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Performance evaluation of different water injection schemes in Eclipse 100 reservoir simulation: A comparative analysis

Bachelor thesis

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Performance evaluation of different water injection schemes in Eclipse 100 reservoir simulation: A comparative analysis

Anotace:

Vstřikování vody je běžně používaná metoda v ropném a plynárenském průmyslu pro zlepšení regenerace ropy a zlepšení tlaku v nádrži. Účinnost různých schémat vstřikování vody se může lišit v závislosti na charakteristikách nádrže a provozních parametrech. Cílem této studie je posoudit a porovnat výkonnost různých schémat vstřikování vody pomocí softwaru Eclipse 100 pro simulaci nádrže. Hodnocení se zaměřuje na důležité ukazatele výkonnosti, včetně kumulativního faktoru regenerace ropy, doby průniku vody a účinnosti zametání. K dosažení tohoto cíle se používá model syntetické nádrže s reprezentativními geologickými vlastnostmi a chováním kapalin. Je provedeno několik simulačních scénářů představujících různá schémata vstřikování. Zjištění odhalují, že pětibodový vzor dosahuje nejvyšší výtěžnosti ropy (51,3 %), zatímco obrácený pětibodový vzor vykazuje nejnižší výtěžnost (46,09 %). Ve většině vzorů dochází k rychlému nárůstu vodního řezu během zaplavení vodou, dosahující 98 %; obvodový vzor však ukazuje mírně nižší úbytek vody o 93 % v důsledku větší vzdálenosti mezi injektážními a těžebními vrty. Navíc bylo zjištěno, že udržování tlaku je účinnější v pětibodovém a směrovaném vedení vedení ve srovnání s obvodovým a obráceným pětibodovým vzorem. Pokud jde o rychlost produkce, pětibodový vzor ukazuje nejvyšší rychlost ropy (173,63 MMstb), ale prudce klesá, jak se nábřeží blíží k centrálnímu vrtu. Naopak periferní vzor si udržuje stabilnější dlouhodobé plató. Usměrněná linie pohonu také vykazuje vyšší produkční rychlost (160,53 MMstb) ve srovnání s obráceným pětibodovým vzorem (155,86 MMstb) díky přítomnosti více těžebních vrtů, ačkoli oba modely vykazují podobný dlouhodobý pokles produkce.

Klíčová slova: Vstřikování vody, simulace nádrže, vzor zaplavení vodou, těžba ropy, účinnost zametání.

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Annotation:

Water injection is a widely utilized technique in the oil and gas sector aimed at boosting oil recovery and enhancing reservoir pressure. The success of different water injection strategies can differ based on reservoir properties and operational factors. This study's main goal is to evaluate and compare the performance of different water injection strategies using the Eclipse 100 reservoir simulation software. The evaluation focuses on important performance indicators, including cumulative oil recovery factor, water breakthrough time, and sweep efficiency. To accomplish this, a synthetic reservoir model with representative geological properties and fluid behavior is utilized. Multiple simulation scenarios representing different injection schemes are conducted. The findings reveal that the five-spot pattern achieves the highest oil recovery (51.3%), while the inverted five-spot pattern exhibits the lowest recovery (46.09%). In the majority of cases, water cut exhibits a rapid rise during water flooding, reaching as high as 98%. Nevertheless, the peripheral pattern demonstrates a slightly lower water cut, around 93%, attributed to the greater distance between injection and production wells. Moreover, the study finds that pressure maintenance proves to be more effective in the five-spot and directed line drive patterns compared to the peripheral and inverted five-spot patterns. Regarding production rate, the five-spot pattern exhibits the highest oil rate (173.63 MMstb). However, this rate sharply declines as the waterfront approaches the central well. In contrast, the peripheral pattern maintains a more consistent and stable plateau in the long term. The directed line drive pattern also exhibits a higher production rate (160.53 MMstb) compared to the inverted five-spot pattern (155.86 MMstb) due to the presence of more production wells, although both patterns exhibit similar long-term production decline.

Keywords: Water injection, reservoir simulation, waterflooding pattern, oil recovery, sweep efficiency.

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Number of annexes:1

Declaration

I declare that I have prepared the bachelor's thesis myself and that I have stated all the used information resources in the thesis.

In Olomouc, July 14, 2023 ……………………………………

Saman Abdullah

Acknowledgment

I would like to express my heartfelt gratitude to Palacky University Olomouc for providing me with the opportunity to undertake my BSc project. The support and resources offered by the university have been instrumental in the successful completion of my academic endeavor.

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List of abbreviations

Abbreviation	Description
API	American Petroleum Institute
B_o	Oil formation volume factor
B_w	Water formation volume factor
GOR	Gas oil ratio
K_{rw}	Water relative permeability
K_{ro}	Oil relative permeability
M	Mobility ratio
OOIP	Original oil in place
P_i	Initial pressure
Pc	Capillary pressure
P_b	Bubble point pressure
P_r	Average reservoir pressure
RF	Recovery factor
stb	Stock tank barrel

1. Introduction

As the demand for oil continues to rise, the efficient extraction of hydrocarbon resources from reservoirs becomes increasingly crucial. In mature oil fields, where primary recovery methods have reached their limits, the implementation of enhanced oil recovery techniques, such as water injection, is essential (Davarpanah et al., 2018).

Water flooding involves injecting water into the reservoir through dedicated injection wells to displace and push the remaining oil towards production wells. Increased recovery rates are the result of the efficient movement of oil that water injection facilitates through the reservoir (Thakur, 1991). This technique makes use of the water's inherent energy as well as the effectiveness of interactions between water and oil to effectively remove oil. Water flooding is effective when it can increase sweep efficiency, increase the volumetric sweep of the reservoir, and maintain reservoir pressure. By injecting water, a liquid with a lower viscosity than oil fills the reservoir, making it easier for trapped oil to flow out and be displaced. Additionally, flooding with water helps to preserve reservoir pressure by limiting unfavorable outcomes like gas cap expansion or water coning, which could obstruct oil production (Chatetha, 2004).

The implementation of water flooding requires careful planning and engineering considerations. The reservoir's characteristics, including permeability, porosity, heterogeneity, and fluid properties, are crucial factors in designing an effective water flooding strategy. Reservoir simulation, using advanced software tools, helps optimize the injection rate, injection pattern, well placement, and timing to maximize the efficiency of water flooding operations (Marek, 2013).

To optimize water flooding operations, various water injection schemes have been developed and implemented including peripheral injection, infill injection, pattern injection and line drive injection. These schemes differ in their design, injection patterns, rates, and types of injected water. By carefully evaluating and selecting the most appropriate injection scheme, reservoir engineers and operators can maximize oil recovery, prolong the field's productive life, and ensure sustainable hydrocarbon extraction (Songqi et al., 2021).

Reservoir simulation plays a crucial role in the design and evaluation of water flooding projects. Advanced reservoir simulation software enables engineers to create detailed reservoir models that capture the complexity of the subsurface (Ovalles et al., 2016). By inputting reservoir properties, fluid behavior, and operational parameters, simulations can predict the fluid flow patterns, pressure distribution, and oil recovery performance under various water flooding scenarios. These simulations aid in decision-making processes, allowing for the optimization of injection rates, well spacing, and other operational parameters to maximize oil recovery (Zhong et al., 2013).

1.1. Problem statement

Theoretical studies have shown that peripheral injection, line-drive injection, and regular injection patterns (such as 4-spot and 5-spot) have the potential to significantly enhance oil recovery in reservoirs. However, it is important to recognize that the effectiveness of each pattern can vary depending on the unique characteristics of the reservoir. Reservoirs show different geological features, such as variations in permeability distribution, rock heterogeneity, and fluid behavior, which can impact the performance of different injection patterns. Therefore, it is crucial to conduct a comprehensive evaluation to determine the injection pattern that leads to the highest oil recovery for a specific reservoir condition. This project aims to address this challenge by undertaking an extensive analysis and comparison of various injection patterns using a conceptual model to generate consistent reservoir conditions for evaluation.

1.2. Aim of project

The main objectives of this project are:

1. To construct a reservoir model utilizing the Eclipse simulator. This will involve developing a comprehensive and accurate representation of the reservoir to simulate its behavior under different conditions.
2. To assess the effectiveness of water flooding in enhancing oil recovery. This involves evaluating the impact of water flooding techniques on the overall production of oil from the reservoir.
3. To analyze and compare the performance of various water injection schemes. This includes evaluating different strategies and approaches for water injection and determining their effectiveness in maximizing oil recovery from the reservoir.

2. Background

2.1. Waterflooding

Waterflood has an extensive and continuous history that can be traced back to the mid-nineteenth century. The process of water injection began with a single well and gradually expanded to encompass the utilization of multiple wells, forming circular and peripheral drives. A significant milestone in the history of waterflood occurred in 1924 when the first implementation of the five-spot pattern flood took place in Pennsylvania's Bradford Field (Deppe, 1961). This approach was followed by the expansion of waterflood application from Pennsylvania to Oklahoma in 1931, specifically targeting the shallow Bartlesville sand formation. Subsequently, in 1936, waterflood was adopted in Texas, focusing on the Fry Pool of Brown County. As advancements in technology occurred and the understanding of waterflood improved, it became a widely embraced practice in the 1950s (Willhits, 1986).

By the 1970s, waterflooding had become a common and established method employed in most onshore reservoirs in the United States and numerous other oil-producing countries. Its purpose was to extract additional oil reserves by effectively utilizing water injection strategies. The implementation of waterflood methods has been pivotal in enhancing reservoir performance and maximizing oil recovery in these areas (Satter, 2016).

In practical application, waterflooding entails injecting water into designated wells while simultaneously producing oil from neighboring wells. The primary objective is to displace oil from the injection wells towards the producing wells, all while ensuring reservoir pressure maintenance. Historically, waterflooding was commonly employed in depleted or nearly depleted reservoirs where a free gas phase was present.. During the initial stages of waterflooding, the injected water would fill the pores previously occupied by gas. The gas would then dissolve in the water, restoring the reservoir pressure. However, more efficient waterflooding practices require injecting water at pressures above the bubble point pressure of the oil (Songqi et al., 2021). This is done to prevent the release of gas within the reservoir. When dissolved gas is liberated, it reduces the relative permeability of the oil phase and leads to lower production rates as the gas becomes mobile. Nevertheless, there have been cases in the past where water was injected slightly below the bubble point pressure.

Waterflood design, which encompasses factors such as the location, development schedule, and injection rates of the wells, is a topic of great interest to reservoir engineers. The fundamental principle behind waterflood operations is to optimize the ultimate recovery of oil by specifically targeting areas and zones where significant amounts of oil remain after primary recovery methods have been applied (Mamghaderi et al., 2012).

The effectiveness of waterflooding depends significantly on the characteristics of the rock and fluids, as well as how it is managed through reservoir surveillance (Li et al., 2020). Waterflood projects tend to be more successful in relatively homogeneous formations with favorable porosity and permeability, minimal highly permeable conduits or fractures, and oil that is light or medium in gravity (20˚ API or higher), along with a relatively high oil saturation (Chen, 2019).

The recovery of oil achieved through waterflooding is commonly referred to as secondary recovery. Based on industry experience, it is estimated that waterflooding can recover approximately 15-30% of the original oil in place (OOIP) in most cases. Over the years, the performance of reservoirs undergoing waterflood operations has significantly improved, particularly in complex geological settings. This improvement can be attributed to factors such as detailed reservoir characterization, enhanced well planning based on robust simulation models, advanced downhole equipment, the utilization of "smart wells," and the implementation of real-time reservoir surveillance and analysis (Yazdani and Sahraei, 2019).

