OPTIMIZATION OF SURFACTANT FLOODING ON BJG FIELD USING DYNAMIC PATTERN

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ABSTRACT
Mature fields, also known as brownfields, are fields that are in a state of declining production or reaching the end of their production lives. Development of mature oil fields has been, and will increasingly be, an exciting subject (Babadagli, 2007). New studies already discovered innovative ways of finding, developing, and producing hydrocarbons that are efficient and cost-effective and minimize harm to the environment. BJG Field is one of the mature fields which is produced in 1927, one of the efforts for enhancing the production is using waterflood at the beginning of 2001. To increase production further, then we need to conducted studies as an application of the second recovery from BJG Field. This research aimed to conduct a study of dynamic pattern surfactant flooding using IMEX and STARS simulator to obtain an optimum surfactant injection scenario. Simulation is done with real data from the BJG field, and the result has shown the scenario which has the most significant oil production and the highest recovery factor. The increment of oil recovery factor is 32.29% from the waterflood case. From the results of studies and simulation shown that dynamic pattern inverted five-spot pattern can be used.

Keyword: surfactant flooding; dynamic pattern; inverted five-spot

INTRODUCTION
Petroleum is still the primary source of energy in Indonesia and worldwide. Therefore effective strategies to maximize the amount of petroleum are vital to the future energy supply. BJG Field is one of the mature fields which is produced in 1927; one of the efforts of enhancing production is using waterflood at the beginning of 2001. Today, Oil rates production already declining. To increase production furthers, then we need to conducted studies as an application of the second recovery from BJG Field. Surfactant flooding is being considered as the most appropriate Enhanced Oil Recovery (EOR) techniques with the consideration of reservoir characteristics and the availability of surfactant in Indonesia. This technique requires the financial cost of high uncertainty, so we need significant planning before injecting the surfactant. Dynamic Pattern is the new method to sweep or displace oil from the reservoir. With help from dynamic patterns, the recovery factor can be optimized. The process of choosing the location and the number of wells in dynamic patterns is not a simple procedure because of the number of variables involved. The excellent behavior depends on the reservoir properties and interaction with other wells, and it can only be predicted through numerical simulation. Therefore, each combination of numbers and well positions must be tested.

METHODOLOGY
Potential Pattern Selection
The objective is to select the proper pattern that will provide the injection fluid with maximum possible contact with the crude oil system. This selection can be achieved by converting existing production wells into injectors or drilling infill injection wells (Gholamzadeh, 2012). The following factors must be considered when choosing the patterns:
- Provide the desired oil production capacity,
• Provide sufficient injection capacity to support oil production,
• Maximize oil recovery with a minimum of water production,
• Use reservoir heterogeneity to the best advantage,
• Use the existing wells to minimize the number of new wells required,
• Structure, the dip of reservoir, fault, and size of the reservoir,
• Topography,
• Wells spacing.

In general, the selection of a suitable flooding pattern for the reservoir depends on the number and location of existing wells. In some cases, producing wells can be converted to injection wells. In contrast, in other cases, it may be necessary or desirable to drill new injection wells.

Surfactant Flooding
Among chemical flooding methods, surfactant flooding processes are particularly useful for recovering a significant fraction of conventional oil left in the reservoir after waterflood. The basic principle behind the use of surfactant flooding is to recover the capillary-trapped residual oil remaining after waterflooding by injecting a surfactant solution. The residual oil can be mobilized through a substantial reduction in the interfacial tension (IFT) between oil and water. If the interfacial tension can be reduced between the oil and water, the resistance to flow is reduced (Emegwalu, 2009). Surfactant is a polar compound that composes amphiphilic molecules with the hydrophilic and hydrophobic parts. They have one part that has an affinity for nonpolar media and another part that has an affinity for polar media. The non-polar (tail) and polar (head) portions respectively shown in the figure below:

