Reservoir Management Structure A Field "RK" Using Water Injection Project Planning With the Suspended Well Reactivation Method

ABSTRACT

In reservoir management to increase oil production in structure A of the "RK" Field with an area of 98.12ft2, a thickness of 76,124 ft, a porosity of 0.21%, and an initial water saturation of 0.25% which already matches the high watercut, it is necessary to plan water injection to increase the recovery factor. This is considered based on water availability, production performance results, and also from an economic perspective. The structure development study of "RK" Field A contains five active production wells and four suspended wells. Of the four suspended wells, one well was used as an injection well and three wells were reactivated to determine the effect of the waterflooding injection using reservoir simulation methods by analyzing field petrophysical data such as oil saturation, permeability, and OPU maps. Based on the reservoir simulation, waterflooding injection was carried out in the AB_05 injection well with daily injection rates varying from 141 to 1200 BWIPD with injection pressures varying from 1782 to 2537 psi using one injection well. Based on the results of running simulations, the most optimal scenario is obtained with an injection rate of 750 BWIPD with an injection pressure of 2411 psi which produces a cumulative production of 4,687 MMSTB from 3.55 MMST, a recovery factor of 56,511% from 42.8% and a water cut of 60.9% from 43% so it is economical to carry out. water injection in structure A of the RK field.

Keywords: : Reservoir Management, Increased Production, Waterflooding, Recovery factor Development scenario.

1. INTRODUCTION

Hydrocarbons are produced from below the surface through primary, secondary and tertiary methods (enhanced recovery, EOR). Primary recovery refers to the recovery of oil by relying solely on the natural energy of the reservoir. Secondary recovery is a recovery technique used to increase the natural energy of a reservoir by artificially injecting fluid (gas or water) into the reservoir to force oil to flow into the wellbore and to the surface. The primary objective of a secondary recovery program is also to restore and maintain reservoir pressure, which typically decreases during the primary recovery phase. Secondary recovery may only be carried out when primary recovery is no longer economically feasible to produce oil from the reservoir to the surface. Water and gas injection is a secondary recovery method. [1] Water injection is the process of injecting water into a reservoir through one or more injection wells surrounding one or more production wells with the aim of maintaining pressure in the reservoir in order to achieve optimal production and maximize final yield. This is one of the most useful techniques to increase oil production from petroleum reservoirs. This is not only due to the low cost of water or availability of water especially in offshore locations, but also due to the characteristics of water that help to efficiently sweep away trapped oil. [2] In this research, water injection was carried out using the reservoir simulation method.The simulation study takes the example of structure A Field "RK". Developing a field is an important activity in determining the future action of a field to obtain an optimum recovery factor.

Reservoir simulation is an artificial reservoir model that resembles a real reservoir. The reservoir parameters in the model are the same as the real reservoir parameters and with an artificial model like this, it is possible to plan several development scenarios without having to execute them in the real reservoir. This type of activity model can reduce the costs of developing a field. In a field development scenario, there is a water injection scenario to increase oil recovery in a field. The main reason why this water injection is performed is that it is most often successful and most commonly used [3].The choice of water as an injection agent is based on the relatively high mobility of water, and is supported by the ease and economy of obtaining water. The most important thing about water injection is the ability of water to easily spread in the reservoir, resulting in quite high efficiency in oil sweeping where the reservoir is where oil and gas accumulate. There are several important factors to consider to ensure the success of a water injection process, including reservoir depth, slope, level of reservoir heterogeneity, petrophysical properties, driving mechanism, remaining oil reserves, remaining oil saturation and oil viscosity. [4] Several factors are considered in waterflooding work, namely permeability, water saturation, remaining oil saturation, type of reservoir rock, water injection discharge, and type of water injected.

*Waterflooding*carried out when the reservoir pressure can no longer push oil naturally and the production rate is low [5].Water injection is classified into 3 types, namely water disposal (used to inject formation water into unproductive layers so that it does not increase oil production), pressure maintenance (used to maintain reservoir pressure high), and waterflooding (pushing hydrocarbons by injection water in a pattern certain conditions so that hydrocarbons can be pushed into production wells) [6]. Water pressure technology has been applied commercially since the 1920s. This technology has been recognized by the industry as a very economical and reliable oil recovery method [7]. Successful water pressure can increase the oil recovery factor from a typical 5-25% at the primary stage to a typical 45% of the initial oil content or original oil in place [6]. In waterflooding operations, injection and production wells will be arranged to form a certain regular pattern, for example a three-point pattern, a five-point pattern, a seven-point pattern, a peripheral pattern and so on. The well pattern where the production well is surrounded by injection wells is called the normal pattern. Meanwhile, on the other hand, if the production wells surround the injection well, it is called an inverted pattern [8]. The problems that will arise in this research are firstly regarding the completeness and accuracy of the data that will be entered into the simulator, this data includes SCAL, PVT data and field production data. Other problems include aligning OOIP and also historical production data from the field and each well (history matching). There are two main problems that can hamper the efficiency of water injection, namely that the injected water cannot squeeze out all the oil in the pore space. This is because the reservoir rock is oil wet. So 25-50% of the oil will remain in the rock pores. The next problem is that the front water can cut or pass through the reservoir due to the heterogeneous nature of the reservoir rock and cause 50-70% of the oil in the reservoir to be unable to be obtained [9].Produced water is the largest liquid waste produced from oil and gas exploration and production with a composition of 80% liquid waste, and in aging oil fields it reaches 95%. Therefore, this needs to be managed with beneficial use. One type of technology that can be used to manage produced water is re-injection technology. This is a technology where the produced water produced in the oil production process will be returned to the oil well. This research provides an overview of the application of injection well technology in the management of produced water produced by oil and gas companies.[10]

