Chemical Injection Development Strategies to Increase Oil Recovery Factors Using Reservoir Simulation (Case Study in JHD Field)

by Joko Pamungkas

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Joko Pamungkas, Harry Budiharjo Sulistyarso and L. Devid Julyanop Purwanto

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Joko Pamungkas[a)], Harry Budiharjo Sulistyarso[b)], L. Devid Julyanop Purwanto

Department of Petroleum Engineering, Faculty of Mineral Technology, Universitas Pembangunan Nasional "Veteran" Yogyakarta, Jl. Pajajaran (Lingkar Utara) Condongcatur, Yogyakarta 55283, Indonesia

[a)]Corresponding author: joko.pamungkas@upnyk.ac.id, [b)]harry_hb@upnyk.ac.id

Abstract. Recently, most oil fields have entered the tertiary stage, which is called Enhanced Oil Recovery. It is applying technology by injecting a particular substance into the reservoir through injection wells, then produced through production wells with specific patterns. One method that is being developed and is also used in field development is chemical injection. There are three types of chemicals used, Alkaline, Surfactants, and Polymers. This research will present a study of strategies to use chemical injection in the JHD field. Four scenarios will be simulated using the CMG STARS 2012 to get the maximum oil recovery factor. The first scenario is the base case, using 12 production wells and six water injection wells. The second scenario is injecting polymers. The third scenario is injecting surfactants, and the fourth scenario is injecting surfactants-polymers. Prediction of the recovery factor obtained until 2031 is for the first scenario is 25.8%, the second scenario is 28.85%, the third scenario is 31.05%, and the fourth scenario is 34.69%. From the four scenarios, it is found that Surfactant-Polymer injection has maximum results compared to other scenarios.

Keywords EOR, Polymer, Surfactant

INTRODUCTION

Chemical injection is one of the types of Enhanced Oil Recovery (EOR) by adding chemicals to the water flooding to increase oil recovery to increase sweeping efficiency and/or reduce residual oil saturation in reservoirs. There are three types, including chemical injection, namely Polymer Injection, Surfactant Injection, and Alkaline Injection. In its development, many injection processes use a combination of the three chemicals, including polymer-surfactant (micellar polymer) and alkaline-surfactant-polymer (ASP), to improve the properties of each injection fluid.

Surfactant solution is used because the solution itself is a micro-emulsion injected into the reservoir, initially contacting the surface of oil bubbles through a thin film of water, a barrier between reservoir rocks and oil. Surfactants begin their role as surface-active agents to reduce the surface tension of oil-water. Unlike polymer injection, polymer injection is enhanced water injection. The addition of polymers to injection water is intended to improve the nature of the pressing fluid. Polymers dissolved in injection water will thicken water, reduce water mobility, and prevent water from breaking through oil. While Micellar-Polymer Injection is one chemical injection that uses surfactants and polymers as its pressing fluid, or it can be said that the combination of surfactant injection and polymer injection aims to reduce the surface tension between the oil phase and the water phase.

This research will present a study of field development strategies using a chemical injection in the JHD field. There are three types of chemical injections consisting of Polymer Injection, Surfactant Injection, and Surfactant-Polymer Injection (Micellar-Polymer) to be simulated using the STARS simulator and then see if there is a cumulative increase in oil production, a recovery factor, and also the age at the time of producing in Layer A-1 of the JHD field.

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METHODOLOGY

The study of reservoir simulation using a chemical injection in the JHD Field is started with preparing data used such as Core Analysis, Fluid properties, well diagram, history of production, and static models of 3D geology to create a dynamic model of the field. Before predicting the model, the model validation is done first through the matching process to equate the model with the actual condition. To see the compatibility of chemical injections with reservoirs in the JHD Field, screening criteria were conducted. After that, predictions by chemical injection in Surfactant Injection, Polymer Injection, and Surfactant-Polymer Injection are carried out with a simulator and carrying out pore volume sensitivity, rate, and pressure injection of the JHD Field to find the best scenario of this layer of development.