A reservoir study is necessary for a proper choice of pattern selection. As mentioned earlier. This type of study is usually performed by in-house or consulting reservoir engineers. The pattern should be chosen based on the characteristics above. The chosen pattern may then be modified to conform to the next criterion. Essentially four types of suitable arrangements are used in fluid injection projects (Ahmad, 2006):
• Irregular injection patterns

Figure 1. Sketch of wells patterns commonly used in field development with injection wells for waterflooding (adapted from http://www.petrowiki.org/waterflooding)

Figure 2. Schematics of Surface-Active molecules

The surfactant type commonly used in the EOR surfactant method is petroleum sulfonates. Surfactants are complex. It is a mix of components that have various structures, heavy molecules, and sulfonate degrees (the function of sulfonate per molecules). STARS is CMG’s new generation advanced processes reservoir simulator. It supports various options such as chemical/polymer flooding, thermal applications, steam injection, horizontal wells, dual porosity/permeability, directional permeabilities, flexible grids, fire flood, and many more. STARS is developed to simulate steam flood, steam cycling, steam-with-additives, dry and wet combustion, along with many types of chemical additive processes. It
uses a wide range of grid and porosity models in both field and laboratory scale.

**Dynamic Pattern**

Dynamic Pattern is onsite function wells are production wells in the base case earlier to replace injection wells into production wells in the base case scenario. The purpose of the dynamic pattern itself is depleted areas that have not been swept away by the previous pattern. However, to choose pattern and how to manage the dynamic factor is very important to consider in the conceptual planning are field location, reservoir shape, oil-in-place, fluid saturations and distributions, reservoir characterization, zonal continuity, fractures and faults, formation dip, directional permeability, gas cap and aquifer size, previous reservoir development, gathering and separation facilities, production methods, production history, previous problems, and previous development studies.

**BJG Field Data**

BJG field in Jambi city located on latitude -2.04922° N and longitude 103.31253° E. Stratigraphy of the study area consists of alternating sandstone bedding and mudstone. The mudstone in the study area, in some places, especially in the bedding sandstone, often found the thin limestone fragment is generally tight with higher resistance more than 10 ohms. In the study area, Air Benakat Formation sandstone layer is a significant reservoir containing hydrocarbons. Good reservoir sandstones typically have a thickness of 5-40 m and deposited on a shallow marine environment/coastal deltaic. Permeability ranging from 10 mD-3 Darcy, porosity 16-18% represents the cut-off reservoir effective in many fields (K <5mD). The high cut-off is affected by the volcanic caustic component in sandstone, and clay content is high due to the energy deposition being. The flow rate is moderate, around <3000 BOPD, although his net pay is relatively large. It is due to a combination of relatively low reservoir energy and low permeability. Based on the detailed correlation of log data that exists (especially the combination of GR, SP, and Resistivity) can be traced to either the entire spread of the layers of sandstone, which is the main reservoir in the BJG field. Based on the structure of production history, the main layers that produce the oil is N/780 and P/820. The other layer is the layer that produces oil R/880, 4/950, and O/800. BJG field discovered in 1924 from the 2006 field data has several wells as much as 141 with the 28 active production wells, nine active injection wells, and five wells as a water source wells. In general, the good completion in a single well-conducted and layer commingled. Meanwhile, production techniques using artificial lift equipment (artificial lift method) with a nod and ESP pump. In general, the results of the RST program at BJG show that fluid content in the sands is variable. The structural complexity of the field causes variability. The N/780 still contains a gas cap while the P/820 sand appears to have a water drive and has no secondary gas cap. The existence of moveable oil has been proven, and the waterflood target is more fully defined (Mas, 1999). Based on the historical performance of the reservoir, the drive mechanism of natural reservoir force is a combination of dissolved gas (solution gas drive) and weak water drive.

| No | Layer | Depth (m) | Rock Lithology |
|----|-------|-----------|----------------|
| 1  | N/780 | 690-890   | Sandstone     |
| 2  | P/820 | 650-900   | Sandstone     |
| 3  | R/880 | 730-990   | Sandstone     |
| 4  | 4/950 | 700-1050  | Sandstone     |
| 5  | 4x980 | 850-1130  | Sandstone     |

