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Polymer Injection as a Development Strategy to Improve Oil Recovery in the BKH Layer of YDP Field

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Abstract: There are still have a potential oil to be produced, the reduced reservoir pressure due to continuous oil production at a high rate, and the high water cut value are the background for the polymer injection process in the BKH Layer of YDP Oil Field. Due to a high water cut value, the study then conducted using a polymer injection method. Screening criteria for polymers injection was conducted to see the suitability of the reservoir, and then carry out an advanced scenarios using polymers of various concentrations to be compared, and see a cumulative incremental oil production and recovery factor. The stages including collecting and preparing data, processing and analyzing RCAL, SCAL, and PVT data, input data to simulation model with actual conditions. The reservoir simulation performed including initialization, history matching and PI matching, carry out polymer injection scenarios with certain polymer concentrations, then predict and analyze the scenario results, and finally determine the best polymer injection scenario to be applied in the BKH layer of YDP field. Based on the results of the study, it is shows that the scenario IV-A is the best scenario for polymer injection compared to other scenarios. Scenario IV-A performed by injection of polymer with a peripheral pattern with an additional 5 (five) injection wells, injection pressure of 1200 psi, injection rate of 300 bbl/d, polymer concentration of 0.6 lb/bbl, incremental recovery factor of 2.01%, and oil production cumulative obtained until December 2035 is 5087 MSTB.

Keywords: Polymer Injection, Oil Production, Water Cut, Polymer Concentration

1. Introduction

Polymer injection is basically an enhanced water injection, where the polymers addition to the injection water is intended to improve the properties of the displacing fluid. Polymer injection can increase oil recovery which is quite high compared to conventional water injection. If the reservoir oil is more difficult to move than the water, hence the water tends to penetrate the oil, this will be causing water produced rapidly and lowering oil recovery factor [1-3].

The polymer dissolved in the injection water and will thicken the water, reduce the mobility of water and prevent water from penetrating the oil, this will increase the vertical and horizontal sweep efficiencies. Sweep efficiency is also affected by the mobility ratio between the displacing fluid and the forced fluid [1-4]. Polymer injection can improve the mobility ratio between water and oil, namely by increasing the viscosity of water so that the mobility ratio between water-oil can decrease and ultimately increase the sweep efficiency [2, 5]. Two factors that required to be considered in polymer injection are reservoir heterogeneity [2, 3] and the ratio of reservoir fluid mobility [2, 6].

The mechanism of polymer has been known for a long time is a decrease in the mobility ratio of water to oil. The polymer makes the mobility ratio low due to the increase in the effective viscosity of water by displacing fluid [2, 3]. Some of the guidelines used to select a reservoir to be injected with polymers include: mobility ratio between 5 to 40 and/or there is considerable variation in the permeability distribution, it has high oil permeability and viscosity, reservoir temperature less than 100 - 200 °F, the moving oil saturation must be high enough, and reservoir with water propulsion whose initial production is small or non-existent [2, 3, 7, 8].

Sheng, J. J et al [5] and Wicaksono, H et al [9] state there are two main types of polymers, namely synthetic polymers such as hydrolyzed polyacrylamide (HPAM) and biopolymers such as xantham gum. Polymers that are rarely used are natural polymers and their derivatives, such as guar gum, sodium carboxymethyl cellulose, and hydroxyl ethyl cellulose (HEC).

This paper discusses about the feasibility application of polymer injection as one of the solutions to handle the high water cut problem occurred in the YDP field, especially in BKH layer as one of the main oil produce reservoirs. Besides, the other purpose is to optimize and improve oil recovery due to polymer injection applied. The development plan of this polymer injection was carried out using reservoir simulation, with the sensitivity variables are pattern, injection pressure, injection rate, and polymer concentration to find the best scenario that will be applied in the field.

2. Basic Concepts and Methodology

2.1. Screening Criteria of Polymer Injection

Screening criteria required for all EOR methods, that aims to obtain oil in a field so that it is more optimum, not only obtaining oil from a field but also saving costs so that there is no waste in the purchase of materials that will be used for the implementation of EOR [10, 11]. The screening criteria of polymers shown in Table 1.

Table 1. *Screening criteria for polymer injection [11].*

	Units	Recommended
Oil		
Gravity	API	>15
Viscosity	cP	Water <μ< 150
Composition		Not critical
Reservoir		
Oil Saturation	% PV	>50
Formation		Sandstones preferred, but can be used in Carbonate, not fractured
Net Thickness	ft	Not critical
Permeability	mD	>10
Depth	ft	Not critical
Temperature	°F	<200
Salinity	g/l	<20
Water Hardness	g/l	<5

Viscosity is the most important parameter in polymer solutions [2, 3]. The factors that affect the viscosity of the polymer are as follows: effect of salinity [4, 5], concentration [6, 8], effect of shear rate, and effect of temperature [2, 3, 6]. Beside, there are some judging from the reservoir condition, such as depth, layer heterogeneity level, physical properties of reservoir rocks, drive mechanism, and fluid mobility comparison [2-4, 11, 12].

2.2. Reservoir Simulation Stages

In carrying out a reservoir simulation plan, there are several stages that need to be carried out, in general they are as follows [13-15]:

1. Data preparation, data collection, data processing and data validation for entry data.
2. Creation and determination of the model to be used in the simulation based on data of geology, geophysics, reservoir, petrophysical, and production.
3. Initialization and history matching of the reservoir model to be used.
4. Planning the simulation scenario.
5. Conducted of reservoir simulation to obtain production performance data, as well as visualization of saturation distribution oil.
6. Analysis and evaluation of simulation results.

2.2.1. Data Preparation and Processing

(i). Processing Routine Core Analysis

In conducting reservoir simulation, rock region is needed to group between reservoirs with similar properties. This rock region determination serves to speed up the history matching process and produce accurate prediction results. Rock region division can be done in 2 (two) ways based on the initial water saturation value (Swi), and using permeability data [16].