CASE STUDY

This research will present a case in Sumatra's oil and gas fields, namely the JHD field. The main reservoir of this field is located in Lower Talang Akar Formation. It is known that the A-1 layer has an OOIP of 30.32 MMSTB. Cumulative reservoir oil production A-1 (until April 2015) reached 5.29 MMSTB and a recovery factor of 9.9%. Layer A-1 began production in September 2005. The number of wells in Layer A-1 up to the end of April 2015 consisted of 12 active wells and six water injection wells. The implementation of the injection in this field began in May 2013.

Data Preparation

Initial Condition

The first data that must be prepared is the initial condition of layer A-1. This includes the initial pressure and temperature, formation volume factor, the solubility of a gas in oil, initial oil in place, reserve, and drive mechanism on the layer, as shown in **TABLE 1**.

TABLE 1. Initial Condition of Layer A-1 on JHD Field

Initial Condition	Layer A-1
P_i, psia	2307
T_i, Of	236
B_{oi}, bbl/STB	1.3
R_{si}, SCF/STB	489.39
P_b, psia	2122
OOIP, MMSTB	30.32
Drive Mechanism	Solution Gas Drive

Rock Region

The rock region determination for the A-1 Layer in the JHD Field is based on the permeability distribution. With this method, three regions can be obtained that can be seen in **FIGURE 1**.

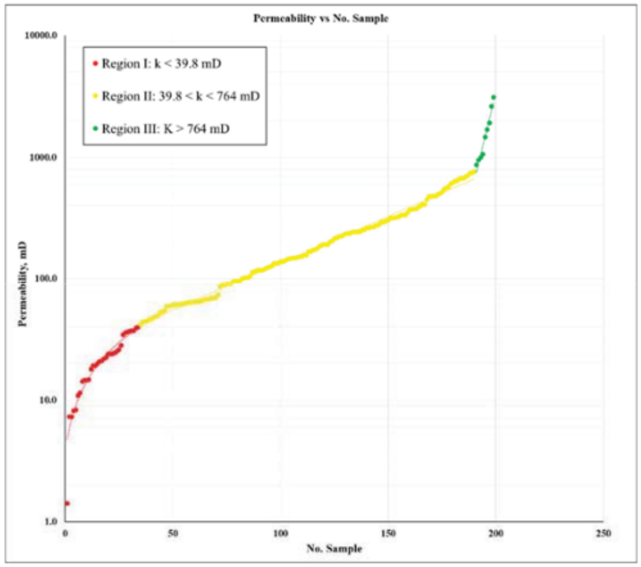
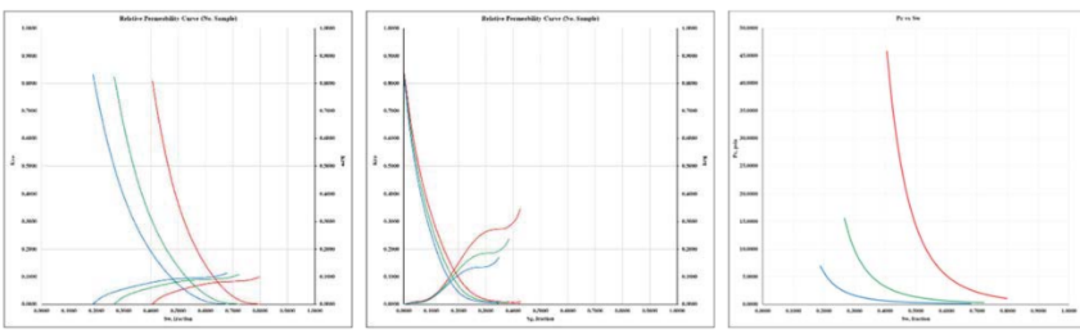


FIGURE 1. Rock Region of Layer A-1 on JHD Field

Relative Permeability and PC Normalization De-Normalization

It produces a curve of oil-water system relative permeability, gas-oil system relative permeability, and capillary pressure in each region, determined in the previous stage and shown in **Figure 2**.



