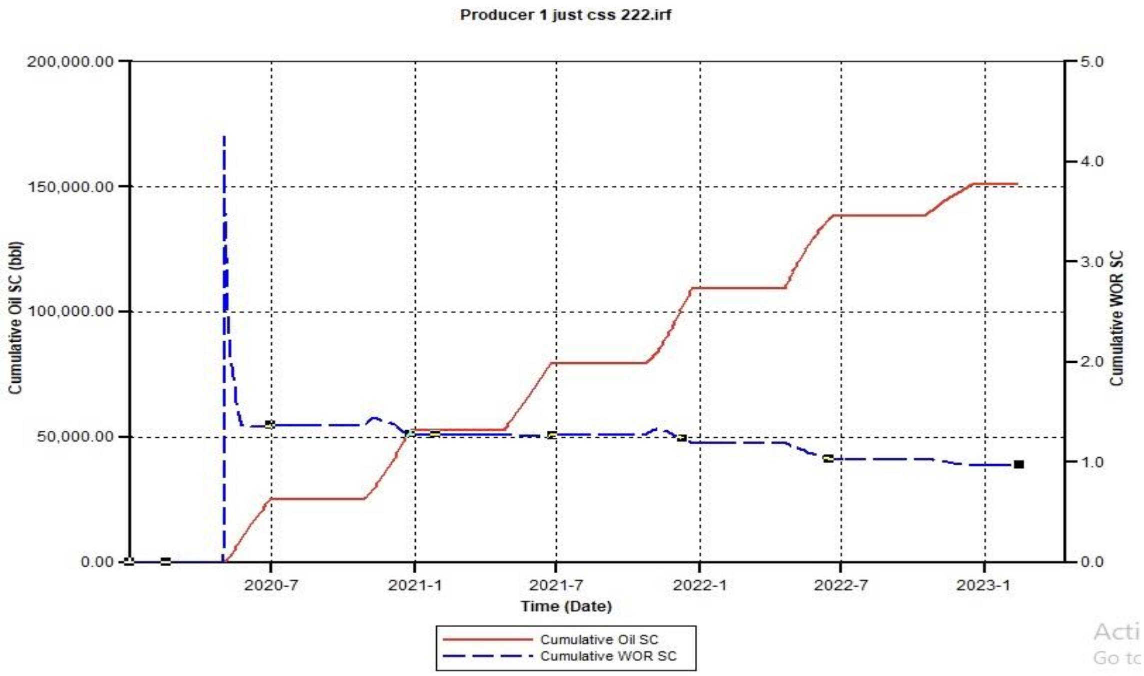


Figure B.5. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 222 using 750 Injection Rate*



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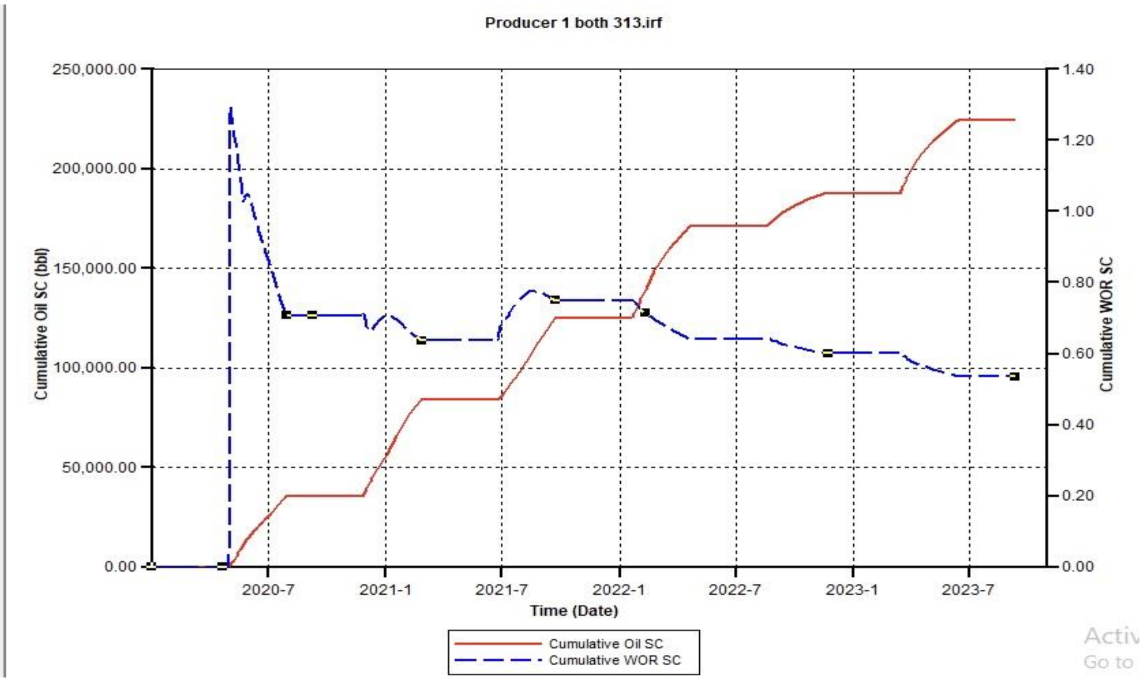
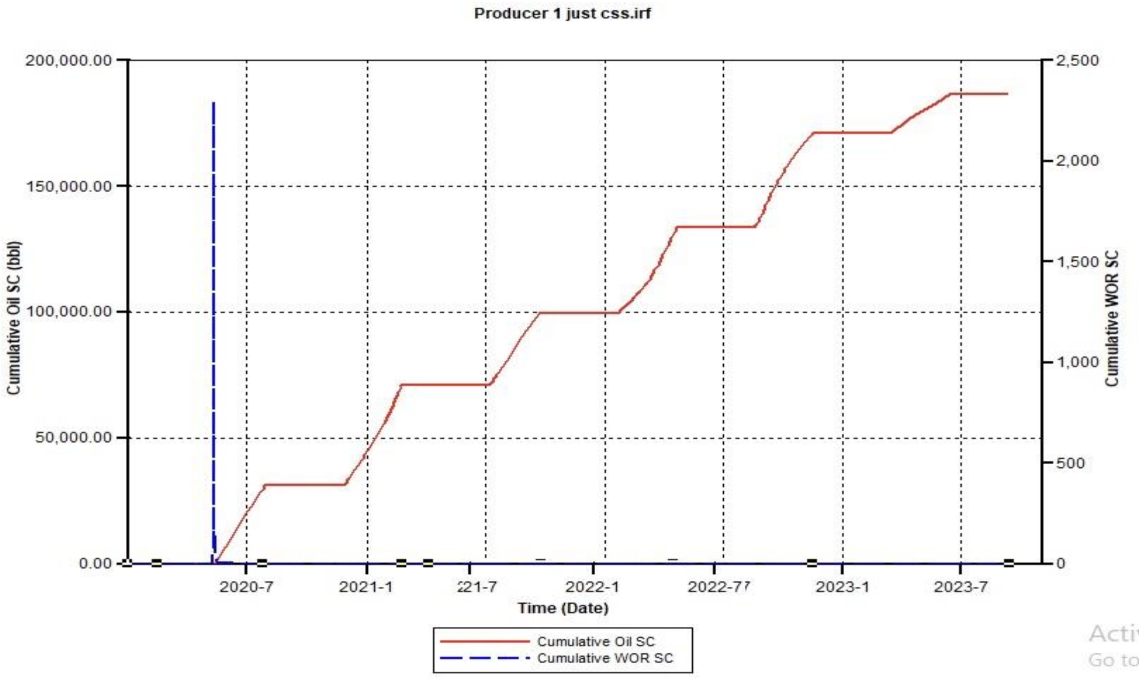


Figure B.7. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 313 using a 750 Injection Rate*