Table 1. Productive Layer BJG Field

| No | Layer | K, mD | Sw, % | Porosity, % |
|----|-------|-------|-------|-------------|
| 1  | N/780 | 21.98 | 32    | 22.9        |
| 2  | P/820 | 17.4  | 45.2  | 23.8        |
| 3  | R/880 | 16.54 | 40.9  | 22.9        |
| 4  | 4/950 | 10.35 | 37.5  | 24.3        |
| 5  | 4x980 | 21.49 | 32    | 23.4        |

Table 2. Characteristic Summary of Rock Reservoir

| No | Layer | P* (psi) | Ph (psi) | T (°F) | 5G (min/ak) | Boi (Bbl/STB) | Viscositas minyak (Cp) | Klarutan Gas (Srf/STB) |
|----|-------|----------|----------|--------|-------------|--------------|------------------------|------------------------|
| 1  | N/780 | 924      | 725      | 133    | 0.75        | 1.37         | 0.311                  | 204.311                |
| 2  | P/820 | 1156     | 1130     | 135    | 0.76        | 1.505        | 0.407                  | 410.168                |
| 3  | R/880 | 1200     | 682      | 149    | 0.75        | 1.268        | 0.393                  | 149.785                |
| 4  | 4/950 | 1280     | 3260     | 145    | 0.808       | 1.216        | 0.408                  | 391.401                |
| 5  | 4x980 | 1280     | 1260     | 165    | 0.808       | 1.216        | 0.408                  | 391.401                |

Table 3. PVT Data BJG Field

The data obtained are as follows:

- Models geological zone in which the property is contained porosity, net-to-gross (NTG) and permeability,
• Special core data (relative permeability and capillary pressure) available,
• PVT data available,
• Petrophysics data (well log lumping data) available,
• Data production and water injection wells available,
• Pressure static well available,
• Historical data and cross-section in which there are well available in the history of perforation, simulation, and coordinate well.

The selection of the regions that will be used in this study is based on several aspects of the reservoir, such as a large number of reserves, the number of production and injection wells available. Also, there is no communication between other regions. The region that will be used is zone-A, which is in region P/820.

Table 4. Well List in Zone-A

| Well Name | Status      |
|-----------|-------------|
| BJG-14    | Oil Producer|
| BJG-16    | Oil Producer|
| BJG-20    | Oil Producer|
| BJG-55    | Oil Producer|
| BJG-66    | Oil Producer|
| BJG-73    | Oil Producer|
| BJG-79    | Oil Producer|
| BJG-82    | Oil Producer|
| BJG-93    | Injector    |
| BJG-120   | Injector    |
| BJG-122   | Oil Producer|
| BJG-128   | Oil Producer|
| BJG-129   | Oil Producer|

Well Active in this region only five wells, BJG-93 and BJG-120 as an injector, BJG-64, BJG 122, BJG-128 as producer wells. The IOIP calculation from PETREL and CMG is 16.6 Mmstb and 16.0 Mmstb. The differences are 3.75%.

Table 5. Differences Cumulative Production Output Simulator and History Data

| Parameter                  | Output Simulator | History Data | Diff  |
|----------------------------|------------------|--------------|-------|
| Oil Cumulative Production (Mmstb) | 6.17             | 5.96         | 3.5%  |
| Water Cumulative Production (Mmstb) | 1.8              | 1.97         | 8.6%  |

History matching result is shown in appendix A.

