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Study of Low Salinity Water Flooding in Naturally Fractured Carbonate Reservoirs

Lv, Jiateng

UNIVERSITY OF CALGARY

Study of Low Salinity Water Flooding in Naturally Fractured Carbonate Reservoirs

by

Jiateng Lv

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Abstract

With the rapid development of the petroleum industry, the oil and gas exploration field has been expanding, and carbonate reservoirs have been discovered in large quantities. Carbonate rocks contain more than 50% of the global hydrocarbon reserves and Carbonate Reservoir occupy a very important role in the distribution of oil and gas fields in the world.

Low salinity waterflooding has been identified as a promising technology to improve oil recovery. However, the main mechanisms supporting this recovery method have not been fully understood, especially for applications in the Naturally Fractured Carbonate Reservoirs, which presents challenges in designing the optimal salinity of injection solution. Changing the wettability to a more ideal state for oil recovery during low salinity water injection is the main reason.

The thesis applies Low Salinity Waterflooding in Naturally Fractured Carbonate Reservoir. The performance and key mechanism of Low Salinity Waterflooding applied in a Naturally Fractured Carbonate Reservoir is conducted through reservoir simulation. Three different salinity fluids are designed to be injected into three types of reservoirs to investigate the performance of a salinity waterflood in Naturally Fractured Carbonate Reservoir and provide feasibility for future development in Naturally Fractured Carbonate Reservoir

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Symbols	Definition
Aβ	reactive surface area
Eaβ	the activation energy
kf_x; kf_y, kf_z	Fracture Permeability
Koβ	the reaction rate constant (*LOG-TST-RATE-CONSTANT)
k_{rw}	water relative permeability at the average water saturation in the swept zone
μw	water viscosity
k_{ro}	oil relative permeability in the oil bank ahead of the water (normally equivalent to 1.0)
μo	oil viscosity
k_x; k_y, k_z	Matrix Permeability
kβ	rate constant of mineral reaction β
M	Mobility ratio
ϕ	Fracture porosity
Qb	analogous to the activity product for aqueous reactions (ie. related to molality).
$sigma_{x,y,z}$	Fracture Spacing
So	oil saturation at the start of the waterflood
Som	Mobile oil saturation
Sorw	the residual oil saturation to water
λ	Interporosity Flow Coefficient
ω	Storativity Ratio

Abbreviations

EDL	electric double layer
EOR	Enhanced Oil Recovery
IFT	interfacial tension
LSW	Low-Salinity Water
MIE	multiple ion exchange
NG	Net to Gross
OOIP	original oil in place
OWC	oil-water contact
PVT	Pressure volume temperature
RF	recovery factor
TDS	Total Dissolved Solids
WAG	water-alternate-gas

Chapter One: INTRODUCTION

1.1 Carbonate reservoir description

With the rapid development of the petroleum industry, the oil and gas exploration field has been expanding, and carbonate reservoirs have been discovered in large quantities. Carbonate reservoirs occupy a very important position in the distribution of oil and gas fields in the world. According to statistics (Yanhui et al., 2011), among the more than 200 large oil fields in the world, 40 % are carbonate reservoirs. Carbonate reservoirs are dominantly composed of limestone and dolomite, and account for about 20% of the world's sedimentary rocks. At present, more than 40 countries and regions in the world have found carbonate reservoirs, and their original production accounts for more than 60% of the world's crude oil production. Figure 1.1.1 shows the Geographic Distribution of Carbonate Reservoirs in the world. However, there are still many shortcomings in the development of carbonate reservoir technology. Therefore, how to effectively develop carbonate reservoirs has become an important topic in today's oil industry.

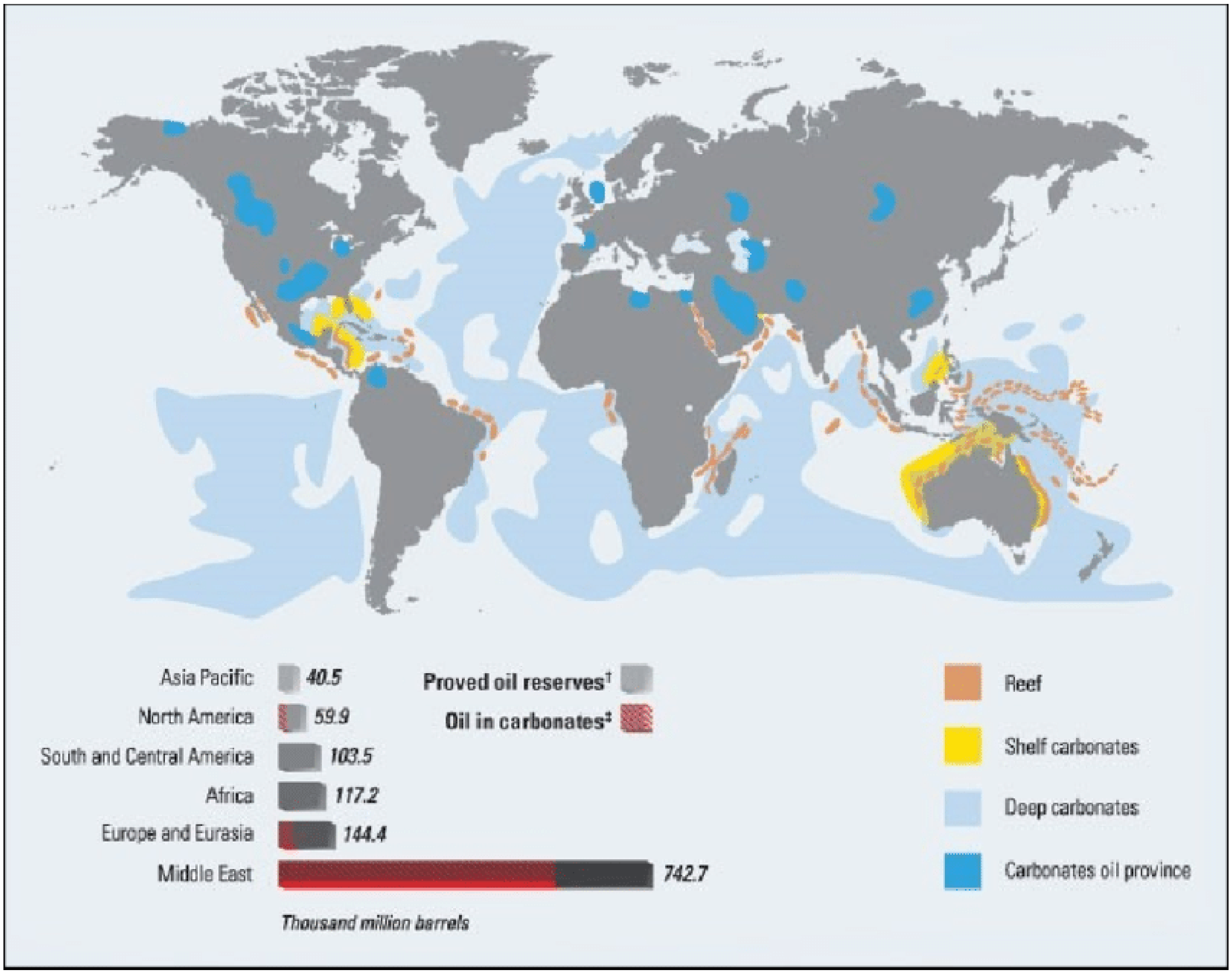


Figure 1.1.1 Geographic Distribution of Carbonate Reservoirs (Muriel 2007)

1.2 Development characteristics of carbonate reservoirs

Due to the geological influences of natural energy, development degree, fault and vertical crack development degree of carbonate reservoirs, oilfields show different development characteristics in terms of water content increase, production decline and formation energy change, fully reflecting the complexity of carbonate reservoirs and the difficulty of mining. The specific characteristics are as follows:

1.2.1 Changes in water content

According to the characteristics of single well production in oil fields, the water content changes of carbonate reservoirs are mainly divided into three types: intermittent effluent, violent flooding and slow rise. Rapid production declines are indicative that the size of the reservoir encountered are relatively small and the connectivity is relatively poor, and the phenomenon of cave collapse may occur.

1.2.2 Changes in oil well production

The changes in carbonate reservoir production can be divided into three types: rapid decline, intermittent production and slow decline. Slowly decreasing oil wells indicate that the size of the reservoirs encountered in the drill is relatively large and there is good connectivity. The intermittent production type of oil wells shows that the storage connectivity and scale distribution of the reservoirs encountered are more complicated. Wells with a rapidly declining production rate indicates a reservoir with low permeability and/or insufficient pressure support.

