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RESEARCH ARTICLE

Surfactant-Polymer Slug Optimization, Injection Rate & Pattern Size Determination Using The Cmg Simulator In The Mj Well

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Absract

The MJ well is one of the oldest in the Central Sumatra field. This field was originally produced in 1952, with a reserve of 4.5 MMSTB. This explains why EOR studies are needed to increase the production of oil.

The MJ well can be injected with surfactant-polymer based on the EOR screening criteria. Surfactant performance mechanisms can minimise IFT and displacement, however, polymers can limit mobility by increasing the viscosity of formation water and sweep efficiency. It is preferable to use reservoir modelling before applying surfactant-polymer to a well. Surfactant-polymer simulation, specifically CMG software, is used in this research. Several simulations were run using sensitivity such as slug SP, injection rate, and pattern size to determine the best approach for use in the MJ well. Surfactant injection was performed after a year of applying a water flood followed by injection of surfactant-polymer with several slug variations, namely 0.2 PV, 0.3 PV, 0.4 PV, 0.5 PV, and 0.6 PV at varied injection rates. 1600 BPD, 2300 BPD, and 3000 BPD, as well as many well-pattern variations, including a 5-spot pattern, a 7-spot pattern, and a 9-spot pattern.

Based on the simulation, optimal results are obtained at a slug of 0.6 PV, an injection rate of 3000 BPD, and a 5-Spot well pattern with a total amount of oil of 2,023,700 bbl and a recovery factor of 81.67%.

Keywords: Surfactant -Polymer, Injection Rate, Slug, Pattern, EOR

1. Introduction

1.1 Background

Oil output in Indonesia continues to fall year after year, with only 783,695 BOPD recorded in February 2018 (skkmigas, 2018). Along with population growth, Indonesia's oil consumption climbed to 44% in 2019, with an oil production target of 922,000 BOPD (Acquah-andoh, Putra, Ifelebuegu, & Owusu, 2019). This issue arose as a result of decreased output from numerous oil fields around Indonesia. According to the skkmigas yearbook (2018), the fields that have had a fall in production include the South Sembakung field, Kerendan field, and others, which have seen a 3.6% decrease in production (801 BOPD to 772.3 BOPD). The condition of older wells, which has a total reduction in oil output of 5% -20% every year, is one of the causes of the decline in production. The reservoir pressure of an old well falls below the bubble point pressure, it has a large water cut and multiple wells are classified as non-active (Bae, Masduki, Permadi, & Abdurrahman, 2017).

The Enhanced Oil Recovery (EOR) technique can improve sweep efficiency by eliminating residual oil saturation in the reservoir. This approach has been shown to boost oil recovery by 60% (Speight, 2015). With the advancement of technology, numerous approaches from this EOR are being explored anew, such as Surfactant-Polymer Flooding (SP Flooding), which is capable of lifting more oil saturation that has been left behind. SP Flooding was initially used in China, namely in the Daqing field (Gao, Towler, Li, & Zhang, 2010). The use of SP Flooding increased oil recovery by 7% to 64.4% (Felix, Ayodele, & Olalekan, 2015).

This study will discuss the use of SP Flooding in oil recovery in the MJ well using the Computer Modelling Group (CMG) Simulator, and before conducting the simulation modelling, a screening analysis process will be performed to determine which EOR method is the most optimal for application to the MJ well.

Furthermore, the researcher analysed the operational parameters of the success of SP flood activities such as the slug size with slug variations used 0.2, 0.3, 0.4, 0.5 and 0.6 PV (Gharbi, Alajmi, & Algharaib, 2012), the injection rate for optimising this model is 1600 bbl/day, 2300 bbl/day and 3000 bbl/day and the pattern size determination is N-5 Spot, N-7 Spot and N-9 spot. Based on the values of the recovery factor, oil flow rate, and cumulative oil, the optimal model will be chosen from all of the models that have been created to optimise oil production in this MJ field.

2. Literature review

Oil production utilising the EOR process is increasingly successful, with EOR accounting for approximately 3% of global production (Gao et al., 2010). This figure is rising, and it is expected that EOR technology will become the dominant technique in the oil and gas industry in the future.