2.2. Water flooding performance

A common response observed in reservoirs undergoing waterflood is characterized by an initial increase in oil production, followed by a decline, and eventually the breakthrough of injected water at the production wells. Figure 1 illustrates a typical graph depicting the relationship between oil production rates and the duration of waterflood operations in a reservoir with a gas cap. The graph demonstrates the filling of pore spaces that were initially occupied by free gas, as well as the rise and fall of secondary oil saturation periods (Li and L.C., 2016). Over time, the water-to-oil ratio continues to increase, and the point of economic viability is reached when water production becomes excessive (as shown in Figure 2). This situation is further compounded by the presence of highly conductive pathways or channels that are often found in the formation (Haryanto and Saltanat, 2019)

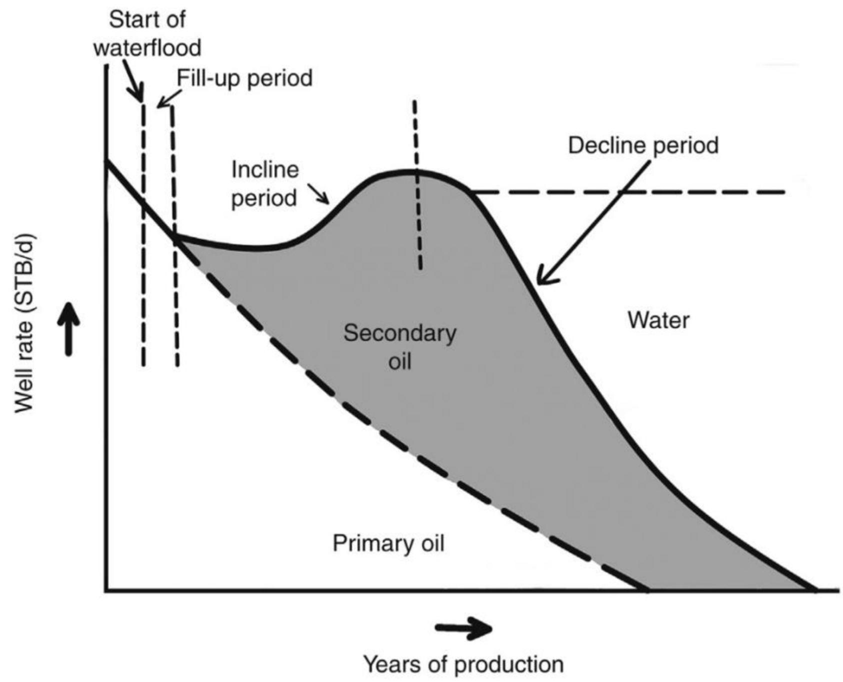

Figure 1 An instance demonstrating a successful waterflood operation (Satter, 2016).

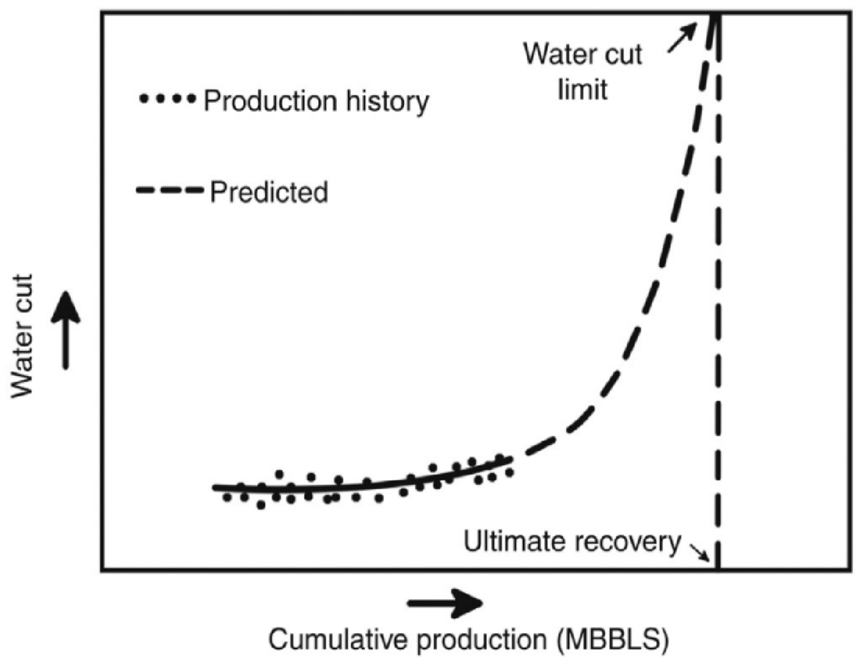

Figure 2 Increase water-cut in an oil well for a typical reservoir under water flooding (Satter, 2016).

2.3. Factors affecting waterflood performance

Waterflooding performance is influenced by various factors that interact with each other and impact the efficiency of the process. The most important factors are:

2.3.1. Injection strategy

2.3.1.1. Well spacing

Well spacing plays a crucial role in waterflooding as it determines the distance between injection and production wells. Proper well spacing is essential to achieve optimal sweep efficiency and prevent bypassed oil zones. By spacing wells appropriately, injected water can effectively sweep through the reservoir, maximizing the contact with oil-bearing zones and enhancing overall recovery (Yan et al., 2012). The determination of well spacing takes into account reservoir characteristics, fluid properties, and the desired waterflood pattern to ensure efficient fluid movement and effective displacement of oil.

2.3.1.2. Conversion schedule

The conversion schedule, which dictates the timing and sequence of converting production wells to injection wells, is another critical factor. The conversion schedule affects the progression of the waterflood front and the displacement of oil within the reservoir. By strategically converting production wells to injection wells at the right time, water can be directed to previously un-swept areas, improving sweep efficiency, and increasing overall oil recovery (Satter, 2016). Proper planning and implementation of the conversion schedule contribute to optimizing waterflooding performance.

2.3.1.3. Waterflood pattern

The waterflood pattern chosen for a waterflooding operation has a significant impact on its overall performance. The waterflood pattern refers to the arrangement and configuration of injection and production wells within the reservoir. Different patterns, such as line drive, five-spot, or inverted nine-spot (Figures 3), have varying effects on fluid distribution and sweep efficiency (Liu et al., 2018).

The waterflood pattern directly influences how effectively injected water contacts and displaces the oil in the reservoir. A well-designed pattern ensures that water spreads evenly throughout the reservoir, reaching a larger portion of the oil-bearing zones. This leads to improved displacement and recovery of oil, enhancing the waterflooding performance (Zhou et al., 2004). The choice of waterflood pattern also affects the coverage and sweep efficiency within the reservoir. An optimal pattern effectively sweeps through the reservoir, minimizing the risk of bypassed oil zones where water fails to displace the oil. By achieving better reservoir coverage, a well-selected waterflood pattern can maximize oil recovery and improve overall performance (Li et al., 2016).

Wells within a waterflood pattern are typically spaced at 40, 80, and 160 acres, as commonly observed. However, literature indicates that some reservoirs also have wells drilled at 20 or 320 acres spacing. The choice of well spacing depends on the characteristics of the reservoir, such as tightness or heterogeneity. In tighter or more heterogeneous reservoirs, smaller well spacing is necessary, requiring more injectors within the pattern. Additionally, directional permeability within the reservoir can influence the plans for well conversion during water injection. To avoid premature water breakthrough, the water injection is implemented transversely to the direction of directional permeability (Satter, 2016).

Proper consideration of the waterflood pattern is crucial in planning and implementing a successful waterflooding operation. Through reservoir simulation studies, engineering analysis, and experience, the most suitable pattern can be selected to optimize fluid distribution, enhance sweep efficiency, and ultimately maximize oil recovery from the reservoir.

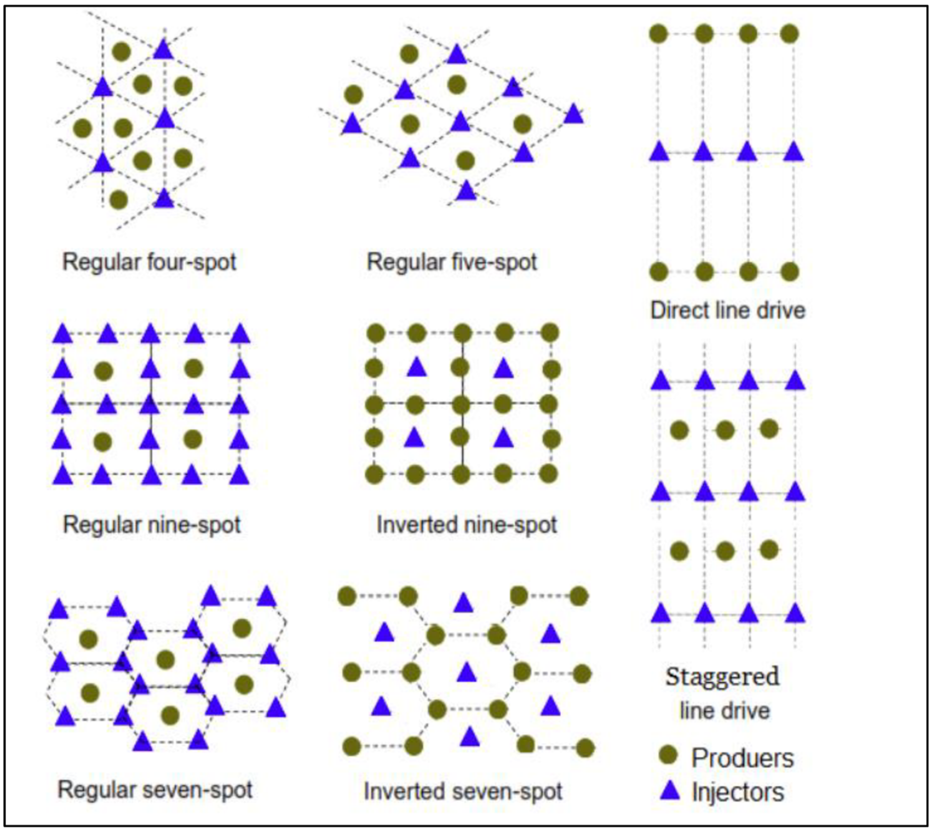

Figure 3 Illustrate the arrangement of production and injection wells in the various water injection schemes (Temizel et al., 2017).

2.3.2. Mobility ratio (M)

The water-to-oil mobility ratio plays a crucial role in determining the efficiency of waterflooding. It is considered a significant factor as it has a direct impact on the displacement of fluids in the porous medium. When the mobility ratio exceeds one, it is regarded as unfavorable because water exhibits higher mobility compared to oil. Consequently, the injected water has a tendency to bypass the oil, resulting in early breakthrough at the producers. On the other hand, when the mobility ratio is below one, water exhibits lower mobility than oil. This scenario facilitates better displacement, leading to enhanced oil recovery. The mobility ratio can be mathematically expressed as follows:

$$M = \frac{Mobility\ of\ displacing\ fluid}{Mobility\ of\ displaced\ fluid} = \frac{\lambda_w}{\lambda_o} = \frac{K_{rw}/\mu_w}{K_{ro}/\mu_o} \tag{1}$$

Where:

M: Mobility ratio

λ_w: Mobility of water

λ_o: Mobility of oil

K_{rw}: Relative permeability of water

K_{ro}: Relative permeability of oil

μ_w: Viscosity of water

μ_o: Viscosity of oil

2.3.3. Reservoir heterogeneity

The performance of water flooding in oil reservoirs is greatly influenced by reservoir heterogeneity. Heterogeneity pertains to the variances in rock properties, such as permeability and porosity, within the reservoir. These variances can manifest in both horizontal and vertical directions and significantly impact the effectiveness of fluid displacement during water flooding (Mamghaderi et al., 2012; Yan et al., 2012; Hasan et al., 2020).. The effects of reservoir heterogeneity on water flooding performance can be summarized as follow:

1. Channeling and bypassing: In a reservoir with heterogeneity, there can be coexistence of high-permeability channels or layers alongside low-permeability zones. When water flooding occurs, the injected water has a tendency to flow preferentially through these high-permeability pathways, bypassing substantial sections of the reservoir rock. This phenomenon is referred to as channeling or bypassing. Consequently, the injected water fails to effectively contact and displace the oil, leading to a decrease in the ultimate oil recovery.

2. Early water breakthrough: Reservoir heterogeneity can lead to early water breakthrough at the production wells. If the permeability variations favor water flow more than oil flow, the injected water can reach the production wells quickly, displacing only a small fraction of the oil in the reservoir. This premature water breakthrough reduces the sweep efficiency and overall oil recovery.