2. MATERIALS AND METHODS

The research flow diagram can be seen in Figure 1.

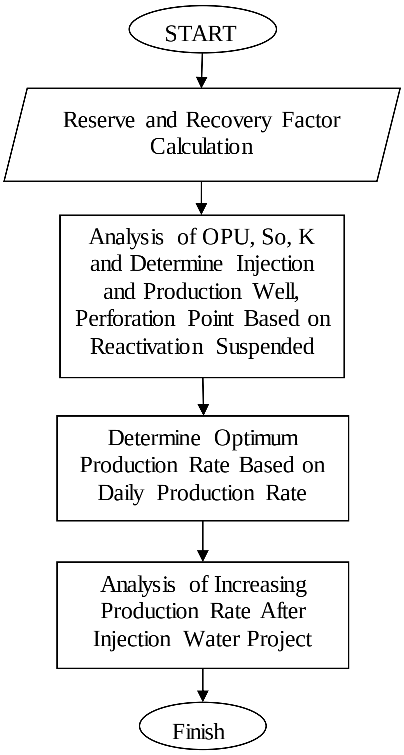


Fig.1. Research Methodology Flowchart

Based on Figure 1, it can be seen that this research began by calculating the recovery factor and remaining reserve values to determine whether the field under study was suitable for development and accelerating production by injecting water and reactivating suspended wells. Next, the location of the injection well is determined based on the OPU map, oil saturation and permeability. Then determine the optimal injection rate based on the daily water production rate. In this research, 3 development scenarios were carried out to see the increase in production from each scenario and the scenario with the highest increase in production after water injection was selected.

The OOIP of a field also needs to be calculated to determine whether a field is still suitable for development or not by looking at the advantages and disadvantages of each field development option. OOIP of a field can be calculated using the formula:

$$OOIP = 7758 \frac{A\, X\, h\, x\, \emptyset\, x\, (1-sw)}{Boi} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

Where:

A = Area, acres
h =Net pay thickness, ft
Φ =Porosity, fraction
Swi =Initial water saturation, fraction
Boy =Initial oil formation volume factor, bbl/STB

The Recovery Factor calculation at this stage aims to determine the maximum reserve value obtained after water injection. The RF value calculation is carried out using the following equation:

$$RF = 54{,}898 \times \left[\frac{\emptyset\,(1\text{-}Swi)}{Boi}\right]^{A} \left(\frac{1000.k.\mu_{wi}}{\mu_{oi}}\right)^{B} (S_{wi})^{C} \left(\frac{Pb}{Pa}\right)^{D} \ldots\ldots\ldots\ldots\ldots\ldots\ldots..(2)$$

Where:

A = 0.422;
B = 0.77;
C = 1.903; And
D = - 0.2159

Determining Estimated ultimate recovery aims to determine the maximum reserves that can be taken at the primary recovery stage. Estimated Ultimate recovery can be determined with the following equation:

$$EUR = RF\ OOIP \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots..(3)$$

Remaining reserves are remaining reserves that have not been produced. Remaining reserves in the RK field can be calculated as follows:

$$RR = EUR - NP \ldots\ldots\ldots\ldots..\ldots\ldots\ldots(4)$$

3. RESULTS AND DISCUSSION

3.1 Calculation of Reserve and Recovery Factor Structure A Field "RK"

Calculation of reserves and recovery factors at this stage aims to determine the value of reserves in structure A of the "RK" Field and to determine whether the field is suitable for development and accelerating production by injecting water and reactivating suspended wells.