Many types of EOR, such as polymer surfactants, have been integrated with the times and technology to further optimise oil output.

Polymers act as mobility buffers and aid the process of SP injection. The main objective of SP injection is to lower the surface tension between the oil and water phases. SP injection was created by studying the behaviour of three phases, including the water phase, the oil phase, and the microemulsion phase, as well as changes in the states observed, namely water, oil, surfactants, polymers, total anions, and calcium ions (Rita, 2018).

According to Gao, reservoir heterogeneity, oil viscosity, remaining oil saturation, polymer dispersion ability in the reservoir, polymer and surfactant suitability, well spacing and flow rate, and quality control of the injected polymer is all factors that influence the success of SP injection applications in the field. In addition, when combining SP injections, several factors must be considered, including interactions on polymers and surfactants, rock adsorption, and chromatographic separation of various components that can harm the SP injection process (Raffa et al., 2016). Both surfactant injection and polymer injection as well as SP injection have different functions, along with the mechanism of each of these injections.

2.1 Screening Criteria

1. Conventional screening

This screening procedure is carried out by comparing the fluid and rock data on the screening table. If the data value falls inside the range, it is assumed to meet the criterion, and vice versa. The results are presented in the form of tables and colour codes, with blue cells indicating that the criteria have been met and red cells indicating that the conditions have not been met. The final findings are determined by examining the amount of data that fits the requirements to be used as a percentage value.

Before applying the screening criteria, several general considerations must be studied. First, geological studies are frequently conducted since operators have discovered that unanticipated reservoir heterogeneity has caused many EOR field projects to fail. Second, when an operator considers EOR in a specific application, the selected reservoir must contain enough oil to make the project possibly lucrative. Furthermore, deep reservoirs may result in surface facilities, equipment, and available pipes being evaluated during the screening phase and the selection of the best EOR technology for a given field (Abu El Ela, Sayyouh, & Sayed El Tayeb, 2014).

2. The screening process uses EORgui software

The software can be used to perform a rapid screening of fluid and rock characteristics data to make recommendations for an EOR method in the field, but it cannot be used to analyse the economics of the resulting EOR method.

2.2 Surfactant-Polymer Flooding

2.2.1 Surfactant Flooding

Since 1970 (Samanta, Ojha, Sarkar, & Mandal, 2011), surface active agents (surfactants) have been a good type of EOR because they can significantly activate the surface of another substance that cannot initially be mixed by lowering the surface tension (surface tension.) of a medium and lowering the interfacial tension between two phases with different degrees of polarity (Felix et al., 2015)(Gong & Rossen, 2018). Figure 2.1 shows a surfactant injection scheme with one production and one injection well.

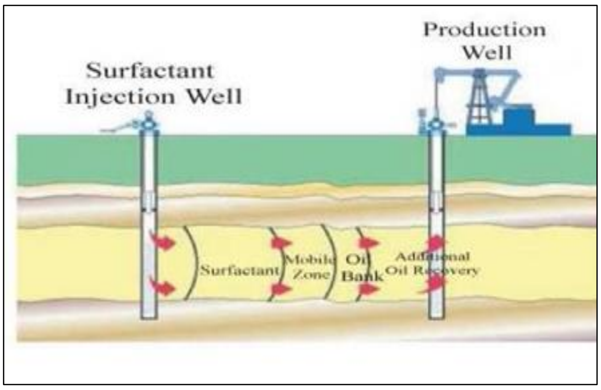

Fig 1. Schematic of the Surfactant Injection Mechanism (Emegwalu, 2009)

2.2.2 Polymer Flooding

Polymer injection is the most extensively used chemical EOR technique in the world, with the primary goal of increasing water viscosity (Bordeaux Rego, Botechia, & Schiozer, 2017). Polymer use can also reduce water permeability and water output. When compared to ordinary water floods, this reduces mobility and increases sweeping efficiency. Although polymer injection improves oil recovery, it has the potential to reduce residual oil saturation. Furthermore, the physical properties of the polymer (for example, retention in porous media, Non-Newtonian effects, and degradation) must be taken into account to generate realistic scenarios for strategy selection. Problems with polymer injection have been reported, which can have a negative impact on economic returns.