3. Fingering and viscous instability: In reservoirs with heterogeneity, water flooding may encounter two phenomena: fingering and viscous instability. Fingering involves the creation of narrow, preferential flow paths within the reservoir, where water channels through high-permeability zones, leaving substantial areas of the reservoir unaffected. Viscous instability arises due to the disparity in viscosity between water and oil, leading to unstable flow patterns that further promote the development of finger-like flow paths. Both fingering and viscous instability can diminish the efficiency of water flooding and restrict the contact between water and oil, thereby limiting the overall effectiveness of the process.

4. Poor sweep efficiency: Reservoir heterogeneity hinders the efficient sweep of the reservoir, as water tends to take the path of least resistance through high-permeability regions. This leads to uneven displacement of oil, leaving behind pockets of trapped oil in low-permeability zones. The poor sweep efficiency in heterogeneous reservoirs results in lower oil recovery and leaves significant amounts of bypassed oil.

5. Pressure variations and coning: Reservoir heterogeneity can cause pressure variations within the reservoir during water flooding. When water is injected into a heterogeneous reservoir, it can create pressure differences between high-permeability and low-permeability zones. These pressure differentials can cause water and oil to redistribute unevenly, leading to coning effects. Coning occurs when water or gas congregate at the bottom of an oil column, creating a cone-like shape. This further reduces the effectiveness of water flooding by limiting the contact between water and oil.

2.3.4. Optimum well injection rate

The rate at which oil is recovered from a reservoir depends on the water injection rate employed. The ideal injection rate for an injection well ensures maximum contact with the remaining oil and achieves oil recovery within the desired timeframe. Throughout the project's lifespan, the water injection rate may vary due to several influencing factors. These factors include the properties of the rock and fluids, mobility values of the fluids in both swept and unswept regions, and the geometry of the wells, such as their pattern, spacing, and wellbore radius (Temizel et al., 2016).

Muskat (1950) and Duppe (1961) have presented analytical equations for injection rates in regular patterns with unit mobility and free gas saturation. The emergence of reservoir simulation has allowed for the generation of multiple waterflooding scenarios using varying injection rates, well locations, configuration of horizontal sections, and other parameters, facilitating the optimization of a waterflood design.

2.3.5. Injection pressure

The injection pressure in water flooding directly impacts the performance of the process. Higher injection pressure improves fluid mobility, enhances sweep efficiency, and increases oil recovery. It helps control fluid distribution, mitigates reservoir heterogeneity, and maintains reservoir pressure. However, excessive pressure can cause formation damage. Optimal injection pressure is crucial for maximizing oil recovery while avoiding potential drawbacks (Singhal, 2009).

2.3.6. Water injectivity

Water injectivity refers to the rate of water injection relative to the pressure difference between the injector and producer in a reservoir. It is measured in barrels per day per pounds per square inch (bbl/d/psi). In the initial stages of injecting water into a reservoir depleted by solution gas drive, a decline in water injectivity is observed. This decline occurs as the pore spaces that were previously occupied by free gas gradually become filled (Marius, 2021).

Once the fill-up is complete, water injectivity is influenced by the mobility ratio. In the case of a unit mobility ratio, water injectivity remains constant. However, it increases when the mobility ratio exceeds unity, indicating an unfavorable condition for displacing oil. Conversely, water injectivity decreases when the mobility ratio is less than unity, indicating a favorable condition for displacing oil (Liu and Tian, 2013).

The incompatibility between the injected water and the formation water can result in reduced water injectivity. This reduction occurs due to factors such as differences in salinity or other chemical properties between the injected water and the formation water.

3. Methodology

3.1. Static model

Using relevant data from a field located in the CAL-M-120 block, some 100 km off the coast of Brazil, the ECLIPSE simulator is used to construct an oil reservoir through static modeling. In this specific location, six wells were drilled during exploration and appraisal activities, finding a significant oil deposit in the Paleocene sand and detecting hydrocarbon presence in the Jurassic and Permian layers.

The model is built on a symmetrical grid with dimensions of 68x91x36 in the i, j, and k axes, respectively. The grid's dimensions are 298 feet in the i direction and 300 feet in the j direction. Each cell in the model has a height between 2.5 and 10 feet. Furthermore, a bottom aquifer surrounded the oil reservoir on all sides. A 3D viewer, represented by Figure 4, displays the oil reservoir model.

Different porosities and permeabilities are assigned to various reservoir grids to make the study more realistic and applicable. According to Figures 5a and b, the permeability values range from 0.25 to 3000 mD, while the porosity values range from 2% to 30%. Table 1 summarizes the reservoir model's attributes.

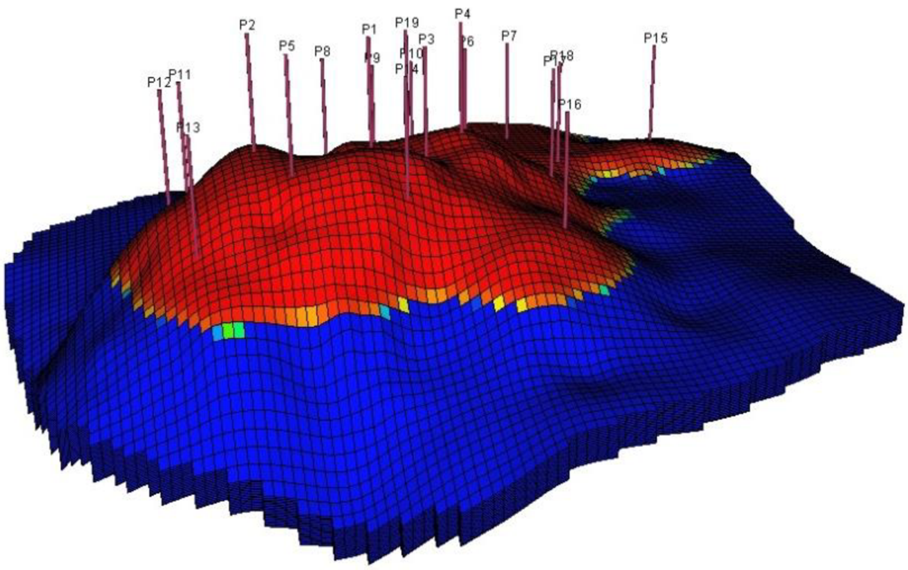

Figure 4 Show a 3D view of reservoir model with aquifer support.

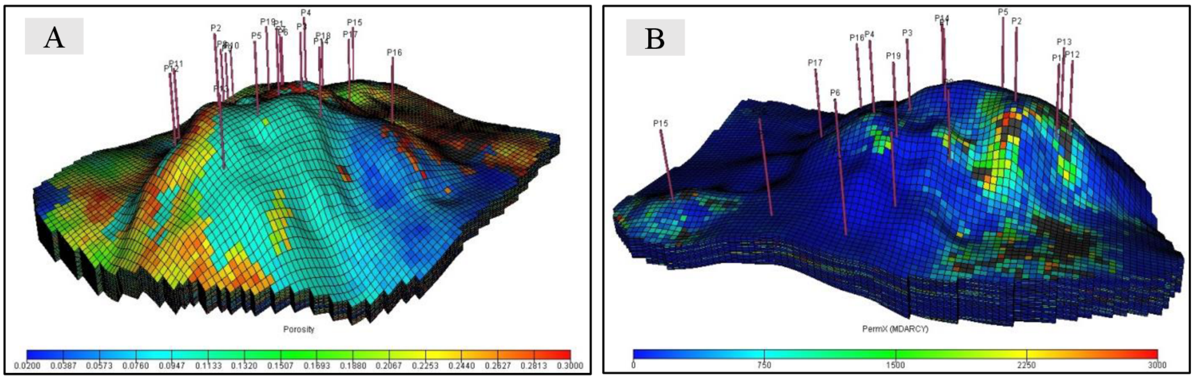

Figure 5 Show the properties distribution of the reservoir model a) porosity b) permeability.

Table 1 Model parameters used to construct an oil reservoir.

Properties	**Values**
Grid Dimension in I, J and K direction	68x91x36
Reservoir pore volume	1521x 10^6 bbl
Water-Oil contact (WOC)	8692 ft
Initial reservoir pressure	3800 psia
Oil, water density	42, 63 Ib/ft^3
Bw, Cw, μ_w	1.01 bbl/STB, 3.3 x10^{-6} psi^{-1}, 0.3 cp
PV compressibility	3.0 x 10^{-6} psi^{-1}
Initial oil in place	338128386 bbl

3.2. Dynamic model

After building the static model, several input data are needed to convert the static model into the dynamic model, such as fluid characteristics, initial reservoir condition, and relative permeability. The minimal set of input data required to create the dynamic model is shown in Figure 6. Figures 7 and 8 depict fluid characteristics, relative permeability, and capillary pressure information for the reservoir.

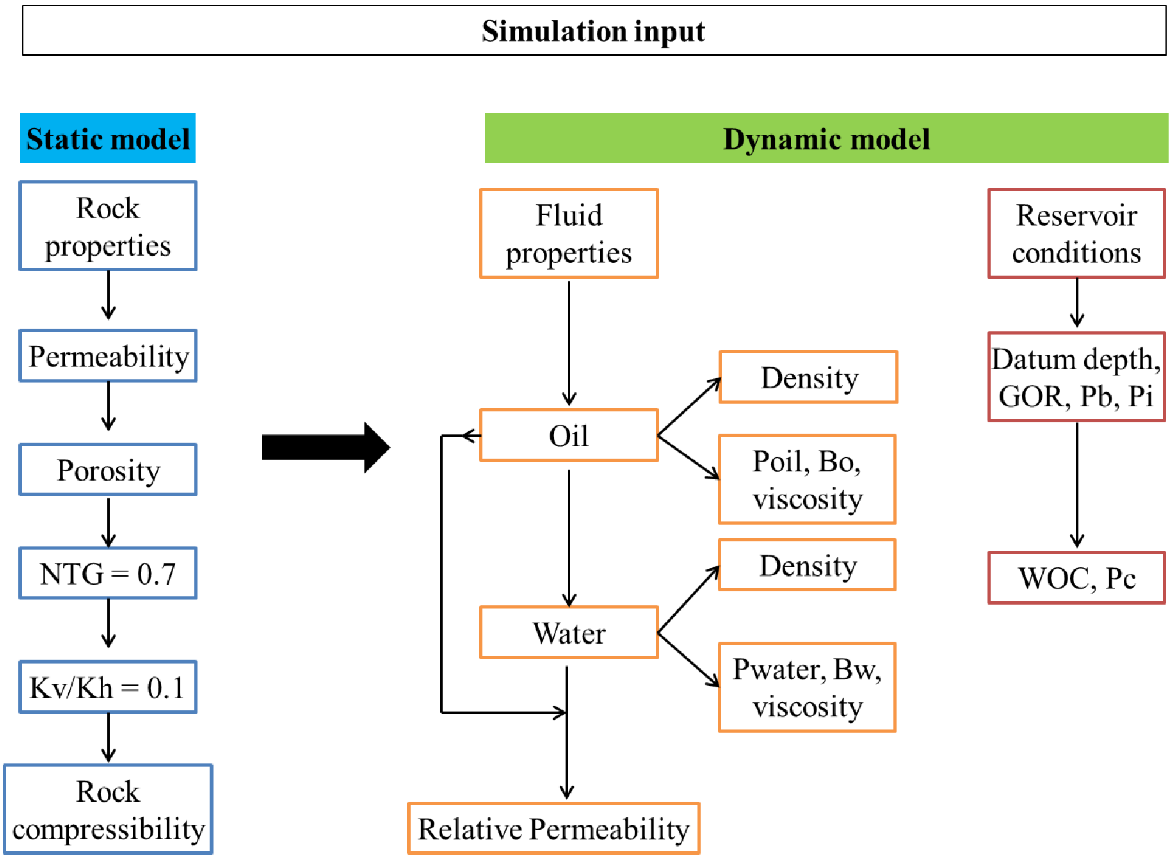

Figure 6 Flow chat show minimum reservoir simulation input data.