(ii). Processing Special Core Analysis

Fractional Flow

Fractional flow is a function of saturation along the relative permeability variation. The flow fraction equation is a quantitative model to calculate the flow fraction of the total fluid flowing in the linear pressing of water [15, 17]. The fractional flow equation for linear immiscible displacement in a porous medium is shown in field units can be written as follows:

$$\mathrm{Fw} = \frac{1+\frac{1.1270\mathrm{x}10^{-3}\mathrm{ko}}{\mathrm{qt}}\left(\frac{\partial \mathrm{Pc}}{\partial \mathrm{L}}-0.4330\mathrm{x}\Delta\gamma\sin\alpha\right)}{1+\frac{\mu\mathrm{w\ kro}}{\mu\mathrm{o\ krw}}} \tag{1}$$

for the horizontal reservoir ($\sin\alpha = 0$), hence the Equation (1) can be re-written as follows:

$$\mathrm{Fw} = \frac{1}{1+\frac{\mu\mathrm{w\ kro}}{\mu\mathrm{o\ krw}}} \tag{2}$$

where:

qt = total flow rate, bbl/d

kro = relative permeability to oil, fraction

krw = relative permeability to water, fraction

A = cross-sectional area for flow, ft^2

μo = oil viscosity, cP

μw = viscosity of water, cP

Pc/∂L = differential pressure, psi/ft

γ = specific gravity of the fluid, fraction

α = angle of inclination, degrees

Processing Relative Permeability

Rock permeability is a value that indicates the ability of a porous rock to pass fluids. Permeability is divided into three based on the number of flowing fluid phases, namely absolute, effective, and relative permeability. Absolute permeability is the permeability if the fluid flowing through a porous medium is only one phase. Effective permeability is the permeability of rock where the fluid flowing is more than one phase, oil-water, gas-water, or gas-oil. Meanwhile, relative permeability is a comparison between the two permeability [15, 17].

2.2.2. Data Input

Data input is the process of entering data into simulation software, but it should be noted that the data to be input has previously been validated or has gone through the processing process and is in accordance with the data format required by the simulator [15, 17].

2.2.3. Initialization

Initialization is a review of the data entered into the simulator. Initialization aims to see the stability of the model, aligning the in-place model with the in-place volumetric or geostatic calculation results [13-15].

As for the criteria for the initialization process for a field with quite a lot of wells, generally the difference between the in-place simulation results and the allowable volumetric is <5%. As for the field with few wells, the difference between the in-place simulation results and the allowable volumetric is <10%. The initialization process is carried out by adjusting the parameters of rock physical properties that affect the initial hydrocarbon reserves, such as:

1. Net to gross on the model used.
2. Capillary pressure curve (Pc).
3. Oil formation volume factor (Bo) curve.
4. Depth of Water Oil Contact (WOC) and Gas Oil Contact (GOC).

2.2.4. History Matching

History matching is the process of modifying the parameters used in model making, in order to create harmony between the model and real conditions, which is based on the measured parameter data over a certain period of time [13-15].

The purpose of the alignment process is to validate the reservoir simulation model with the actual reservoir conditions. The alignment will be show by a production versus time graph. A reservoir model said to be aligned if it meets the following history matching criteria [15]:

1. The cumulative difference between the model's liquid production and the actual <1%
2. Cumulative difference between model and actual oil production < 5%
3. Cumulative difference between model water production and actual < 10%
4. Cumulative difference between model gas production and actual < 20%

If the reservoir model is not in accordance with the actual conditions, it is possible to change several parameters according to Rukmana, D et al [15], including:

1. Change the volume of the aquifer which will affect the type of mechanism, pressure, and production rate.
2. Reservoir transmissibility
3. Capillary Pressure (Pc)s
4. Oil and water relative permeability curve
5. Rock region
6. Compressibility
7. Pressure Volume Temperature (PVT)
   1) Well Data: Productivity Index (PI), Borehole Pressure (BHP), Skin factor
   2) Fluid contact: OWC, GOC, Gas Water Contact (GWC).

2.2.5. PI Matching

In the oil field, after doing history matching and before making predictions, the next step is to do PI matching. PI matching which aims to equalize the trend of oil and water production in the last 3 to 6 months before making predictions later. The provisions for PI matching according to Rukmana, D et al [15] are as follows:

1. Performed on wells that have been selected as key-wells.
2. Production data taken from the last 3 to 6 months.
3. Parameters that are matched are oil rate and water rate.
4. PI Matching is carried out on both key-well and field wells.
5. Parameters changed during PI Matching are well data: PI, Injectivity, Skin, table vertical flow performance (for flowing wells), and others.

2.2.6. Prediction Stage

The prediction stage is forecasting reservoir behavior for production scenarios [13-15]. This stage can be done when the reservoir model is aligned with the actual reservoir condition so that the forecast can be applied to the actual reservoir in the field and the prediction results given can be accurate according to the actual conditions. Forecasting that can be done through reservoir simulation models include:

1. Relationship of reservoir pressure with cumulative fluid production.
2. The relationship between reservoir pressure and fluid production rate.
3. The relationship between production rate and time.
4. The amount of ultimate recovery for various scenarios and production methods.
5. Optimum number and distribution of absorption points.
6. Reservoir behavior towards various production methods.
7. The most optimum and economic development scenario.

2.3. Methodology

The method in preparing this paper is by conducting a simulation model. The variables considering includes injection-producer pattern [18-20], injection pressure [15, 21], injection rate [15, 22, 23], and concentration of polymer [6, 8, 24]. The procedure used in this study is as follows:

1. Collect and identify geological data, reservoir data, and production data as well as operational data.
2. Perform data processing obtained.

3. Creating a reservoir model that can represent actual conditions, which includes the initialization process, PI matching, and history matching.
4. Perform screening criteria to see the suitability of the injection fluid with the reservoir in the BKH layer of YDP field.
5. Planning production predictions with various scenarios.
6. Analyze the simulation results and determine the best scenario.

3. Results and Discussion

The field development planning in this research begins with the screening criteria then continuing the preparation and processing of data for reservoir simulation study. Screening criteria was conducted in BKH layer of YDP field to review the EOR criteria that want to apply. The screening criteria carried out in the study based on reservoir characteristics as shown in Table 1 [11], refer to reservoir properties in BKH layer of YDP field as shown in Table 3. Based on the screening criteria, it is shows that in BKH layer of YDP field the polymer injection is suitable and recommended to be applied in the field. The result of the screening criteria then used as a reference to conductg the polymer injection simulation study.

Reservoir data processing carried out in this study is Routine Core Analysis (RCAL) data processing, Special Core Analysis (SCAL) data processing, and PVT data processing. Routine Core Analysis The results will be obtained in the form of estimates of porosity, permeability, and rock density. In addition, the results of Routine Core Analysis can also be used as a reference for the distribution of rock regions in reservoir simulations. Determination of rock region in BKH layer of YDP field is grouped based on its permeability value. The result of rock region in BKH Layer of YDP field is show in Figure 1.