RESULT AND DISCUSSION

The main objective of this study is to predict the surfactant flooding scenario using mature field data. Running surfactant flooding scenario using STARS including Base Case Scenario (without infill drilling), Huff and Puff surfactant flooding, Pattern inverted five-spot surfactant flooding, Dynamic Pattern inverted five-spot surfactant flooding. The prediction surfactant flooding scenario for 15 years. The best scenario will be chosen based on the best oil recovery factor. Based on Craig Rule (Fertl, 1978), the relative permeability curve at zone-A at the BJG field shown the intersection between kro and krw curve at Sw about 0.44-0.62, meanwhile Swc is 0.3-0.44. The form of kro curvature shown that this reservoir is a good candidate for surfactant flooding, surfactant is lowering Sor and increasing relative permeability. This study will use continuous surfactant flooding. The continuous surfactant flooding is most effective, due to continuous surfactant flooding reaches all the capillary trapped oil. Water gets slightly higher than the base case at the end of the simulation, most probably due to the surfactant went into the most permeable layers and reduced the residual oil in those layers. When less oil is present, the oil does not prevent water from flowing, and it allows more water flow in these layers. Permeability distribution in Figure 3 depicts that the are that has a higher permeability value is at layer ten. Figure 3 also shows that the permeability is laterally spreading in the middle of the model. Permeability at layer 20 to layer 35 (last layer) is very tight. Therefore layer 10-17 will be chosen as a water injected layer. Permeability distribution is closely related to the distribution of initial oil saturation due to capillary pressure that propagates in a model based on the size of the permeability.

Figure 3. Permeability Map before Surfactant Flooding (3 Maret 2013): A. Layer 2; B. Layer 10; C. Layer 24; D. Layer 28; E. Layer 34
Waterflooding Scenario
In this scenario, simulation running from 1927 to 2013. BJG field already has been waterflooding since 1991 until today, and water cut in the BJG field already shown 99%. It means that the waterflooding scenario already reaches the optimum of waterflooding, so surfactant flooding as tertiary production is necessary to be applied in this field. The recovery factor only achieved 19.25%, and the oil rate is starting to decrease. Therefore there are many recoverable oil reserves to the estimated oil in place in the reservoir still left.

Therefore, to produce more oil, we will simulate this region using surfactant flooding. The design of the constraint for water cut is 96%, usually for economical purpose, and bottom hole pressure is set 1200 psi as a constraint.

Base Case Surfactant Flooding Scenario
This Scenario is to inject surfactant from 2013 until the water cut reached 96%. Active wells will be used in this scenario left only three producers and two injectors. Model reservoir and well position number is shown below:

Figure 4. Water cut after waterflooding BJG Field in 2013.

Figure 5. Bottom Hole Pressure is shown that 1200 psi as a constraint injection

Rate injection is being used as one of the constraints of this study. Sensitivity needs to be done to determine the most optimum rate injection. The result of sensitivity is shown below, comparing between 100 bbl/day to 600 bbl/day.

Table 6. Rate Injection Sensitivity vs. Recovery Factor

| Rate of Injection (bbl/day) | Recovery Factor (%) |
|----------------------------|---------------------|
| 100                        | 19.2                |
| 400                        | 19.25               |
| 600                        | 19.23               |

The table shown that the optimum injection rate is in 400 bbl/day due to the recovery factor has the most significant value.

After the water channels are formed, if the only surfactant is used for the flood, without any profile control, most likely, the surfactant flood will follow the existing water channels in the formation and still leave many oil containing areas untouched. Because the sweep efficiency is not optimized, the oil recovered using this tertiary recovery process is often disappointing. Several scenarios after the base case of surfactant flooding are conducted to increase the recovery factor.
Huff and Puff Surfactant Flooding Scenario

Surfactant Huff ‘n’ Puff Method is one of EOR method which can obtain higher oil cumulative production. So that, we can get a higher recovery factor as the main purpose of applying EOR. This method is different from surfactant flooding. Surfactant Huff ‘n’ Puff method is applied by injecting surfactant to the production well instead of injection. The cycle consists of surfactant injection, shut-in production well to wait for surfactant soaks. In other words, soaking time, and eventually producing oil cumulative with higher oil rate than the natural depletion one. This scenario of Huff and Puff surfactant flooding will use the same constraint BHP and injection rate the same as the base scenario. Rate injection is 400 bbl/day, and the surfactant concentration is 10%. This case needs five additional wells in the outer ring and six additional wells in the inner ring.