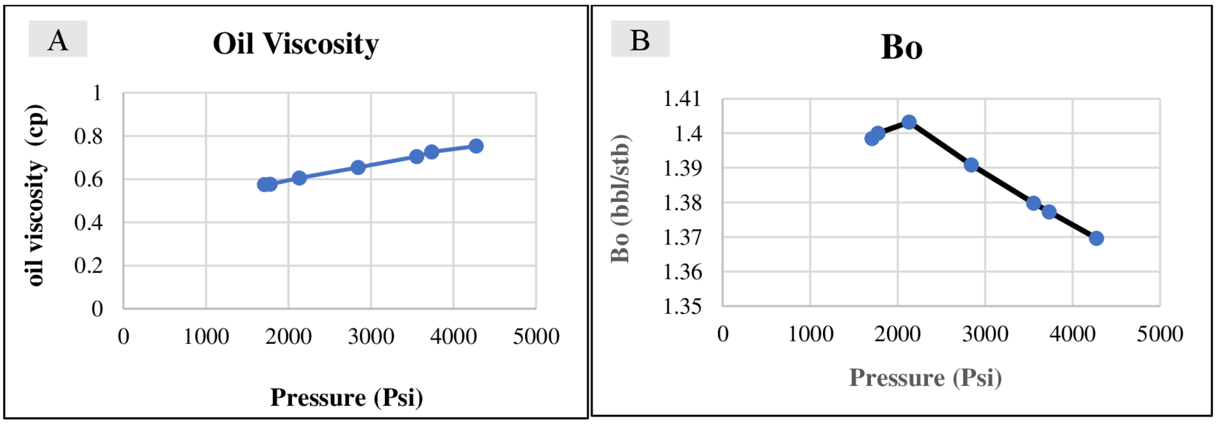

Figure 7 Fluid model used in the reservoir simulation study a) oil viscosity b) oil formation volume factor.

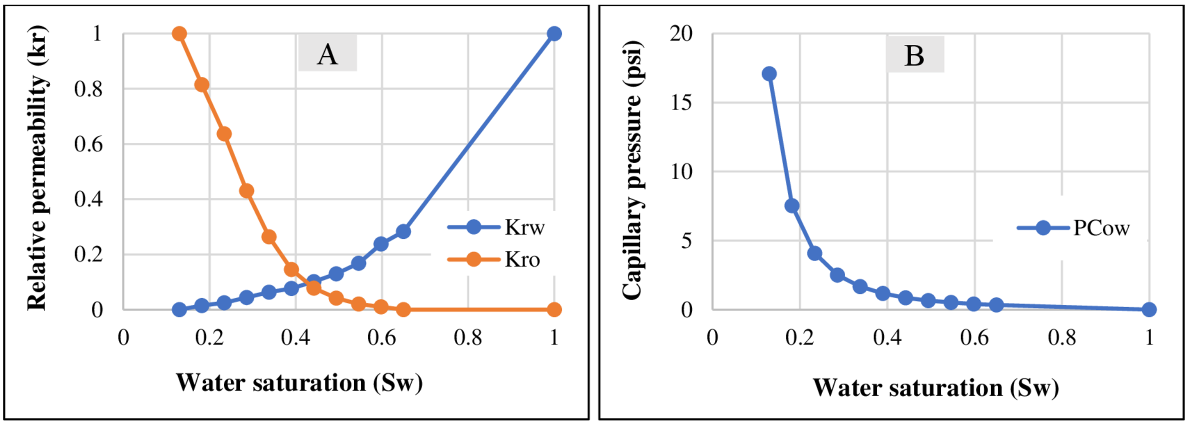

Figure 8 Show a) oil-water relative permeability b) oil-water capillary pressure used in the simulation study.

3.3. Simulation study

Using dynamic modeling, numerous scenarios were simulated in accordance with the project's goal after the oil reservoir model had been initialized with the appropriate data. Natural depletion production was anticipated in the initial scenario, often known as the basic case. A total of 19 vertical oil producers were included in the base. Taking into account the characteristics of the reservoir, these wells were completed at various depths. Additionally, the wells were controlled with different liquid rates, ranging from 13,000 to 25,000 stb/day (stock tank barrels per day), and the simulation was conducted for a duration of 20 years.

To assess and compare the effectiveness of different water injection schemes, multiple water injection patterns were evaluated to determine the optimal field development plan that would result in the highest recovery efficiency compared to other options. The following injection patterns were considered in this study:

- Five spot pattern: In this pattern, four peripheral injection wells are positioned around a central production well, forming a square or rectangular shape. To achieve this setup, the reservoir is divided into equal squares, and the distance between the injection wells and the production well is set at 2120 ft. A total of 55 wells were assigned for this scenario, comprising 22 oil producers and 33 water injectors (as shown in Figure 9). All the producers' wells are controlled by liquid rate while injector wells are controlled by bottom-hole pressure (bhp). The simulation was conducted over a 20-year period to assess the performance of this pattern.

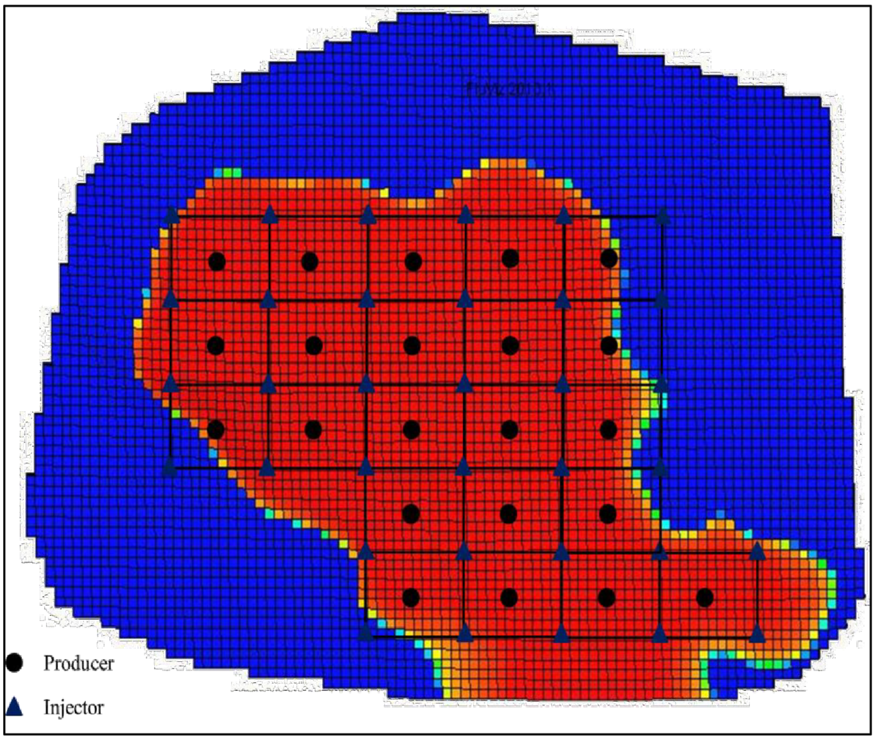

Figure 9 Illustrate the arrangement of production and injection wells in the five-spot pattern scenario.

- Inverted five-spot pattern: In this pattern, a central injection well is surrounded by four peripheral production wells, forming a square or rectangular shape. In order to establish this configuration, the reservoir is divided into uniform squares, with a spacing of 2120 ft between the injection wells and the production well. 50 wells in total, including 27 oil producers and 23 water injectors, were allotted for this particular situation (as illustrated in Figure 10). While bottom-hole pressure (bhp) controls the injector wells, liquid rate controls the producing wells. The simulation was conducted over a period of 20 years to evaluate the effectiveness of this pattern.

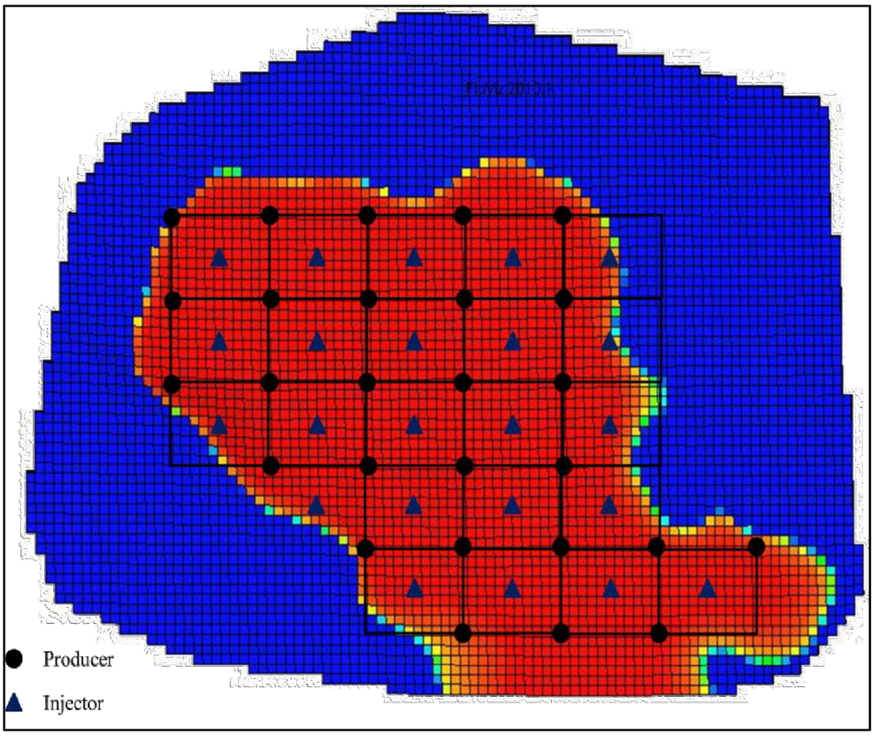

Figure 10 Illustrate the arrangement of production and injection wells in the inverted five-spot pattern scenario.

- Direct Line Drive Water Injection: In this arrangement, the production wells are positioned perpendicular to the injection wells, which are arranged in a straight line or in parallel lines along one direction. 34 wells in all, including 15 oil producers and 19 water injectors, were assigned to this scenario in order to carry out this pattern (Figure 11). Injector wells are controlled by bottom-hole pressure (bhp), whereas production wells are controlled by liquid rate. In order to evaluate the effectiveness and performance of this pattern, a 20-year simulation was run.

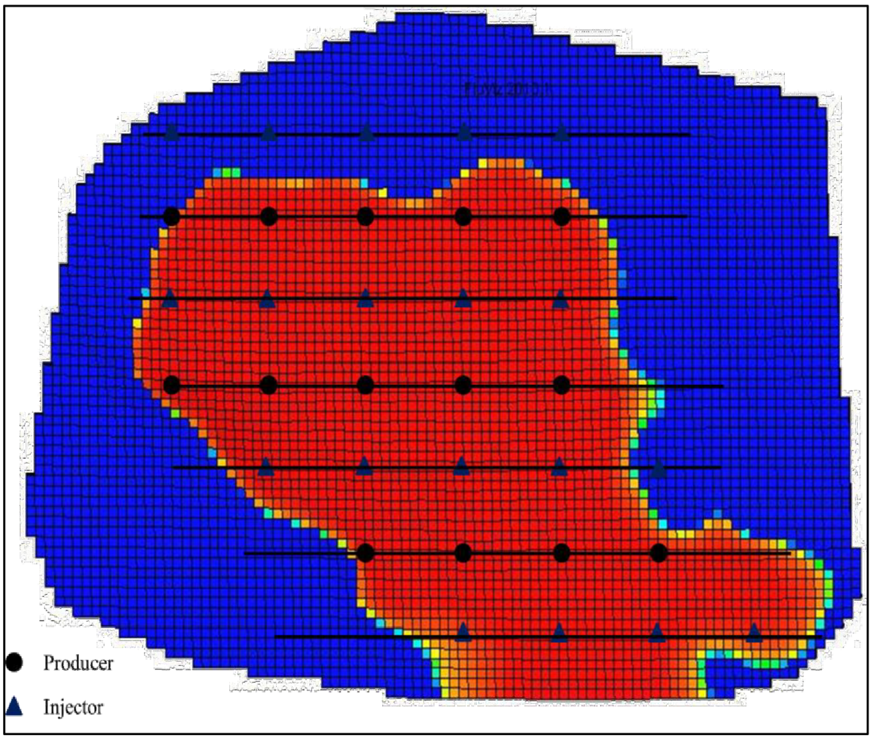

Figure 11 Illustrate the arrangement of production and injection wells in the direct line drive water injection scenario.