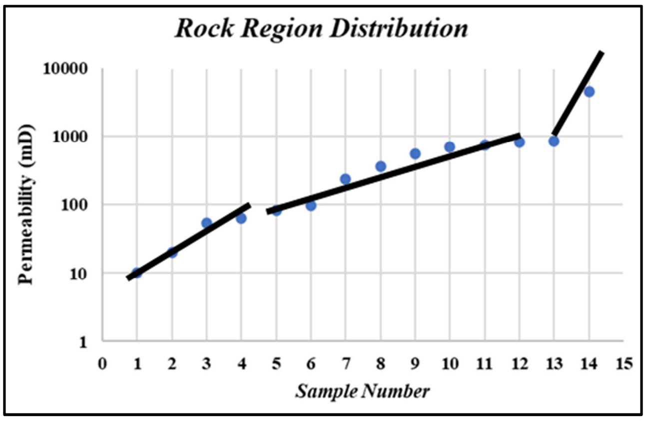

Figure 1. *Rock region in BKH Layer of YDP field.*

Based on the RCAL data processing, the distribution of rock regions in the BKH layer of YDP field as shown in Figure 1, divided into 3 (three) regions. Region 1 has a permeability range of less than 90 mD, region 2 has a permeability range of 90-900 mD, while region 3 has a permeability range of more than 900 mD. For SCAL data processing in the YDP field is not available, an approach is carried out with SCAL data from the nearest field, namely the PM field which is located approximately 27 km from the YDP field. Before being used as reservoir properties, it is necessary to shift or validate SCAL data from the PM field so that it can represent the characteristics of the YDP field. After processing, the end-point value of SCAL data will be obtained after shifting at BKH layer of YDP field is shown in Table 2, while Figure 2 is the result of shifting by doing fractional flow, respectively.

Table 2. *End point data after shifting.*

Region	k mD	ϕ fraction	Swi fraction	Sor fraction	Krw @Sor	Kro @Sor
1	37	0.14	0.33	0.22	0.62	1
2	420	0.21	0.28	0.20	0.63	1
3	1246	0.22	0.27	0.23	0.68	1

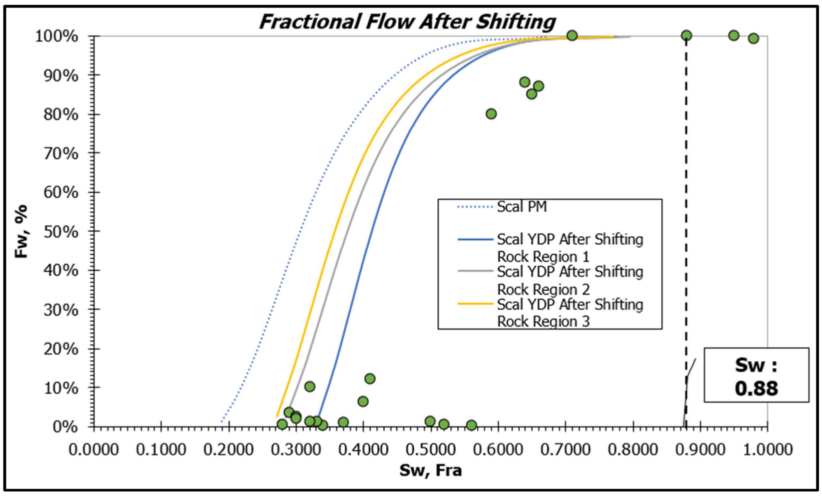

Figure 2. *Fractional flow result after shifting.*

Furthermore, Pressure Volume Temperature (PVT) data processing and analysis were carried out after Routine Core Analysis (RCAL) and Special Core Analysis (SCAL) data has been analyzed. PVT data processing can only be done using the black oil model with a systematic correlation processed by the simulation. The physical properties of the reservoir fluid are obtained from PVT surface sampling from one of the wells as shown in Table 3.

Table 3. *Reservoir properties in BKH layer of YDP Field.*

Parameters	Units	Values
Oil Gravity	API	33.6
Oil Viscosity	cP	3.22
Formation		Sandstones
Permeability	mD	888.4
Temperature	°F	153.6

After the data has been prepared and processed properly, proceed with reservoir simulation. The initial stage in the reservoir simulation after data input is carried out is the alignment of the reservoir model with the actual conditions in the data. The alignment stage begins with the initialization stage, namely the alignment stage of OOIP simulation results with OOIP results from volumetric calculations. In the initialization of OOIP, modifications were made to the capillary pressure parameters of each rock region. The results of the initialization process for BKH layer of YDP field showed that the difference between the simulated OOIP and the actual OOIP was 0.01%, with a simulated OOIP value of 17.93 MSTB. In addition to alignment against OOIP values, Alignment is also carried out at the initial pressure by changing the parameters in the initial conditions such as the lowest known oil depth. Based on available historical data, the initial pressure in BKH layer of YDP field is 597.5 psi at a datum depth of 1350 ft. Pressure alignment will then be performed at the datum depth. The initial pressure in the simulation is 597.34 psi, with a percent error of 0.03%.

After the initial conditions have been aligned with the existing data, it is followed by the history matching stage which is the alignment of the flow rate and cumulative production of the simulation results with the flow rate and cumulative production in actual conditions. History matching in BKH layer of YDP field uses the liquid rate constraint as a control in the simulator. Alignment is done by changing the field parameters in the form of the relative permeability of oil and water so that a small difference will be obtained. The results of history matching are shows in Figure 3 through Figure 5. Based on the history matching results, it can be said that the simulation model was match with the actual conditions.