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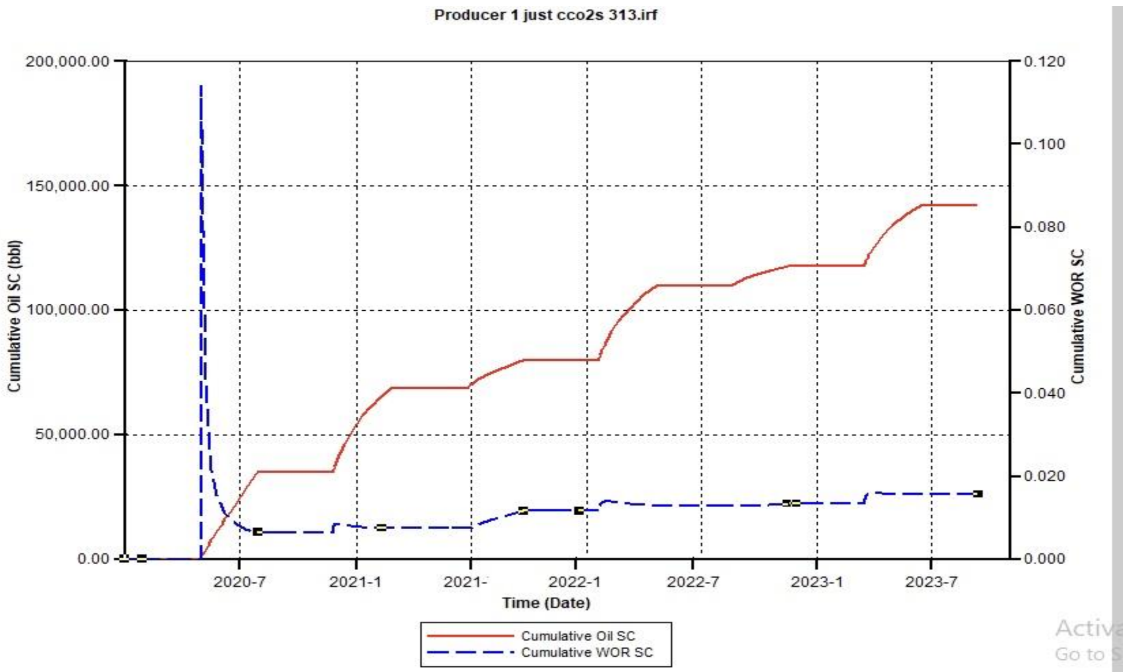


Figure B.9. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 313 using 750 Injection Rate*

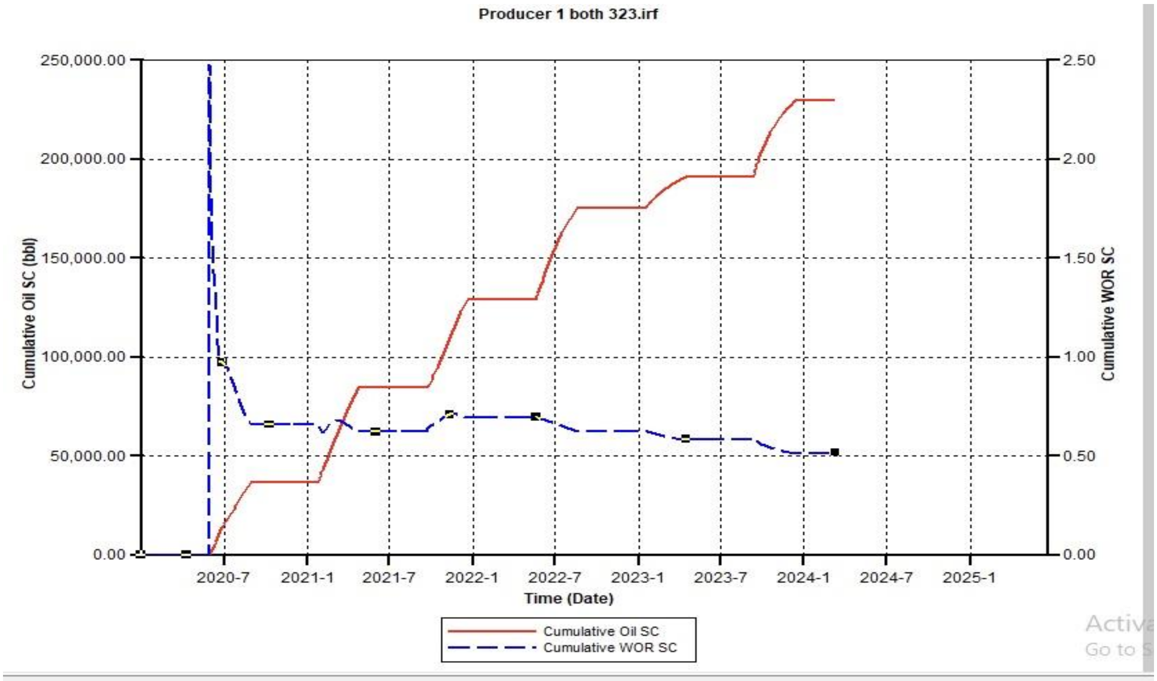


Figure B.10. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 323 using a 750 Injection Rate*

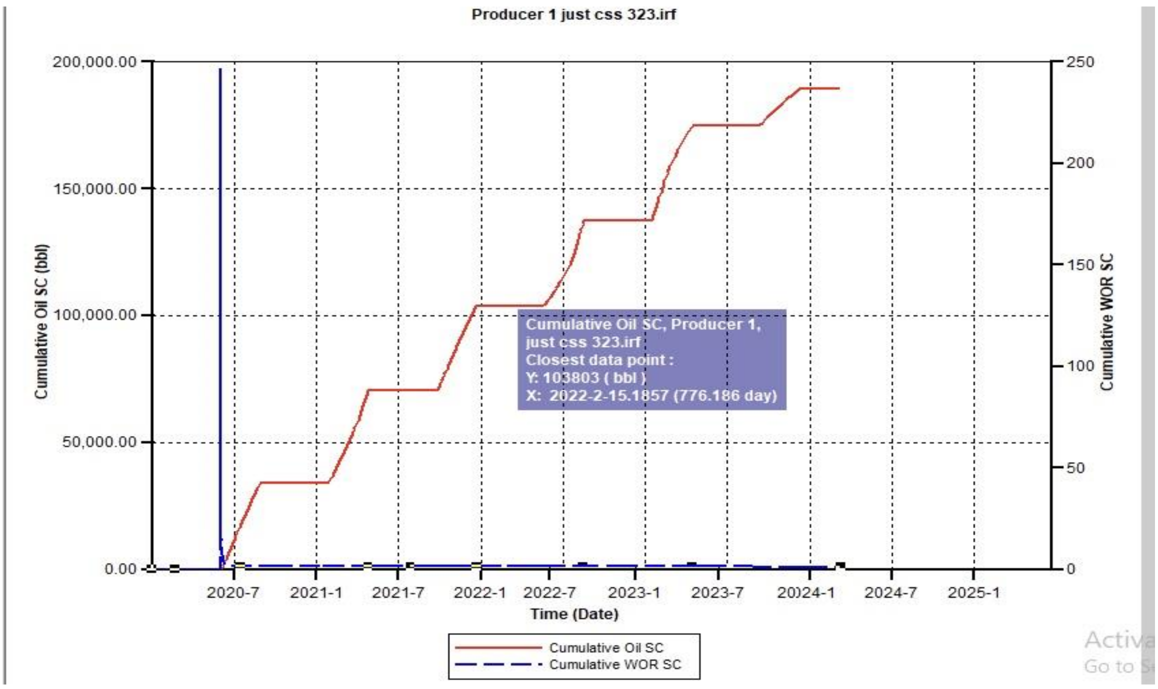


Figure B.11. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 323 using 750 Injection Rate*

