Waterflooding Development Prediction in Carbonate Reservoir at Field X using Reservoir Simulation

Novia Fazilani¹, Sugiatmo Kasmungin²

¹ Petroleum Engineering Graduate of Trisakti University
² Lecturer Faculty of Earth Technology and Energy at Trisakti University

Email: noviafazilani@gmail.com

Abstract. Field X consist of a carbonate reservoir, producing since April 2014 with only 2 existing wells present, which is well NF-01 and NF-02. Production history of the field was performed from year 2014 until 2016. The original oil in place of Field X is 9.204 MMSTB (volumetric) and 9.0308 MMSTB (simulation). A method of optimizing Field X is Waterflooding after primary recovery has been done. In this study, the software used for the development of Field ‘X’ is Computer Modeling Group (CMG) IMEX Black Oil, by applying waterflooding as a method of optimizing the field, the optimization can be determined based on the consideration of various development scenarios. Reservoir simulation process consists of several steps which are; data preparation, model and grid construction, initialisation, history matching and prediction forecast. All the data up until history matching was given and the focus of this paper is to evaluate and predict several scenarios. The period of development is done for 19 years which is until December 2035. Several scenarios predicted were In-fill, conversion of wells, peripheral, 5-spot patterns and pilot studies. As the prediction developments were conducted, recovery from each scenario varies. These scenarios are then compared to be able to find the optimum result. After simulating several scenarios of as follows; infill-18 wells, infill-26 wells, infill-horizontal wells, covert all non-producing wells, peripheral wells, invert and normal 5-spot wells and comparing the recovery factor, it can be said that waterflooding implementation was insignificant as there were only a slight increase in recovery factor. The optimum scenario from waterflooding implementation is the peripheral pattern with a recovery factor of 38.17%.

Keywords: Waterflood; Injection; Carbonate; Reservoir; Simulation

1. Introduction
The first step in improving the oil recovery after natural depletion is injecting fluids that are initially not present in the reservoir for pressure maintenance. Although primary recovery may rely on the expansion of an aquifer or a gas cap that supports the pressure maintenance, in secondary recovery fluids are injected into the reservoir for this purpose. Waterflooding is the most commonly used secondary oil recovery method for both conventional and heavy oil reservoirs because of its relative simplicity, availability of water, and cost-effectiveness. Like primary recovery, the efficiency of waterflooding is determined by key factors, such as hydrocarbon properties, microscopic oil displacement efficiency, rock/fluid properties, and reservoir heterogeneities. Ultimately, the recovery factor for waterflooding is determined by a number of external factors, including the structure, number and placement of water injection and production wells. The choice of these parameters to maximize
the reservoir sweep is the first step of waterflooding optimization and an essential part of profitable field development planning. The optimization of waterflooding over the development of the reservoir has traditionally relied on the updating of reservoir models over large time intervals based on historical production data.

As for the application of these methods, simulation studies are often done in advance, where this process can be used as a determining factor as to whether or not that method should be implemented. Reservoir simulation is a developing application technique for reservoir development and management. It can be used to forecast the production behaviour of oil and gas fields, optimize reservoir development, and evaluate the distribution of remaining oil through history matching. It is an important tool that facilitates reservoir engineers as they work to optimize the design of well development schemes, improve the efficiency of reservoir development, and enhances in oil and gas recovery.

In this study, the software used for the development of Field ‘X’ is Computer Modeling Group (CMG) IMEX Black Oil, by applying the waterflooding as a method of optimizing the field, the optimization can be determined based on the consideration of various development scenarios. As various development scenarios have been achieved, the optimum field development scenario can then be selected.

Therefore in general, the application of reservoir simulation in Field X is intended to obtain optimum field development scenario for Field X, evaluate the performance of waterflood implementation and recognize the reservoir condition.

Field X is located at West Java where the reservoir consists of only one layer. The field currently has two existing wells producing from year 2014 with a cumulative production of 692.70 MSTB.