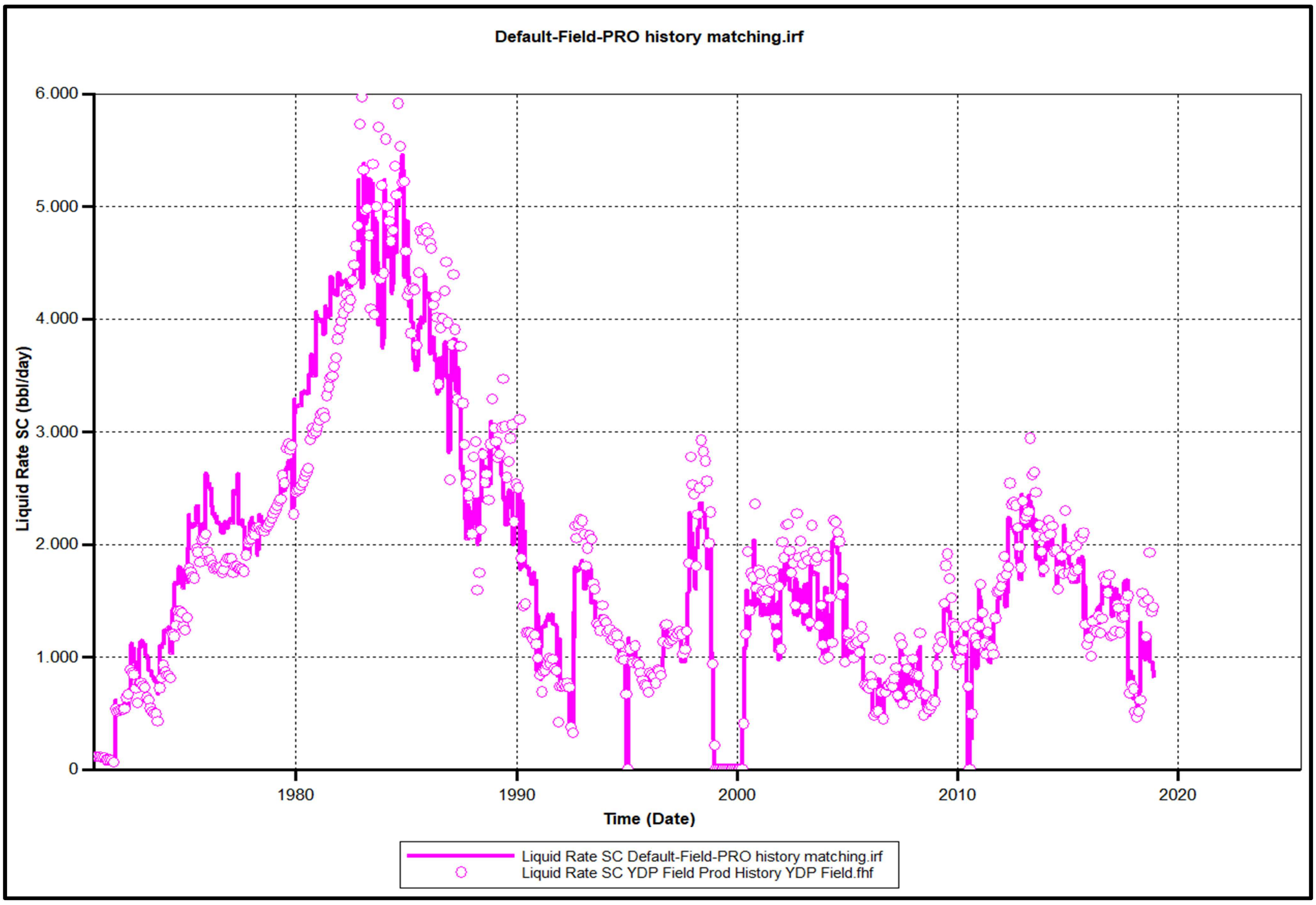

Figure 3. *History matching result of liquid rate.*

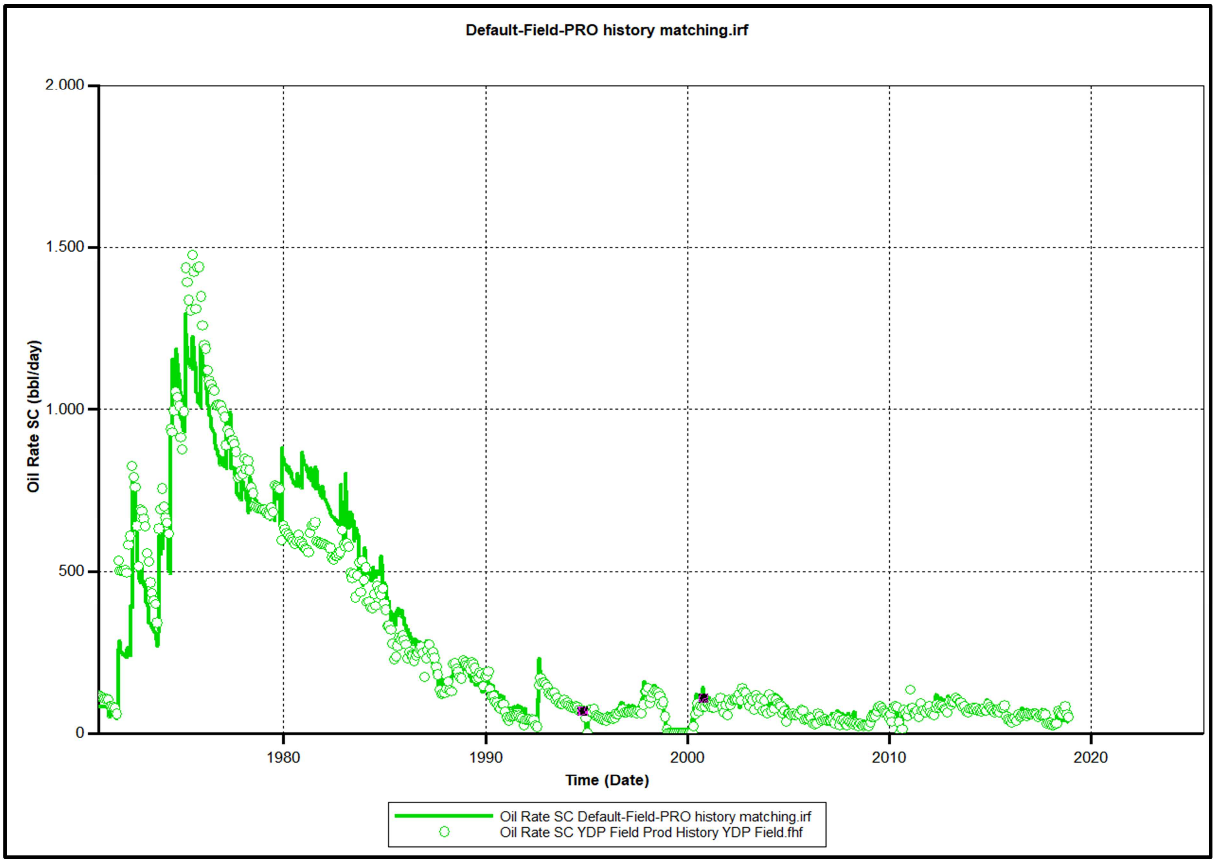

Figure 4. *History matching result of oil rate.*

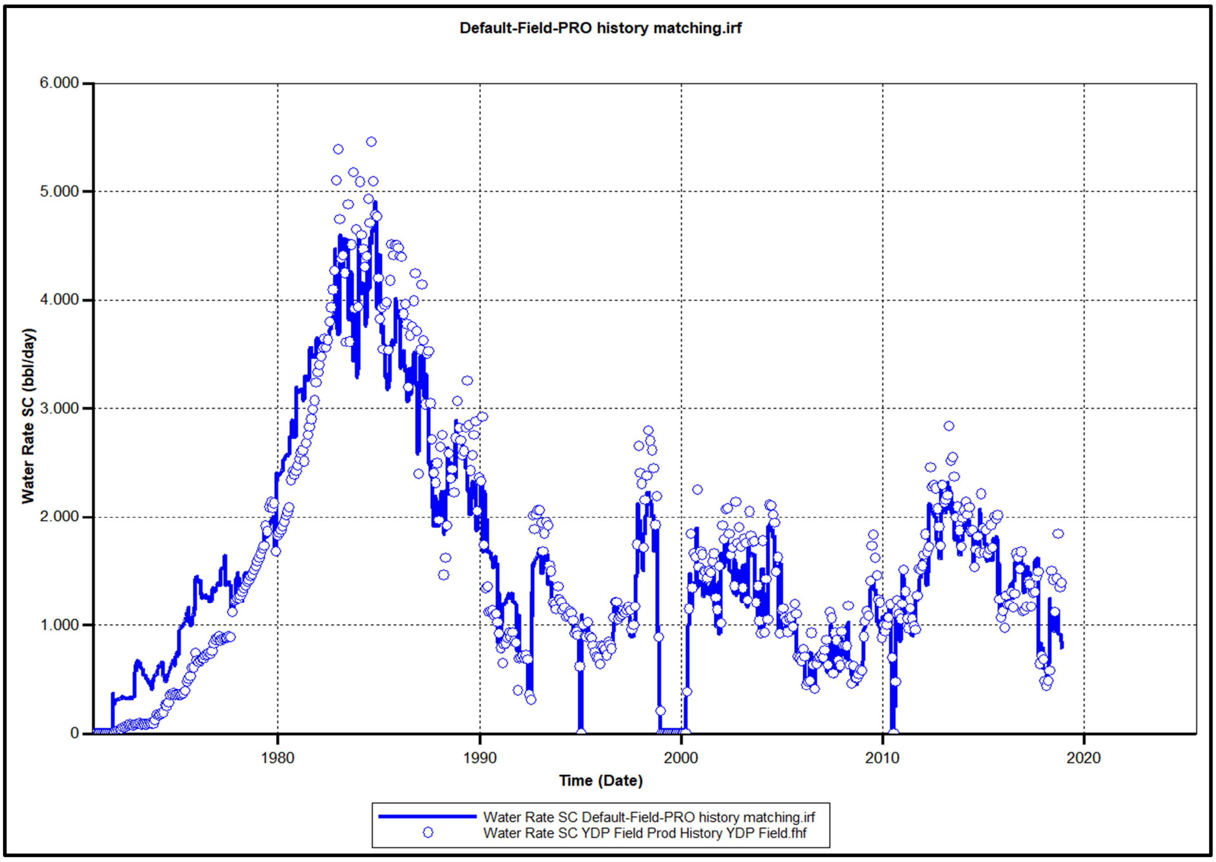

Figure 5. *History matching result of water rate.*

After the two stages of alignment have been carried out, the alignment of the productivity index or PI matching is also carried out. PI matching is done so that the prediction of oil production is not too optimistic or pessimistic. In this study, PI matching is carried out by aligning the rate of oil production for the last 6 months, namely July 2018 - December 2018, at key wells, assuming the drawdown pressure in the simulation with the same data. Based on the key well provisions, namely the wells are still producing until the end of history matching and the cumulative production of wells is more than 75% active wells, then the key wells in BKH layer of YDP field are wells YDP-01, YDP-08, YDP-10, YDP -15, and YDP-24. The results of productivity index (PI) matching on the key wells are shows in Figure 6.