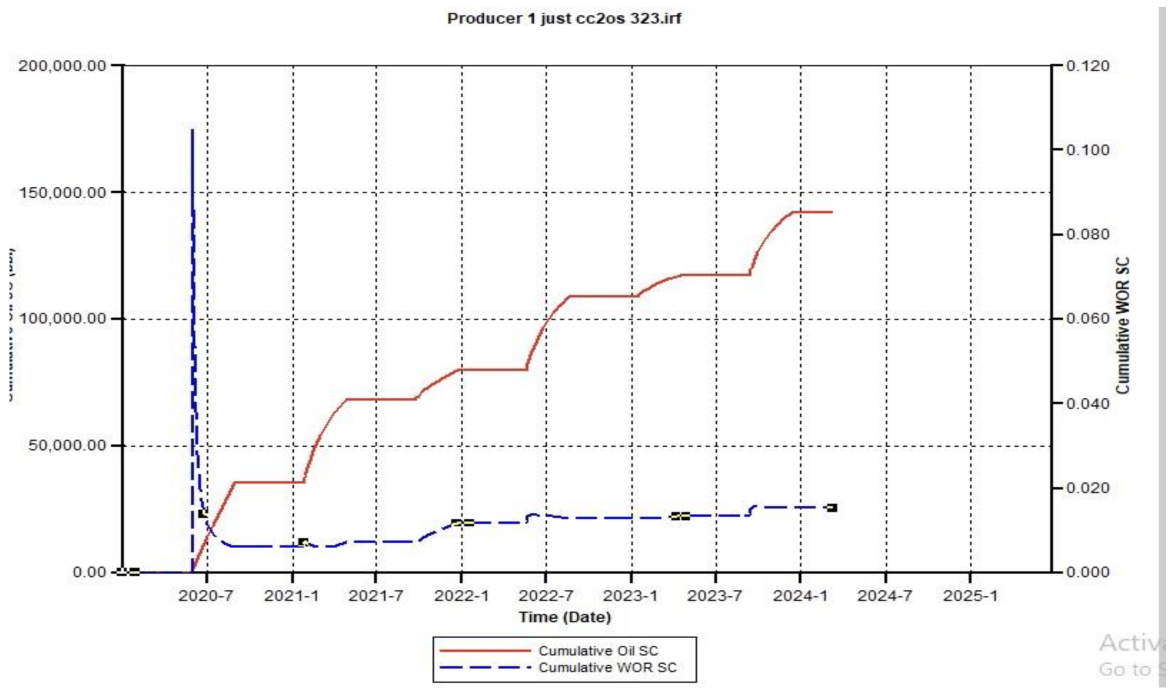
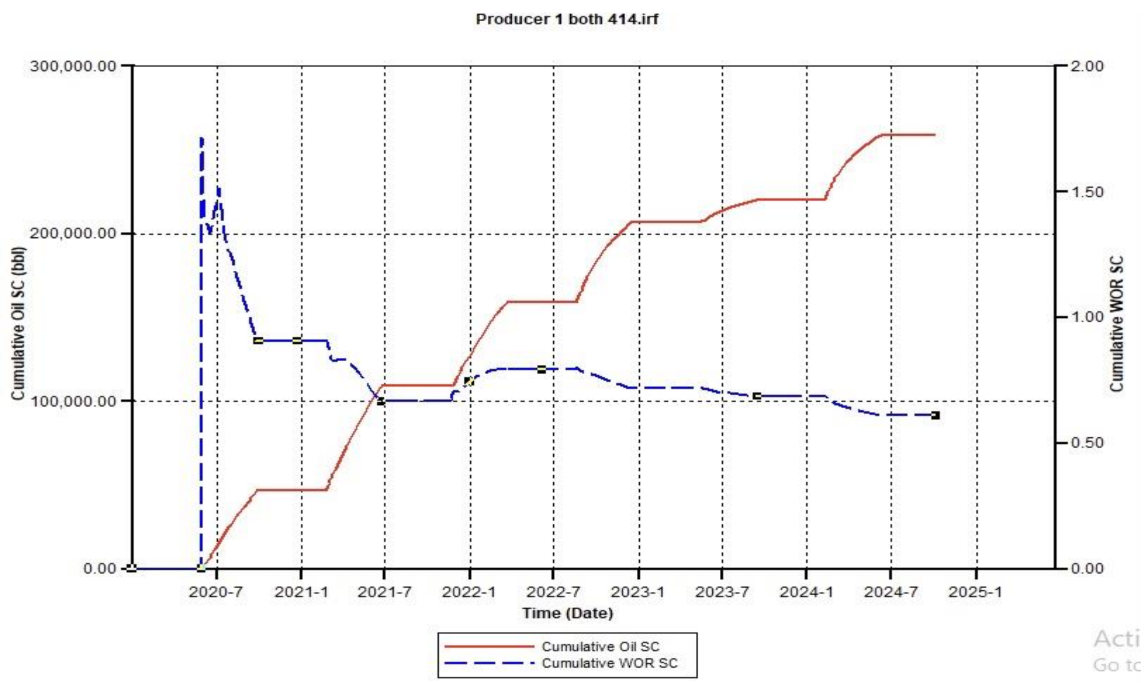


Figure B.12. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for* CCO_2S *323 using 750 Injection Rate*



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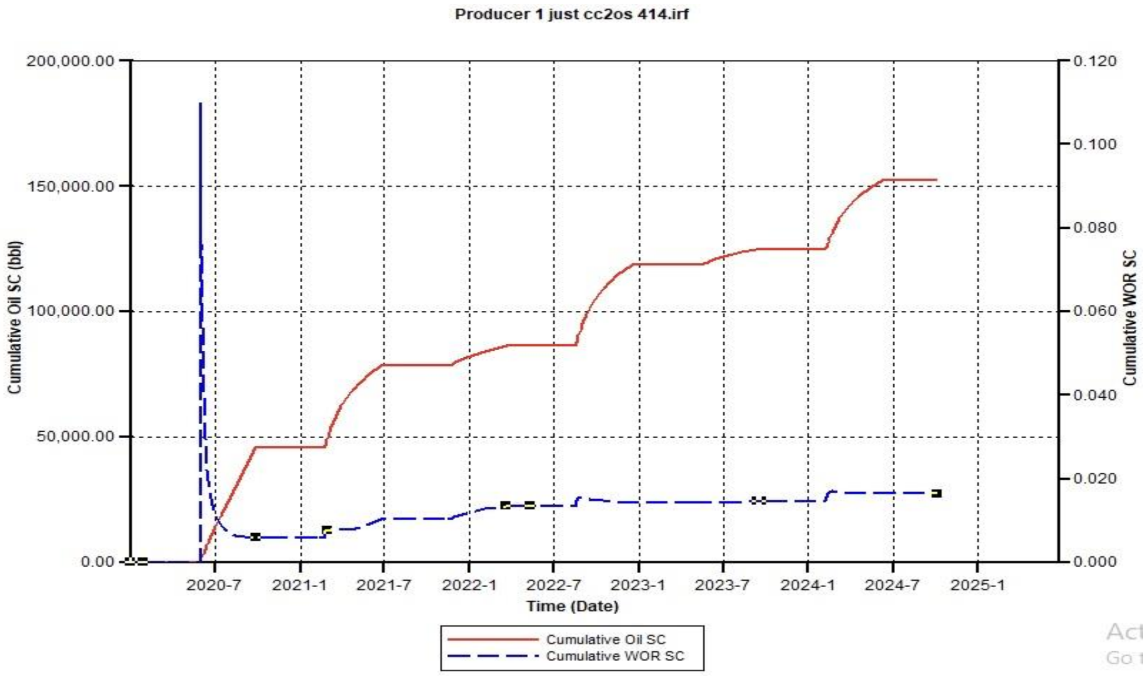

Figure B.14. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO₂S 414 using 750 Injection Rate*

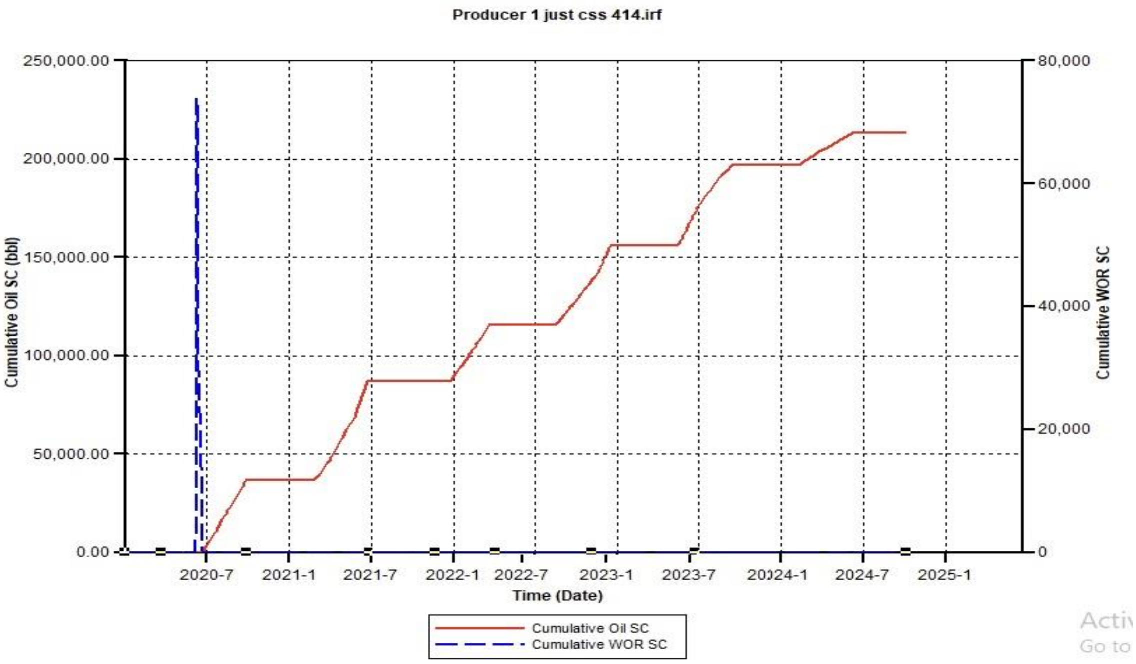

Figure B.15. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 414 using 750 Injection Rate*