- Peripheral water injection: In this pattern, water injection wells are positioned around the periphery or outer edges of the reservoir. The injection wells are strategically located to create a barrier or boundary for the injected water, forcing it to flow towards the central area of the reservoir where the oil-bearing formations are located. A total of 12 injector wells were drilled at the water-oil contact (WOC) to implement this design, and 19 oil producers were strategically placed throughout the reservoir to extract oil (Figure 12). Injector wells are controlled by bottom-hole pressure (bhp), whereas production wells are controlled by liquid rate. To assess the effectiveness and efficiency of this pattern, a simulation was run over a 20-year period.

•

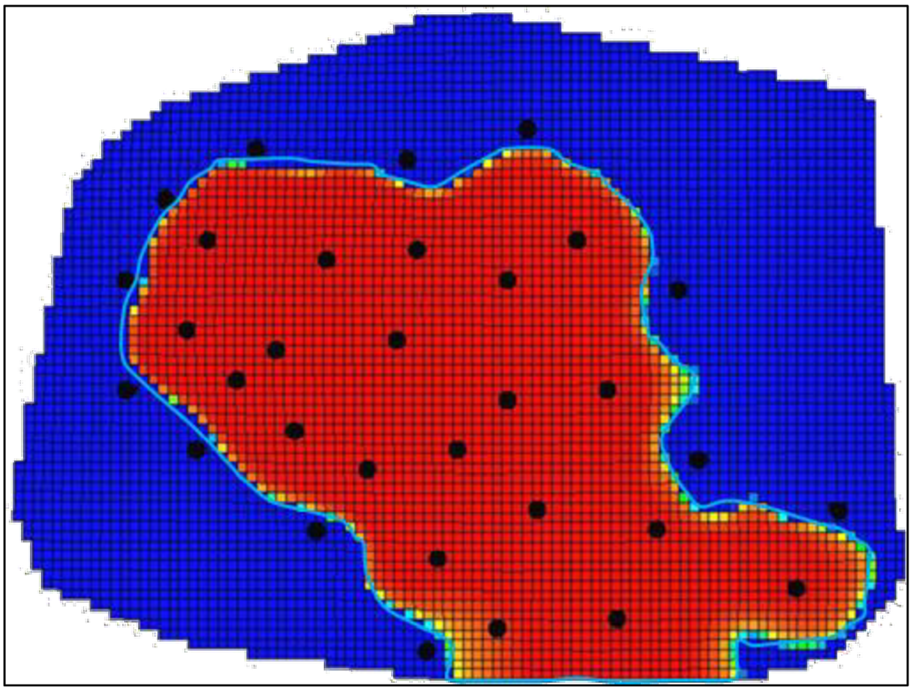

Figure 12 Illustrate the arrangement of production and injection wells in the peripheral water injection scenario.

It is important to note that in this study, the evaluation focused on achieving the maximum oil recovery for each injection pattern, without considering the optimal number of wells from an economic standpoint. While a particular pattern may yield the highest oil recovery, it may not necessarily be the best scenario when considering the cost and number of wells involved in that specific pattern. The economic feasibility and practical considerations associated with the number of wells used in a pattern should be taken into account to determine the overall viability and profitability of a given approach.

4. Results and Discussions

4.1. Natural depletion (Base case)

After conducting the simulation study for duration of 20 years, the outcomes for the natural depletion scenario are depicted in figures 13, 14, 15, and 16. Natural depletion typically leads to a gradual decrease in the reservoir's energy, decreased oil production rates and recovery efficiency over time. Figure 13 illustrates that only 5.1% of the initial oil in place has been recovered after the 20-year period. The relatively low recovery factor can be attributed to the declining pressure of the reservoir, which diminishes the energy available to drive oil flow towards the production wells.

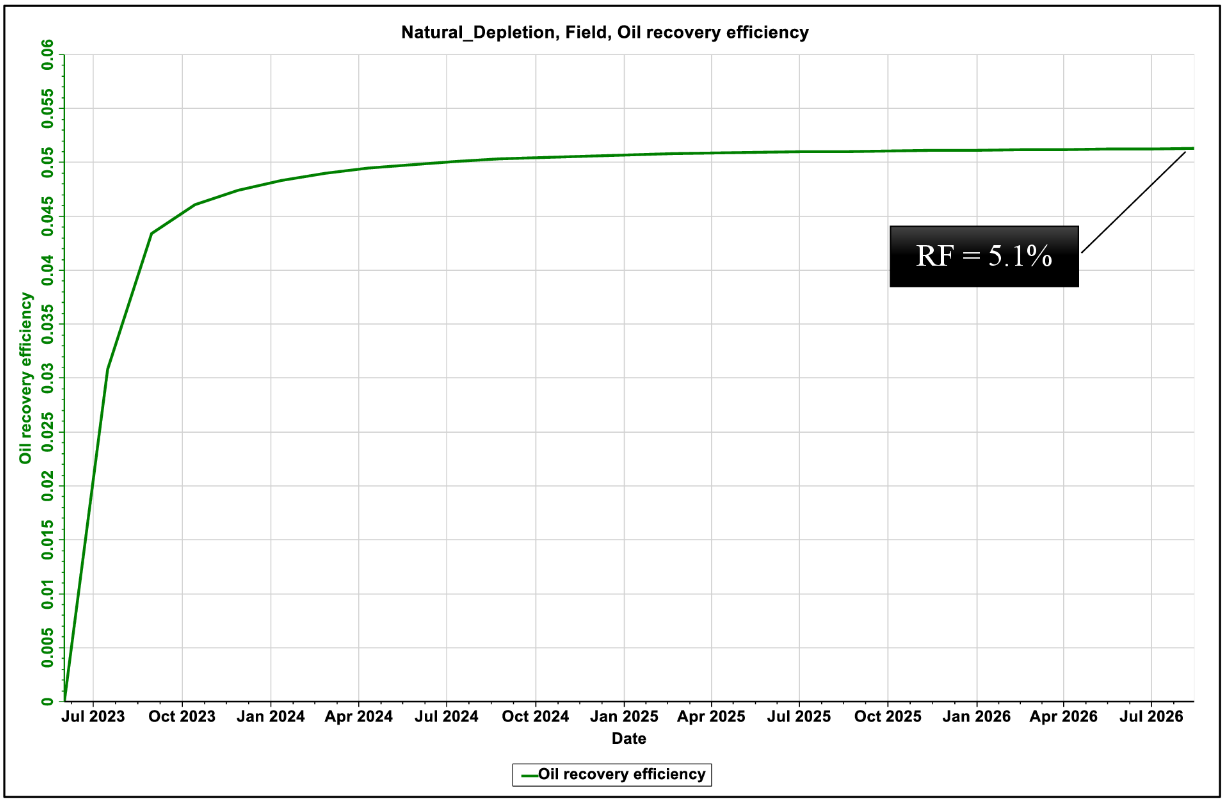

Figure 13 Illustrates the field oil recovery efficiency for the natural depletion scenario

.

Furthermore, the simulation results presented in Figure 14 indicate that the water cut, which represents the proportion of water produced in relation to the total fluids, has reached a significant value of 84% by the end of the 20-year period. This substantial water cut suggests a notable influx of water into the reservoir, which is a common phenomenon in naturally depleted reservoirs due to the sudden decline in reservoir pressure.

Another noteworthy observation from the simulation study is the sudden decrease in reservoir pressure from the initial pressure of 3800 psi to 1698.7 psi, as depicted in Figure 15. This decline in pressure directly results from the natural depletion process, as the reservoir's energy diminishes over time.

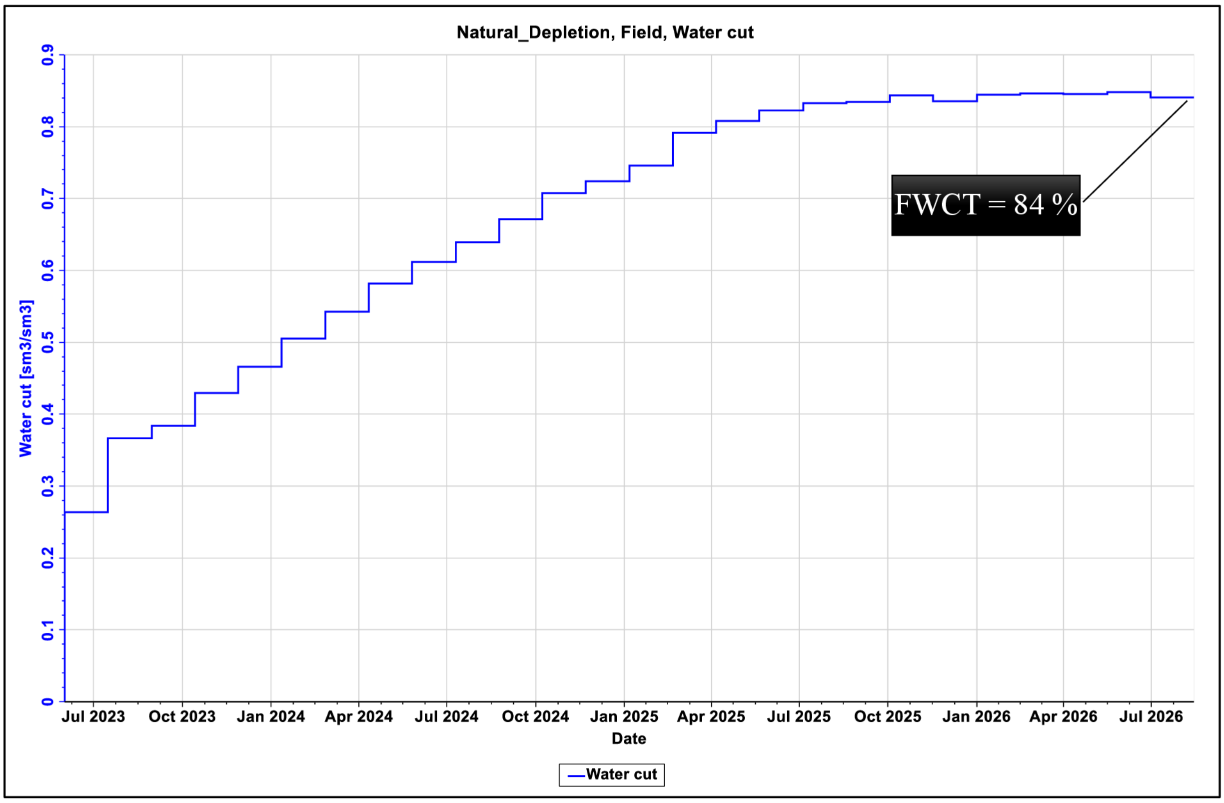

Figure 14 Illustrates the field water cut for the natural depletion scenario.