1.2.3 Changes in formation energy

At the beginning of the oilfield production there were fewer oil wells, this resulted in a slower pressure drop. However, as the number of oil wells put into production continues to increase, the pressure plummets. As the single well production intensity decreases and the water content of the carbonate reservoir increases, the capacity of the reservoir bottom water is replenished, making the pressure drop relatively slow. According to the oil and gas capacity evaluation standard, the formation capacity has a certain amount of natural energy, and the total pressure drop of the geological reserves produced by each layer belongs to a relatively ample pressure range. Therefore, the energy of carbonate reservoirs is relatively abundant and has a certain natural ability. However, with the complexity of the reservoir distribution of carbonate reservoirs, as the oilfield continues to develop the fracturing between the formations becomes uneven, so it is necessary to inject water into the developed areas of the carbonate reservoirs. This is the optimal way to maintain the energy of the formation.

1.3 Measures to improve the development level of carbonate reservoirs

1.3.1 Fresh Water injection

Since the geological conditions of carbonate reservoirs are more complicated, the water content of most oil wells rises faster, therefore maintaining formation pressure can effectively avoid cracking, closure or collapse of the formation skeleton. For carbonate reservoirs with larger scale and better connectivity, the method of water injection development can effectively prolong the life of carbonate reservoir production and thereby greatly improve oilfield production and ultimate recovery factor. The numerical results of carbonate reservoirs show that water injection in the later stage of oilfield development can effectively improve oil production speed and annual production. For the layered carbonate reservoirs with edge water and fracture development and insufficient edge water energy, it is best to inject water into the edges of the reservoir to resupply the natural edge water. If the area of the carbonate reservoir is relatively large and internal water injection energy is required, a combination of edge and central injection method will be taken. The internal water injection wells should take control of the water injection volume and water injection intensity. Also, an intermittent water injection method or mild water injection method should be applied to the carbonate reservoir. Over all, in the development of carbonate reservoirs, water injection can be used to supplement the formation energy, thereby improving the development efficiency of carbonate reservoirs.

1.3.2 Reasonable oil production speed

Because the bottom water distribution of carbonate reservoirs is not uniform, only by increasing the number of producers and/or injectors in the reservoirs can the oil recovery be optimized, so that the carbonate reservoirs can maximize the economic and social benefits in the development process. According to the geological characteristics of carbonate reservoirs and production dynamics, it is necessary to effectively determine the oil recovery rate

1.3.3 Development of natural energy

Carbonate reservoirs have a certain amount of natural energy, and the natural drive types mainly include bottom water drive and elastic drive. Because carbonate reservoirs have complex water bodies, as the reservoir pressure gradually decreases the rock skeleton of carbonate reservoirs collapses or deforms. This will cause the formation cracks to close or generate cracks to connect with the water body and may even lead to an acceleration of oil filed decline rate and violent flooding. In short, the determination of natural energy plays an important role in the development of carbonate rock.

1.3.4 Development of well spacing and well pattern

The collective distribution of carbonate reservoirs is closely related to the development of karst caves, and the distribution of caves on the plane is uneven and zoning. Therefore, the development of carbonate reservoirs should be determined based on the distribution of ancient karst caves. The size of caves in the ancient near-surface dissolved reservoirs is relatively small, which is mainly based on cracks and dissolved pores, therefore the size distribution of caves in the ancient karst waterway reservoirs of carbonate reservoirs is uneven. According to the distribution density of the cave, the understanding degree of the reservoir and the numerical value of the carbonate rock, the development well spacing and the well pattern are mainly distributed according to the ancient near-surface karst reservoir, so that the oil can be effectively developed from the carbonate reservoir

1.4 Conclusion

According to the above argument, the carbonate reservoir has a certain elastic drive and low water driving energy. The use of water injection for carbonate reservoir can effectively extend the production life of the oilfield, thus effectively developing the carbonate reservoir and greatly improve oilfield production.

Chapter Two: LITERATURE REVIEW

2.1 Waterflood Description

Waterflooding is the most successful and widely used enhanced oil recovery method of secondary recovery, in which water is injected into the reservoir formation to displace residual oil. Waterflooding is also a preferred method due to water being widely available and inexpensive relative to other fluids, easy to inject, and highly efficient in displacing oil. Besides, water flooding has relatively small damage to the formation. During water injection, other methods for improving oil recovery factor in the reservoir can be further applied. Figure 2.1.1 shows a brief description of waterflooding. The water from injection wells physically sweeps the displaced oil to adjacent production wells. The principal reason for waterflooding an oil reservoir is to increase the oil-production rate and, ultimately, the oil recovery. This is accomplished by "voidage replacement"—injection of water to increase the reservoir pressure to its initial level and maintain it near that pressure. The water displaces oil from the pore spaces, but the efficiency of such displacement depends on many factors including: Mobile oil saturation and Mobility ratio significantly affect waterflood efficiency. (Petrowiki.org, 2019)

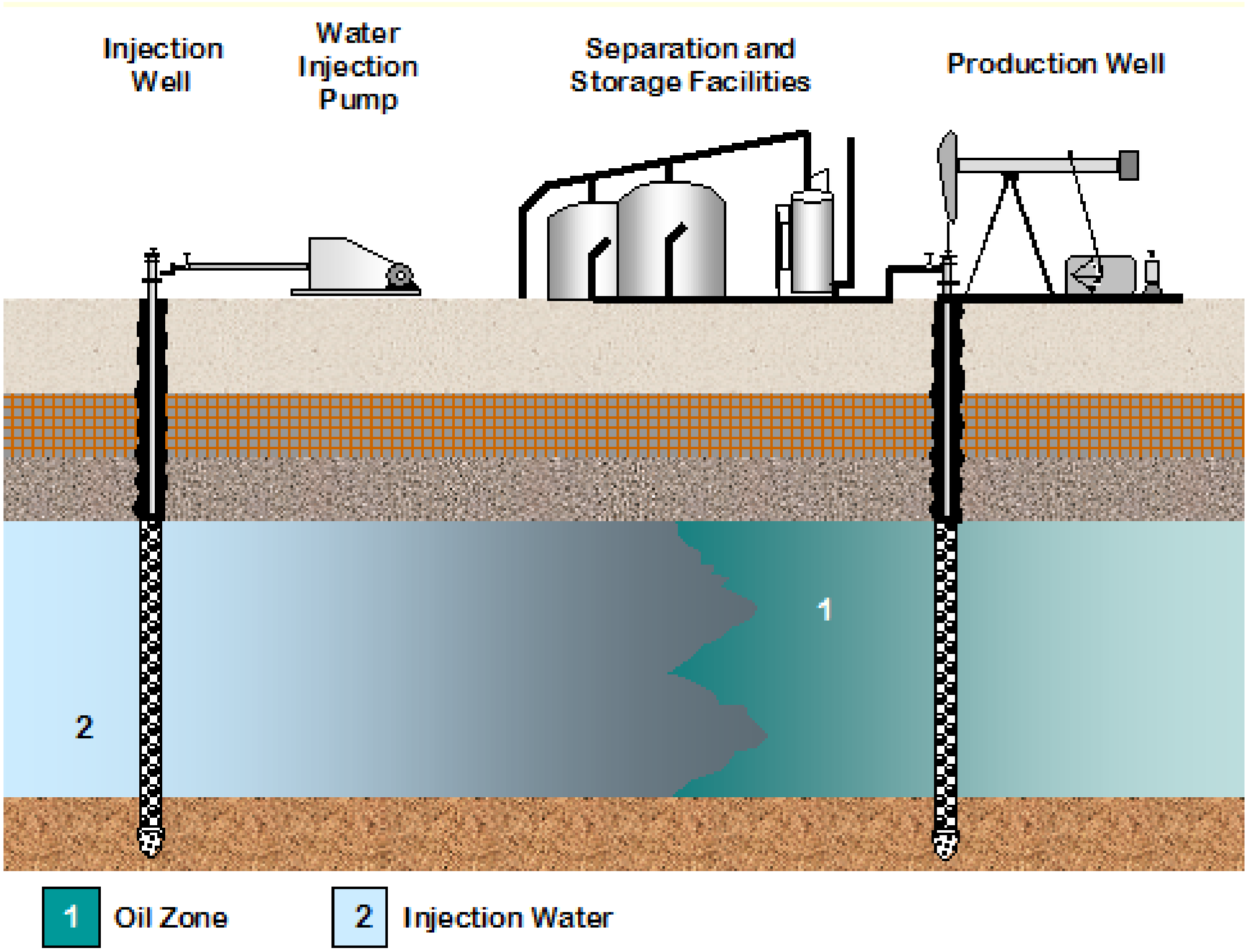


Figure 2.1.1 Waterflooding Description (Waterflooding)

Mobile oi1 saturation is the oil saturation at the start of the waterflood, S_o, minus the residual oil saturation to water, S_{owr}.

$$\mathbf{S_{om}} = \boldsymbol{S_o} - \boldsymbol{S_{orw}}$$

Higher values of mobile oil saturation results in higher waterflood oil recovery.