Table 1. Calculation data for RF and RR values

A	98.12	Ft2
h	76.124	ft
Poro	0.21	%
Swi	0.25	%
Boy	1.1002	bbl/STB
Np	3.55	MMSTB

OOIP $= \frac{7758 \times A \times h \times \phi \times (1-Swi)}{Boi}$

$= \frac{7758 \times 98.12 \times 76.124 \times 0.21 \times (1-0.25)}{1.1002}$

=8.2954 MMSTB

RF = NP/OOIP

=3.55/8.2954

= 42.833%

EUR = OOIP x (1- RF)

=8.2954 x (1- 0.42833)

= 4.7422 MMSTB

RR = EUR – NP

= 4.7422 –3.55318977780942

= 1.1890 MMSTB

3.2 Determination of Suspended Wells to be Converted to Injection Wells and Production Wells

3.2.1 Determining Suspended Wells to Be Reactivated to Become Production Wells

Before carrying out waterflooding injection activities in the "RK" field, a reactivation scenario for wells that have been suspended will be carried out first. This aims to maximize production due to waterflooding injection. Determining which wells will be reactivated is based on understanding common injection patterns. You can see in Figure 2 the location of the well that has been suspended. Based on an understanding of the waterflooding injection pattern, conclusions can be drawn for the candidate reactivation wells, namely wells AB_03, AB_04, and AB_06. Based on the determination of the reactivation well, an injection pattern, namely a 5-spot pattern, can be obtained if the AB_05 well is converted into an injection well.

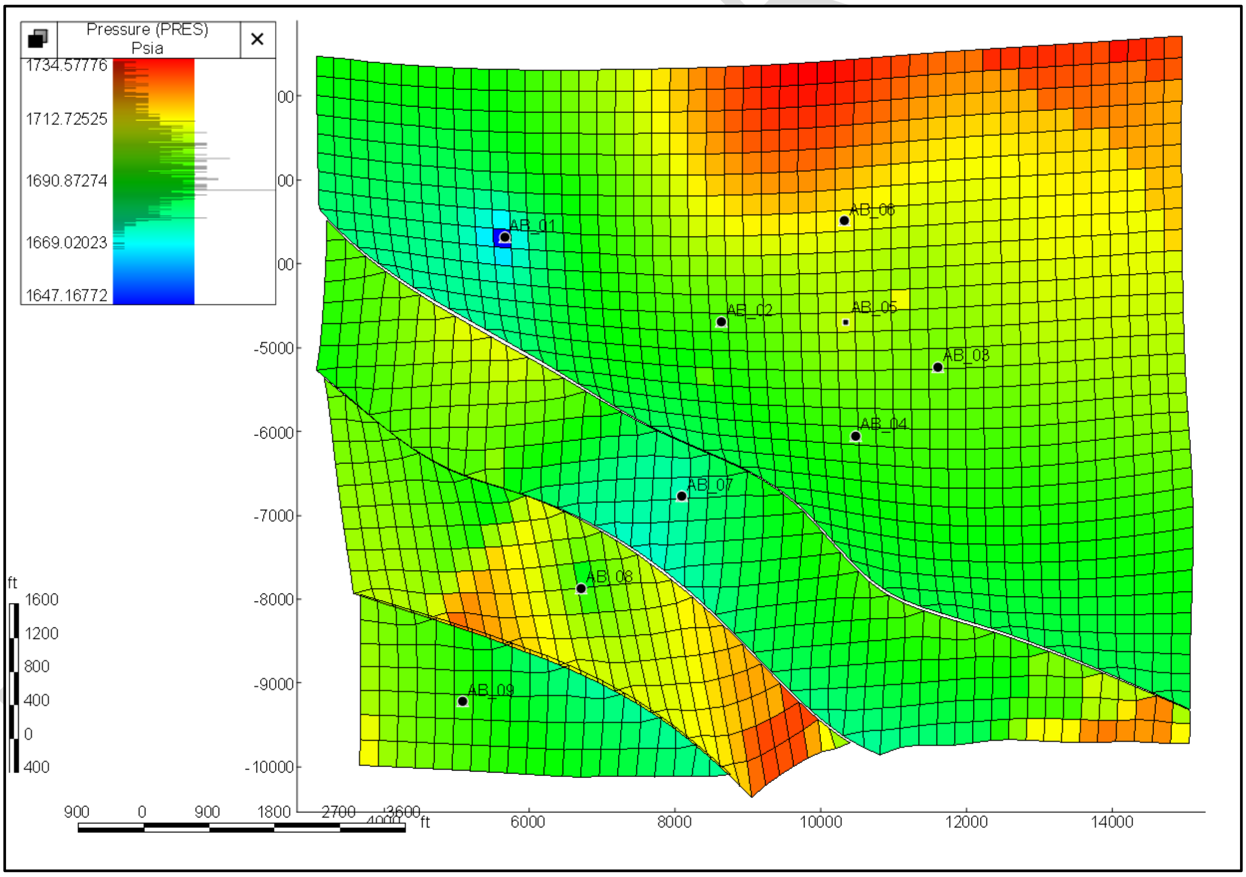


Fig.2 "RK" Field Reactivation Well Candidate

Based on the location of the wells in the “RK” field, wells AB_02, AB_03, AB_04, AB_05, and AB_06 can form a 5-spot injection pattern. In this research itself, the pattern used is inverted 5-spot, where there are 4 production wells and 1 injection well.