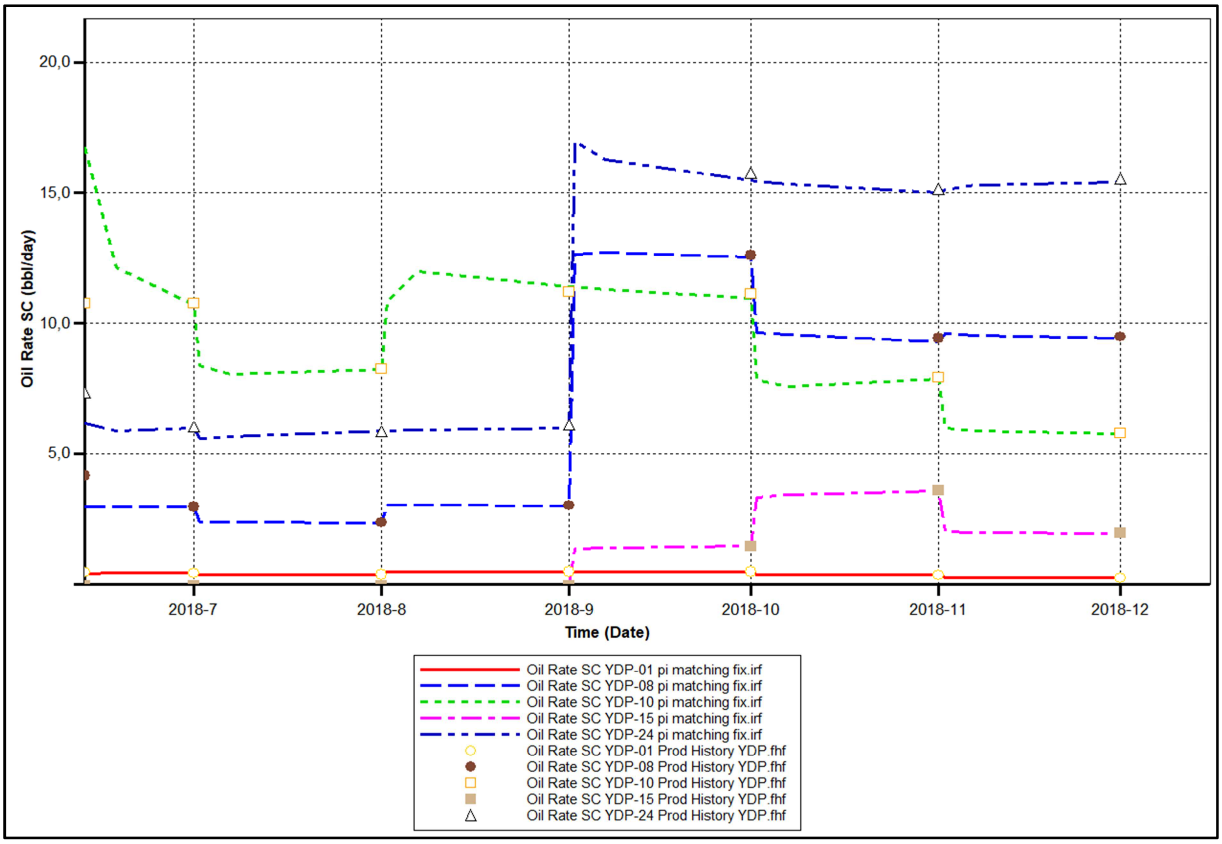

Figure 6. *Oil rate production curve of key well result after PI matching.*

Prediction or forecast is the final stage of reservoir simulation. This stage aims to predict the behavior of the reservoir in the future based on the expected conditions. Prediction is done by applying several field development scenarios. Before the development of an advanced polymer injection scenario has been carried out, rate, cumulative, and pressure predictions have been made under conditions without any development efforts or commonly referred to as basecase conditions. Prediction on the basecase is done to compare the results of the basecase predictions with the predicted results from the scenario development, so that it is known how much the cumulative increase in oil production and recovery factor will be.