Mobility ratio, M, is the water mobility in the water invaded portion of the reservoir divided by the oil mobility in the non-contacted portion. In turn, the mobility of the fluid is the permeability of the rock to that fluid divided by the fluid viscosity. Hence, in terms of relative permeability:

$$\mathbf{M} = \frac{k_{rw}}{\mu_w} / \frac{k_{ro}}{\mu_o}$$

Below, Figure 2.1.2 illustrates the relationship between rock wettability to water-oil mobility ration and oil viscosity.

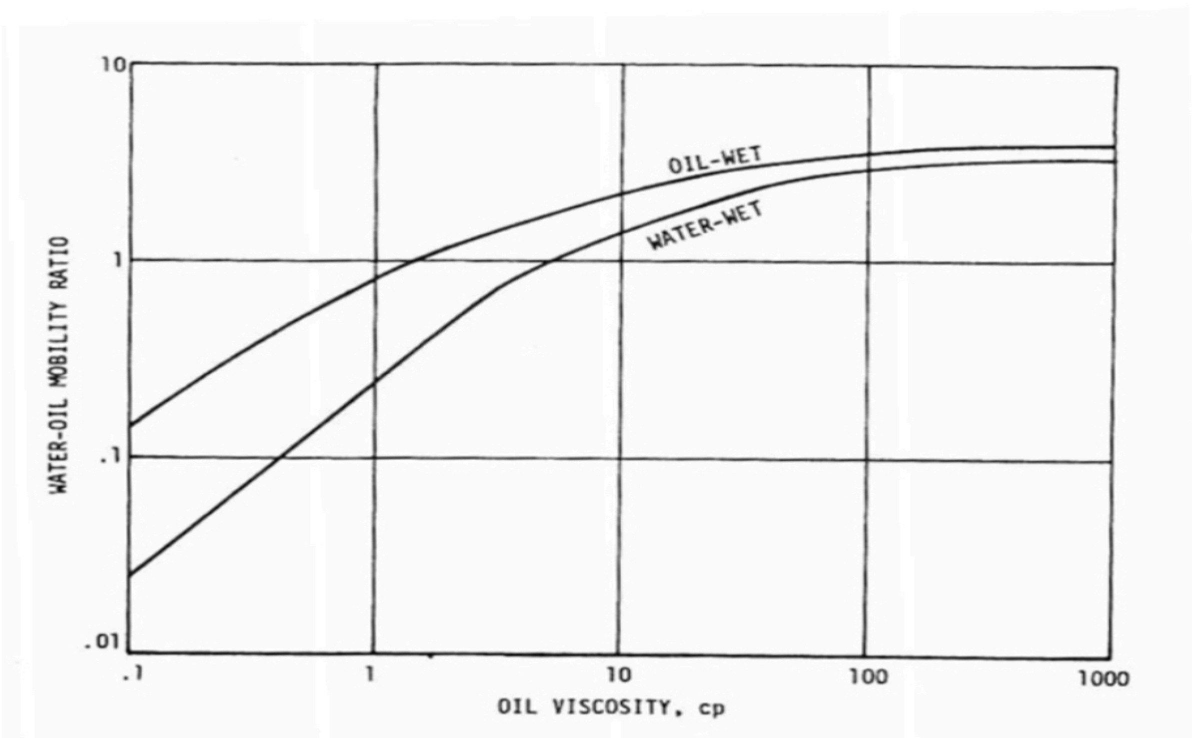


Figure 2.1.2 Effect of oil viscosity and rock wettability on mobility ratio, water viscosity = 0.5 cp. (Interstate Oil Compact Commission, 1983).

In carbonate systems, the injected water will dissolve minerals as it moves through the formation until it reaches saturation, and then precipitate scale as pressure drops in the producing wellbores. The only effective solution to this problem is to squeeze inhibitor into the formation periodically, but these treatments can be expensive. One work-around solution is to use brackish water as make-up water with the water injection system described above.

2.2 Low Salinity Water Flooding Description

A brief description of low salinity water flooding is the water injection with salinity lower than the formation brine salinity to improve oil recovery. The word "Salinity" defined in terms of the Total Dissolved Solids (TDS), which includes monovalent/divalent Anions and Cations. Salinity can be simply divided into two categories, Low Salinity Brine and Formation Brine. The fluid contains 500 – 3000 ppm (CMG, 2017) total dissolved solids are classified as Low Salinity Brine, and fluid contains more than 30000 ppm (CMG, 2017) total dissolved solids is classified as Formation Brine. In general, water flooding typically involves the injection of seawater, with a salinity of about 35000 to 40000 ppm (CMG, 2017), or reinjection of produced water, the formation brine, or water from another higher saline source.

From the result of field applications and laboratory tests, the low-salinity water (LSW) injection is one of the most valuable EOR methods because of its lower chemical cost, less environmental impact and better field-scale implementation compared with the conventional chemical EOR methods (Dang et al. 2013; Zeinijahromi et al. 2015). In addition, low-salinity water injection can be combined with a variety of existing methods to improve the oil recovery factor, which assists in further improving reservoir production efficiency. Observation of waterflood core experiments implemented a few year ago discovered that higher oil recovery will be obtained when done on core with high-salinity initial water with low salinity. The salinity waterflooding influences the wettability of the formation, thereby allowing it to have better production performance than water flooding. Since the low salinity waterflooding benefits and effects have drawn the attention of the oil industry, more and more laboratory core-flood research has been carried out and several companies have progressed to field tests. Because low salinity waterfloods can enhance oil recovery by changing the ionic component or brine salinity, low salinity water injection has been utilized as a promising oil recovery method in recent years. The applications of nanoparticles with low-salinity water flooding has also exhibited remarkable results in enhanced oil recovery (Sheng, 2014; Ebrahim et al.2019)

A study conducted by Reiter (1961) investigates the first signs of an expected improvement in oil recovery during the low-salinity waterflood. He compared oil production rate increases with water injection at different salinities. Later, Bernard (1967) examined the relative effectiveness of freshwater and saltwater during water injection and demonstrated that the oil recovery increased when water salinity dropped from 15,000 to 100 ppm, Tang and Morrow (1997) also investigated the benefits of reducing brine salinity on oil recovery performance. Figure 2.2.1 shows the difference in mobilization of crude oil with different salinity water injection.

In terms of low salinity water injection, a large amount of published data indicates that the interaction of many factors such as crude oil properties, brine salinity, brine composition, rock mineral composition, and reservoir temperature can affect oil recovery (Purswani et al. 2017). Jadhunandan and Morrow (1995) and Yildiz and Morrow (1996) confirmed that the brine composition influences the oil recovery efficiency of water flooding, they also discovered that the brine composition can be modified to optimize the recovery efficiency of water flooding. Austad et al. (2007, 2011), Fathi et al. (2010), Zhang et al. (2006) and Qiao et al. (2014) also indicated that improving oil recovery is not only due to low salinity, but also depends on the specific composition of the injected water (Qiao et al., 2016). Based on extensive laboratory research on carbonate and sandstone reservoirs, the presence of Mg2 +, Ca2 +, and $SO4^{2-}$ ions in seawater has proven to be potentially decisive ions that will increase oil production during Low Salinity Waterflooding (Bader 2007; Puntervold et al. 2007; Shariatpanahi et al., 2010; Strand et al., 2008; Zhang et al., 2007a)