(a) (b) (c)

FIGURE 2. (a) Relative Permeability Curve of Each Region for Water-Oil System (b) Relative Permeability Curve Of Each Region for Gas-Oil System (c) Capillary Pressure Curve of Each Region for Water-Oil System

Model Validation

Initialization

The initialization process is done by doing the OOIP initialization, which aligns the OOIP simulation results with the OOIP volumetric calculation results. At the OOIP initialization, a modification to the capillary pressure value of each rock region was made.

The results of OOIP initialization can be seen that the simulation OOIP is 30.30 MMSTB, while the OOIP from the previous study results is 30.32 MMSTB. OOIP results of the initialization process indicate that the model is correct, with a difference of 0.00% (less than 1%). These results can be seen in **TABLE 2.**

TABLE 2. The Result of the Initialization Process

Parameters	Data	Dynamic Model			
		First		Final	
		Result	Diff	Result	Diff
In-Place, MMSTB	30.32	26.67	12.05%	30.30	0.07%
Pressure, psia	2307	2323.7	0.72%	2323.7	0.72%

History Matching and PI Matching

To equalize the reservoir fluid flow rate (gas, oil, and water) in the history matching process, this is done using the data of the water-oil system relative permeability, and the gas-oil system of each region can be modified with endpoint constraints. The purpose of the alignment process is to validate the reservoir simulation model with the actual reservoir conditions. The results of history matching can be seen in **TABLE 3**.

TABLE 3. The Result of History Matching

Parameters	Data	Dynamic Model			
		Initial HM		Final HM	
		Model	Diff	Model	Diff
Oil, MMSTB	5.29	4.96	6.13%	5.24	0.93%
Water, MSTB	175.18	271.1	54.7%	175.04	0.08%
Gas, MMMSCF	12.14	19.12	57.57%	12.70	-4.60%

Field Development Scenarios

For the forecast, there are four production scenario plans. The scenario developed at Layer A-1 starts with Scenario I (Base case), then continues with Scenario II, Scenario III, and scenario IV. The reservoir performance forecasting is conducted from May 2015 to June 2031. Explanation of the differences in each scenario can be seen in **TABLE 4**.

TABLE 4. Development Scenarios Summary of Layer A-1

Case	Objectives
Scenario 1	Basecase (12 production wells + 6 water injection wells)
Scenario 2	Skenario I + Varying Polymer Injection (0.05 pv, 0.1 pv,0.2 pv, 0.3 pv)
Scenario 3	Skenario I + Varying Surfactant Injection (0.05pv, 0.1 pv, 0.2 pv, 0.3 pv)
Scenario 4	Skenario I + Varying Surfactant-Polymer Injection (0.05pv, 0.1 pv, 0.2 pv, 0.3 pv)

Screening Criteria

It can be seen in **Figure 3.** Layer A-1 The JHD field has three EOR methods that have the highest total values to be applied. Chemical flooding is the one that has the highest value. These screening criteria are used as a reference for conducting this study simulation reservoir of chemical flooding.

Res. Charct. JHD / EOR Method	Oil Properties			Reservoir Characteristics						Total Values
	Grav (°API)	Visc. (cp)	Comp.	Oil Sat. (%PV)	Lith.	Net Thick (ft)	Perm. (mD)	Depth (ft)	Temp. (°F)	
	39-40.9	0.88-0.94	C1-C7: 73%; C2-C7: 42%; C5-C12: 19%	51	Sand	2.5-41	61-741	5302-6749	235-236	
Gas Injection method										
Nitrogen & Flue Gas	>35↗48	<0.4↘0.2↘	High % of C1 to C7	>40↗75	Sand or Carbonat	Thin unless dipping	NC	>6000	NC	19
Hydrocarbon	>23↗41↗	<3↘0.5↘	High % of C2 to C7	>30↗80↗	Sand or Carbonat	Thin unless dipping	NC	>4000	NC	20
CO2	>22↗36↗	<10↘1.5↘	High % of C5 to C12	>20↗55↗	Sand or Carbonat	Wide Range	NC	<2500	NC	21
Immiscible Gases	>12	<600	NC	>35↗70↗	Sand or Carbonat	NC if dipping /or good Vertical Perm.	NC	>1800	NC	21
Chemical Injection Method										
Micellar /Polymer ASP & Alkaline Flood	>20↗35↗	<35↘13↘	Light, Intermediate, Some Organic Acid for alkaline Floods	>35↗53↗	Sand Preferred	NC	>10↗450↗	<9000↘3250	<200↘80	24
Polymer Flooding	>15-<40	<150,>10	NC	>70↗80↗	Sand Preferred	NC	>10↗800↗	<9000	<200↘140	18
Thermal Injection Method										
Combustion	>10↗16	<5000-1200	Some Asphalitic Component	>50↗72↗	High Por.Sand	>10	>50	<11500↘3500	>100↗135	16
Steam	>8-13.5	<20E+4↘4700	NC	>40↗66↗	High Por.Sand	>20	>200	<4500↘1500	NC	17