2.3 Slug Size

The quantity of surfactant is the amount of surfactant required in pressing to push out the remaining residual oil by reducing the surface tension. Do not use too much surfactant slug since it is inefficient, and do not use too little because it will not all flow through the oil surface. The best design is obtained by maintaining constant polymer and surfactant concentrations while altering slug size (Gharbi et al., 2012).

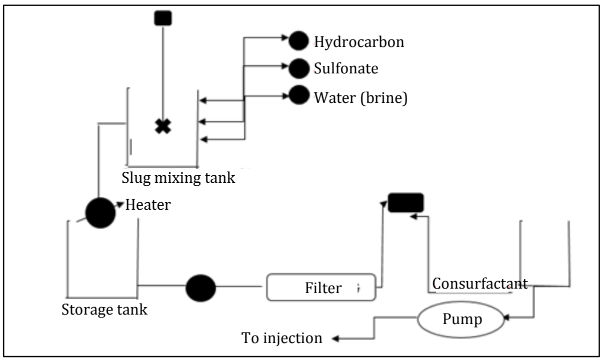

Fig 2. Slug Surfactant Mixing System Diagram

2.3.1 Slug Surfactant Mixing System

In most micellar formulae, the miscible slug components have various compositions. Surfactants are effective at extremely low concentrations in most slugs because they are made of at least four separate components: petroleum sulfonate, liquid (aqueous) phase, hydrocarbons, and cosurfactants (Gharbi et al., 2012). Except for cosurfactants, all of these components are measured in the tank. They are combined in a large mixer until they are homogenous.

2.4 Injection Rate

The magnitude of the injection rate depends on the difference in injection pressure at the bottom of the well, usually a maximum injection rate is desired, but some limitations must be considered and formations with higher temperatures require a higher injection rate (Wang, Hill, & Schechter, 1993).

The lower limit of the injection rate is the rate at which oil is produced which is the economic limit. The upper limit of the injection rate is the rate related to the injection pressure which starts to cause cracking in the reservoir which can be controlled by controlling the pressure of the injection rate (Behzadi, Hampton, & Corp, 2018).

2.5 Injection Well Patterns

The geological conditions of the reservoir, specifically the uniformity of formations, types of traps, existing wells, reservoir driving mechanisms, the volume of hydrocarbons, and the slope of the rock layers being pushed, all play a role in increasing oil recovery (Annisa Arisyi M., Syamsul Irham, 2015).

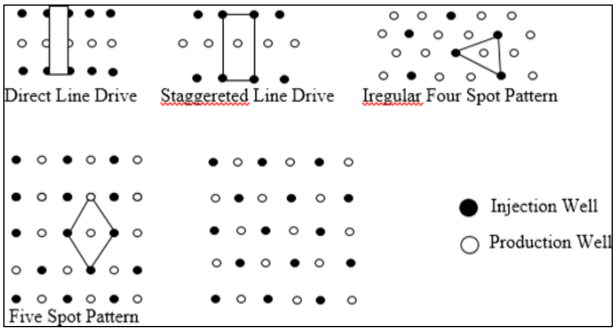

Fig 3. Injection Well Patterns – Production (Annisa Arisyi M., Syamsul Irham, 2015)

The symmetrical pattern is very effective for reservoirs with relatively small slopes and large areas. Injectors and manufacturers are generally interspersed. Another pattern where injectors and manufacturers are grouped may be required for reservoirs with significant degreasing. For example, a peripheral or flank injection pattern may be required to effectively reservoir anticlinal or monoclinal (Fanchi & Fanchi, 2006).

2.6 State Of The Art

The surfactant-polymer injection research undertaken in this study is not the first, but there have been numerous earlier investigations with differences in the sensitivity of operational parameters, reservoir types, and simulators. The difference in this study is the use of the CMG simulator to create a model with three operating parameters, namely slug size, injection rate, and well pattern.

3. Research methodology

In preparation for this Final Project, researchers conducted modelling at Riau Islamic University by creating a conceptual model based on the simulation method. In terms of collecting data techniques, data gathered from research outcomes, publications, and papers based on research themes are examples. After the results are collected, the data is evaluated, which leads to the conclusions that are the research objectives.