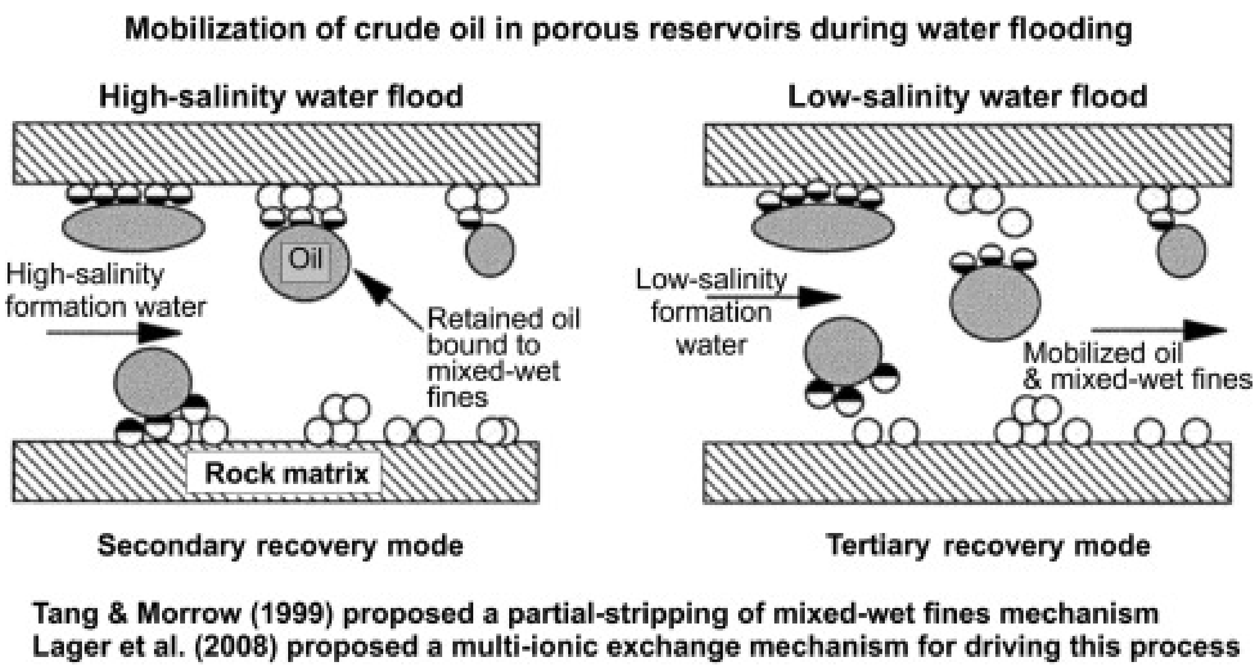


Figure 2.2.1 Crude Oil Mobilization with different salinity waterflooding (Yuan, B., & Wood, D. A. (2018))

2.3 Waterflooding to Low Salinity Waterflooding

Conventional waterflooding is a method of secondary recovery in which water is injected into a reservoir to achieve additional oil recovery, supplement natural energy and maintain formation pressure. At present, water injection is a simple, reliable and economical oil recovery technology that is accepted worldwide. Most of the traditional reservoirs have been, are being or will be considered to apply waterflooding as the secondary oil recovery.

In most water injection projects, especially in offshore oil fields, injection water is usually selected based on economic considerations and the compatibility of the injected water with the existing reservoir brine to avoid damaging the formation. However, several authors have reported that injecting low-salinity brines can increase oil recovery by a factor up to 40% compared to conventional high-salinity water injection in different sandstone reservoirs, because low salinity brines have a better effect on changing reservoir wettability (McGuire et al., 2005). A research of Morrow shows that based on experiments and research, the lower salinity brine injection improves the recovery factor by about 29% more than higher salinity brine injection (McGuire et al., 2005).

Low-salinity waterflooding has a bright future because 50% of the world's conventional oil reservoirs are located in sandstone reservoirs and most of them contain clay minerals, which are favorable conditions for Low-salinity waterflooding (Dang et al., 2016). The ionic composition of injected brine could impact oil recovery in sandstones. Numerous experimental data and industrial results demonstrate that higher oil recovery is observed for the Low Salinity process compared to water flooding.

In addition, compared to other chemical EOR technologies, Low-salinity waterflooding can achieve considerable low-cost recovery with relatively simple operations. Low-salinity waterflooding can also be considered for secondary and tertiary recovery or combined with other EOR methods such as chemical flooding (such as polymers or surfactants) or miscible water-alternate-gas (WAG) to improve oil recovery. The cost of Low Salinity Water Injection is inexpensive because there are no expensive chemicals required. Also, according to industry reports, by using Low-salinity waterflooding, the amount of oil recovery can increase by 6% to 12% of original oil in place (OOIP), and residual oil saturation can decrease by 25% to 50% (Dang et al., 2016). The improvement in oil recovery is seen within lab experiments and Single-Well Chemical Tracer tests of as much as 38%, and an additional recovery of 29% in reservoir cores is obtained by reducing the salinity of the injected water. Figure 2.3.1 shows the growing interest in the Low Salinity Process.

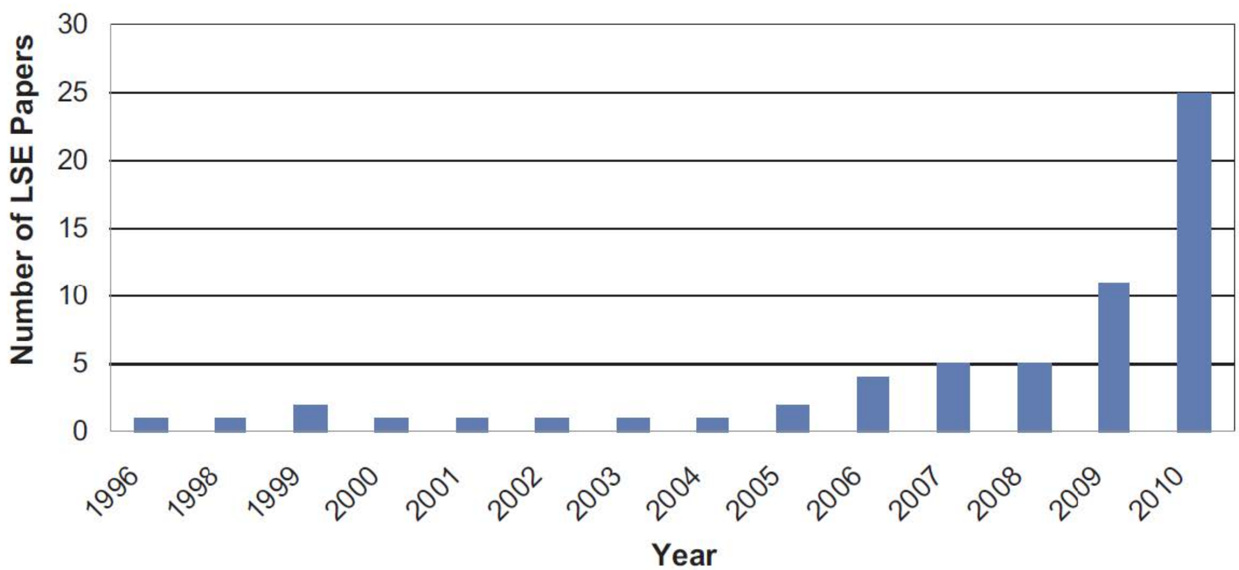


Figure 2.3.1 Growing Interest in the Low Salinity Process (Morrow et al., 2011)

2.4 Low Salinity Water Flooding Mechanisms

Four key variables of reservoir properties affect the Low Salinity process. The Reservoir Lithology affects the presence of Clay minerals (primarily kaolinite) in the formation, and there is no beneficial effect observed in clastics in the absence of clays. The Composition of Crude Oil affects the presence of polar components in crude oil, and there is no benefit been seen with Synthetic and Depolarized Oils; the naturally occurring surface active agents (resins and asphaltenes) can change the rock wettability. The presence of Connate Water indicates there is no benefit seen in dry outcrop cores saturated with 100% oil. The Divalent Ion Content in the Formation Water affects the presence of divalent ions (Ca2+, Mg2+) necessary for clastics plus $SO4^{2-}$ for carbonates.

Today, industry is increasingly inclined to use Low-salinity waterflooding to improve oil recovery, but no specific mechanism has been proposed yet. Researchers such as Tang and Morrow have shown that relative water and oil permeability will change through Low-salinity water injection and rock wetting conditions tend to be more water wet. Therefore, at a given water saturation, the relative permeability of the oil will increase, which will cause less oil trapping in the pore structure. However, the complexity of the composition of the mineral, oil, and water phases creates severe conditions for explaining the reasons for this phenomenon (Atthawutthisin 2012).

Different physical and chemical mechanisms have been proposed to verify that wettability changes are one of the main reasons for enhanced oil recovery by Low-salinity waterflooding in sandstones and carbonates. These mechanisms are divided into salting out, multiple ion exchange (MIE), fine particle migration, electric double layer (EDL) expansion, mineral dissolution and pH adjustment (Purswani et al. 2017). Higher oil recovery can be observed for Low Salinity Multi-ion Exchange

(MIE). The Multi-ion Exchange (MIE) for sandstone is concerned with cation exchange, while for carbonates, it is anion exchange. In rock dissolution, the transformation of chalk to other minerals was suggested as the mechanism for wettability alteration for chalks. In fines migration, the release of fines would increase the water wetness; transportation of fines would block some pore-throats, which will divert fluid flow and increase sweep efficiency.