To find out the most optimal polymer injection scenario applied to BKH layer of YDP field, sensitivity was carried out on injection pattern, injection pressure, injection rate and polymer concentration. The development scenario is divided into 4 (four) scenarios, where in scenario I sensitivity is applied to the injection pattern, in scenario II sensitivity to injection pressure is carried out, scenario III is sensitivity to injection rate, and scenario IV is sensitivity to polymer concentration.

In scenario I, a polymer injection scenario with a concentration of 0.3 lb/bbl was developed with different injection patterns. An injection pressure of 578 psi is used and an injection rate 193.21 bbl/d/well. The injection pattern to be applied to the BKH layer of YDP field polymer injection scenario, including the pattern inverted four spot, four spot, direct line drive pattern, five spot and peripherals. Forecasting oil rate results of scenario I is shows in Figure 7, while the summary is shows in Table 4. Based on the results of the development of scenario I in Table 4, the higher increasing in oil production in the development of scenario I is scenario I-E.

The results of the best scenario from scenario I, namely scenario 1-E, then proceed to scenario II, developing a polymer injection scenario with a peripheral pattern of adding 5 (five) injection wells as the best pattern. Sensitivity to injection pressure was performed with a constant injection rate of 193.29 bbl/d/well. Forecasting oil rate results of scenario II is shows in Figure 8, while the summary is shows in Table 4.

Based on the results of the development of scenario II in Table 4, it is shows that the largest increase in oil production is scenario II-E. The optimum injection pressure obtained at BKH layer of YDP field is 1200 psi.