Figure 8. Position of injector and Producer wells for Huff ‘n’ Puff case

| Outer ring wells | Inner ring wells |
|------------------|-----------------|
| B1G-120          | B1G-128         |
| L2               | B1G-093         |
| L4               | L10             |
| L5               | L6              |
| B1G-064          | L7              |
| B1G-122          | L8              |
| L3               | L9              |
| L1               | B1G-020         |
|                  | L11             |

Huff and Puff scenario with peripheral injection outer ring wells on 1 March 2013 is in shut-in condition. The inner ring wells will inject surfactant within seven days and three days more to wait for surfactant soaking in a reservoir. 10 March 2013, the function injector wells changing to producer wells meanwhile outer ring wells open as injector surfactant. The recovery factor of this scenario is 37.02%.

It is not significant to the base case scenario. It only has 7.01% incremental. This scenario uses peripheral injection, which generally yields a maximum oil recovery with a minimum of produced water. The production of significant quantities of water can be delayed until only the last row of producers remains. Because of the unusually small number of injectors compared with the number of producers, it takes a long time for the injected water to fill up the reservoir gas space. The result is a delay in the field response to the flood. For a successful peripheral flood, the formation permeability must be large enough to permit the movement of the injected water at the desired rate over the distance of several wells spacings from injection wells to the last line of producers. Watered-out producers may be converted into injectors to keep injection wells as close as possible to the waterflood front without bypassing any movable oil. However, moving the location of injection wells frequently requires laying longer surface water lines and adding costs. Injection rates are generally a problem because the injection wells continue to push the water greater distances. This scenario also proved that this scenario might be better than the base case. STARS proved this simulator could not be used for Huff and Puff surfactant flooding conditions since STARS calculation depends on the capillary number, speed, and sensitivity grid. STARS does not calculate the soaking time. So for Huff and Puff condition, STARS not suitable for being used.

Figure 9. Oil Recovery Factor of Huff and Puff Surfactant Flooding

Inverted Five-Spot Pattern Scenario

A prior art well pattern comprised of a series of inverted five-spot sub-patterns is illustrated. In this configuration, the wells at the corners of each square are production wells, and a
single injection well is centrally positioned in the square. A breakthrough in the interface between the injected fluid and the oil bank cusps into each production well. As will be understood, in a series of five-spot sub-patterns, both conventional and inverted five-spot sub-patterns are present (Moore, 1983). If the injected fluid is more mobile than displacing fluid (viscosity oil high), a pattern is having more producers than injectors to balance production and injector rates. Injected fluid is less than mobile or when formation permeability is low, a pattern having more injector to the producer. For either the normal (or regular) 5 spot or inverted five spots (inverted means one injector per pattern), the ratio of producer and injector is 1:1. Therefore, pattern selection BJG Field chosen is an inverted five-spot pattern. The inverted five-spot pattern has one injector and four producers. An additional ten new producers and three injectors applied for building one pattern in the reservoir. The factors to which injection water-sensitivity studies relate are water-source and -volume options, source water/connate water compatibility, and source water/reservoir rock interactions. After the preliminary reservoir evaluation indicates that surfactant flooding is likely to be economically justified and that it will significantly increase the volume of oil recovered, the next consideration is to find an acceptable source from which to obtain enough water for the proposed design surfactant flooding project.

![Figure 10. Position injector and producer wells in Pattern](image)

Table 8. Well list is being used for Normal Inverted Five-spot

| Producer  | Injector  |
|-----------|-----------|
| P1        | BJG-120   |
| P2        | BJG-20    |
| P3        | BJG-93    |
| P4        | I6        |
| P5        | I2        |
| P6        | I1        |
| BJG-122   |           |
| P8        |           |
| P14       |           |

![Figure 11. Inverted Five Spot Well Management](image)

Injection Surfactant after water cut 96%, which is for this case, is in March 2028. We can see that the result has shown that this scenario is got higher recovery factor and cumulative oil than Huff ’n Puff Scenario.