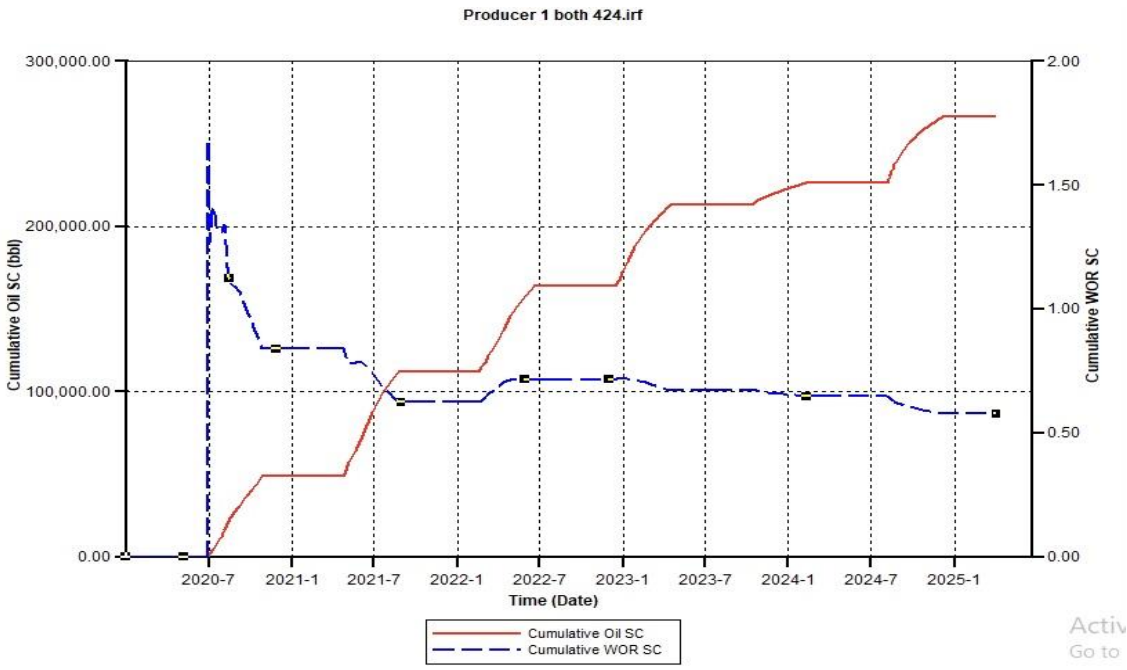

Figure B.16. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and* CCO_2S *424 using a Injection Rate*

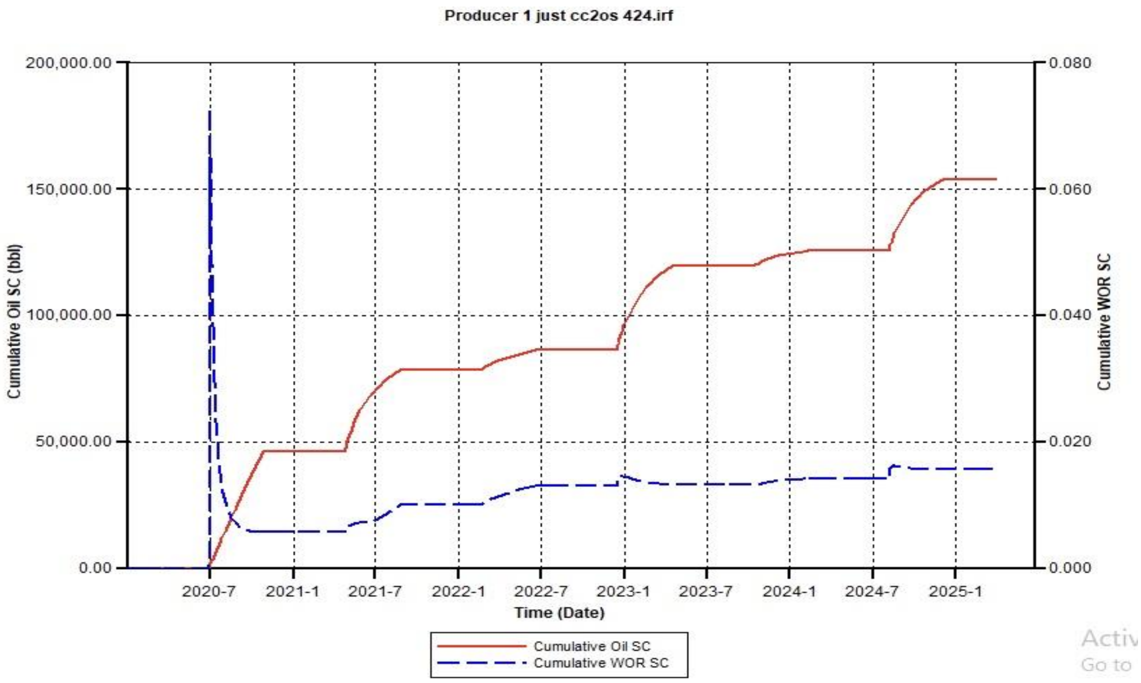

Figure B.17. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for* CCO_2S *424 using 750 Injection Rate*

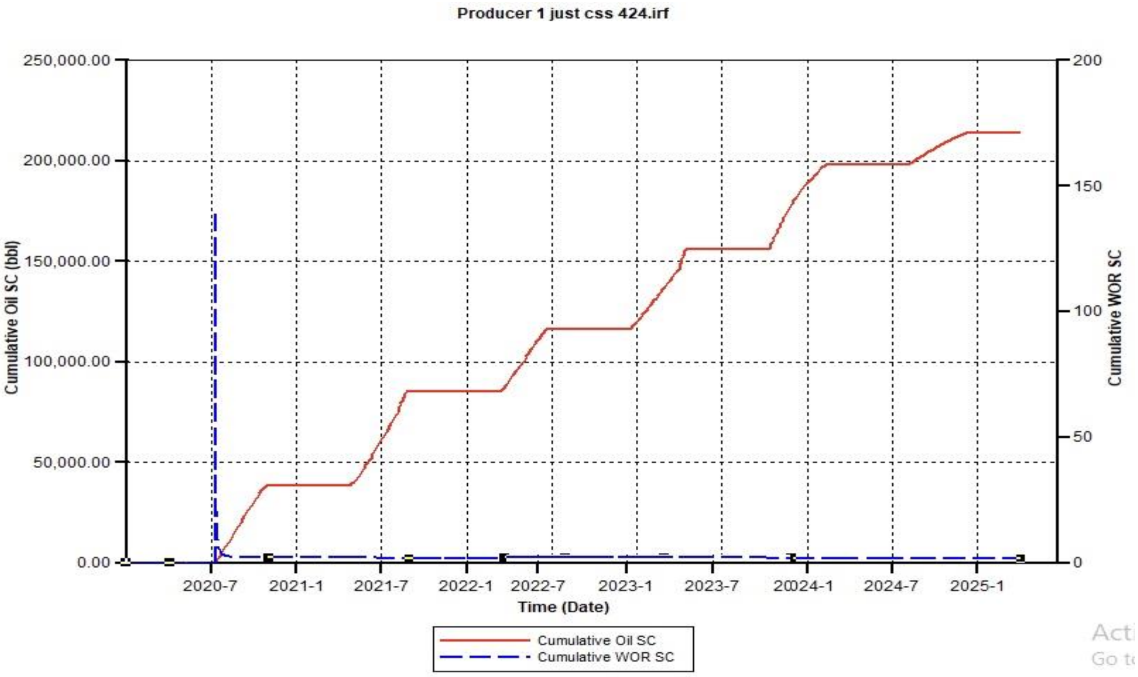

Figure B.18. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 424 using 750 Injection Rate*