3.2 Types Of Research

This research is a simulation using Computer Modeling Group (CMG) software, which is a reservoir simulator that is widely used in the petroleum industry where the advantage of this simulator is that there are several other simulators such as IMEX (Implicit Explicit Black Oil Simulator), STARS (Thermal & Advance Processes). Reservoir Simulator), GEM, and WINPROP (Tehran, 2006).

3.3 Reservoir Properties

The MNS field is located in Sumatra's Central Basin. The MNS field is one of the largest in Southeast Asia, with an OOIP of around 9 MMSTB. The MNS field was discovered in 1944 and produced for the first time in 1952. The residual reserve is a sandstone-type reservoir with a thickness of 270 ft and a reservoir depth of roughly 2342 ft (Hartono et al., 2017). Table 1 following provides a more detailed description of the MJ field.

Table 1. Reservoir Properties Data (Hartono et al., 2017)

Reservoir Properties	Value
Water Density	62,60 lb/ft^3
Oil Density (API)	36API
Rock comprehensibility	5,8 x 10^{-6}psi^{-1}
Water viscosity	0,44cp @P &T reservoir
Oil viscosity	3.5cp@ P& Treservoir
Oil Formation Volume Factor	1.049bbl/STB
Reservoir depth	2342ft
Reservoir temperature	199,4 ^{o}F
Reservoir pressure	350psig
Bubble point pressure	235psig
Oil saturation	20 %
Porosity	32,30 %
Permeability	343mD

Table 2. Fluid Properties

No	Component	*Pcrit* Psi	*Tcrit* °F	MW lb/lbmol
1	Water	3200	374	18
2	Oil	453	134	205,65
3	Polymer	0	0	10.20
4	Surfactan	0	0	288,18

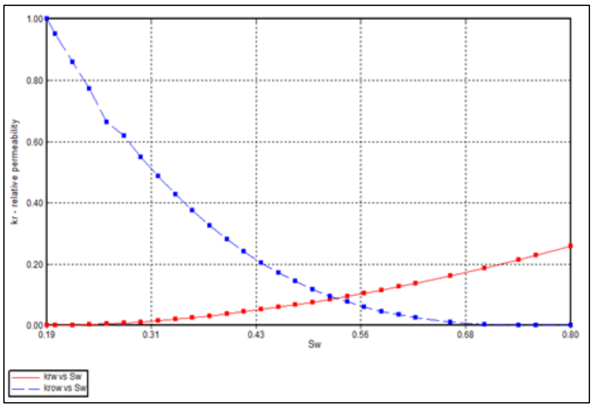

Fig 4. Krvs Sw relationship curve

Figure 4 shows a graph of permeability related to water saturation that shows that this reservoir region is water moist for an oil-water system. Water wet is a rock attribute that indicates how much water has soaked the rock. A graph demonstrating the intersection of the curves at an Sw value of 0.55 or greater than the midpoint of water saturation backs up this claim.

3.4 Basecase Modeling

In this Final Project, a 3D simulation model was created using CMG STARS and processed from existing secondary data. In providing an overview of the reservoir, choose a Cartesian grid model consisting of a grid block matrix of 15 grids in the i direction, 15 grids in the j direction, 5 grids in the k direction and has 5 layers (15x15x5) so that the total grid blocks are 1125 grid blocks. In this case, the permeability value i is 343 md, permeability j is 343 md, permeability k is 34.3 md, and the same porosity value in each layer is 32.3% with a formation thickness of 54 ft. The conceptual model of a 2D (2-dimensional) Cartesian grid is shown in Figure 3.3., while the conceptual model of the 3D (3-dimensional) Cartesian grid is shown in Figure 5.