Austad et al. (2010) purpose the concept of salting-in machine for sandstone reservoirs. They suggested that clay particles act as cation exchangers on the sandstone surface. For carbonate rocks, a similar mechanism is also proposed, which is described as a rock dissolution mechanism and is the result of the wettability change process caused by the migration of divalent ions from the rock surface toward the brine.

To illustrate the phenomenon of rock dissolution in carbonate reservoirs, Yousef et al performed a zeta potential measurement. (2011) because it has been widely used to determine the surface charge of rocks in specific saltwater environments (Esmaeili et al., 2016; Rahbar et al., 2017; Vinogradov et al., 2010). Their results showed that the zeta potential of the carbonate surface is reduced, and the salinity of the brine is decreased as well, this indicates that Ca2 + ions migrate from the rock surface to the low-salinity brine to re-establish the chemical balance between saline and rocks (Purswani et al. 2017). In addition, in the presence of low salinity water, the reduction of the positive charge on the carbonate surface causes the electric double layer to swell and results in a thicker, more stable water film.

Electric double layer is also considered as a possible mechanism for sandstone reservoir wettability changes, which is highly dependent on the electrostatic interactions between brine-oil and brine-rock interfaces (Myint and Firoozabadi 2015; Nasralla and Nasr -El-Din 2014). Electric double layer is a function of the pH and salinity of the brine and the type of cations surrounding the clay or sandstone particles. As electrolyte concentration in brine is reduced, the screening potential from ions would be correspondingly lowered down. This would induce the expansion of electrical double layers surrounding the mineral particles and oil droplets. Then, the repulsion force between these particles and droplets would increase, which could stimulate mineral particles and/or oil droplets liberation, and eventually induce fines migration and/or wettability alteration. Based on this mechanism, when low salinity water is injected, electric double layer will expand at the oil-brine interface and rock-brine interface. The expansion of the electric double layer results in an overlap between the two electric double layers, which leads to an increase in the repulsive force between them. When these repulsive forces exceed the binding force between the acidic groups in the oil and the clay surface, the water layer between the oil and the clay surface swells, resulting in the oil particles to desorb from the clay surface and the water wettability of the oil surface increase (Hilner et al. 2015; Myint and Firoozabadi 2015).

When ions are present in a system that contains an interface, the ion density will vary near that interface. The boundary we identify as the surface defines the surface excess charge. If it is possible to separate the two bulk phases at this boundary, each of the separated phases carries an equal and opposite charge. These two charged portions of the interfacial region are known as an electrical double layer.

An electrically charged surface in contact with water generates an electrical field that attracts oppositely changes ions; these ions form a diffuse layer of charge outside the charged surface. The diffuse layer of charge and the surface charge form a so-called electrical double layer. The Electric double layer is electrically neutral. Lowering the water salinity develops a thicker water film when compared to the high-salinity water, which demonstrates the expansion of the double layer by low-salinity water that provides a greater opportunity for the oil to be swept. Double-layer thickness is a function of the electric charges that are the oil/brine and rock/brine interfaces, which can be estimated by measuring the zeta-potential (ζ-potential).

Multiple ion exchange (MIE) is another mechanism that affects the wettability change process in carbonate rocks. This is the accumulation of divalent ions (Mg2 +, Ca2 +, and $SO4^{2-}$) in brine, rocks, and crude oil (Zhang et al. 2007a). Based on this mechanism and the reaction shown in equation (1) and (2), due to the positive surface charge of the carbonate, the $SO4^{2-}$ ions present in the brine phase are attracted to the surface of the carbonate rock, resulting in the surface potential decreasing, thereby attracting divalent positive ions closer to the surface. Depending on the temperature, Ca2 + ions (below 70 ° C) or Mg2 + ions (above 100 ° C) show higher activity near the surface of the rock and the interact with the negative carboxyl terminus of crude oil attached to the carbonate surface interaction. It is worth noting that when more positive ions are present in the solution, a stronger interaction with the carboxy terminus occurs, which contraries to the attractive force between crude oil and the carbonate surface, and it releases oil particles from the rock surface to improve oil recovery significantly. (Zhang et al. 2007a)

$$RCOO^{-} - Ca - CaCO_3\,(S) + Ca^{2+} + SO_4^{2-} = RCOO - Ca^{2+} + Ca - CaCO_3\,(S) + SO_4^{2-} \quad (1)$$

$$RCOO^{-} - Ca - CaCO_3\,(S) + Mg^{2+} + SO_4^{2-} = RCOO\text{-}Ca^{2+} + Mg - CaCO_3\,(S) + SO_4^{2-} \quad (2)$$

By inserting relative permeability, capillary pressure, and residual oil saturation between the two wetting states, various methods have been tried to simulate the change in wettability during low salinity waterflood displacement (Delshad et al., 2009; Jerauld et al., 2008). The low salinity waterflood injection was simulated by describing the secondary and tertiary low salinity waterflood processes in a one-dimensional reservoir by applying conventional fraction-flow theory. Jerauld et al. developed a model that estimates the relative permeability of low-salinity and high-salinity water in the reservoir. They also demonstrated that fine-grid simulations are not necessary to represent dispersion and the performance of the simulation can be easily enhanced by defining the salinity dependence of relative permeability. Atthawutthisin (2012) 's Eclipse 100 software was used for 3D simulation of LSW flooding in heterogeneous synthetic reservoirs. Atthawutthisin (2012) used Eclipse 100 software to carry out the three-dimensional simulation during low salinity water flooding on a heterogeneous synthetic reservoir. A series of low salinity waterflooding experiments conducted by Shojaei et al. (2015), was performed on crude ageing sandstone cores. The relative permeability and capillary pressure curves were obtained using Sandra simulator through a history matching method. They point out that as the interfacial tension (IFT) decreases and the wettability changes to more water wetting, the residual oil saturation changes linearly with the salinity of the injected brine. There is a critical salinity, but it is not the lowest salinity value at which the interfacial tension (IFT) between oil and brine is minimum. Omekeh et al. (2012) combined the multiple ion exchange process associated with the standard Buckley-Leverett two-phase model to study the wettability mechanism of oil-wet sandstone rocks during the low salinity waterflooding process. They observed that due to the different desorption ranges of the divalent ions (calcium and magnesium), various components of the brine gave different recovery curves.

Yu et al. (2009) and Andersen et al. (2012) developed a simple model to consider the changing wettability during the low salinity waterflood by involving one or two chemical species. However, Qiao et al. (2014) mentioned that the method is not sufficient to capture the complex interactions between brine, oil, and multiple components in solid surfaces. Brady uses a surface complexation model with carbonate and sandstone-related reaction networks. However, they did not couple the model with multiphase flow to understand the dynamic impact on wettability changes (Qiao et al., 2014). Then Qiao et al. (2014) established a mechanical model that coupled multiphase flow and transport by considering a detailed surface and an aqueous multicomponent reaction network to capture competitive interactions between oil, brine and the surface of Stevns Klint chalk. They further extended the model to include limestone surface complexation and mineral dissolution and precipitation reactions to provide a model for Low Salinity Waterflooding displacement in different carbonate reservoirs with different mineralogical characteristics (Qiao et al., 2016).

Low salinity water injection is an emerging EOR technology that can control the salinity of injected water to improve oil recovery. In the past, water injection design was largely independent of the composition of the injected brine. Corefloods and other tests have shown that changes in the composition of the injected brine can improve the basic water injection performance by 5% to 40% of the original oil equivalent (OOIP), which indicates that the composition of the brine can be changed to optimize the water injection rate (Dang et al., 2016).

2.5 Wettability Phenomenon

Wettability is one of the most important concepts in Low Salinity Waterflooding. Wettability is defined as the tendency of a fluid to diffuse or adhere to a solid surface in the presence of another immiscible fluid. When two immiscible phases are in contact with a solid surface, one phase generally adheres more firmly to the solid than the other. The stronger adhesion phase is called the wetting phase (Green, 1998). When fluids are water and oil, wettability is the tendency of rocks to preferentially absorb oil, water, or both oil and water. The wettability of reservoir rocks is an important attribute that determines the success of waterflooding because it greatly affects the location, flow and distribution of fluids in the reservoir (Puntervold, 2008). In a balanced system, the wetting fluid is located on the pore wall and occupies the smallest pore, while the non-wetting fluid is in the pore body. This means that the water phase in the wet reservoir will remain in the smaller pores and on the walls of the larger pores by capillary forces, while the oil phase will occupy the center of the larger pores and form small balls that may extend in many pores on.