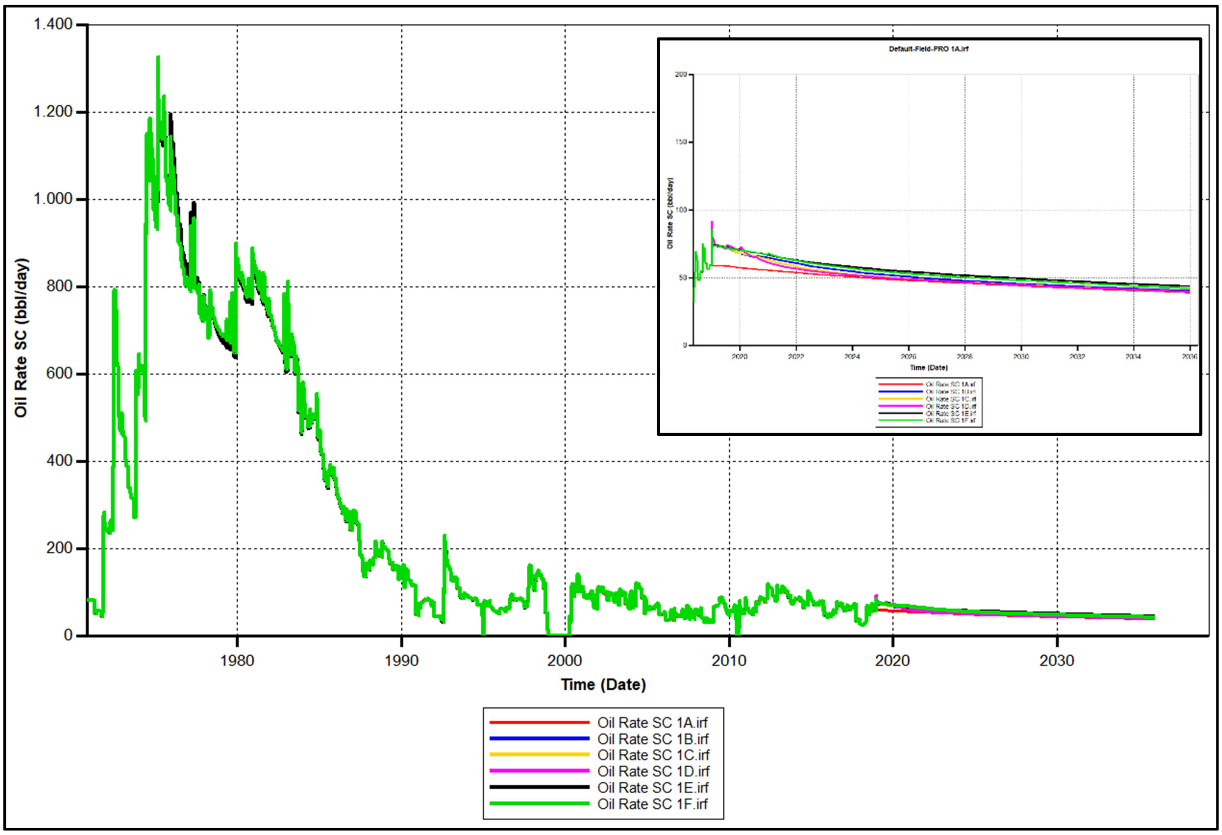

Figure 7. *Oil rate forecasting production results of scenario I.*

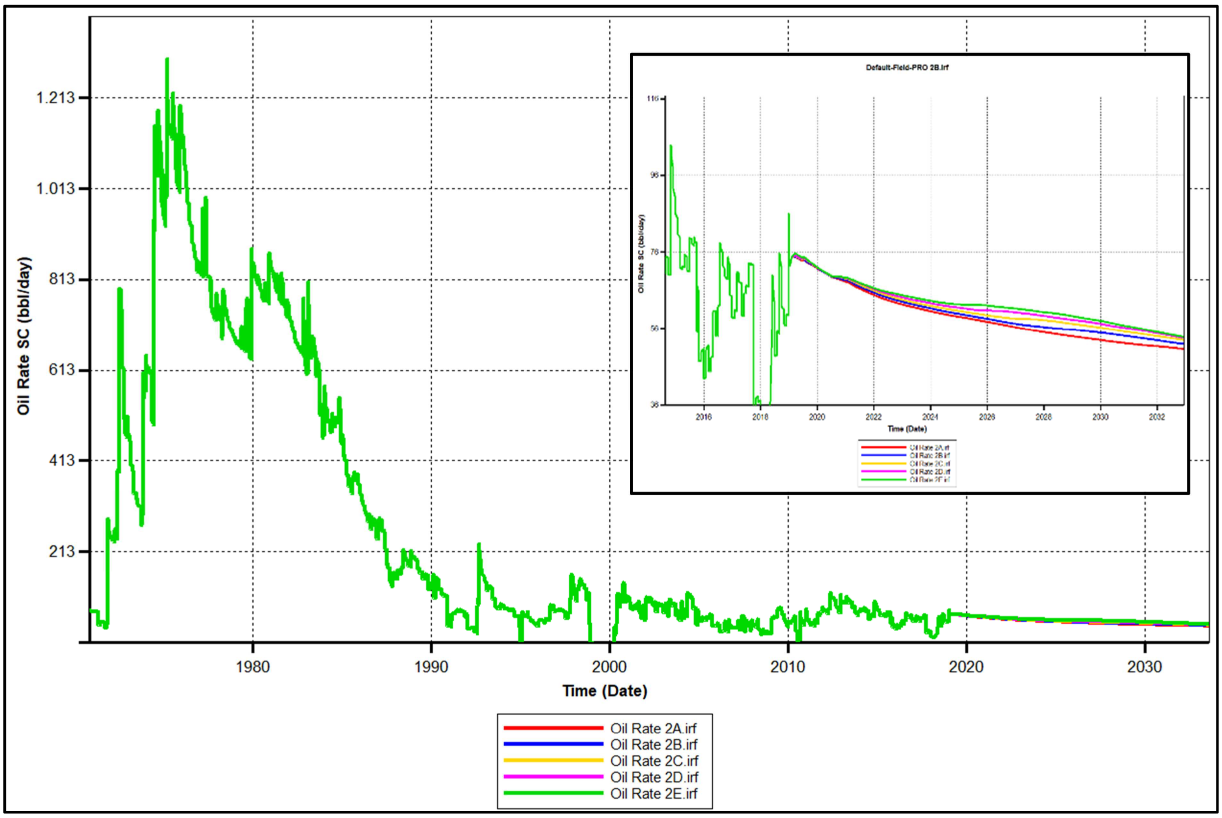

Figure 8. *Oil rate forecasting production results of scenario II.*

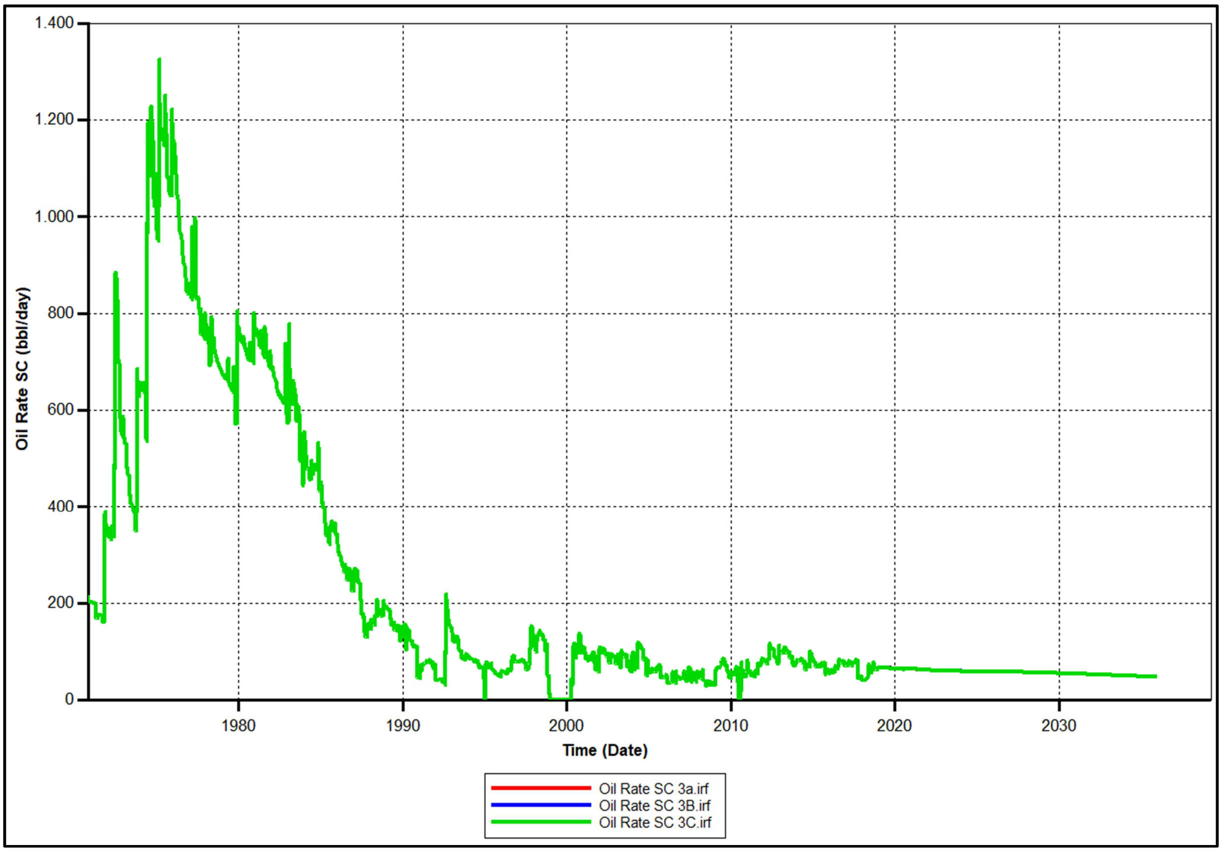

Figure 9. *Oil rate forecasting production results of scenario III.*

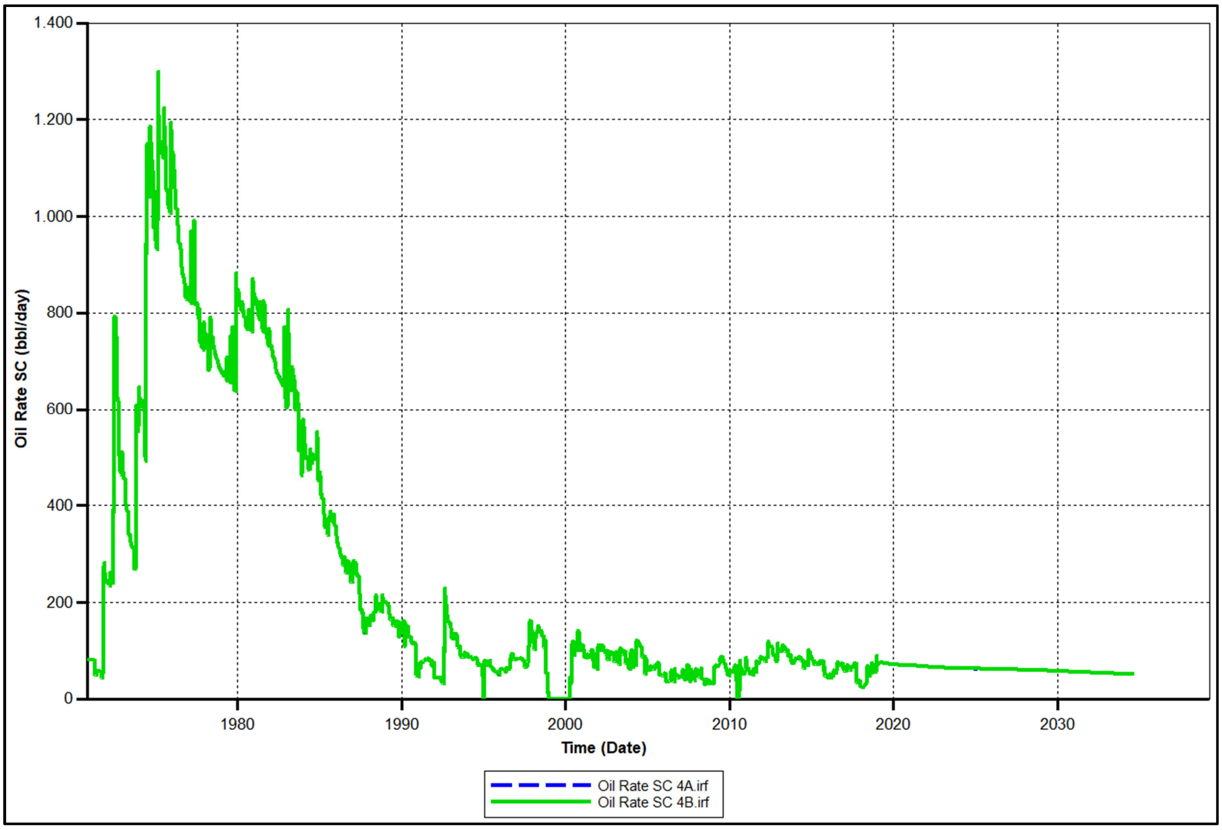

Figure 10. *Oil rate forecasting production results of scenario IV.*

Scenario III, a polymer injection scenario was developed which was applied to scenario II-E, namely field development with a peripheral pattern of adding 5 (five) injection wells with an injection pressure of 1200 psi. In this scenario III, sensitivity to the injection rate was carried out in order to obtain the most optimum injection rate. Forecasting oil rate results of scenario III is shows in Figure 9, while the summary is shows in Table 4. Based on the results of scenario III development in Table 4, it is shows that the higher increasing in oil production is scenario III-A. The optimum injection rate obtained at BKH layer of YDP field is 300 bbl/day at each new injection well.

Scenario IV, a polymer injection scenario was developed which was applied to scenario IV-A, namely field development with a peripheral pattern of adding 5 (five) injection wells with an injection pressure of 1200 psi and an injection rate of 300 bbl/day. In scenario IV, sensitivity to polymer concentration was carried out in order to obtain the most optimum polymer concentration. Forecasting oil rate results of scenario IV is shows in Figure 10, while the summary is shows in Table 4. Based on the results summary of the development of scenario IV in Table 4, it is shows that the increasing in oil production in the development scenario IV-A and scenario IV-B is the same. Therefore, the optimum polymer concentration obtained in BKH layer of YDP field is 0.6 lb/bbl.

Based on the analysis of the planning for the further development of polymer injection scenarios that have been simulated by sensitivity to the injection pattern, injection pressure, injection rate and polymer concentration, the results of each scenario are as shown in Table 4. It can be concluded that the most optimum polymer injection scenario in BKH layer of YDP field development planning is scenario IV-A. This scenario was developed with a peripheral pattern, with an additional 5 (five) injection wells, an injection pressure of 1200 psi, an injection rate of 300 bbl/d and a polymer concentration of 0.6 lb/bbl. The scenario IV-A resulted in cumulative oil production of 5087 MSTB, and incremental recovery factor of 2.01%.