![Figure 12. Oil Recovery Factor vs. Time for Inverted Five-spot pattern scenario](image)

The recovery factor can achieve until 38.76% and cumulative oil production 6.08 Mmstb. This scenario proved that with this scenario of inverted five spots, oil could sweep more than Huff’n Puff surfactant flooding case.

![Figure 13. Oil Saturation before and after surfactant Flooding: A. Before Surfactant Flooding Layer 10; B. After Surfactant Flooding Layer 10; C. Before Surfactant Flooding Layer 14; D. After Surfactant](image)
Flooding Layer 14; E. Before Surfactant Flooding Layer 16; F. After Surfactant Flooding Layer 16

Results of the STARS simulation shown that the sweep efficiency of this case has less residual oil saturation. The water cut reaches 96% in December 2029. Figure 13 shown that oil saturation already swept by surfactant flooding. At layer 10, residual oil saturation still exists. The solution that we need to find the best position for producer and injector wells and the rotation of the dynamic pattern. Wells spacing also needs to be considered. At layer 16, oil already swept better after surfactant flooding with the regular inverted five-spot pattern. It is due to the effect of the addition of the surfactant itself, lowering interfacial tension, swept efficiency increasing and recovery efficiency will be increasing.

**Dynamic Pattern of Inverted Five-Spot**

Figure 13 shown that not all residual oil saturation swept by inverted five-spot patterns. Therefore we need another method for sweeping the rest of residual oil saturation using Dynamic Pattern. The dynamic Pattern is conducted after the water cut reaches 96%. For dynamic patterns using an inverted five-spot pattern will be rotating dynamically 45 degrees as Figure 14. The formation of the dynamic pattern is shown in the below picture.

![Inverted five-spot pattern](image)

Inverted five-spot pattern with size 250 feet and distance between producer to the producer where $a = 176.77$ feet and distance between producer and injector, $l = 50$ feet.

![Well Spacing for region Zone-A](image)

Dynamic Pattern will start in December 2029 after the water cut reached 96%. The result of the dynamic pattern shown below:

![Oil Recovery vs. Time for dynamic pattern scenario](image)
Water cut reaches 96% twice when 2013 and December 2038. The second water cut is due to the sweep efficiency of the dynamic pattern of inverted five-spot. A measure of the effectiveness of an enhanced oil recovery process that depends on the volume of the reservoir contacted by the injected fluid. The volumetric sweep efficiency is an overall result that depends on the injection pattern selected, off-pattern wells, fractures in the reservoir, the position of gas-oil and oil/water contacts, reservoir thickness, permeability and areal and vertical heterogeneity, mobility ratio, density difference between the displacing and the displaced fluid, and flow rate. This result showed that volumetric sweep efficiency for this scenario has a better result than other scenarios. Recovery factor Dynamic pattern is 51.54%, which has incremental recovery from normal inverted five-spot is 12.78%. The recovery factor dynamic pattern could be the surfactant flooding job, which in surfactant flooding surfactant molecules act on the solid-fluid or oil/water interfaces. They are used either for wettability alteration or for lowering the oil/water interfacial tension (IFT). In the latter case, the molecules adsorb on the oil/water interface and reduce the IFT and capillary pressure responsible for the trapping of the oil in the pores. When used together with an alkali, surfactants reduce the IFT to a deficient value and, in principle, the reduction of the residual oil to nearly zero. Furthermore, low IFT implies that oil can be easily emulsified, which may offset the gain obtained from improved displacement because of the need to separate the produced oil by chemical methods. Surfactants can be injected into fractured carbonate reservoirs to improve oil recovery by spontaneous imbibitions into the matrix by wettability alteration.