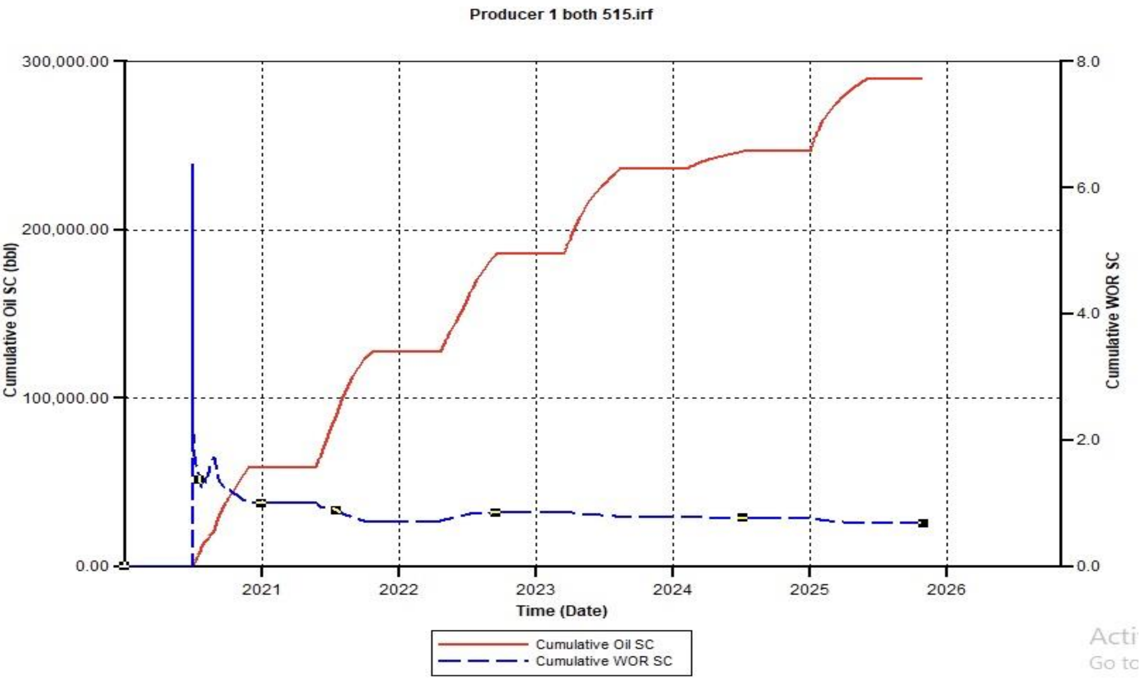

Figure B.19. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 515 using a 750 Injection Rate*

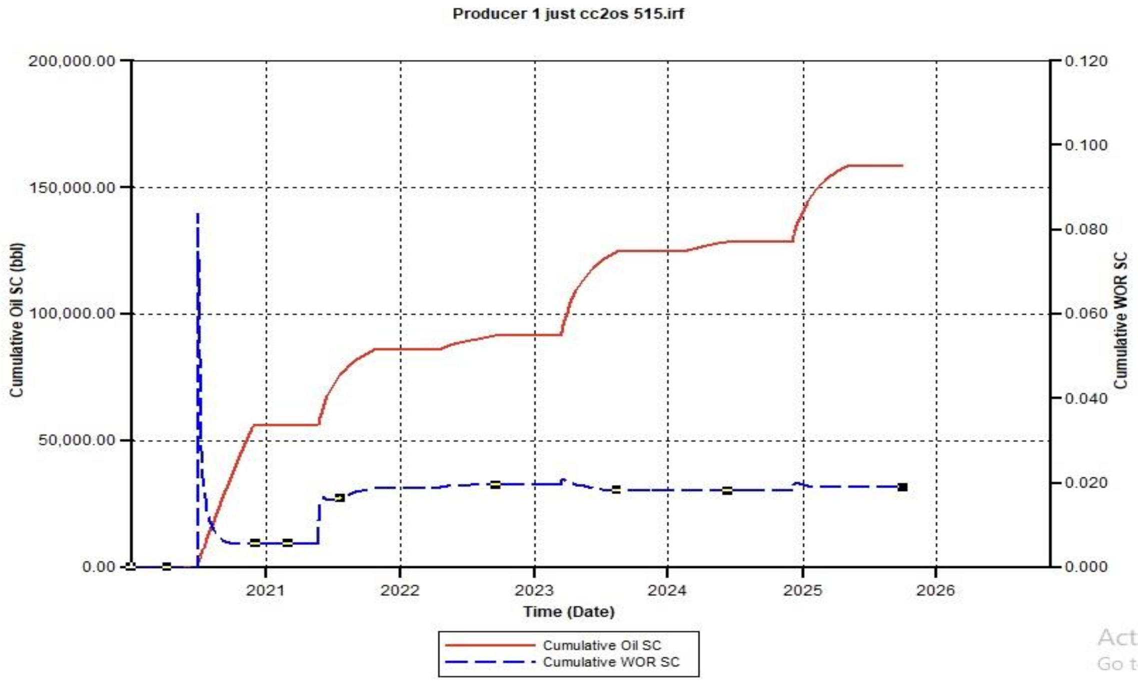

Figure B.20. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 515 using 750 Injection Rate*

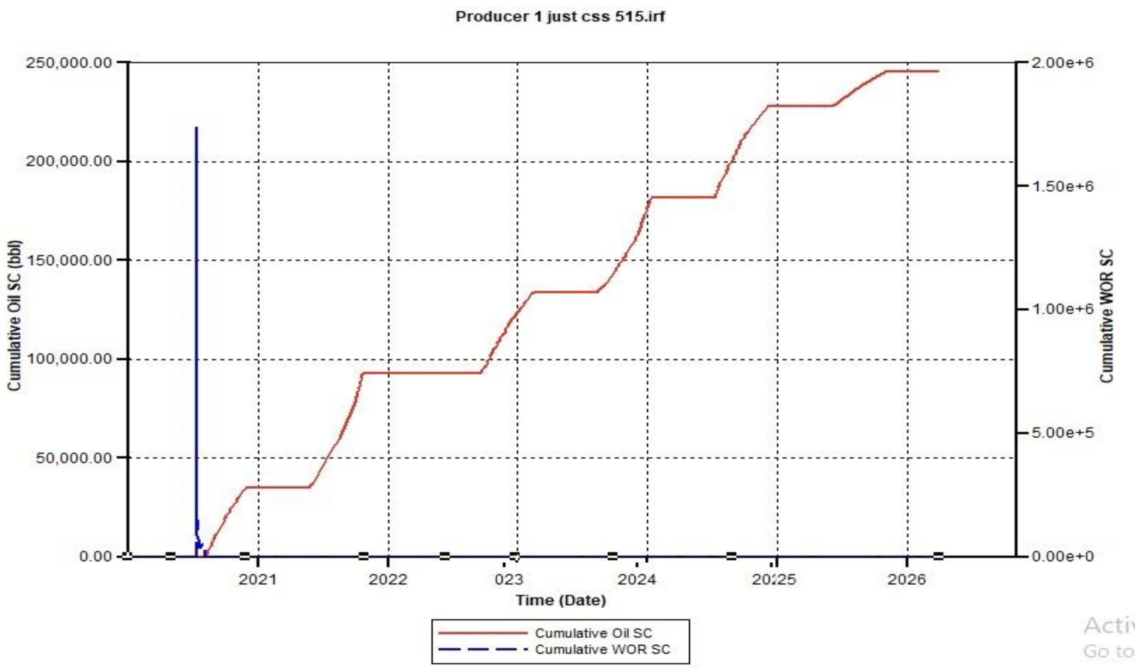

Figure B.21. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 515 using 750 Injection Rate*