Value	
3	
2	
1	

Note	
_	Under Value represent the approximate mean or average for current field project
↘	Indicate higer Value of parameter is better
NC	Not Critical

FIGURE 3. Rock Region of Layer A-1 on JHD Field

Injection Time of Layer A-1 on JHD Field

This prediction uses the sensitivity of pore injection volume. There are 0.05; 0.1; 0.2; and 0.3 PV from each scenario, with a sensitivity rate to adjust the 16-year prediction period from May 2015 to June 2031. With injection pressure sensitivity so that injection fluid can enter the rock pore maximally. The injection duration for each pore volume can be seen on **TABLE 5**

TABLE 5. Injection time

Sensitivity PV	0.05	PV	0.1	PV	0.3	PV	0.5	PV
Pore Volume Total	13,969	Mm^3	13,969	Mm^3	13,969	Mm^3	13,969	Mm^3
Injection Volume	698.45 4,393.11 4,393,118.35	Mm^3 Mbbl bbl	1,396.9 8,786.23 8,786,236	Mm^3 mbbl bbl	4,190.7 26,358.71 26,358,710.1	Mm^3 mbbl bbl	6,984.5 43,931.18 43,931,183.5	Mm^3 mbbl bbl
Number of Wells	6	Wells	6	Wells	6	Wells	6	Wells
Rate/Well	3,500	bbl/day	3,500	bbl/day	3,500	bbl/day	3,500	bbl/day
Field Rate	21,000	bbl/day	21,000	bbl/day	21,000	bbl/day	21,000	bbl/day

Injection Well Location

The injection wells' location in the "JHD" Field Layer A-1 for all scenarios is the same. The most optimum pattern in this field using the peripheral pattern. This chemical injection is carried out through injection wells in the aquifer (water) zone. The location of injection wells can be seen in **FIGURE 4**.

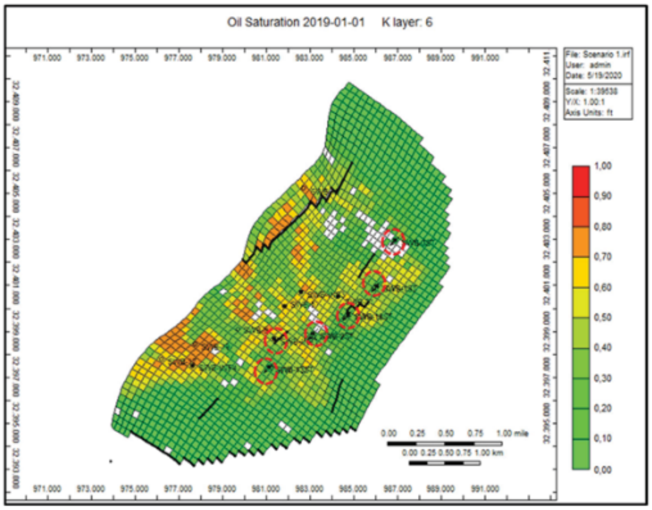


FIGURE 4. Injection Well Location of Layer A-1 on JHD Field

Scenario 1 (12 Production Wells + 6 Water Injection Wells)

The scenario I of the A-1 layer in the JHD Field is to produce production wells from the end of history (April 2015) to June 2031. The scenario I is conducted with twelve production wells and six water flooding wells. The cumulative oil production in Scenario I was 7.83 MMSTB. The Recovery Factor of Scenario I is 25,825%.