Wetting was found to have a significant effect on key petrophysical properties such as residual saturation, relative permeability, capillary pressure, and capillary desaturation. It has been shown that wettability affects the relative permeability curve of water-oil systems.

It is thought that most reservoir rocks were originally water-wet. Numerous core flooding experiments and pilot tests have shown that Low Salinity Waterflooding has better oil recovery than conventional high salinity water injection. It also has advantages over conventional chemical EOR methods in terms of operating costs, environmental impacts and on-site process implementation.

In general, recovery is highly dependent on the salinity concentrations of the reservoir formation water and the injected brine. The composition of the injected brine plays a very important role in the additional oil recovery by LSW. An article about low-salinity waterflooding with nanoparticles concluded that low-salinity waterflooding can recover 6.1% original oil in place more than high-salinity waterflooding because the contact angle measurements indicate that low-salinity water will reduce the contact angle between oil and water. (Ebrahim et al., 2019)

The relative permeability of the wetting phase is lower than the relative permeability of the non-wetting phase. A study has shown that if the crude oil, rock and brine system becomes water wet, the relative permeability of water will decrease, and the relative permeability of oil will increase Morrow et al. (1973). Experiments have found that low-salinity brine has a significant effect on the shape and endpoint of the relative permeability curve (Webb et al., 2008; Kulkarni and Rao, 2005; Rivet, 2009; Fjelde et al., 2012), which results in lower relative water permeability and higher relative oil permeability. These study strongly support the hypothesis that the wettability changes during Low Salinity Waterflooding. They also suggest using changes in the relative permeability curves to represent wettability change in the Low Salinity Waterflooding model. Figure 2.5.1 shows an intuitionistic view of how the Low Salinity Injection works in ions function.

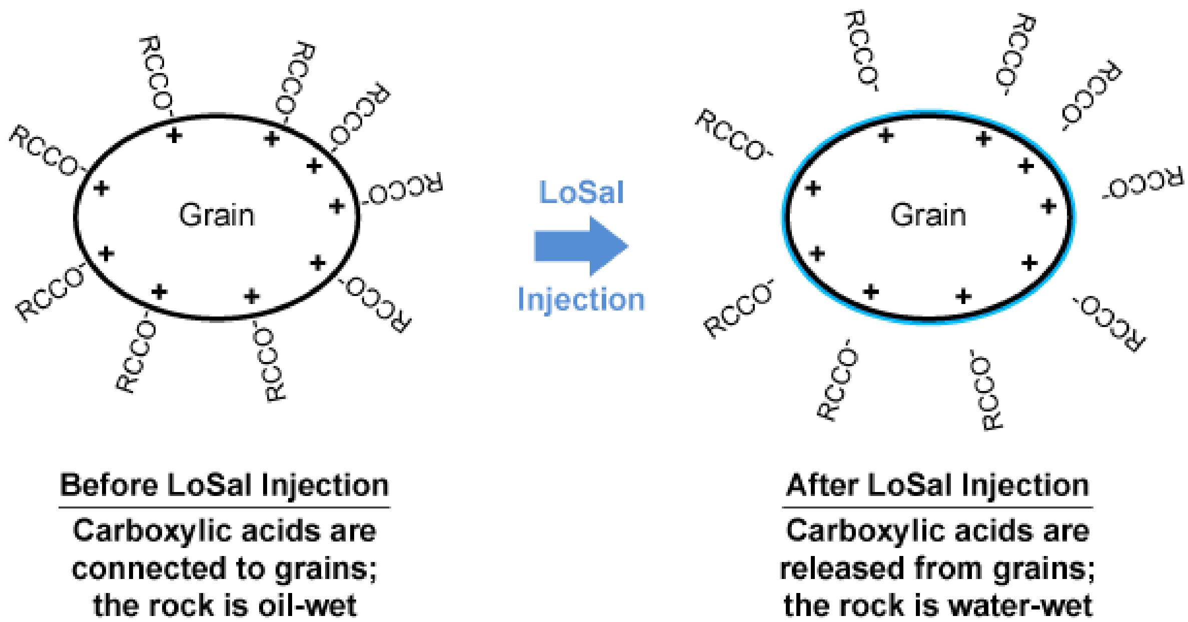


Figure 2.5.1 Mechanistic Modeling of Low Salinity Water Injection (Cpge.utexas.edu, 2019)

2.6 Low Salinity Waterflooding in Carbonate Reservoirs

Carbonate rocks contain more than 50% of the global hydrocarbon reserves. Carbonates are formed in special environments and their source is biochemical. Organisms play an important role in determining reservoir quality and have a direct role in determining reservoir quality. Compaction, petrification, and other diagenesis processes lead to large changes in carbonate reservoir quality. The complex flow mechanism and strong adsorption capacity of crude oil on carbonate formations can reduce the hydrocarbon recovery of oil-wet carbonate reservoirs to 10% (Derkani et al., 2018). Low salinity waterflooding has been identified as a promising technology to improve oil recovery. However, the main mechanisms supporting this recovery method have not been fully understood, which presents challenges in designing the optimal salinity and ionic composition of any injection solution. Generally, it is believed that carbonate low-salinity water injection involves multiple mechanisms. However, changing the wettability to a more ideal state for oil recovery during low salinity water injection is the main reason, but how this change happens is still a topic of debate.

It was initially shown that changing the composition of the brine or reducing the salinity of the injected brine to less than the initial formation water can lead to additional oil recovery from the Berea sandstone (Reiter, 1961; Jadhunandan, 1990-1995; Yildiz, 1996; Tang, 1997). Such results have attracted many oil and gas companies, such as BP, Shell, Exxon Mobil, Schlumberger, Total and Statoil to investigate and further explore the potential and applicability of low salinity water injection to improve oil recovery. Low salinity waterflooding, also known as designer water injection, advanced ion management and intelligent water injection, inject brine and also called smart water or dynamic water with controlled ion concentration and composition into wells (Robertson, E.P. 2007; Ligthelm, D.J. et al., 2009; Gupta, R. et al., 2011). The designed formula disrupts the equilibrium of the initial oil-rock-brine system, leading to changes in initial wettability conditions and positive effects on capillary pressure and relative permeability (Sheng, 2013). Compared with simple water injection methods, low salinity waterflooding can produce up to 10% extra crude oil (Kokal, 2010). During low salinity waterflooding, no expensive chemicals are added; therefore, the technology is cheap and environmentally friendly, and there are no related injection issues. In addition, the use of low salinity waterflooding to improve the recovery efficiency from the water injection process is economically effective (Sheng, 2013).

The water treatment process of low salinity waterflooding is carried out in two stages: nanofiltration and reverse osmosis. During the nanofiltration process, contaminations such as sulphate and other divalent pollutants remove ions to reduce the hardness of the brine and the possibility of membrane blockage during reverse osmosis (Sheng, 2013). During reverse osmosis, salinity is reduced by removing salt from the injected brine. Low salinity waterflooding allows variations in the operating window of key parameters so that the ion concentration and composition of the injected brine can be customized to suit specific reservoir conditions, taking into account clay swelling and reservoir acidification, and preventing corrosion and aerobic bacteria problems. The advantage of this technology over most EOR processes is its lower operating and capital costs. In addition, Low salinity waterflooding is not only suitable for the early stages of the oil recovery process which is different from EOR technology but can also be applied later in the reservoir's life cycle (Kazankapov, 2014; Yousef et al., 2012). Low salinity waterflooding technology can also be used with chemical and thermal EOR processes. Studies have shown that the use of low salinity water instead of seawater during polymer flooding can significantly reduce polymer consumption by 5 to10 times, which complements the potential benefits of low salinity waterflooding itself (Shaker Shiran et al., 2013). Proper implementation of low salinity waterflooding can potentially increase the hydrocarbon recovery of the original oil in place by up to 40%, which is equivalent to reducing the remaining oil saturation by up to 20% of the pore volume (Kazankapov, 2014; Matthiesen et al., 2014; Jerauld et al., 2006; Sohal et al., 2016; Chandrasekhar et al., 2016). Low salinity waterflooding has proven to be a promising way to increase oil recovery and can be used onshore and offshore.

The carbonate surface is initially water-wet and contains positively charged surface static electricity over a wide pH range (Gomari et al., 2006). However, the adsorption of negatively charged carboxylic acid species (–COO$^-$) in heavy end fractions of crude oil such as resins and asphaltenes fractions, onto the surface of positively charged carbonate rocks can cause large crude oil particles to cover the carbonate surface and may promote mixed-wet or oil-wet characteristics (Marathe et al., 2012; Gomari et al., 2006; Sauerer et al., 2016; Karimi et al., 2015). Compared to minerals in sandstone reservoirs, quartz, carbonate reservoir rocks have inherently higher chemical activity. In addition, due to the poor correlation between permeability and porosity, difficulties exist in modeling permeability distributions and predicting reservoir behavior in carbonate rocks. Researchers have also reported the presence of fractures and large-scale heterogeneity resulted in available complex paths for fluid flow (Badri et al., 2009). Therefore, the combination of these factors, as well as a decrease in humidity, leads to low oil recovery (30-10%) in oil-wet carbonate reservoirs (Puntervold et al., 2009; Montaron 2009).