In this Paper, there are several scenarios obtained from production forecast such as; forecasting existing wells (base case), adding wells (infill) and five-spot patterns, waterflood exercises are also done for further analysis of the field. By modeling the reservoir, applying the fluid and rock characteristics and then applying for further development, the results obtained can predict the optimum development scenario for Field X. Further analysis of Field X is also done with pilot studies of different scenario patterns and also by changing the characteristics.

**Review of Waterflooding and Reservoir Simulation**

The terms primary oil recovery, secondary oil recovery, and tertiary (enhanced) oil recovery are traditionally used to describe hydrocarbons recovered according to the method of production or the time at which they are obtained. [1]

Primary oil recovery describes the production of hydrocarbons under the natural driving mechanisms present in the reservoir without supplementary help from injected fluids such as gas or water. In most cases, the natural driving mechanism is a relatively inefficient process and results in a low overall oil recovery. The lack of sufficient natural drive in most reservoirs has led to the practice of supplementing the natural reservoir energy by introducing some form of artificial drive, the most basic method being the injection of gas or water.

Secondary oil recovery refers to the additional recovery that results from the conventional methods of water injection and immiscible gas injection. Usually, the selected secondary recovery process follows the primary recovery but it can also be conducted concurrently with the primary recovery. Waterflooding is perhaps the most common method of secondary recovery. However, before undertaking a secondary recovery project, it should be clearly proven that the natural recovery processes are insufficient; otherwise there is a risk that the substantial capital investment required for a secondary recovery project may be wasted.
Carbone Reservoirs
The initial pore structure of carbonate sediments is similar to clastic sediments but is more varied because of the diversity of sediment. Because carbonate sediments are soluble and brittle, diagenetic processes often alter the properties of the original deposit and leave complex pore systems that may bear little resemblance to the original pore space.

Porosity in carbonate systems is categorized as primary or secondary by origin. Primary (or matrix) porosity refers to intergranular pore space between grain materials and/or skeletal materials that often have internal (cellular) porosity. Primary porosity is controlled by grain size and shape and by the nature of the skeletal organisms. Secondary porosity is created by diagenetic changes.

2. Method
Reservoir simulation is a developing application technique for reservoir development and management. It can be used to forecast the production behavior of oil and gas fields, optimize reservoir development schemes, and evaluate the distribution of remaining oil through history matching. It is an important tool that facilitates reservoir engineers as they work to maximize the design or patterns of well development scenarios, improve the efficiency of reservoir development, and enhance oil and gas recovery. The steps in reservoir simulation consist of data preparation, model making, initialization, history matching and forecast.

3. Results and Discussion
The scenarios of the production performance are: Scenario I (Base Case), Scenario II (Base Case + Infill 18), Scenario III (Base Case + Infill 26), Scenario IV (Scenario I + 2 Horizontal Well), Scenario V (Convert all production shut wells into Injector), Scenario VI (Peripheral Injection), Scenario VII (Normal 5-Spot Pattern), Scenario VIII (Invert 5-Spot Pattern).

In Scenario I, the two existing wells are forecast until year 2035, where the forecast is done without any other activities added. With natural flow with a driving mechanism of Water Drive, the cumulative production is 692.7 MSTB and a recovery factor of 7.67%.

Scenario II (Base Case + Infill 18), there will be an infill of 18 additional wells; with a total of 20 wells where the assumption was that the well drainage is 250 meters. Many trials were conducted on an optimum positions of the infills and therefore the results were that the cumulative production is 3414.5 MSTB with a RF of 37.81%.

Scenario III (Base Case + Infill 26), there will be an infill of 26 additional wells, with a total of 28 wells where the assumption was that the well drainage is 125 meters. The cumulative production is 3540.4 MSTB with a RF of 39.2%.

Scenario IV (Scenario I + 2 Horizontal Well), there will be an additional 2 horizontal wells from Scenario I with 20 wells, totalling of 22 wells. Many trials were done on the best position for the horizontal wells, but since Field X itself is not that big in terms of space and area, it was quite difficult to implement this scenario. The results were that the cumulative production is 3468.3 MSTB with a RF of 38.4%.