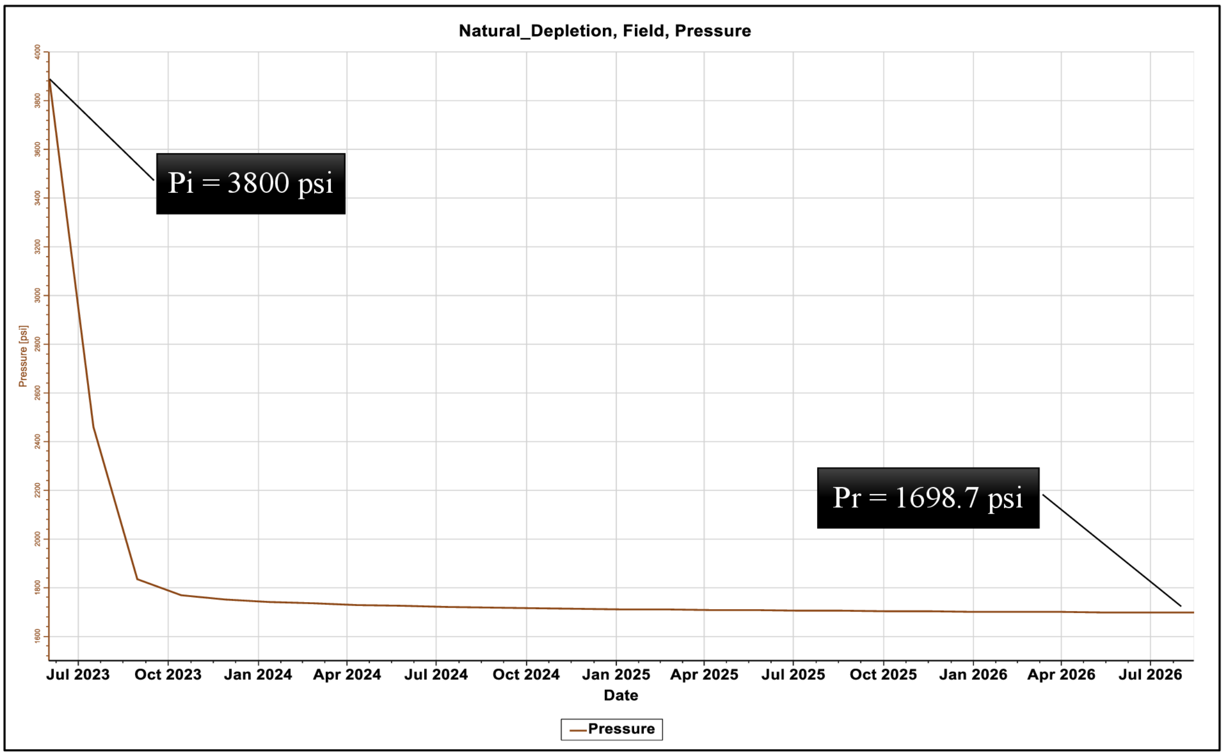

Figure 15 Illustrates average reservoir pressure for the natural depletion scenario.

4.2. Water flooding scenarios

4.2.1. Recovery factor analysis

The variations in the recoveries observed in the analyzed patterns can be attributed to multiple potential factors, which are further elaborated upon in this section. From figures 16 and 17, it can be seen that the 5-spot pattern demonstrated the highest oil recovery at approximately 51.3%. On the other hand, the peripheral flood pattern also showed promise, with a field oil recovery efficiency close to the five-spot pattern at 49.06%. The peripheral pattern demonstrated the ability to sweep oil from all directions towards the producers, minimizing entrapment. Theoretically, increasing the number of injectors should result in greater recovery, but it can also lead to early water breakthrough. However, in the case of peripheral water injection, the lower number of injectors delayed water breakthrough in the producers and resulted in lower water cuts after breakthrough.

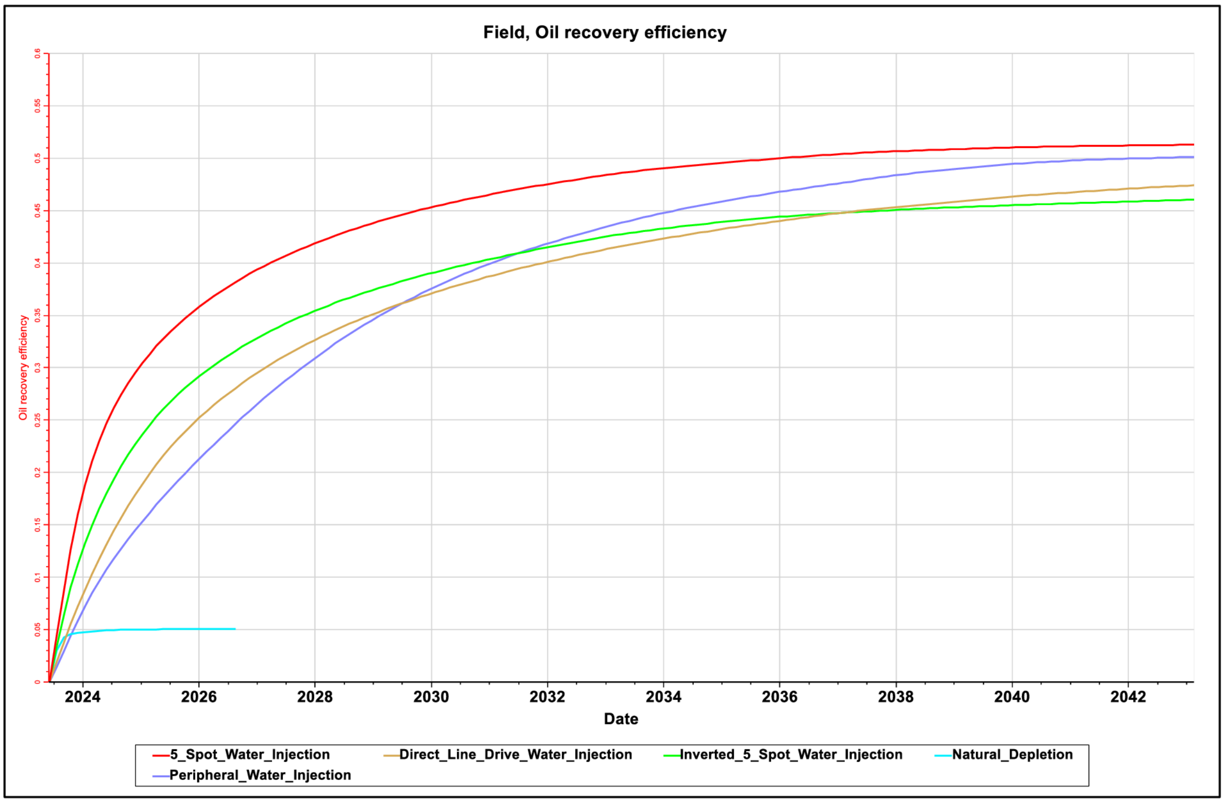

Figure 16 Illustrates field oil recovery efficiency for different water injection patterns.

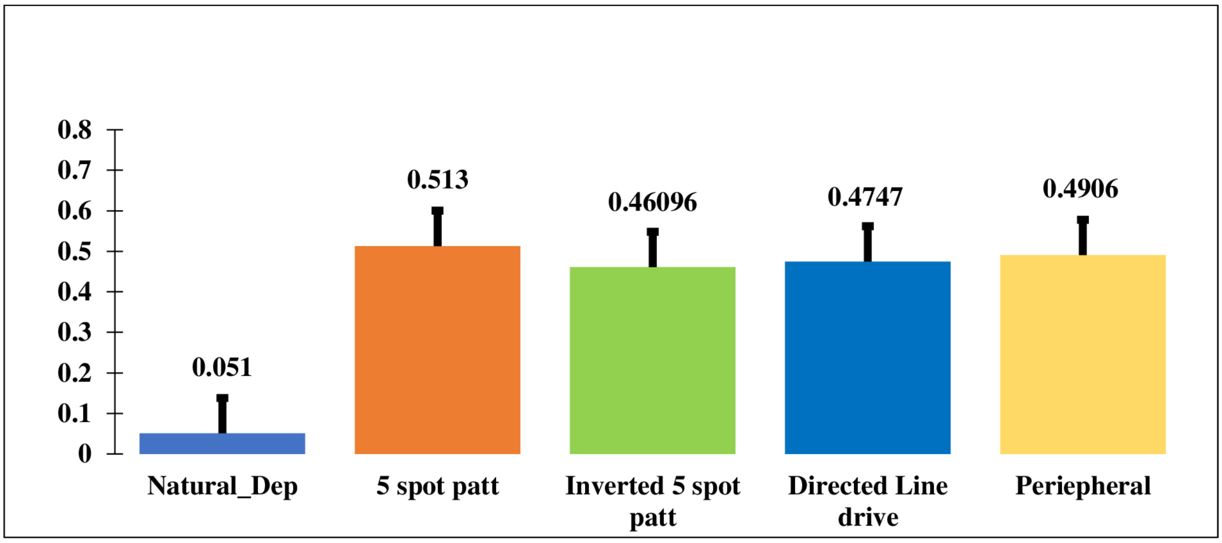

Figure 17 Compare field oil recovery efficiency for flood patterns.

A similar situation was observed when comparing the peripheral flood pattern to the inverted 5-spot and directed line drive patterns. As shown in Figures 16 and 17, the peripheral pattern exhibited higher recovery rates compared to the inverted 5-spot and directed line drive patterns, which stood at 46.09% and 47.47% respectively. Despite having a lower number of injector wells in the peripheral pattern, the additional injectors in the other patterns only accelerated water breakthrough without significantly enhancing oil sweep. Beyond a certain point, employing more injectors becomes counterproductive to the overall recovery process. Hence, due to its lower number of injectors, the directed line drive pattern should have exhibited superior performance compared to the inverted 5-spot pattern.

4.2.2. Water cut analysis

In general, for all the studied patterns, an increase in water production was accompanied by a decrease in oil production. As evident from Figures 18 and 19, the water cut graphs for the normal 5-spot, inverted 5-spot, and directed line drive patterns exhibit similarities, with values of approximately 97.95%, 98%, and 98%, respectively. However, a notable difference in water cut was observed in the case of peripheral water injection when compared to other flood patterns. This discrepancy can be attributed to the lower number of injector wells in the peripheral water injection, as well as the greater distance between the injector wells and the producer wells, leading to reduced water production and ultimately resulting in lower water cut values.

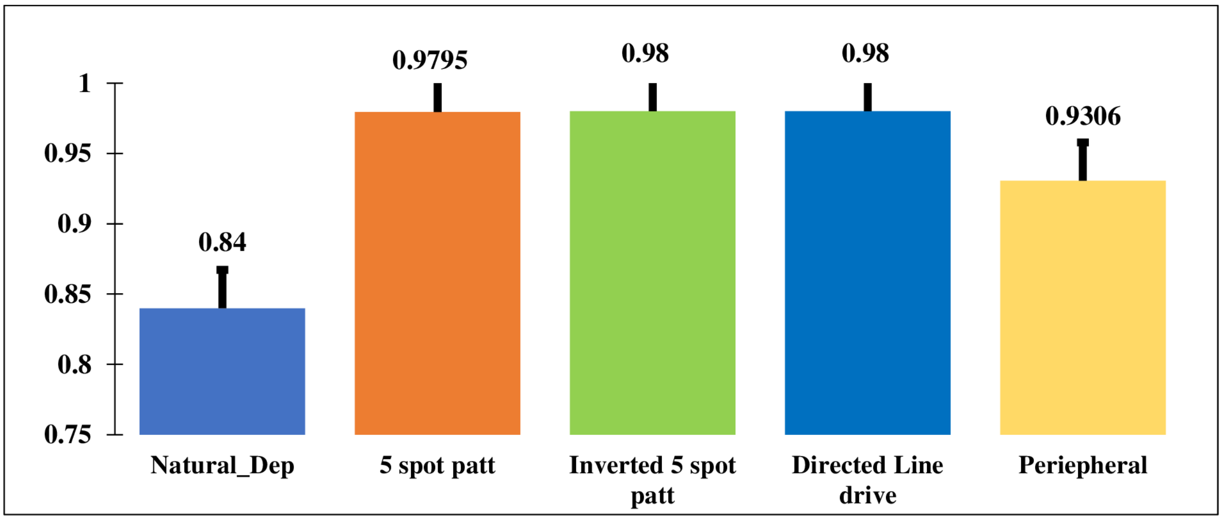

Figure 18 Compare field water cut for flood patterns.