It is suggested that low salinity waterflooding in carbonates can improve oil recovery even with higher salinity of the injected brine, as long as it contains active ions with different relative concentrations compared to formation water. Literature research shows that the carbonate rock wetting condition can be altered by increasing the concentration of divalent anions (e.g., SO_4^{2-}), decreasing the concentration of divalent cations (Ca^{2+} or Mg^{2+}), reducing the salinity of brine, or removing sodium chloride(NaCl) from seawater (Austad et al., 2011; Awolayo et al., 2014; Fathi et al., 2011).

Chapter Three: STUDY OF THE OIL FILED

3.1 Study of the Oil Field

3.1.1 Description

The location of the oil field is shown in Figure 3.1.1.1. The oil field is in Eastern Indonesia in the Seram Area. The Bula Basin in Seram overlies and is partly incorporated in a fold/thrust and zone formed where the outer margin of the Australian continental shelf collided with Irian Jaya in the mid-Tertiary (Hutchinson, 1996). The bulk of the sequence is composed of a variety of Mesozoic to Middle Tertiary open marine pelagic and oceanic deposits, including clays, limestones and thin sands. Figure 3.1.1.2 shows the surface geology and structure map of the field.

The Dutch focused on the Pliocene to Pleistocene marginal marine sand and limestones, which was first discovered oil in the early 1900s. Recent discoveries in complex folds and thrust zones have successfully positioned oil in fractured Jurassic limestone. Geochemical studies show that the oil comes from Triassic-Jurassic marine carbonate rock type II source rocks (Peters et al., 1999).

Figure 3.1.1.1 Location map showing position of the oil field in Seram, Eastern Indonesia

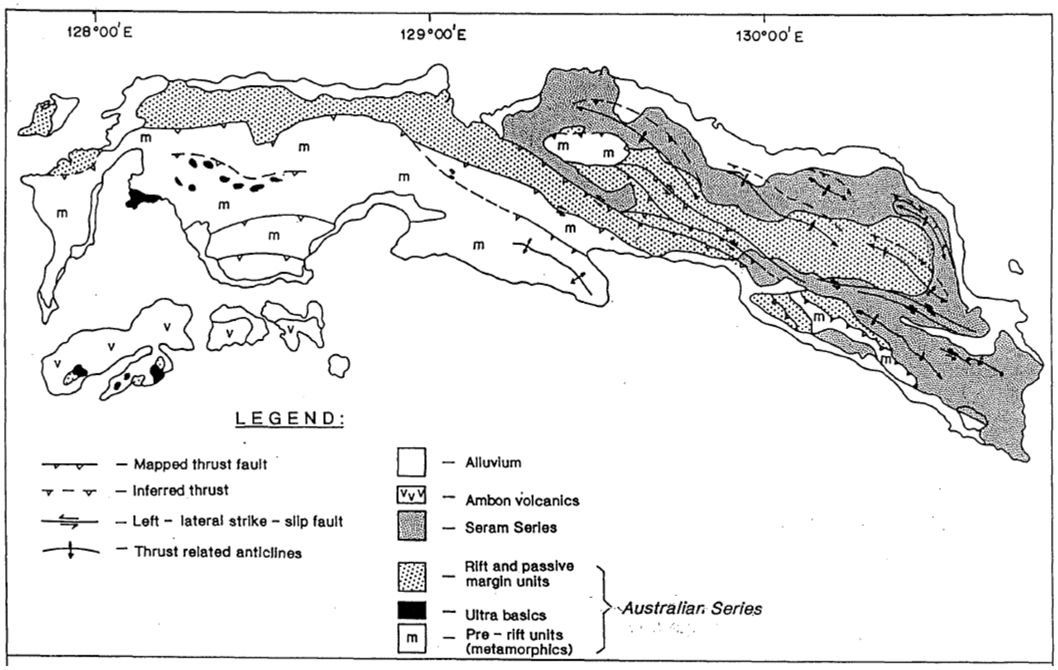


Figure 3.1.1.2 Generalized surface geology and structure map – Seram Island. Control on Eastern part of Island from SAR, field geology and seismic.

3.1.2 Petroleum System

In the Bula Basin, there is only one small field, Bula Le Mans, with approximately 15 million barrels. It belongs to the petroleum system that can be defined as a Triassic-Jurassic marine carbonate type II mudstone source rock and has a Pleistocene reef-like sandy limestone reservoir. It is defined as "Mesozoic-Fufa". In the closed Jurassic and Triassic sequences, the marginal closed marine sandstone reservoirs have two now closed small oil fields, indicating the existence of a second petroleum system. This refers to the "Mesozoic-Mannasla" which was defined by Howes and Tisnawijaya (1995). The Oseil field is a new discovery in the petroleum system and is currently under development.

3.2 FRACTURED CARBONATE CHARACTERISTIC

3.2.1 Natural Fracture Reservoir

Natural fractures are caused by stress in the formation usually from tectonic forces such as folds and faults. Natural fractures are more common in carbonate rocks because its characteristic is brittle. Fractures orientation occur in preferential directions, determined by the direction of regional stress. This is usually parallel to the direction of nearby faults or folds as shown in Figure 3.2.1.1. However, in the case of faults, they may be perpendicular to the fault or there may be two orthogonal directions. The fracture intensity would be higher closer to a fault.

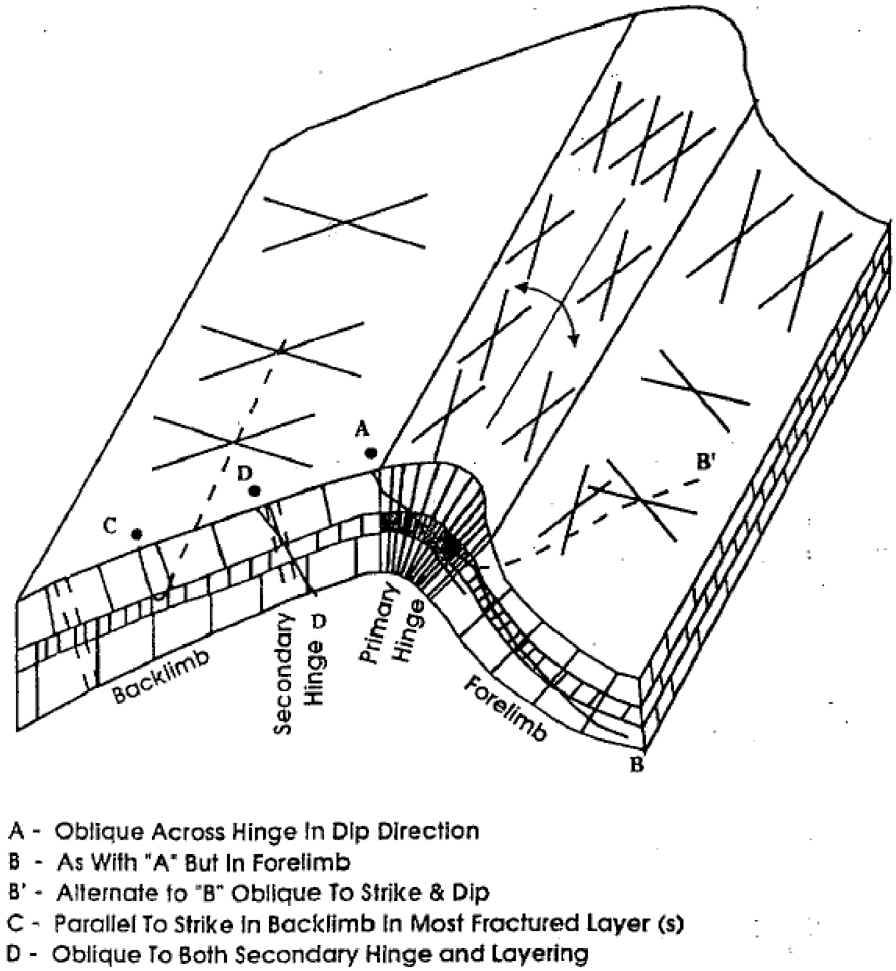


Figure 3.2.1.1 Typical fractured asymmetric fold (Aguilera, 1995)

Natural fractures dip angle is commonly vertical as shown in Figure 3.2.1.2 and lead to rapidly water fingering and result to low recovery factor. Horizontal fractures may exist for only a short distance because most of the facture can be re-sealed by overburden pressure.