3.2.2 Determination of Injection Well Candidates

Based on the previous determination of reactivation well candidates, the suspended AB_05 well will be converted into an injection well. This aims to meet the previously determined injection pattern criteria, namely the inverted 5-spot pattern. Apart from that, an analysis will be carried out on the OPU grid value and the permeability around the AB_05 well. This aims to determine whether there is still oil that will be forced out by waterflooding and also the effectiveness of the waterflooding injection carried out. The following is the distribution of OPU, Permeability and Oil Saturation values for each layer with existing wells, shown in the image below.

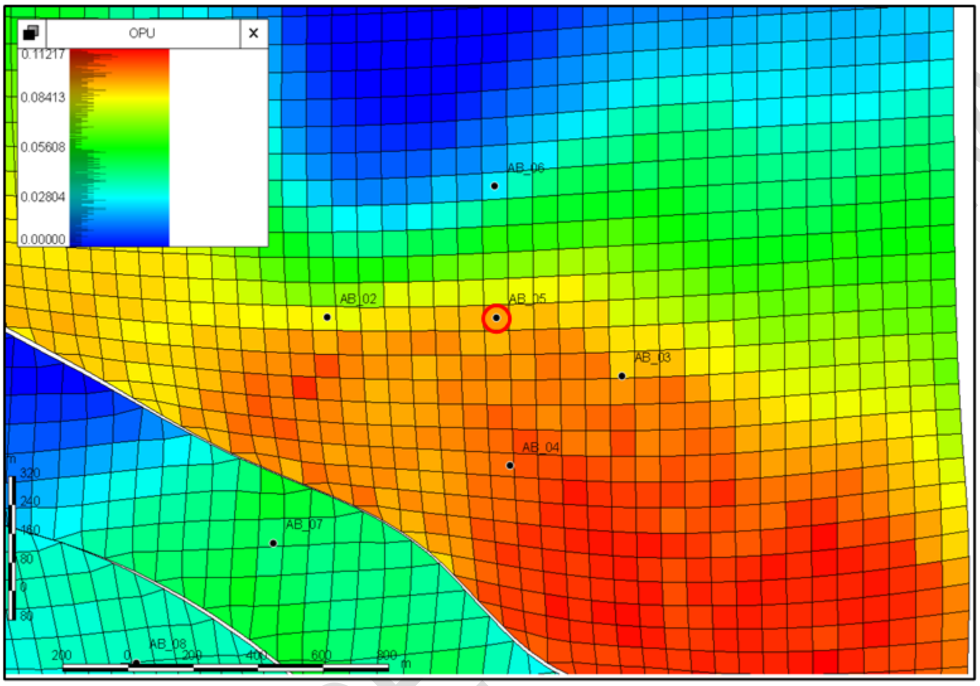


Figure 3. OPU Distribution Map Around Well AB_05

Based on the picture above, it can be seen that the area around well AB_05 has a fairly high OPU value. This can maximize oil production produced by waterflooding injection pressure.

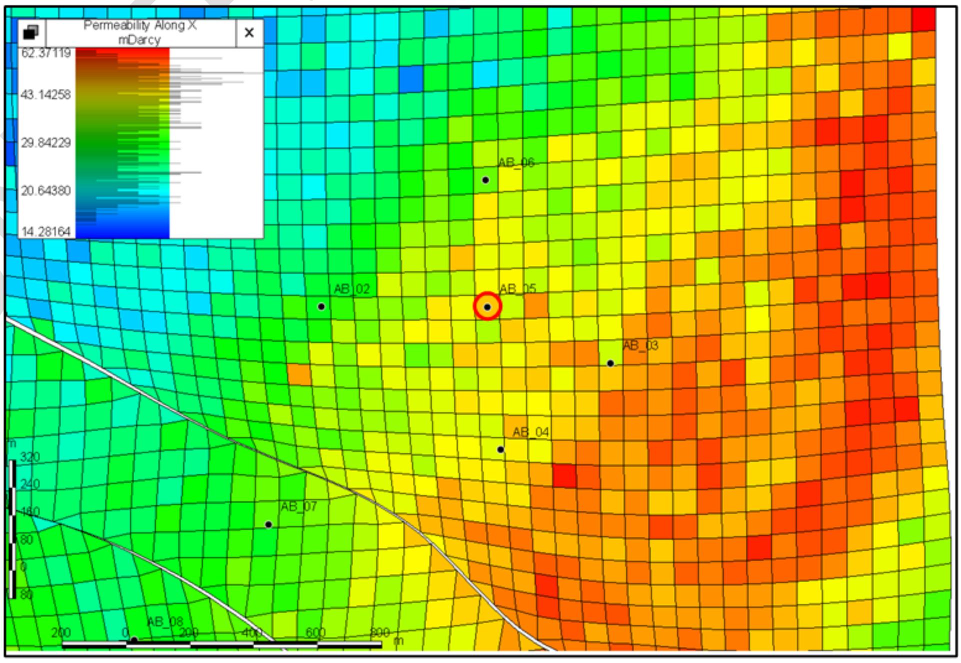


Figure 4. Permeability Distribution Map Around Well AB_05

Based on the image above, it can be seen that the area around well AB_05 has quite high permeability. This can maximize oil production produced by waterflooding injection pressure.