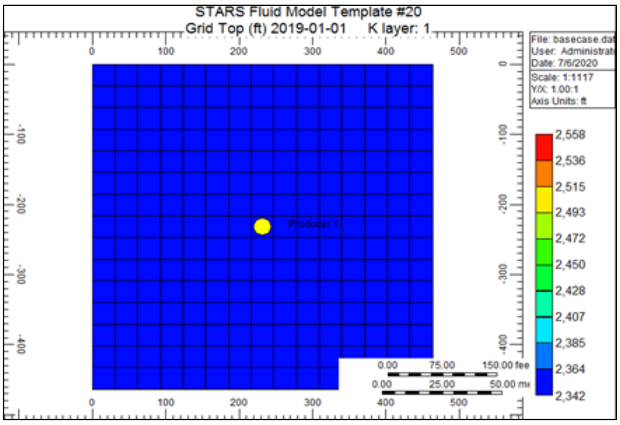

Fig 5. 2D Cartesian Basecase Grid Conceptual Model

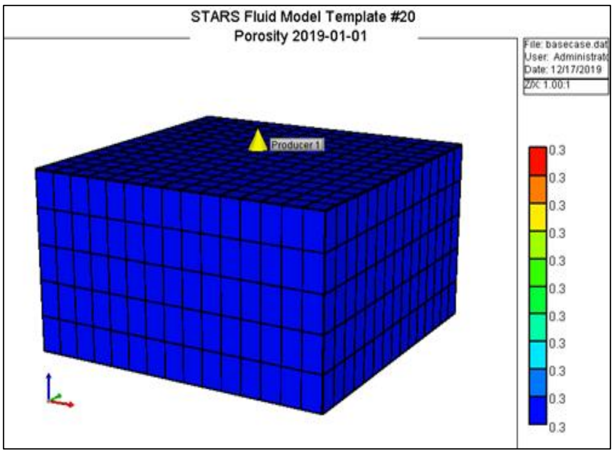

Fig 6. Dimensional Cartesian Grid Conceptual Model

4. Results and Discussion

This study's modelling scenario is focused on the impact of operating parameters such as slug size, well pattern, and injection rate on oil rate production, cumulative oil, and recovery factor. Table 2 displays the outcomes of the modelling scenario:

Table 2. Oil Rate, Cumulative Oil and Recovery Factor Values at N5-Spot with Injection Rates of 1600 bbl/day, 2300 bbl/day and 3000 bbl/day

Injection Rate	Pattern Size	Slug	Oil Rate(bbl)	OilCumulative (bbl)	Recovery Factor (%)
1600 bbl/day	n-5spot	0.2	294	1.668.140	67,3
		0.3	388	1.725.020	69,1
		0.4	418	1.786.880	72,1
		0.5	507	1.842.830	74,3
		0.6	512	1.897.480	76,5
2300 bbl/day	n-5spot	0.2	382	1.683.990	67,9
		0.3	404	1.738.070	70,2
		0.4	587	1.833.000	73,9
		0.5	700	1.898.550	76,6
		0.6	765	1.973.360	79,7
3000 bbl/day	n-5spot	0.2	461	1.693.910	68,3
		0.3	569	1.772.360	71,5
		0.4	740	1.851.630	74,7
		0.5	908	1.924.980	77,6
		0.6	1039	2.023.700	81,6

Table 3. Oil Rate, Cumulative Oil and Recovery Factor Values at N7-Spot with Injection Rates of 1600 bbl/day, 2300 bbl/day and 3000 bbl/day

Injection Rate (bbl/da)	Pattern Size	Slug	Oil rate (bbl)	Oil Cumulative (bbl)	Recovery Factor (%)
1600	N-7Spot	0.2	263	1.584.460	64,1
		0.3	290	1.623.200	65,5
		0.4	337	1.678.210	67,7
		0.5	385	1.713.570	69,1
		0.6	415	1.749.460	70,6
2300	N-7Spot	0.2	326	1.602.750	64,4
		0.3	386	1.660.380	67,0
		0.4	449	1.712.620	69,1
		0.5	540	1.765.710	71,2
		0.6	607	1.813.020	73,1
3000	N-7Spot	0.2	379	1.610.510	64,9
		0.3	466	1.677.960	67,7
		0.4	552	1.726.890	69,6
		0.5	688	1.786.660	72,1
		0.6	704	1.837.530	74,1

Table 4. Oil Rate, Cumulative Oil and Recovery Factor Values at N9-Spot with Injection Rates of 1600 bbl/day, 2300 bbl/day and 3000 bbl/day