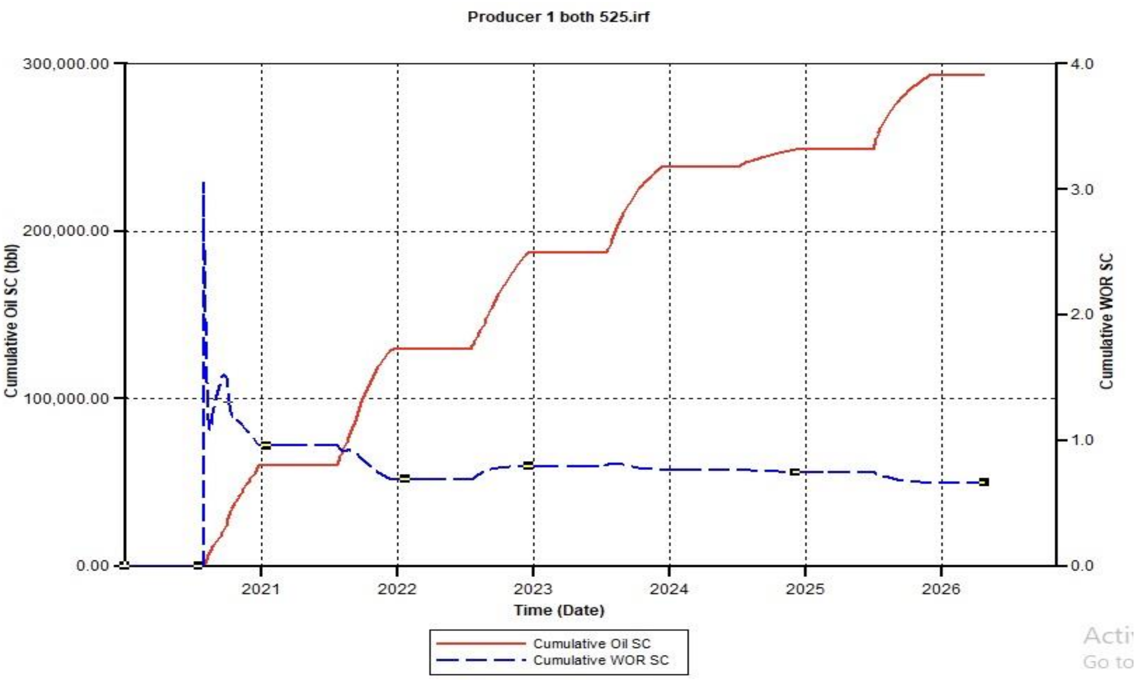

Figure B.22. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for the combination of CSS and CCO_2S 525 using a 750 Injection Rate*

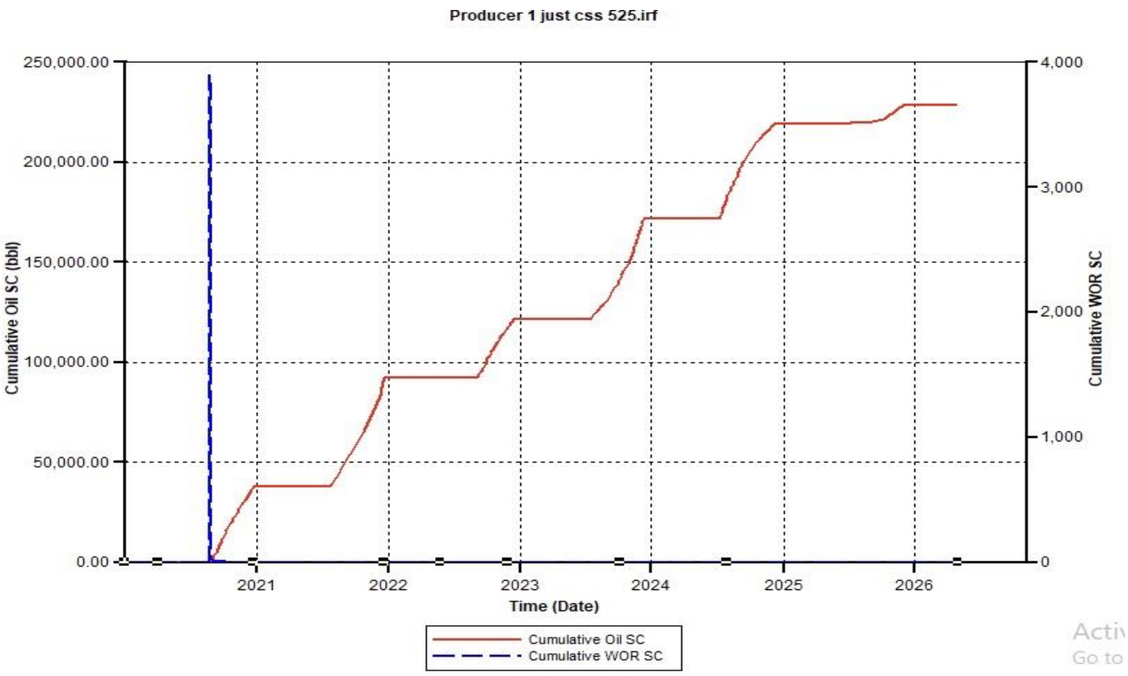

Figure B.23. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CSS 525 using 750 Injection Rate*

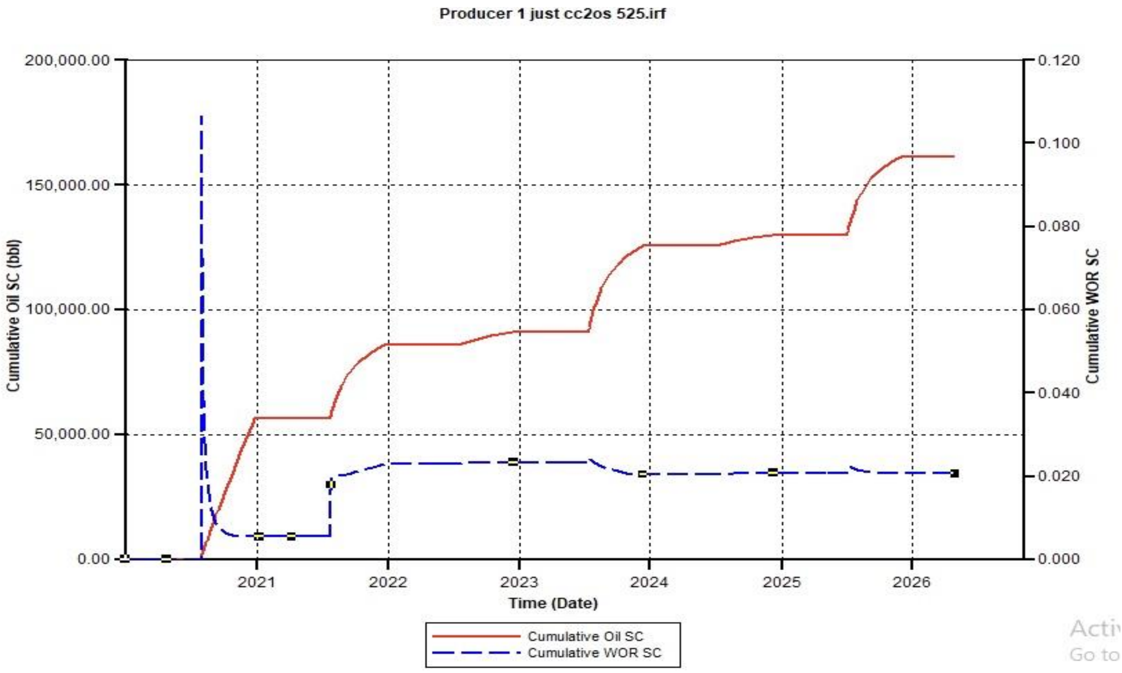

Figure B.24. *Cumulative Oil SC and Cumulative Water Oil Ratio (CWOR) for CCO_2S 525 using 750 Injection Rate*

Appendix C: Simulation Data File for CSS

** The problem is three cycles of steam stimulation, with water and **

** a dead oil. A two-dimensional cross-sectional study is required. **

** Features: **

** 1) Two-dimensional cross-sectional r-z coordinates. **

** 2) Distinct permeability layering. **

** 3) Black-oil type treatment of fluids. **

** 4) Sharp changes in oil viscosity occur at the steam front **

** (487 cp at 125 F to 2.5 cp at 450 F). **

** 5) Automatic initial vertical equilibrium calculation. **

```
** 6)  Multi-layer well with additional injection and production                **

** operating constraints.                                            **

** ==============  INPUT/OUTPUT CONTROL
======================

** 2022-02-25, 5:15:38 AM, PC

** 2022-02-25, 5:23:12 AM, PC

RESULTS SIMULATOR STARS 201410

INTERRUPT STOP

TITLE3 'Problem 1A:  2-D CYCLIC STEAM INJECTION'

*INUNIT *FIELD   ** output same as input

TITLE1 'ISA YAKUBU'

TITLE2 'MSc THESIS'

OUTPRN GRID OBHLOSS PRES SG SO SOLCONC SW TEMP VISG VISO W
X Y

OUTPRN WELL ALL

WRST 200

WPRN GRID 200

WPRN ITER 200

OUTSRF SPECIAL BLOCKVAR PRES 2,1,2

            BLOCKVAR SO 2,1,2

            BLOCKVAR SG 2,1,2

            BLOCKVAR TEMP 2,1,2

            BLOCKVAR CCHLOSS 1,1,4

            BLOCKVAR CCHLOSS 7,1,4

            MATBAL  WELL 'OIL'
```