Scenario 2 (Scenario I + Varying Polymer Injection)

Scenario 2 is done by varying the injection using a polymer. Injection volume, injection rate, and injection pressure at the injection well are obtained by applying sensitivity. Scenario 2-B is a more maximal scenario than other Scenarios 2, with an injection volume of 0.1PV, an injection rate of 3500 bbl/day, and an injection pressure of 2000 psi. The cumulative oil obtained was 8.7428 MMSTB, with a recovery factor of 28.85%. In this polymer injection scenario, it affects a significant addition to the recovery factor due to the polymer's addition. Polymers dissolved in injection water will thicken water, reduce water mobility, and prevent water from breaking through oil. This will increase the efficiency of sweeping. Reservoir characteristics in this field also prove that polymer injection can increase RF compared to conventional water injection.

Scenario 3 (Scenario I + Varying Surfactant Injection)

Scenario 3 is done by varying the injection using a surfactant. Injection volume, injection rate, and injection pressure at the injection well are obtained by applying sensitivity. Scenario 3-C is a more maximal scenario than other Scenarios 3, with an injection volume of 0.2PV, an injection rate of 3500 bbl/day, and an injection pressure of 2000 psi. The cumulative oil obtained is 9.4095 MMSTB, with a recovery factor of 31.05%. After the surfactant slug is injected in operation in the field, then followed by a polymer solution. This is done to prevent fingering and channeling. The polymer protects the bank so that it does not occur fingering through the oil zone and, on the other hand, protects the bank surfactant from the breakthroughs of urgent water.

Scenario 4 (Scenario I + Varying Surfactant-Polymer Injection)

Scenario 4 is carried out by varying injection using a surfactant-polymer. Injection volume, injection rate, and injection pressure at injection wells are obtained by applying sensitivity. Scenario 4-C is a more maximal scenario compared to other Scenarios 4, with an injection volume of 0.2PV, an injection rate of 3500 bbl/day, and also injection pressure of 2000 psi. Cumulative oil obtained was 10.5124 MMSTB, with a recovery factor of 34.69%. In micellar-polymer injection, we do not need to inject chemicals and receive another driving fluid, which is water, to increase sweeping efficiency.

RESULTS AND DISCUSSION

Based on **FIGURE 5**, it can be seen that Scenario 4 is the most optimum in the JHD Field (12 production wells, six surfactant-polymer injection wells). This is seen from the cumulative production graph for each scenario, where scenario 4 has the highest cumulative production graph. Furthermore, the most massive addition of RF compared to other scenarios, which is 8.85% of the RF Base case Scenario. The results of each scenario can be seen in **TABLE 6**.