3.3 Determination of Optimum Water Injection Rate Based on Daily Water Production Rate

When carrying out a field development scenario for the "RK" field, it is necessary to pay attention to several factors that have been determined previously. From these several determinations, it is hoped that the field development scenario in the "RK" field will obtain optimal results. The tabulation of "RK" field development scenarios is shown in Table 2.

Table 2.Development Scenario Field "RK"

Scenarios	Information
Basecase	Simulation Until the End of Prediction
Scenario I	Basecase + Reactivation of 3 Suspended Wells
Scenario II	Scenario I + Injection Rate Optimization
Scenario III	Scenario II + Injection Pressure Optimization

1. Scenario 1

The first scenario for developing the "RK" field is carrying out reactivation of 3 previously determined suspended wells, namely wells AB_03, AB_04, and AB_06. The purpose of carrying out this scenario before the waterflooding injection is carried out is to determine the comparison of the effects of the waterflood injection that will be carried out on the scenario if. no water flooding injection was carried out. Well reactivation time is carried out periodically every month. The assumed preparation time for well reactivation is one month.

Table 3. Information and Time for Reactivation of The Field "RK"

Well	I	J	Reactivation Date
AB_03	35	21	01/02/2024
AB_04	30	17	01/03/2024
AB_06	30	28	01/04/2024

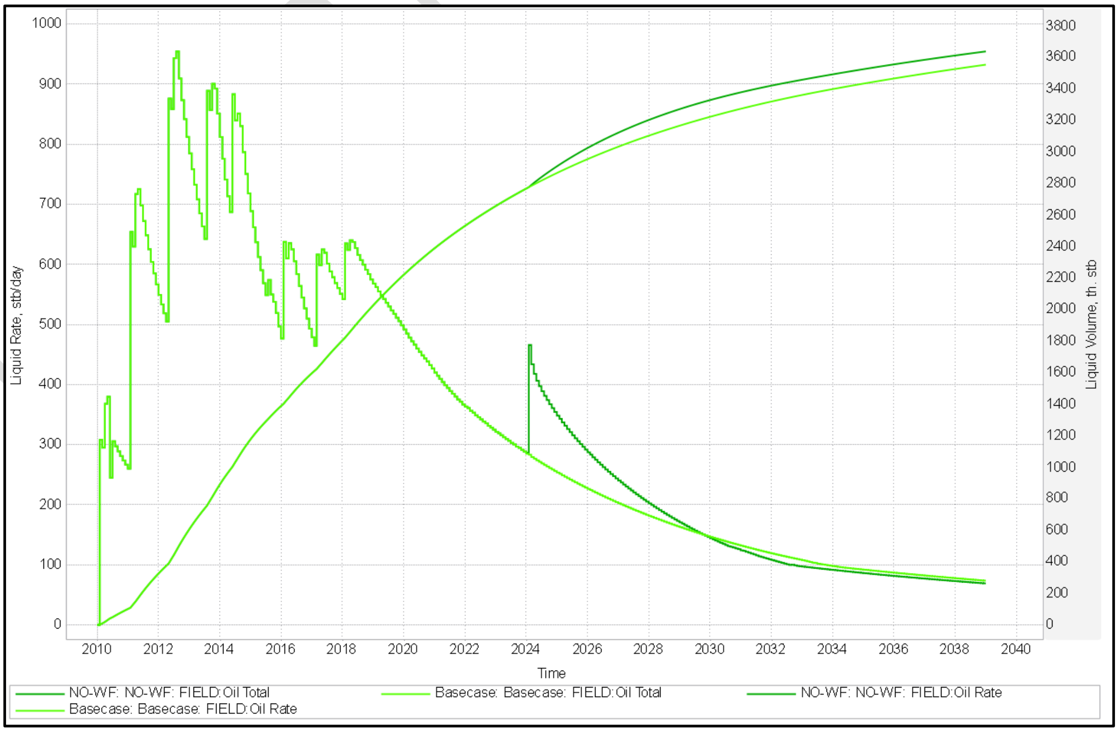


Figure 5. Rate and Total Oil Production in Field "RK" Scenario I

Based on the results of the rate and total production analysis in Figure 5 above, it can be seen that there was an increase in production at the beginning of the prediction until there was a decrease in production until the end of the prediction.