MATBAL WELL 'Water'

OBHLOSSCUM

DRHLOSSCUM

OBHLOSSRATE

DRHLOSSRATE

OUTSRF GRID PRES SG SO TEMP

** ============== GRID AND RESERVOIR DEFINITION =================

*GRID *RADIAL 13 1 4 *RW 10 ** Zero inner radius matches previous treatment

** Radial blocks: small near well; outer block is large

*DI *IVAR 3 10*10 40 120

*DJ *CON 360 ** Full circle

*DK *KVAR 25 25 20 10

** 0 = null block, 1 = active block

NULL CON 1

*POR *CON 0.3

*PERMI *KVAR 2000 1000 500 2000

PERMJ EQUALSI

PERMK EQUALSI / 2

** 0 = pinched block, 1 = active block

PINCHOUTARRAY CON 1

*END-GRID

ROCKTYPE 1

*CPOR 5e-4

*PRPOR 75

*ROCKCP 35

*THCONR 24

*THCONW 24

*THCONO 24

*THCONG 24

*HLOSSPROP *OVERBUR 35 24 *UNDERBUR 35 24

** ============== FLUID DEFINITIONS ======================

** Components are water and dead oil. Most water

** Model and number of components

MODEL 3 3 2 1

** properties are defaulted (=0). Dead oil K values

** are zero, and no gas properties are needed.

COMPNAME 'Water' 'OIL' 'CO2'

CMM

18.01528 228 44

** These four properties

PCRIT

3206.2 0 7376

** are for the gas phase.

TCRIT

705.4 0 31.05

PRSR 14.7

TEMR 60

```
PSURF 14.7

TSURF 60

CPL1

0 300 1.06e+3

MOLDEN

0 0.5

CP

0 5.e-6

CT1

0 3.8e-4

** The dead oil component does

AVG

1.13e-5 0 0.01

** not appear in the gas phase.

BVG

1.075 0 0

VISCTABLE

**     temp

        15     0    26971

        20     0    10024

        40     0     1500

        60     0      300

        80     0      100

       100     0       46
```