Scenario V (Convert all production shut wells into Injector), all production wells that have passed their economic limit of 10 bbl/day will be shut, and convert into an injection well according to their shut in dates. There are a total of 16 wells converted, including the existing wells, where the remaining 4 wells continue producing until year 2035. All the 16 shut wells vary in shut in dates, so the conversion
date of each well varies. The results were that the cumulative production is 3416.4 MSTB with a RF of 37.83%.

Scenario VI (Peripheral Injection), 14 injectors are placed around the reservoirs from Scenario II, totalling up to 34 wells. The injection wells are located at the external boundary of the reservoir and the oil is displaced toward the interior of the reservoir, forming a peripheral pattern. The constraints were BHP of 1500 psi and an injection rate ranging from 500 to 2000 bwpd. The results were that the cumulative production is 3447.1 MSTB with a RF of 38.17%.

In Scenario VII (Normal 5-Spot Pattern), 4 injection wells are assigned to each particular production well resulting in a normal 5-Spot pattern. This pattern is the most commonly used flooding pattern resulting primarily from the regular well spacing required, therefore the amount of injection wells is greater than of the production wells. No production wells are converted in this matter because the objective here is to optimize almost all the productive wells. In this case, 35 additional injection wells were added where the constraints were BHP of 1500 psi and an injection rate ranging from 500 to 2000 bwpd. The results were that the cumulative production is 3438.2 MSTB with a RF of 38.07%.

Scenario VIII (Invert 5-Spot Pattern), for every four producing well, one injector is assigned to every 4 production wells; the purpose is to increase the performance of those four producing wells. The constraints were BHP of 1500 psi and an injection rate ranging from 500 to 2000 bwpd. The results were that the cumulative production is 3410.6 MSTB with a RF of 37.76%.

| Scenario | Number of Wells | Recovery Factor (%) | Incremental RF Towards Scenario I |
|----------|----------------|---------------------|----------------------------------|
| 1        | 2              | 7.67                | 0                                |
| 2        | 20             | 37.81               | 30.14                            |
| 3        | 28             | 39.20               | 31.53                            |
| 4        | 22             | 38.40               | 30.73                            |
| 5        | 20             | 37.83               | 30.16                            |
| 6        | 34             | 38.17               | 30.5                             |
| 7        | 65             | 38.07               | 30.4                             |
| 8        | 27             | 37.76               | 30.09                            |
| 9        | 33             | 38.09               | 30.42                            |

Summarising all the scenarios above (Can be seen in Table.1), the highest recovery factor obtained is the peripheral pattern. But the increase of recovery itself from the implementation of waterflooding is not significant. Many factors contribute to the reasoning of why the implementation of waterflooding
at Field X is not suitable such as; the driving mechanism, rock formation, rock characteristics and reservoir properties.

When Waterflooding a carbonate reservoir, one must consider the same issues that affect any type of recovery. The factors that cannot be changed, the properties of the formation itself, must be worked around and the water used in flooding modified.

In waterflooding, the water displaces oil from the pore spaces, but the efficiency of such displacement depends on many factors, including oil viscosity and rock characteristics. Because carbonate surfaces are positively charged, the water must be altered, generally by adjusting the salinity, which will affect the concentration of sulfate ions (SO$_4^{2-}$), calcium ions (Ca$^{2+}$), or magnesium ions (Mg$^{2+}$).

Studies have found that lowering the salinity of the injection water to different degrees can change rock wettability and improve oil recovery. But it still is not clear why lower salinity water causes this effect. According to Gupta, et al. three main theories exist:

1. Rock dissolution: First proposed by Hiorth et al., this theory explains the low-salinity effect by hypothesizing that the lower calcium concentration in low-salinity brine causes calcium carbonate from the rock to dissolve and establish equilibrium with the brine. When the calcium carbonate dissolves, the adsorbed oil components are removed and the rock surface is rendered more water-wet.