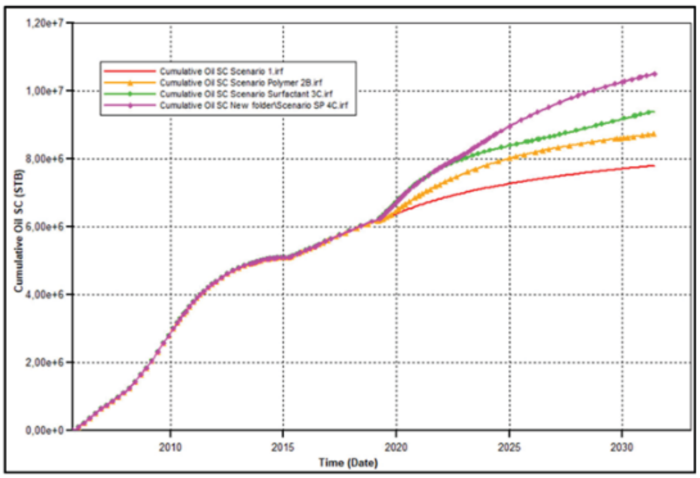


FIGURE 5. Layer A-1 Reservoir Simulation Result

TABLE 6. Summary of Reservoir Simulation Result

Case		Objectives	Forecast		Incremental to BC	
			Np, MMSTB	RF	NP, MMSTB	Δ RF
Scenario 1		Base case (12 Production Wells + 6 Water Injection Wells)	7.831	25.8%		
Scenario 2	A	scenario I + Polymer Injection @0.05 PV	8.6996	28.71%	0.8686	2.87%
	B	scenario I + Polymer Injection @0.1 PV	8.7428	28.85%	0.9118	3.01%
	C	scenario I + Polymer Injection @0.2 PV	8.7102	28.75%	0.8792	2.90%
	D	scenario I + Polymer Injection @0.3 PV	8.5891	28.35%	0.7581	2.50%
Scenario 3	A	scenario I + Surfactant Injection @0.05 PV	9.3759	30.94%	1.5449	5.10%
	B	scenario I + Surfactant Injection @0.1 PV	9.3776	30.95%	1.5466	5.10%
	C	scenario I + Surfactant Injection @0.2 PV	9.4095	31.05%	1.5785	5.21%
	D	scenario I + Surfactant Injection @0.3 PV	9.4048	31.04%	1.5738	5.19%

Case		Objectives	Forecast		Incremental Oil	
			Np, MMSTB	RF	NP, MMSTB	Δ RF
Scenario 4	A	scenario I + Surfactant-Polymer (SP) Injection @0.05 PV	10.4131	34.37%	2.5821	8.52%
	B	scenario I + Surfactant-Polymer (SP) Injection @0.1 PV	10.4343	34.44%	2.6032	8.59%
	C	scenario I + Surfactant-Polymer (SP) Injection @0.2 PV	10.5124	34.69%	2.6814	8.85%
	D	scenario I + Surfactant-Polymer (SP) Injection @0.3 PV	10.4580	34.51&	2.6169	8.67%

We started by collecting and preparing data such as rock properties, fluid properties, well diagrams, and production history to build a dynamic reservoir model. Besides that, from the results of testing the rock's physical properties, we can know the characteristics of the reservoir rock. We can divide the rock region into three regions.

After data processing and data input are complete, it is continued by validating the data by doing initialization and history matching. The In-place initialization process results show that the model is correct, with a difference of 0.07% (less than 1%). Also, it can be seen that the simulated initial pressure and the measured initial pressure are almost the same, with a difference of -0.72%. Meanwhile, The History Matching model process is fair, where the cumulative oil production from the simulation results has a difference of 0.93% (less than 1%); The cumulative water production from the simulation results has a difference of 0.08% (less than 5%); The cumulative gas production from the simulation results has a difference of -4.60% (less than 10%).

Four scenarios were simulated until June 2031. Detailed scenarios are shown in **TABLE 4**. Scenario 1 (Base case: 12 production wells + 6 water injection wells) produces 7,831 MMSTB with RF 25.8%; Scenario 2 (Scenario I + Polymer Injection with varying PV sensitivity) produces 8.7428 MMSTB with 28.71% RF at an injection of 0.1PV; Scenario 3 (Scenario I + Surfactant Injection with various PV sensitivity) produces 9.4095 MMSTB with RF 31.05% at an injection of 0.2PV; Scenario 4 (Scenario I + Surfactant-Polymer Injection with varying PV sensitivity) produces 10.5124 MMSTB with 34.69% RF at an injection of 0.2PV. From the reservoir simulation results, the most optimum development scenario for the JHD Field layer A-1 layer is scenario 4.

CONCLUSIONS

The 4-C scenario is the most optimum scenario for Layer A-1 in the JHD Field (12 production wells, six surfactant injection wells) with an injection volume of 0.2PV, an injection rate of 3500 bbl/day, and also injection pressure of 2000 psi. This can be seen from the cumulative oil obtained by 10.5124 MMSTB with a recovery factor of 34.69%, where RF addition is the biggest compared to other scenarios, which is 8.85% bigger than RF Base case Scenario. The addition of injection wells is also useful to maintain the pressure not to decrease too low.

ACKNOWLEDGMENTS

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