Injection Rate(bbl/day)	*PatternSize*	*Slug*	*Oil Rate(bbl)*	*Oil Cumulative(bbl)*	*Recovery Factor(%)*
1600	N-9Spot	0,2	224	1.171.300	69,3
		0.3	271	1.750.800	70,6
		0.4	313	1.811.020	73,0
		0.5	360	1.864.130	75,2
		0.6	390	1.918.070	77,4
2300	N-9Spot	0.2	332	1.716.100	69,2
		0.3	339	1.744.700	70,4
		0.4	419	1.802.300	72,7
		0.5	503	1.855.000	74,8
		0.6	567	1.901.500	76,7
3000	N-9Spot	0.2	327	1.717.300	69,3
		0.3	375	1.750.800	70.6
		0.4	484	1.811.000	73,0
		0.5	603	1.864.100	75,2
		0.6	734	1.918.000	77,4

Tables 2-4 show the various modelling scenarios used in this study. At the N-5 Spot, the larger the slug size and injection rate, the higher the oil rate, cumulative oil, and recovery factor. The greatest value was reached at N-5 Spot at an injection rate of 3000 bbl/day and a slug size of 0.6 PV with an oil rate of 1039 bbl, total oil of 2,023,700 bbl, and a recovery factor of 81.67%.

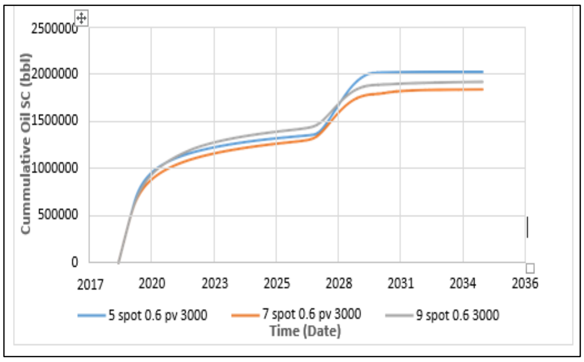

Fig 7. Cumulative oil graphic results from the 3 selected scenarios

The N7-Spot and N-9 Spot followed the same yield pattern as the N-5 Spot, with the highest yield at the N-7 Spot at an injection rate of 3000 bbl/day and 0.6 PV with an oil rate of 704 bbl, total oil of 1,837,530 bbl, and a recovery factor of 74.15%. The greatest yield for N-9 Spot was likewise obtained at an injection rate of 3000 bbl/day with a slug size of 0.6 PV with an oil rate of 734 bbl, total oil of 1,918,000 bbl, and a recovery factor of 77.40%. Figure 7 shows the results of the highest cumulative oil production.

The simulation results show that the N-5 spot well pattern produces better results than the N-7 and N-9 spots because the injection fluid pressure is more evenly distributed in the N-5 well pattern compared to the N-7 and N-9 spots where there are more injection wells, the fluid pressure is more irregular, and there is a risk that more water will be produced due to excessive pressure. As a result, the N-5 spot well pattern has a larger cumulative oil value than the N-7 and N-9 spot well patterns.

4.2. The Effect Of Slug, Injection Rate And Well Pattern On Oil Rate

The conceptual modelling for SP injection in this study was created by analysing numerous operating characteristics such as slug size, injection rate, and pattern size. These operational parameters are critical to the SP injection process's success (Dang, Chen, Nguyen, & Bae, 2011

The slug size employed in this case is 0.2 PV to 0.6 PV. On April 1, 2027, the production of oil in many slugs increased. Slug 0.2 PV had a higher peak oil output of 461 bbl/day, 0.3 PV had a higher peak production of 569 bbl/day, 0.4 PV had a higher peak production of 740 bbl/day, 0.5 PV had a higher peak production of 908 bbl/day, and 0.6 PV had a higher peak production of 1039 bbl/day. Based on slug observation research, the highest oil recovery was observed at 0.6 PV slug.