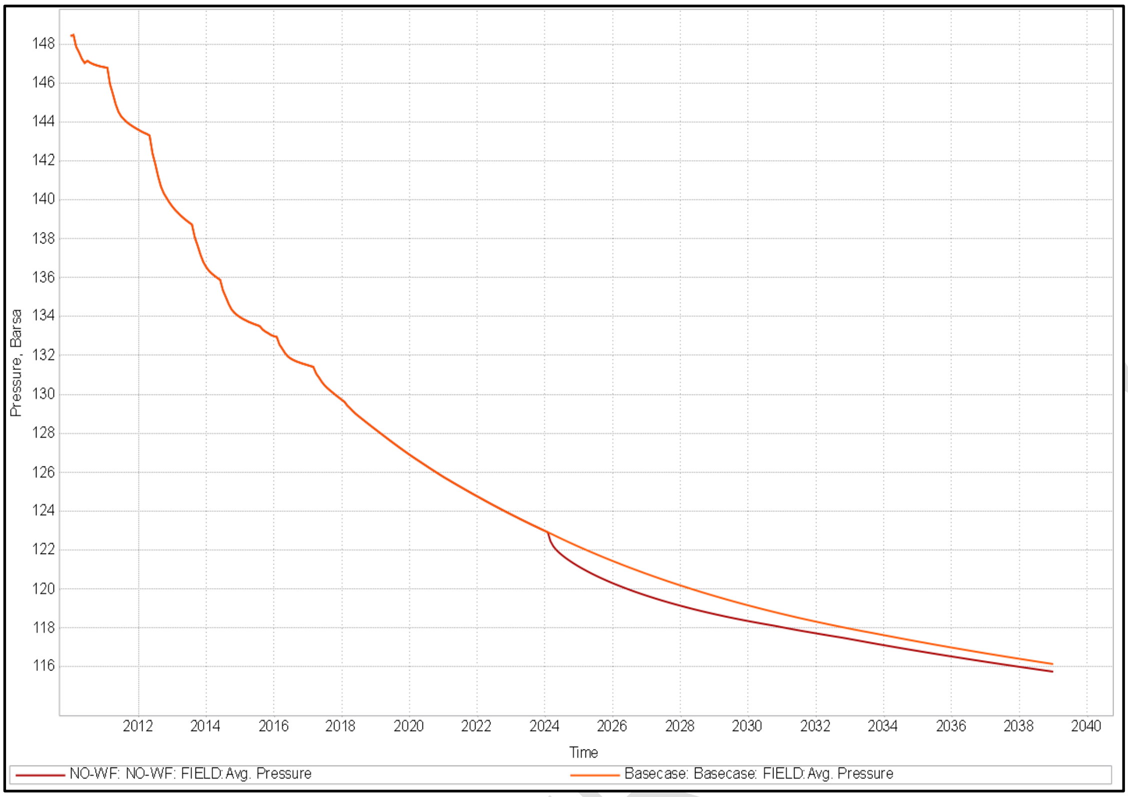


Figure 6. Reservoir Pressure “RK” Field Scenario I

In Figure 6, it can also be seen that the reservoir pressure graph for the "RK" field has decreased compared to when the well was not reactivated. The cumulative oil production obtained from scenario I is 3.637 MMSTB with a recovery factor of 43.847%.

2. Scenario 2

In scenario II, waterflooding injection will be carried out using the previously determined AB_05 conversion well. In scenario II, a water injection rate sensitivity of 141 BWIPD, 300 BWIPD, 450 BWIPD, 600 BWIPD, 750 BWIPD, 900 BWIPD, 1050 BWIPD, and 1200 BWIPD with an injection pressure of 2411 psi will be carried out to see the effect on pressing.

Table 4. Description and Injection Time for Well AB_05 Field “RK”

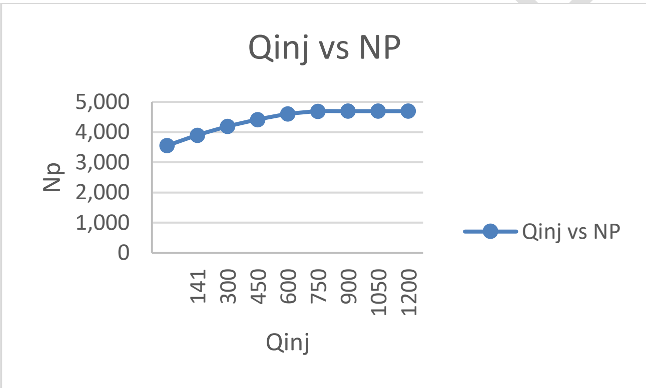
Well	I	J	Perforation		Injection Date
			Top (ft)	Bottom (ft)	
AB_05	30	23	4724	4757	01/05/2024

Based on previously determined information and parameters, a simulation will be carried out according to previously determined conditions, namely 15 year predictions.