114	0	25
120	0	21
140	0	12
160	0	8
250	0	5
300	0	4
350	0	3
450	0	2
500	0	1

** ============== ROCK-FLUID PROPERTIES
======================

*ROCKFLUID

RPT 1

*SWT

** SW KRW KROW

** ....

0.187000 0.0000 0.800000 0.000000

0.250000 0.01230 0.197500 0.000000

0.350000 0.04740 0.080900 0.000000

0.450000 0.12690 0.025600 0.000000

0.550000 0.16920 0.005000 0.000000

0.600000 0.18410 0.000300 0.000000

0.650000 0.28000 0.000000 0.000000

```
*SLT
** S1    KRG     KROG
** ....  .....   ......
0.187000 1.0000  0.000000 0.000000
0.250000 0.19750 0.012300 0.000000
0.350000 0.08090 0.047400 0.000000
0.450000 0.02560 0.129600 0.000000
0.550000 0.00500 0.289200 0.000000
0.650000 0.00030 0.564100 0.000000
0.900000 0.00000 0.800000 0.000000
**  ==============  INITIAL CONDITIONS  ======================
*INITIAL

** Automatic static vertical equilibrium
*VERTICAL *DEPTH_AVE
*REFPRES 75
*REFBLOCK 1 1 4

*TEMP *CON 125

**  ==============  NUMERICAL CONTROL  ======================
*NUMERICAL   ** All these can be defaulted.  The definitions
             ** here match the previous data.
```

```
*SDEGREE GAUSS

*DTMAX 90

NORM PRESS 200 SATUR 0.2 TEMP 180 Y 0.2 X 0.2

*RUN


**  ==============  RECURRENT DATA  ======================

**    The injection and production phases of the single cycling well

**  will be treated as two distinct wells which are in the same

**  location but are never active at the same time.  In the well data

**  below, both wells are defined immediately, but the producer is

**  shut in, to be activated for the drawdown.

*DATE 2020 01 01

   *DTWELL .02

**

**    ** INJECTOR:  Constant pressure steam injection type

**

**    *WELL 1 'Injector 1' *VERT 1 1

**

**

**

**

**

WELL  'Injector 1'  VERT  1  1

                                 ** Starting BHP is 1000 psi
```

```
                    ** Maximum water rate is 1000 BPD
INJECTOR MOBWEIGHT EXPLICIT 'Injector 1'
INCOMP  WATER  1.0  0.0
TINJW  450.0
QUAL  0.7
PINJW  3000.0
OPERATE  MAX  BHP  1000.0  CONT REPEAT
OPERATE  MAX  STW  500.0  CONT REPEAT
**        rad  geofac  wfrac  skin
GEOMETRY  K  0.28  0.249  1.0  0.0
   PERF      GEOA  'Injector 1'
** UBA            ff          Status  Connection
   1 1 4     78075.4  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
   1 1 3     39037.7  OPEN    FLOW-FROM  1
   1 1 2     97594.2  OPEN    FLOW-FROM  2
   1 1 1    195188.0  OPEN    FLOW-FROM  3
**
**    ** PRODUCER:  Constant liquid rate type
**
**    **WELL 2 'Injector 2' *VERT 1 1
**
**
**
**WELL  'Injector 2'  VERT  1  1
```

```
**                              ** Starting BHP is 1000 psi
**                              ** Maximum water rate is 1000 BPD
**INJECTOR UNWEIGHT 'Injector 2'
**INCOMP  GAS  0.0  0.0  1.0
**TINJW  450.0
**QUAL  0.7
**OPERATE  MAX  BHP  1000.0  CONT REPEAT
**OPERATE  MAX  STW  1000.0  CONT REPEAT
**          rad  geofac  wfrac  skin
**GEOMETRY  K  0.28  0.249  1.0  0.0
  **    PERF      GEOA  'Injector 2'
** UBA            ff         Status  Connection
   ** 1 1 4     78075.4  OPEN    FLOW-FROM  'SURFACE'  REFLAYER
    **1 1 3     39037.7  OPEN    FLOW-FROM  1
    **1 1 2     97594.2  OPEN    FLOW-FROM  2
    **1 1 1    195188.0  OPEN    FLOW-FROM  3
**
** **
** ** PRODUCER:  Constant liquid rate type
**
**    *WELL 3 'Producer 1' *VERT 1 1
**
**
**
```

```
**
WELL  'Producer 1'  VERT  1  1
                                ** Starting liquid rate is 1000 BPD
                                ** Minumum BHP of 1 atm
PRODUCER 'Producer 1'
OPERATE  MAX  STL  1000.0  CONT REPEAT
OPERATE  MIN  BHP  10.0  CONT REPEAT
**          rad  geofac  wfrac  skin
GEOMETRY  K  0.3  0.5  1.0  0.0
     PERF      GEO  'Producer 1'
** UBA            ff         Status  Connection
    1 1 4        1.0  OPEN    FLOW-TO  'SURFACE'  REFLAYER
    1 1 3        1.0  OPEN    FLOW-TO  1
    1 1 2        1.0  OPEN    FLOW-TO  2
    1 1 1        1.0  OPEN    FLOW-TO  3
   ** Cycle No. 1  -  Injection
   *SHUTIN 'Producer 1'   ** Shut in producer
OUTSRF GRID REMOVE SO
*TIME 60
   *DTWELL 7
   ** Cycle No. 1  -  Soak
   *SHUTIN 'Injector 1'   ** Shut in injector
OUTSRF GRID SG TEMP
*TIME 90
```

```
  *DTWELL 1
  ** Cycle No. 1  -  Production
  *OPEN 'Producer 1'   ** Turn on producer
OUTSRF GRID PRES
*TIME 150
  *DTWELL .01
  ** Cycle No. 1  -  Injection

  *SHUTIN 'Producer 1'   ** Shut in producer
**OPEN 'Injector 2'     ** Turn on injector
OUTSRF GRID NONE
*TIME 210
  *DTWELL 7
  ** Cycle No. 1  -  Soak
  **SHUTIN 'Injector 2'   ** Shut in injector
*TIME 240
  *DTWELL .5
  ** Cycle No. 1  -  Production
 *OPEN 'Producer 1'    ** Turn on producer
*TIME 300
  *DTWELL .002
  ** Cycle No. 2  -  Injection
  *SHUTIN 'Producer 1'    ** Shut in producer
  *OPEN 'Injector 1'      ** Turn on injector
```

```
OUTSRF GRID SG TEMP
*TIME 360
   *DTWELL 7
   ** Cycle No. 2  -  Soak
   *SHUTIN 'Injector 1'    ** Shut in injector
OUTSRF GRID REMOVE
*TIME 390
   *DTWELL 1
   ** Cycle No. 2  -  Production
   *OPEN 'Producer 1'    *** Turn on producer
OUTSRF GRID SO
*TIME 450
   *DTWELL .01
   ** Cycle No. 2  -  Injection
   *SHUTIN 'Producer 1'   ** Shut in producer
**OPEN 'Injector 2'     ** Turn on injector
OUTSRF GRID NONE
*TIME 510
   *DTWELL 7
   ** Cycle No. 2  -  Soak
   **SHUTIN 'Injector 2'   ** Shut in injector
*TIME 540
   *DTWELL .5
   ** Cycle No. 2  -  Production
```

```
  *OPEN 'Producer 1'    ** Turn on producer
  *TIME 600
   *DTWELL .01
  ** Cycle No. 3 -  Injection
   *SHUTIN 'Producer 1'   ** Shut in producer
OUTSRF GRID NONE
*TIME 660
   *DTWELL 7
   ** Cycle No. 3  -  Soak
   *SHUTIN 'Injector 1'   ** Shut in injector
OUTSRF GRID NONE
*TIME 690
   *DTWELL 1
   ** Cycle No. 3  -  Production
   *OPEN 'Producer 1'   ** Turn on producer
OUTSRF GRID PRES
*TIME 750
   *DTWELL .01
   ** Cycle No. 3  -  Injection
   *SHUTIN 'Producer 1'   ** Shut in producer
**OPEN 'Injector 2'     ** Turn on injector
OUTSRF GRID NONE
*TIME 810
   *DTWELL 7
```

```
  ** Cycle No. 3  -  Soak
  **SHUTIN 'Injector 2'   ** Shut in injector
*TIME 840
  *DTWELL .5
  ** Cycle No. 3  -  Production
 *OPEN 'Producer 1'    ** Turn on producer
*TIME 900
  *DTWELL .002
  *SHUTIN 'Producer 1'    ** Shut in producer
*TIME 960
STOP


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RESULTS PROCESSWIZ KRGCW 0.0001
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```

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RESULTS PROCESSWIZ TABLEIFTS 1.25 4.102

RESULTS PROCESSWIZ TABLEIFTS 1.5 3.805

RESULTS PROCESSWIZ TABLEIFTS 1.75 3.521

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RESULTS PROCESSWIZ TABLEIFTS 1 0.007

RESULTS PROCESSWIZ TABLEIFTS 1.25 0.007

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RESULTS PROCESSWIZ TABLEIFTS 2 0.098

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RESULTS PROCESSWIZ COMPSALINITY 0 0.03 0.05 0.075

RESULTS PROCESSWIZ SALINITYVISC 1 3.5 5.2 10.8

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RESULTS PROCESSWIZ LSWIREACT FALSE TRUE TRUE TRUE TRUE TRUE TRUE FALSE FALSE FALSE FALSE FALSE FALSE 0.9999

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RESULTS PROCESSWIZ LSWIAQINJ

RESULTS PROCESSWIZ LSWIAQINIT

RESULTS PROCESSWIZ LSWIMIN

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RESULTS PROCESSWIZ REACTO2

RESULTS PROCESSWIZ BURN

RESULTS PROCESSWIZ CRACK

RESULTS PROCESSWIZ COMPNAMES

RESULTS PROCESSWIZ BLOCKAGE FALSE 4

RESULTS PROCESSWIZ END

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 EQUALSI 0 1

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

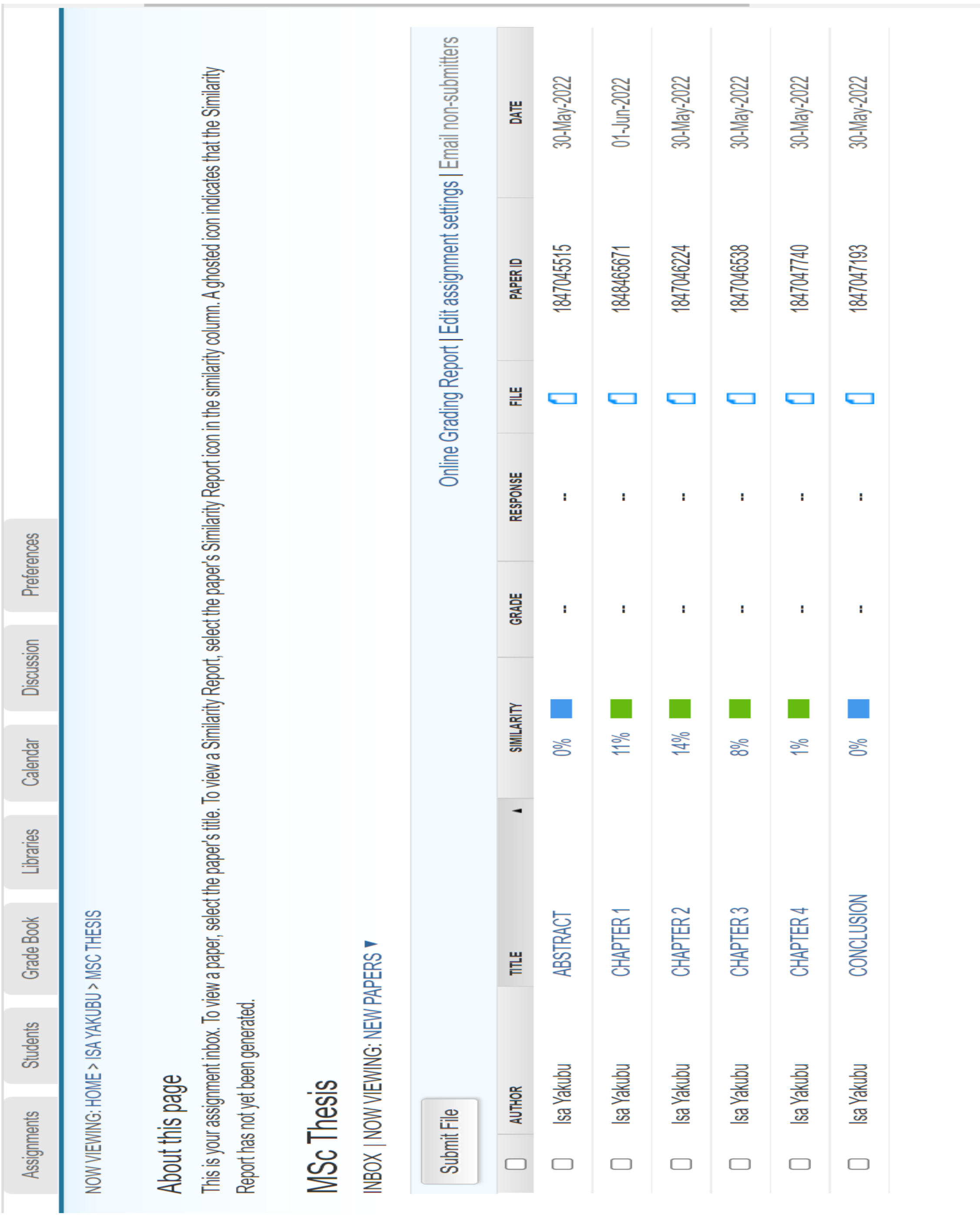
RESULTS SPEC PORTYPE 1

RESULTS SPEC EQUALSI 2 2

RESULTS SPEC SPECKEEPMOD 'YES'

RESULTS SPEC STOP

Appendix D
Turnitin Similarity Report



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Appendix E

ETHICAL APPROVAL LETTER

YAKIN DOĞU ÜNİVERSİTESİ

ETHICAL APROVAL DOCUMENT

Date: 21/06/2022

To the **Institute of Graduate Studies**

The research project titled "**ASSESSMENT OF CYCLIC STEAM STIMULATION AND CYCLIC CO_2 STIMULATION FOR HEAVY OIL RECOVERY**'' 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: Assoc. Prof.

Name Surname: Serhat CANBOLAT

Signature:

Role in the Research Project: Supervisor