Table 4. *Results summary of scenario I - IV.*

Scenario		Sensitivity		Recovery Factor, %	ΔRF %	NP MSTB
Basecase			-	27.82	0.00	4987
	A		Inverted Four Spot	27.84	0.02	4988
	B		Four Spot	28.34	0.52	5013
I	C	Pattern	Direct line Drive	28.16	0.34	5004
	D		Five Spot	28.10	0.28	5001
	E		Pheriperal	28.98	1.17	5045
	F		Pheriperal	28.62	0.80	5027
	A		800	29.10	1.28	5051
	B		900	29.23	1.41	5057
II	C	Pressure	1000	29.34	1.53	5067
	D		1100	29.43	1.61	5072
	E		1200	29.53	1.71	5086
	A		300	29.81	1.99	5086
III	B	Rate	400	29.80	1.99	5086
	C		500	29.78	1.96	5085
IV	A	Concen	0.6	29.83	2.01	5087
	B	tration	0.9	29.83	2.01	5087

4. Conclusions

Based on the results of the analysis and discussion that has been thoroughly executed, the conclusions can withdraw as follows:

1. The optimum injection pressure to be applied in BKH Layer of YDP field is 1200 psi (Scenario II-E), has obtained a total oil production cumulative of 5086 MSTB, recovery factor of 29.53%, and incremental recovery factor of 1.71%.
2. The optimum injection rate to be applied in BKH layer of YDP field is 300 bbl/d (Scenario III-A), has obtained a total oil production cumulative of 5086 MSTB, recovery factor of 29.81%, and incremental recovery factor of 1.99%. The higher of injection rate will be causing early breakthrough of injection fluid.
3. The optimum polymer concentration to be applied in BKH layer of YDP field is 0.6 lb/bbl (Scenario IV-A), has obtained a total oil production cumulative of 5087 MSTB, recovery factor of 29.83%, and incremental recovery factor of 2.01%.
4. Based on the results analysis of injection scenario, it is concluded that the most optimum scenario to be applied for plan development in BKH layer of YDP field was scenario IV-A. The development strategy conducted by peripheral pattern (5 injection wells) with injection pressure of 1200 psi, injection rate of 300 bbl/d, and polymer concentration of 0.6 lb/bbl.
5. The polymer injection was suitable and recommended to be applied to improve oil recovery in BKH layer of YDP field.
6. Besides the injections pressure and rate, polymer concentration, it recommended to be considered also the reservoir heterogeneity (rock types) and injection-production pattern as a significance parameter for future research and when applied in the field.

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