Table 5.Result of Scenario II Field "RK"

Scenario	Qinjeksi (BWIPD)	NP (MMSTB)	RF	WC	INCR. RF
Basecase		3,553189778	42,833%	43,70%	9,930%
Scenario II-1	141	3,896484434	46,972%	42,79%	14,069%
Scenario II-2	300	4,183060976	50,426%	49,72%	17,523%
Scenario II-3	450	4,413857719	53,208%	55,91%	20,306%
Scenario II-4	600	4,595889746	55,403%	58,85%	22,500%
Scenario II-5	750	4,687859531	56,511%	60,81%	23,609%
Scenario II-6	900	4,691710938	56,558%	61,09%	23,655%
Scenario II-7	1050	4,691710938	56,558%	61,09%	23,655%
Scenario II-8	1200	4,691710938	56,558%	61,09%	23,655%

Based on Table 5, the simulation results of the entire scenario II, it is concluded that scenario II-5 is the most optimal scenario where the injection rate is 750 BWIPD because it obtains a recovery factor of 56.511% with a watercut of 60.81%. After carrying out the simulation, the next step is to analyze the voidage replacement ratio (VRR) value to determine the effectiveness of water flooding based on the total injection volume and total liquid volume produced.



Figures. 7 Injection Rate Versus Productive Cumulative

Based on the graph analysis of injection rate vs Np, it is known that there is an increase in Np at an injection rate of 900 BWIPD, but the increase in Np is not optimal. So the most optimum injection rate is 750 BWIPD with a cumulative production value of 4.6878 MMSTB.

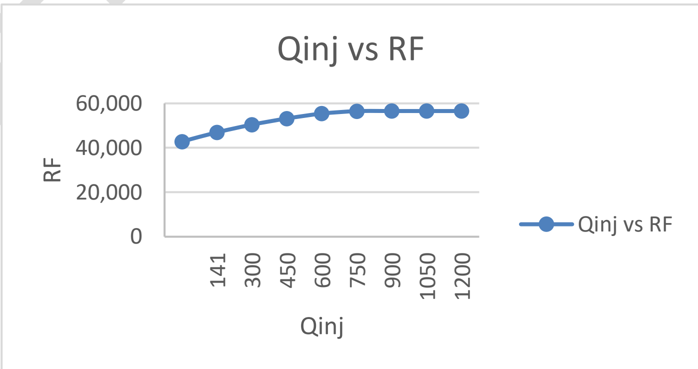


Figure.8 Injection Rate Versus Recovery Factor

Based on the graph analysis of injection rate vs RF, it is known that there is an increase in RF at an injection rate of 900 BWIPD, but the increase in RF is not optimal. So the most optimum injection rate is 750 BWIPD with an RF value of 56.111%.

$$\text{VRR} = \frac{\text{Volume Injected}}{\text{Volume Produced after Injection}}$$

$$= \frac{3663250.568}{3742645.191}$$

$$= 0.979$$

Based on the VRR value obtained, it can be said that the water flooding carried out is quite efficient considering that the VRR almost reaches 1, which indicates that the injection carried out is stable.

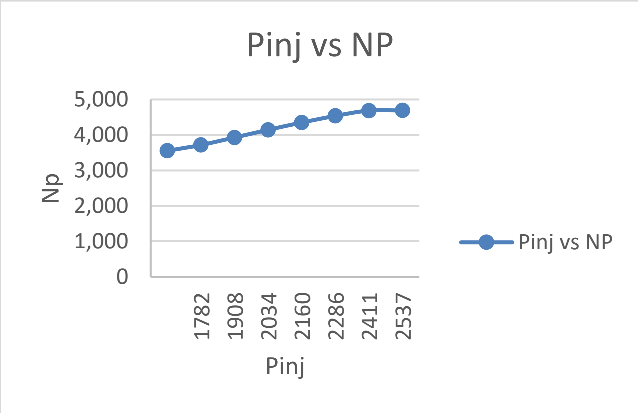
3. Scenario 3

In scenario III, injection pressure sensitivity will be carried out in the injection well with a previously determined injection rate of 750 BWIPD. The purpose of this injection pressure optimization is to determine the optimum injection pressure for waterflooding injection.

Table 6. Result of Scenario III Field "RK"

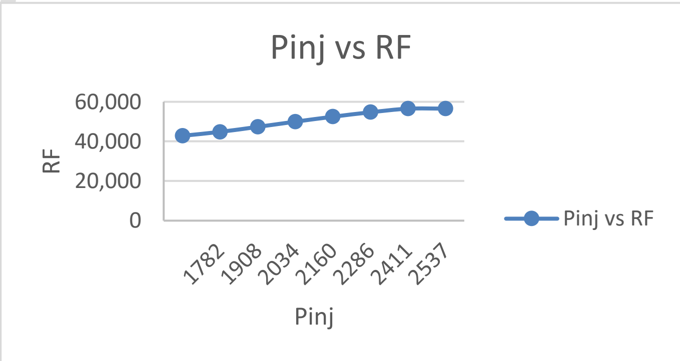
Skenario	Pinj (Psi)	NP (MMSTB)	RF	WC	INCR. RF
Basecase		3,553189778	42,833%	43,70%	9,930%
Scenario III-1	1782	3,717574571	44,815%	42,62%	11,912%
Scenario III-2	1908	3,925828882	47,325%	44,03%	14,423%
Scenario III-3	2034	4,144248247	49,958%	49,91%	17,056%
Scenario III-4	2160	4,350284995	52,442%	55,54%	19,539%
Scenario III-5	2286	4,537381846	54,698%	58,42%	21,795%
Scenario III-6	2411	4,687859531	56,511%	60,81%	23,609%
Scenario III-7	2537	4,691710938	56,558%	61,44%	23,655%

Based on Table 6, the simulation results of the entire scenario III, it is concluded that scenario III-6 is the most optimal scenario where the injection pressure is 2411 psi.