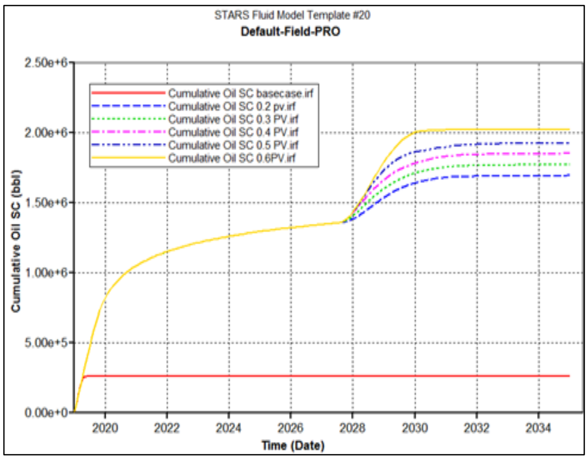

Fig 8. Effect of the Injection Rate of 3000 bbl/day and the N-5 Spot Well Pattern on Cumulative Oil

4.3. The Effect Of Slug, Injection Rate And Pattern Size On Cumulative Oil Production

It will explain the cumulative production as well as the addition of the production flow rate from each scenario. The cumulative rise in oil output for each slug variation is shown below, with slug 0.2 PV experiencing a cumulative increase in oil production of 1,693,910 bbl and slug 0.3 PV seeing a cumulative increase in oil production. Slug 0.4 PV had a cumulative rise in oil output of 1,851,630 bbl, slug 0.5 PV experienced a cumulative increase in oil production of 1,924,980 bbl, and slug 0.6 PV experienced a cumulative increase in oil production of 2,023,700 bbl.

4.4. The Effect Of Slug, Injection Rate, And Pattern Size On The Oil Recovery Factor

The amount of oil recovered cannot be isolated from the success of a chemical injection. The graph below depicts oil recovery at slug 0.6 PV with an injection rate of 3000 bbl/day and the good pattern N5-Spot.

Surfactant-polymer injection results in a higher recovery factor value because, in addition to lowering the interfacial tension of the solution, surfactants can change the wettability of rock that is initially oil wet, making it difficult for oil to flow into water wet. The polymer solution then functions as a co-injection, enhancing sweep efficiency by raising the viscosity of the driving fluid (Hartono et al., 2017). According to Sheng (2013), surfactant injection is the most successful in reducing interfacial tension, while polymer injection has been shown to improve sweep by increasing the viscosity of the driving fluid. Surfactant injection changes the wettability of the rock, whereas the polymer controls water mobility.

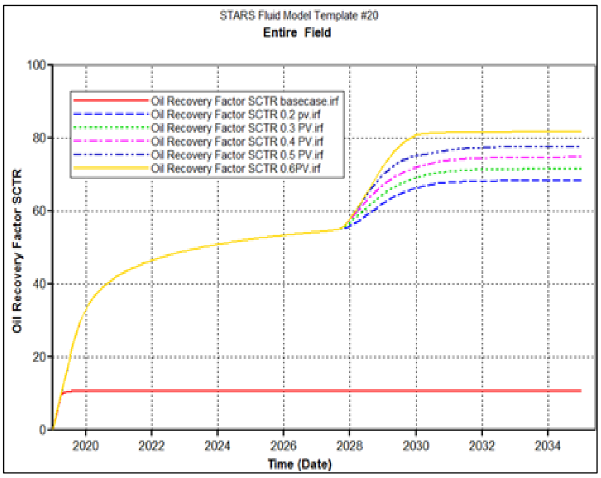

Fig 9. Graph of Recovery Factor

4.5. The Effect Of Slug, Injection Rate, And Pattern Size On Other Reservoir Parameters

4.5.1 Water Viscosity

The lowest slug size, 0.2 PV, can increase water viscosity up to 10.6 cp and continues to grow with slug size, whereas the largest slug size, 0.6 PV, can increase water viscosity up to 11.2 cp. According to Ahmed, Awotunde, Sultan, and Yousef (2017), polymer injection can increase oil removal by increasing the viscosity of the driving fluid, particularly water.