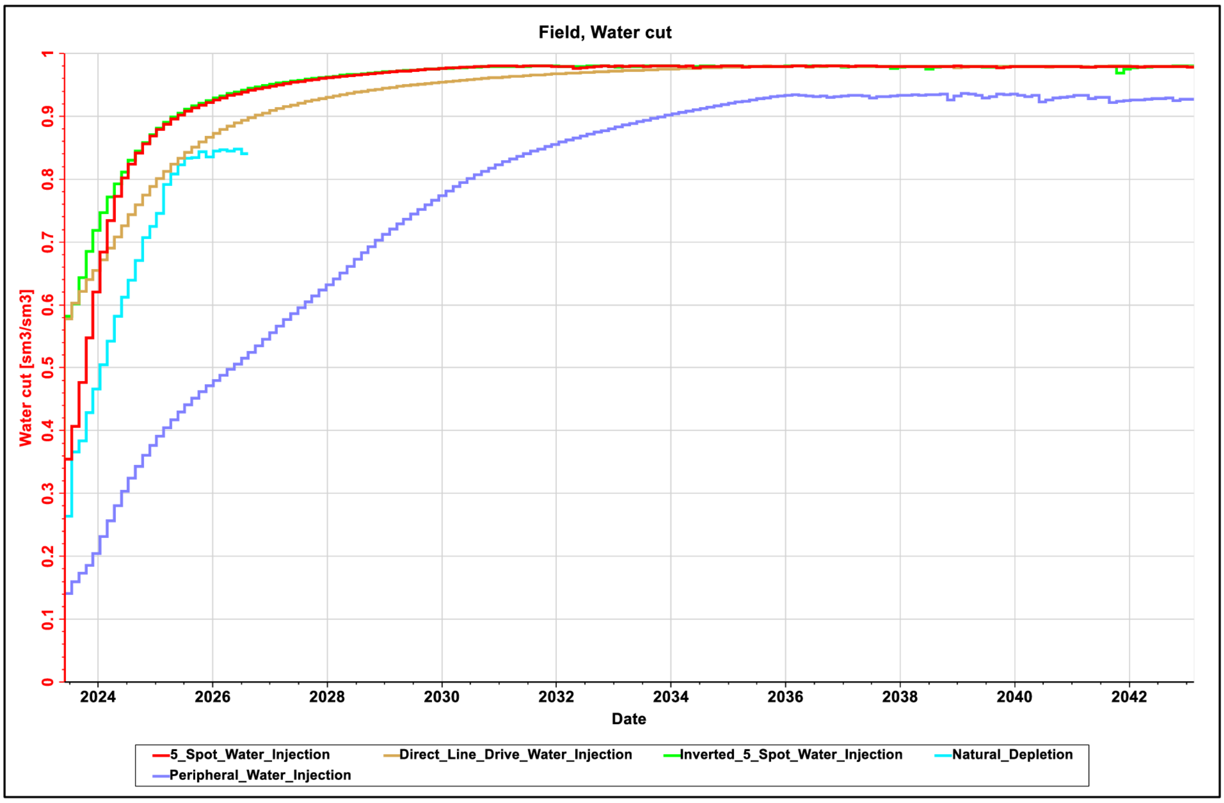

Figure 19 Illustrates field water cut for different water injection patterns.

4.2.3. Reservoir pressure maintenance

The various water injection patterns have different effects on reservoir pressure maintenance. Each pattern influences pressure maintenance differently due to variations in the distribution and movement of injected water within the reservoir. In the case of the normal 5-spot pattern, it typically provides effective pressure maintenance (Figures 20 and 21). The injectors in this pattern are strategically placed to sweep oil from all corners and directions, thereby aiding in maintaining reservoir pressure. From figure 21, it can be seen that the reservoir pressure increased by 84% (from 3800 psi to 7013 psi) compare to the initial reservoir pressure.

On the other hand, due to the injector wells being further away from the producers, a longer water travel distance and possible pressure variations, the peripheral flood pattern may not provide as efficient pressure maintenance (as shown in Figures 20 and 21). Figure 20 shows that maintaining reservoir pressure for the peripheral pattern is slower compared to other patterns.

When compared to directed line drive patterns, the inverted 5-spot pattern might be less effective in maintaining reservoir pressure. Factors including the quantity of injector wells, as well as the distribution and movement of water inside the reservoir, might affect how effectively pressure maintenance is carried out.

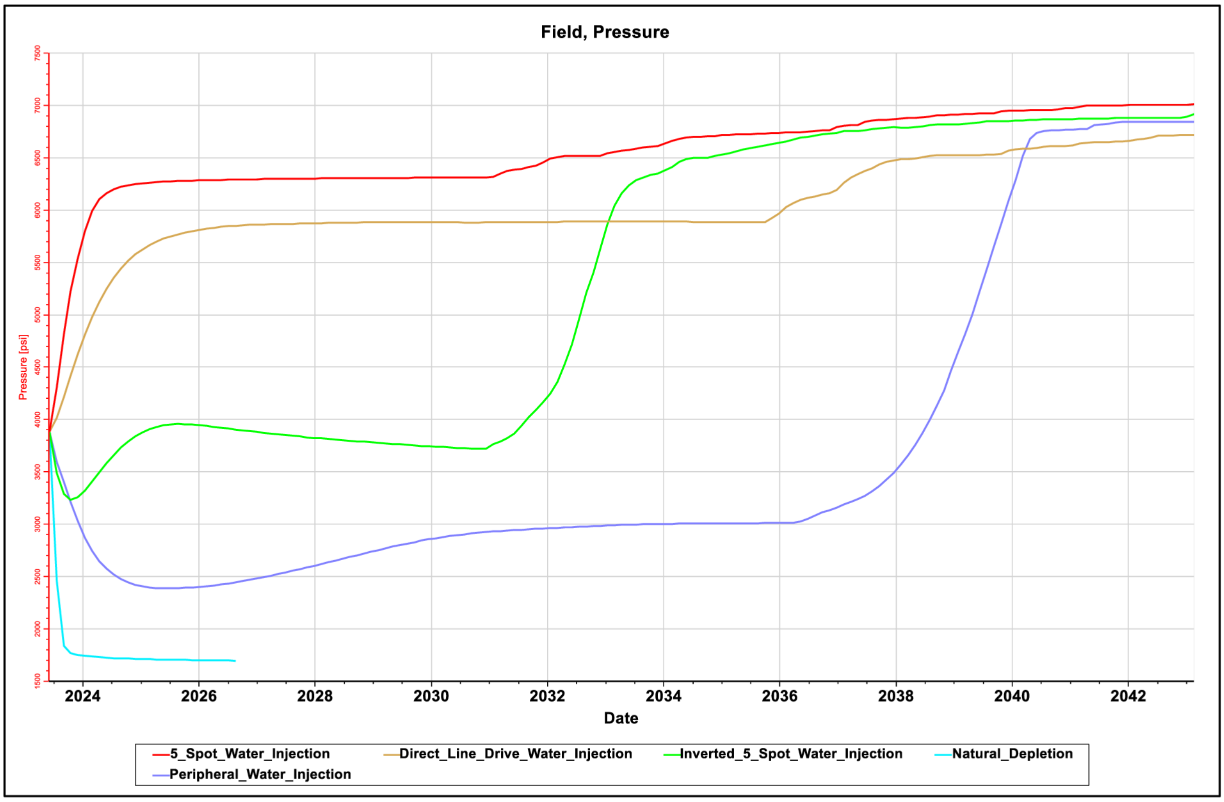

Figure 20 Illustrates average reservoir pressure for different water injection patterns.

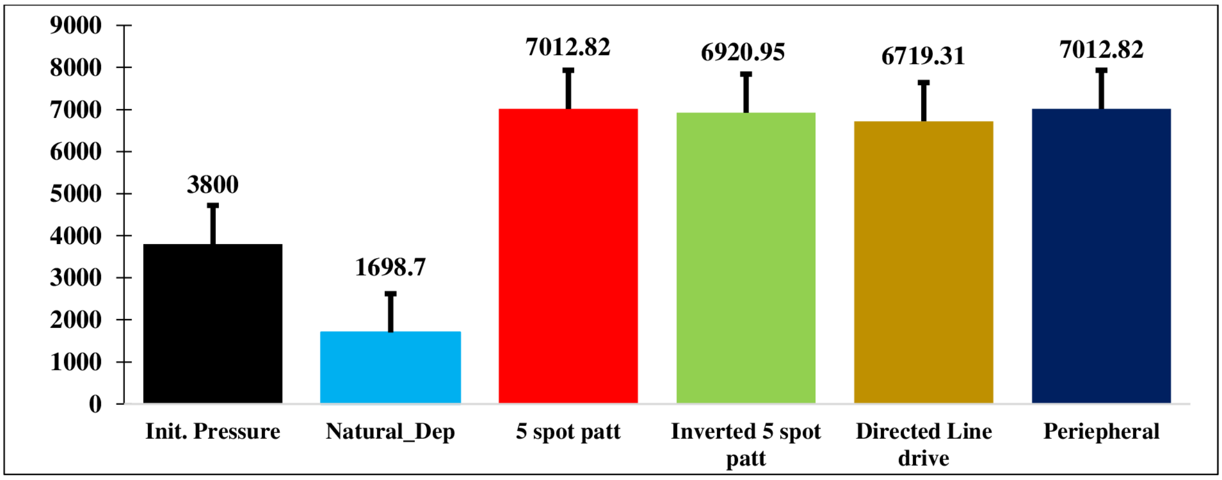

Figure 21 Compare average reservoir pressure for flood patterns.

4.2.4. Oil production rate analysis

The oil production rate for different water flood patterns is influenced by the way water is injected into the reservoir and the resulting displacement of oil. Figures 22 and 23 show the cumulative oil rate for different water injection sachems. According to Figure 22, the 5-spot pattern exhibits the highest production rate (173.63 MMstb). This is attributed to the advancement of the waterfront towards the central well, which mobilizes the oil. However, as the waterfront progresses and reaches the central well, the oil production rate typically decreases. This decline occurs because a larger proportion of the produced fluid consists of water rather than oil.

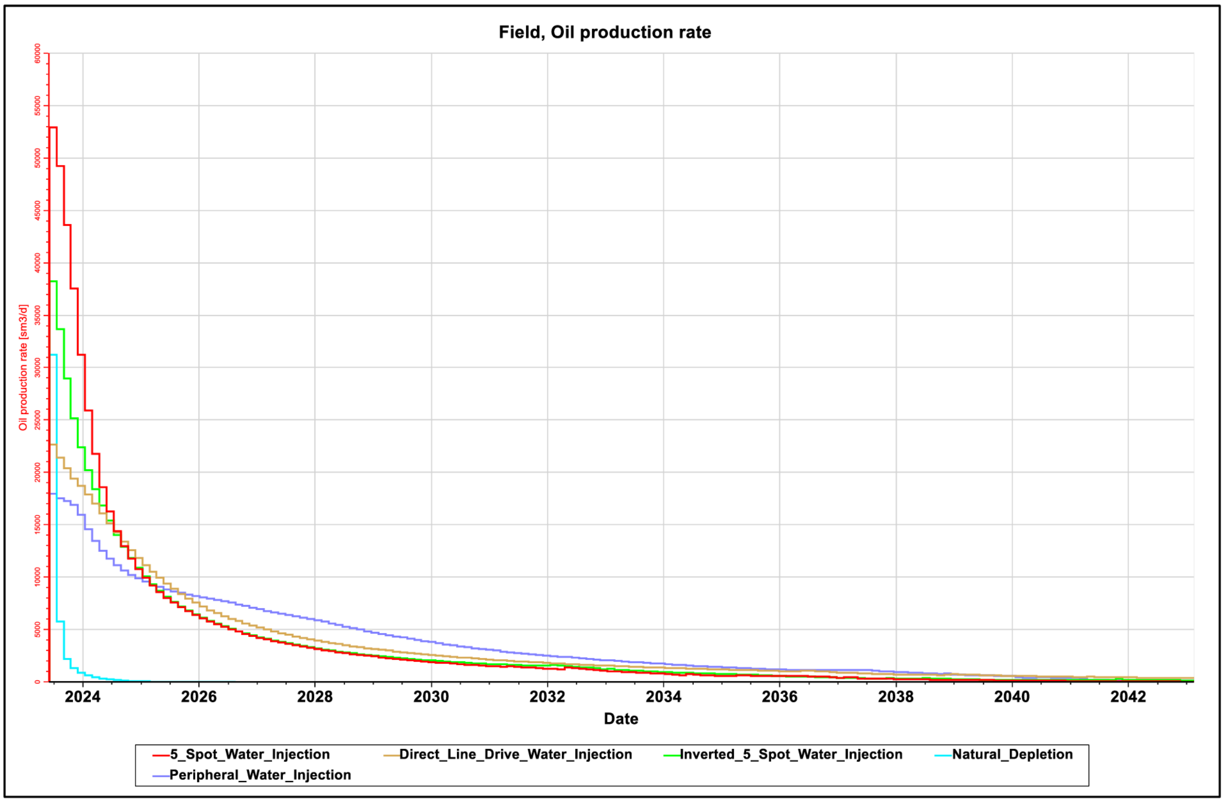

Figure 22 Illustrates field oil production rate for different water injection patterns.