Figures. 9 Injection Pressure Versus Productive Cumulative

Based on the graph analysis of injection pressure vs Np, it is known that there was an increase in Np at an injection pressure of 2537 Psi, but the increase in Np was not optimal. So the most optimal injection pressure is 2411 Psi.



Figures. 10 Injection Pressure Versus Recovery Factor

Based on the graph analysis of injection pressure vs RF, it is known that there is an increase in RF at an injection pressure of 2537 Psi, but the increase in RF is not optimal. So the most optimum injection pressure is 2411 Psi.

4. CONCLUSIONS

Based on the research that has been carried out, the following conclusions can be drawn:

1. Structure A Field "RK" has a total remaining reserve of 1.1890 MMSTB with a recovery factor value of 42.833%So the "RK" Field still has great potential for development planning.

3. Based on the results of the analysis of simulated field development scenarios, the most optimal scenario was obtained, namely waterflooding with an injection rate of 750 BWIPD with an injection pressure of 2411 psi, which resulted in total oil production of 4,687 MMSTB with a recovery factor of 56,511%.
4. IWater injection in this field is important because it has a lot of water availability, namely 60.9%, so it is economical to inject.

Disclaimer (Artificial intelligence)
Option 1:
Author(s) hereby declare that NO generative AI technologies such as Large Language Models (ChatGPT, COPILOT,

2. The development of the "RK" field is waterflooding injection by utilizing 4 suspended wells by reactivating 3 wells and converting 1 well into an injection well to increase production. The suspended wells that were reactivated to become production wells were wells AB-03, AB 04, and AB-06. And the AB-05 well is an injection well.

etc) and text-to-image generators have been used during writing or editing of manuscripts.

Option 2:
Author(s) hereby declare that generative AI technologies such as Large Language Models, etc have been used during writing or editing of manuscripts. This explanation will include the name, version, model, and source of the generative AI technology and as well as all input prompts provided to the generative AI technology
Details of the AI usage are given below:
1.
2.
3.

REFERENCES

[1] Fatima MI, & Liu YT (2022), Reservoir Simulation Model Using Water Injection and Water Alternating Gas Injection Techniques in KEYI Oilfield, Moglud Basin, Sudan. International Journal of Sciences: Basic and Applied Research (IJSBAR), 6(1).
[2] Feyi aigbogun. (2018). optimize water injection operational parameters for improved oil recovery. SPE Society of Petroleum Engineering – 193428-MS.
[3] Smith, James T. (1997), “Waterflooding”, Petroleum Technology Transfer Council (US), Wyoming, United States of America.
[4] Diah D, S., et al. (2015). Evaluation of the Implementation of Water Injection Using Production Decline Data Using the Decline Curve Method in Field "X". National Scholars Seminar, ISSN: 2460-8696.
[5] Terrado, M., Yudono, S., & Thakur, G. (2007). Waterflooding surveillance and monitoring: Putting principles into practice. SPE Reservoir Evaluation and Engineering, 10(5), 552-562.
[6] Juliansyah, O., & Alida, R., 2016. "Analysis of Water Injection Performance Using the PT Voidage Replacement Ratio Method. Pertamina EP Asset 1, FIeld Ramba.”. Patra Academic Engineering Journal.
[7] Alvarez, JM and Sawatzky, RP, 2013, “Waterflooding: Same Old, Same Old?”, SPE.
[8] 165406-MS, the SPE Heavy Oil ConferenceCanada, Calgary, Alberta, Canada
[9] Usman, 2015, "Investigation of the Risk of Introducing Produced Water to Freshwater Injection System", Scientific Contributions Oil & Gas, Vol. 38(1), 25-37.
[10] Sillak Hasiany, 2020. The Application of Well Injection Technology in the Produced Water Management Oil and Gas Industry. Journal of Multidisciplinary Academic, 4(2).
[11] Jibin Wang et al.(2017), Massive Re-Fracturing modeling study of optimized water injection strategy for Zou-6 tail oil in Daqing field, Northeast China. . SPE Society of Petroleum Engineering-186056-MS.
[12] Schumacher, MM1978. Enhanced Oil Recovery: Secondary and Tertiary Methods. New Jersey: Noyes Data Corp.
[13] Ezza E, G., et al. (2013). Waterflood Management. Course and Workshop 2013. Jakarta: Trisakti University.
[14] Ahmed, Tarek H., 2000, “Reservoir Engineering Handbook”, Gulf Publishing Company, Houston, Texas.
[15] Imran, R., 2019 "Reservoir Management Basic Principles and Practical Uses", Yogyakarta.