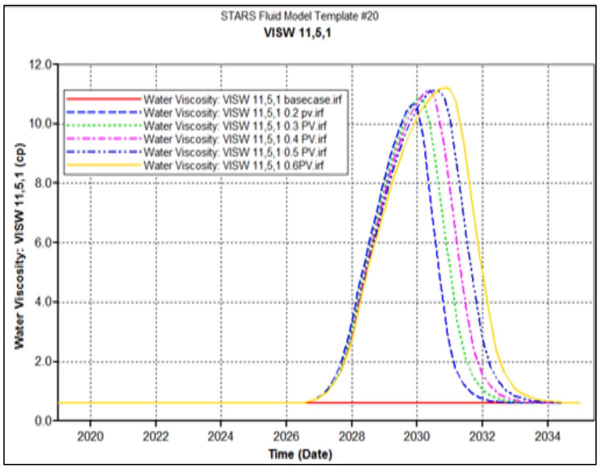

Fig 10. Graph of Water Viscosity After Injection of Polymer at an Injection Rate of 3000 bbl/day and the N-5 Spot Pattern

4.5.2 Surfactant Adsorption

Table 5. Surfactant Adsorption Results in Each Slug

No	Slug(PV)	Adsorbed (lb/ft)
1	0,2	0,1
2	0,3	0,1
3	0,4	0,1
4	0,5	0,1
5	0,6	0,2

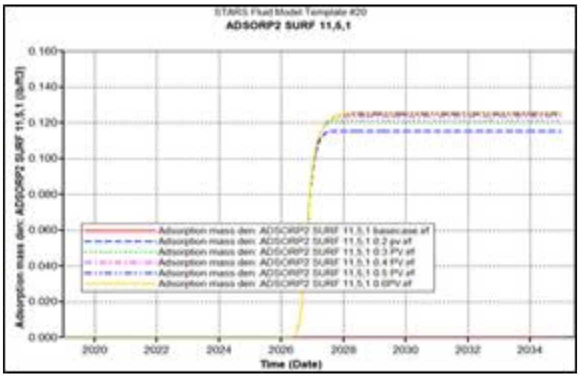

Fig 11. Graph of Surfactant Adsorption at an Injection Rate of 3000 bbl/day and the N-5 Spot Pattern

4.5.3 Polymer Adsorption

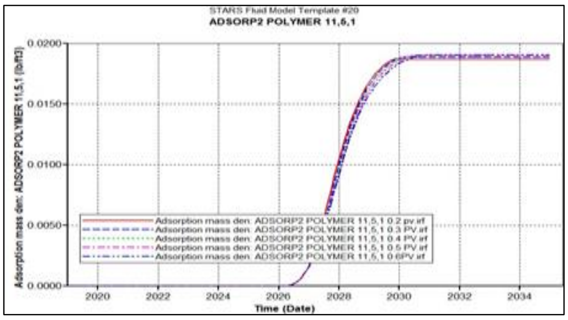

Fig 12. Graph of Polymer Adsorption at an Injection Rate of 3000 and Pattern Size N-5 Spot

According to graph 12, there is a slight increase in polymer adsorption, indicating that the chemical absorbed into the rock is still classified correctly. A table of the polymer adsorption results is shown below.

Table 6. Polymer Adsorption Results in Each Slug

No	Slug(PV)	Adsorbed Polymer (bbl/ft)
1	0,2	0,1
2	0,3	0,1
3	0,4	0,2
4	0,5	0,2
5	0,6	0,2

5. Conclusions

The following conclusions can be made from the surfactant-polymer injection modelling results:

1. The best scenario that can be applied to the MJ well is the N-5 spot modelling with an injection rate of 3000 bbl/day and a slug size of 0.6 PV with an increase in oil rate production of 1039 bbl/day, cumulative oil of 2,023,700 bbl and recovery factor of 81.6%.
2. Increasing the injection rate and slug will affect the increase in oil production. This is evident from the results of the recovery factor simulation of the injection rate and slug obtained, namely in the N5 Spot well pattern with an injection rate of 1600 bbl/day, a slug size of 0.6 PV obtained a value recovery factor of 76.5%, injection rate of 2300 bbl/day, slug size of 0.6 PV obtained a recovery factor value of 79.7% and injection rate of 3000 bbl/day, slug size of 0.6 PV obtained a recovery factor of 81, 6%.
3. The effect of injection rate, slug size and well pattern affects other reservoir parameters such as changes in water viscosity values. Before injection of SP flood, the viscosity of the water was 0.5 cp and after being injected it became 11.2 cp at slug 0.6 PV. Meanwhile, the highest adsorption of surfactants occurred in slug 0.6 PV of 0.125 lb/ft and the highest adsorption of polymer occurred in slug 0.6 PV of 0.019 lb/ft.

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