In the peripheral pattern, the initial oil production is lower compared to other patterns. However, over the long term, it exhibits a more stable plateau. After a 20-year simulation study, a total of 165.88 MMstb of oil is produced, which is higher than the oil rates produced by the inverted 5-spot and directed line drive patterns, amounting to 155.65 and 160.53 MMstb, respectively.

While the production rate for the directed line drive pattern is higher than that of the inverted 5-spot pattern, both patterns exhibit a similar decline in production over the long term. The decrease oil production in the inverted 5-spot pattern is attributed to having less injector wells compared to the directed line drive pattern. Additionally, the directed line drive pattern's observation of a slow drop in oil production suggests that the waterfront is kept parallel to the production wells. However, if the waterfront deviates from its parallel path, the rate of oil production may drop due to the ineffective sweeping of oil.

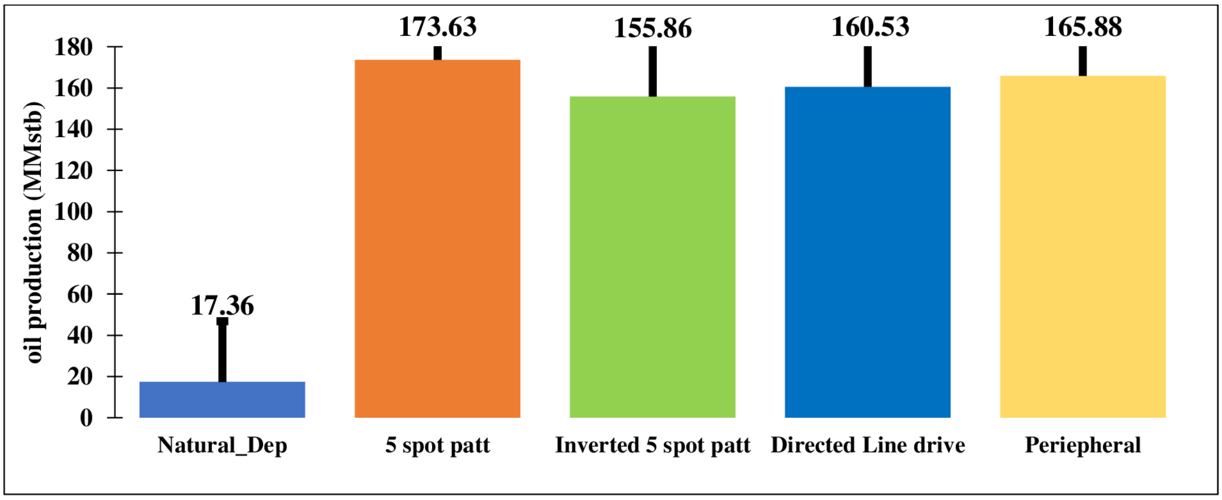

Figure 23 Compare field oil production rate for flood patterns.

To summarize, compared to other water injection techniques, the five-spot pattern and peripheral water injection both had comparable performance and produced the highest oil recovery. However, taking into account cost and the number of wells, peripheral water injection is deemed the most favorable injection strategy for this particular reservoir. It should be noted that these findings might differ in other reservoirs based on the characteristics of the reservoir rock and fluid.

5. Conclusions and recommendations

5.1. Conclusions

The main goal of this project is to evaluate and compare the effectiveness of different water injection schemes in maximizing oil recovery. The key findings and conclusions obtained from this study are as follows:

- The five-spot pattern yields the highest oil recovery (51.3%), while the inverted five-spot pattern leads to the lowest recovery (46.09%).

- The field water cuts experience a rapid increase when water flooding begins, reaching 98% for most patterns, except for peripheral water injection, which reaches 93%. This difference is due to the larger spacing between the injection wells and production wells in the peripheral pattern.

- The five-spot and directed line drive patterns generally offer effective pressure maintenance, while the peripheral and inverted five-spot patterns do not exhibit efficient pressure maintenance when compared to the five-spot patterns. This discrepancy is attributed to the variation in the number and locations of injector wells among these patterns.
- The 5-spot pattern exhibits the highest production rate (173.63 MMstb), but it sharply declines as the waterfront approaches the central well. In contrast, the peripheral pattern maintains a more stable long-term plateau.

- The directed line drive pattern has a higher production rate (160.53 MMstb) than the inverted 5-spot pattern (155.86 MMstb) because of more production wells, while both patterns exhibit similar long-term production decline.

5.2. Recommendations

- Conduct a detailed study to determine the optimal number of wells for each water injection scheme. This analysis should consider factors such as reservoir characteristics, production targets, and economic constraints.

- Investigate the impact of well placement on the performance of water injection schemes. Utilize reservoir simulation techniques to assess the ideal locations for injection and production wells within the reservoir.

- Assess the cost associated with drilling and operating the wells for each scheme. Consider factors such as capital expenditure, operational expenses, and potential return on investment.

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Appendix

```
RUNSPEC
TITLE
 TEAM W
-- Check keywords but do not run simulation
--NOSIM
DIMENS
-- NX    NY    NZ
   68    91     36     /
-- Phases
OIL
WATER
-- Units
FIELD
-- Number of saturation tables
TABDIMS
     1     /
-- Maximum number of wells
WELLDIMS
    30   100   30    30 /
-- First oil
START
   1 JUN 2023 /
-- Memory allocation
NSTACK
  100 /
-- Allow 5000 warnings, messages, but terminate on 1st error message
MESSAGES
```

```
 11*5000  1  /
-- Unified output files
UNIFOUT
==============================================================================
GRID
-- Include corner point geometry model
INCLUDE
'include-files\Team-W_Model-1.GRDECL'   /
INCLUDE
'include-files\POROSITY.GRDECL'  /
INCLUDE
'include-files\PERMX.GRDECL'  /
INCLUDE
'include-files\NTG.GRDECL'  /
COPY
    PERMX  PERMY /
    PERMX PERMZ/

-- kv/kh
MULTIPLY
   PERMZ  0.4  /
/
-- Output .INIT file to allow viewing of grid data in post processor
INIT
==============================================================================
PROPS
--          Oil      Water     Gas
DENSITY
```

```
          42    63    0.1   /
-- Oil:      Poil      Bo      viscosity
PVDO
1745   1.411   0.575
1778   1.403945        0.577
2133   1.4032395       0.605
2845   1.3908227       0.655
3556   1.3798169       0.705
3735   1.3772771       0.727
4274   1.3696577       0.753
/
-- Water:  Pwat    Bw     Cw    viscosity    viscosibility
PVTW
        3800   1.01   3.3E-6    0.3          0   /
INCLUDE
 'include-files\ROCK-RELPERMS.INC'    /
-- Rock compressibility
ROCK
  3800   3.0E-06 /
============================================================
REGIONS
EQUALS
-- Assign relative permeability tables
   SATNUM    1        1   68      1   91      1   36 /
 /
============================================================
SOLUTION
```

```
-- Initial conditions
-- Depth   pressure     OWC     Pc@OWC     GOC     Pc@GOC     Rs from RSVD table
EQUIL
   8084     3800       8692      0.0     1*      0.0             1 /
-- Output initial values of recurrent grid data (eg pressures, saturations)
RPTRST
  BASIC=2  /
-- Output initial Fluid in Place values
RPTSOL
  FIP=1  /
==============================================================================
SUMMARY
INCLUDE
 'include-files\SUMMARY.INC'   /
DATE
-- Total CPU usage
TCPU
-- output in MS Excel format (in .RSM file)
EXCEL
-- Only create output each report step
RPTONLY
==============================================================================
SCHEDULE
-- Output values of recurrent grid data (eg pressures, saturations)
RPTRST
  BASIC=2  /
-- Gas does not redissolve in oil
DRSDT
```

```
  0.0 /
-- Define well head locations and preferred phase
WELSPECS
-- well     group     X    Y           Phase
 P1  Producer  35 52   1*     OIL  /
 P2  Producer  34 64   1*     OIL  /
 P3  Producer  34 46   1*     OIL  /
 P4  Producer  29 41   1*     OIL  /
 P5  Producer 41 61   1*     OIL  /
 P6  Producer 18 38   1*     OIL  /
 P7  Producer 7 30   1*     OIL  /
 P8  Producer 22 55   1*     OIL  /
 P9  Producer 13 48   1*     OIL  /
 P10  Producer 6 42   1*     OIL  /
 P11 Producer 32 71   1*     OIL  /
 P12 Producer 34 73   1*     OIL  /
 P13 Producer 45 71   1*     OIL  /
 P14 Producer 44 50   1*     OIL  /
 P15 Producer 10 12   1*     OIL  /
P16 Producer 45 34   1*     OIL  /
P17 Producer 30 31   1*     OIL  /
P18 Producer 16 26   1*     OIL  /
P19 Producer 24 46   1*     OIL  /
/
-- Define completion data
COMPDAT
-- well   X   Y   Ztop  Zbot  Status          well ID           orientation
 P1    2*   1     29     OPEN     1*  1*   0.580        3*     Z/
```

```
 P2   2*  1   27   OPEN   1*  1*  0.580      3*   Z/
 P3   2*  1   10   OPEN   1*  1*  0.580      3*   Z/
 P4   2*  1   34   OPEN   1*  1*  0.580      3*   Z/
 P5  2*  1   22   OPEN   1*  1*  0.580      3*   Z/
 P6  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P7  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P8  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P9  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P10  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P11  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P12  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P13  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P14  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P15  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P16  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P17  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P18  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
P19  2*  1   5   OPEN   1*  1*  0.580      3*   Z/
/
-- Production control
-- Well Status Control   Oil   Wat   Gas   Liq Resv  BHP
-- name        mode    rate  rate  rate   rate  rate  limit
-- ----  ------  ------    ----  ----  ----   ----  ----  -----
WCONPROD
 P1  OPEN LRAT 3* 25000    1* 1800 /
 P2  OPEN LRAT 3* 13000    1* 1800 /
 P3  OPEN ORAT  2000    4* 1800 /
 P4  OPEN LRAT 3* 25000   1* 1800 /
```

```
 P5 OPEN LRAT 3* 11000   1* 1800 /
 P6 OPEN LRAT 3* 15000   1* 1800 /
P7 OPEN LRAT 3* 15000   1* 1800 /
P8 OPEN LRAT 3* 15000   1* 1800 /
P9 OPEN LRAT 3* 15000   1* 1800 /
P10 OPEN LRAT 3* 15000   1* 1800 /
P11 OPEN LRAT 3* 15000   1* 1800 /
P12 OPEN LRAT 3* 15000   1* 1800 /
P13 OPEN LRAT 3* 15000   1* 1800 /
P14 OPEN LRAT 3* 15000   1* 1800 /
P15 OPEN LRAT 3* 15000   1* 1800 /
P16 OPEN LRAT 3* 15000   1* 1800 /
P17 OPEN LRAT 3* 15000   1* 1800 /
P18 OPEN LRAT 3* 15000   1* 1800 /
P19 OPEN LRAT 3* 15000   1* 1800 /
/
-- Use all memory allocated in NSTACK
TUNING
 /
 /
 2*  100 /
GECON
 FIELD 440 1* 0.93 2* CON YES /
/
TSTEP
160*45/
END
```