2. Surface ion exchange: At typical carbonate reservoir conditions, rock surfaces have a positive charge while the acidic components of oil have a negative charge, causing the rock to be oil-wet or mixed-wet. If the determining anions in the water (e.g. SO$_4^{2-}$) have a higher affinity to the rock surface than the acidic oil components, the anions are adsorbed and the oil is desorbed. If the rock surface charge is decreased (e.g. because of low salinity), desorption of negatively charged oily material is also facilitated.

3. In-situ surfactant formation: The potential of in-situ surfactant generation requires a high pH and Hiorth et al. determined it to be a rare mechanism in waterflooding.

Because about 80% of these geologic formations are oil-wet, carbonate reservoirs pose a problem in oil recovery. The negatively-charged carboxylic acid anions in oil are attracted to positively-charged carbonate surfaces, thus generating oil-wet surfaces. Waterflooding can be ineffective in recovery from carbonate reservoirs because the capillary pressure curve is predominantly negative, therefore surfactant/polymer waterflooding is considered by some in the industry to be a more viable option.

4. Conclusions
The recovery factor obtained from Scenarios before waterflooding (infill) were 37.8%, 39.20%, 38.41% and has chosen Scenario II with a RF of 37.8% as a platform for the implementation of waterflooding. The optimum RF obtained in the Waterflooding Scenario is 38.17% which is the Peripheral Pattern where 14 injectors were placed around the reservoir. Although, many scenarios were conducted, the RF incremental of primary and secondary was not significant therefore implementation of Waterflooding is not suitable for Field X.

Many factors contribute to the reasoning of why the implementation of Waterflooding was not suitable such as; the driving mechanism, rock characteristics and reservoir properties. Carbonate reservoirs present a number of specific characteristics posing complex challenges in reservoir characterization, production and management. The negatively-charged carboxylic acid anions in oil are attracted to positively-charged carbonate surfaces, thus generating oil-wet surfaces, water flows more freely than oil as the oil has the tendency to adhere to the rocks more, and usually oil wet reservoirs tends to have a higher residual oil value. Other recovery method is recommended such as implementation of EOR, specifically chemical flooding of low surface acting agents’ concentration or altering the salinity of the injection fluid in order to change the rock wettability.

5. References
[1] Ahmed, Tarek H., Reservoir Engineering Handbook, Gulf Publishing Company, Houston-Texas, 1989

[2] Alotaibi M.B., Nasralla R.A., and Nasr-El-Din H.A. Wettability Challenges in Carbonate Reservoirs, Presented at the SPE Improved Oil Recovery Symposium, Tulsa, Oklahoma, USA, 24-28 April 2010. SPE-129972, 2010

[3] Buckley, S. E. and Leverett, M. C. Mechanisms of Fluid Displacement in Sands, Trans. AIME (1942) 146,107-116

[4] Craft F.F, Jr., The Reservoir Engineering Aspects Of Waterflooding, Ameco Production Company SPE of AIME, New York, 1978

[5] Doherty, H. L, Basic Applied Reservoir Simulation, Society of Petroleum Engineering, Richardson Texas, 2001

[6] Mattax, Calvin,C. and Robert L. Dalton, Reservoir Simulation, SPE Monograph, Richardson, Texas. 1990

[7] Okasha, Taha M. 2014. Wettability Evaluation of Arabian Carbonate Reservoir after Prolonged Water Injection: A Case Study. Adapted from extended abstract prepared in conjunction with poster presentation at GEO-2014, 11th Middle East Geosciences Conference and Exhibition, 10-12 March 2014

[8] Thakur, Ganesh C and Abdus Satter, Integrated Waterflood Asset Management, PennWell Books, Tulsa, Oklahoma, 1998

[9] Willhite, G, Paul. Waterflooding, SPE Textbook Series, Richardson, Texas, 1986