Oil saturation after the dynamic pattern shown that residual oil saturation in the whole layer swept by surfactant flooding and dynamic pattern. It found that at least 90 percent of the area lying outside the last row of wells and within one well spacing of these wells would ultimately be swept by the injected water.

The highest oil recovery is the dynamic pattern case with the increment of RF is 21.53% from the base case scenario. We can see from the increment of RF that surfactant flooding gives more advantages than keep using the water flooding process in the reservoir with a high water cut. The differences of surfactant flooding and waterflooding simulation is that surfactant has lower areal sweep efficiency than waterflooding, and surfactant will be adsorbed into the rock that decreases the amount of surfactant flow into the producer. By using a surfactant, the water-oil IFT will be reduced then the residual oil will be decreased. It is why surfactant flooding gives higher oil recovery than waterflooding. Injection rates and concentration surfactant are essential parameters to be analyzed. Surfactant injection is a costly project, so we have to consider the
benefit of this project. Therefore we have to consider the economic factor of this project before we inject the surfactant into the reservoir. By having the right combination of rate injection and concentration of surfactant, the highest oil recovery and great benefit can be achieved. The higher the suitability formula of surfactant at certain reservoir conditions, the higher the RF value. Therefore, it is usually previously before injection performs laboratory research that matches the type of surfactant in which core samples have been taken as an example of a reservoir. A sensitivity analysis is essential because a chemical project has significant risks based on financial, process, and reservoir uncertainties. Chemical flood simulations are dependent on a large number of variables used for reservoir description, fluid and rock properties, and process design. Following the assessment of the base case simulation, a method of testing the sensitivity of each key process variable was generated with the intent of obtaining the optimum surfactant design and observing the effects of uncertain design parameters. One crucial obstacle of this study was designed within the field's well constraints, an important design parameter that can affect the project life, chemical behavior during the flood, and reservoir heterogeneity. One of the new techniques is introduced by a dynamic pattern case, and the collaboration with surfactant flooding, in this case, can be applied in a mature field. The five-spot pattern has a sweeping efficiency of about 72 percent (Crawford, 1960). There should be any calculation worked on some price sensitivity that is the oil price, surfactant price, and new reasonable price.

CONCLUSIONS

Dynamic Patterns can be applied in a mature field. The differences of Initial Oil in Place of PETREL and CMG is only 3.75%, so initialization for this model matches. The best scenario surfactant flooding for the mature field, especially BJG field is the dynamic inverted five-spot pattern shown with recovery factor, is 51.54%. RF Incremental between inverted five spot and dynamic pattern inverted five-spot is 12.78%. To obtain reliable surfactant flooding future performance prediction, we need to input the surfactant parameter derived from laboratory measurements. CMG does not account for the spreading of the adsorption of surfactants on the huff and puff scenario. Need to consider economic calculation for infill drilling and price of surfactant.

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NOMENCLATURE

\( P_c \) Capillary Pressure psi
\( N_{ca} \) Capillary Number
\( v \) Darcy velocity ft/s
\( \mu_w \) Water viscosity cp
\( \mu_o \) Oil viscosity cp
\( \gamma \) Interfacial Tension
\( S_w \) Water Saturation %
\( Boi \) Oil Formation Volume Factor
\( \phi \) Porosity %
\( K \) Rock Permeability mD
\( P_i \) Initial reservoir pressure psia
\( P_a \) Abandon reservoir Pressure psia
\( S_{wc} \) Critical water Saturation fraction
\( S_{or} \) Residual Oil Saturation fraction
\( B_w \) Water Formation Volume factor
\( OOIP \) Original Oil-In-Place

APPENDIXES

History Matching Result

History Matching Oil Rate

History Matching Water Rate Producer

History Matching Water Rate Injector

History Matching Water Cut

History Matching Gas Oil Rate
History Matching Pressure

![Graph showing pressure changes over time.](image-url)