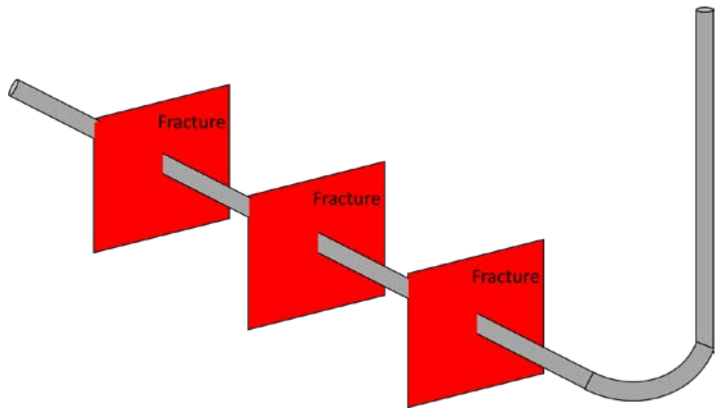


Figure 3.2.1.2 Horizontal well drilled perpendicular with vertical fractures. (Integrated Petrophysical Study Report 2009)

3.2.2 Fractures Morphology

Fractures morphology relates to the form of natural fractures including open, deformed, mineral-filled, and vuggy fractures (Aguilera, 1995).

1. Open fractures

They are uncemented and do not contain any kind of secondary mineralization. Fracture width is very small but increases permeability significantly parallel to the fractures. This type of fracture might have a positive effect on oil flow but a negative effect on water or gas flow due to coning effects.

2. Deformed fractures

Fractures are called deformed when they are filled with finely abraded material resulting from grinding or sliding motion. This drastically reduces the fractures permeability.

3. Mineral-filled fractures

These fractures are cemented by secondary mineralization. Usual filling materials include quartz and calcite. These types of fractures might create permeability barrier to all type of fluid flow. On the other hand, partial mineralization might have positive effect on oil recovery because it might act like a natural proppant that prevents the closing of the fracture as the reservoir is depleted.

4. Vuggy fractures

Vuggy fractures can provide significant porosity and permeability. These types of fractures are the result of percolating acid waters through fractures. Due to the round shape of the vugs, these types of fractures are unlikely to close as the reservoir is depleted.

3.2.3 Reservoir Classification

Developing naturally fractured reservoirs has led to numerous failures. Initial high oil rates have led engineers to overestimate production forecast of wells. In fact, many reservoirs that produce at high initial rates decline drastically after a short period of time. This occurs because the producible oil has been stored in the fracture system. Consequently, it is important to estimate oil in place with reasonable accuracy within the fracture system.

If the permeability of the matrix is very low, then the oil flow from the matrix into the fractures might be very slow and only the oil originally within the fractures will be produced in a reasonable span of time. If the matrix has a reasonable permeability, then the storage capacity of the matrix becomes important.

It is important to visualize that storage capacity of naturally fractured reservoirs vary extensively, depending on the degree of fracturing in the formation and the value of primary porosity. The greater value of primary porosity and its distribution, the greater the success possibility of naturally fractured reservoirs.

There are 3 schematic sketches of porosity distribution in fractured reservoir rocks (McNaughton and Garb, 1975).

1. Reservoir Type A

Type A reservoir has a high storage capacity in the matrix but low storage capacity in the fractures, as shown in Figure 3.2.3.1. The storage capacity in the matrix porosity is larger than storage capacity in the fractures due to small porosity fracture contribution to the rock. In general, this situation would tend to occur in reservoirs where the matrix porosity is rather high (about 10-35%). The fractures serve as the principal flow conduits and the reservoirs typically are identified as dual-porosity systems. Therefore, conventional exploitation method can be applied to this kind of reservoir because fractures contribute permeability to an already producible reservoir.

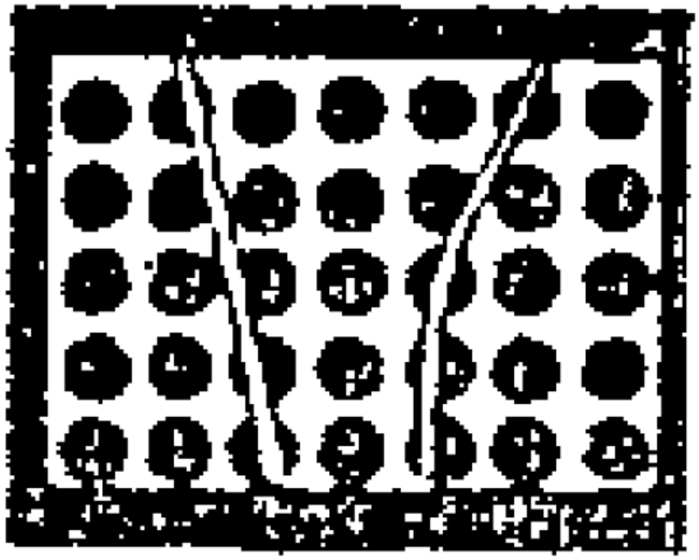


Figure 3.2.3.1 Type A reservoir: high storage capacity in matrix and low storage capacity in fractures (Aguilera, 1995)

2. Reservoir Type B

Type B reservoir has about equal storage capacity in matrix and fractures as shown in Figure 3.2.3.2. In this case, the matrix has rather low porosity about 3-7% and the fractures provide an essential permeability.

Figure 3.2.3.2 Type B reservoir: about equal storage capacity in matrix and fractures (Aguilera, 1995)

Type B reservoir can be sub-classified into B1 and B2 based on the characteristic of the matrix system:

i. Type B1

The matrix in a type B1 reservoir has low but effective porosity and capillary pressure suggesting a good pore geometry, as shown in Figure 3.2.3.3. As such, the matrix will contribute effectively to the storage capacity of the reservoirs. Type B1 is an ideal combination between porosity and permeability.

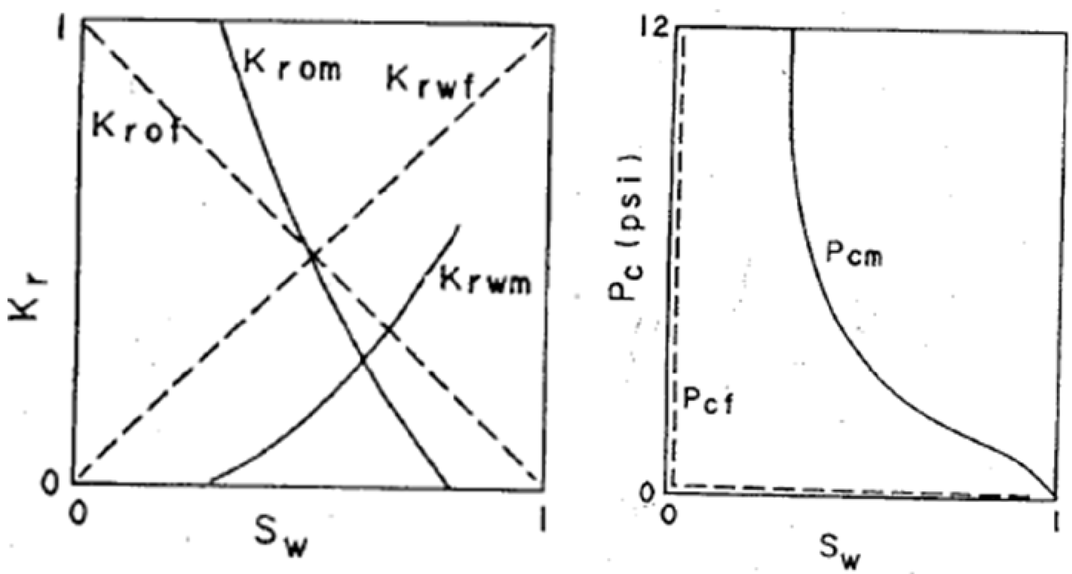


Figure 3.2.3.3 Relative permeability and Capillary pressure curve for Type B1 reservoir (Aguilera, 1995)

The relative permeability for the fracture is shown as a straight line with 45^{o} angles. This assumes that the fracture system is approximately equivalent with a bundle of tubes, where the irreducible water and residual oil saturation are equal to zero.

i. Type B2

The matrix system in a type B2 reservoir is not a good reservoir rock as shown by the capillary pressure curve in Figure 3.2.3.4, even if there is some matrix porosity.

Consequently, the fractures have only a fraction of the total porosity, but they might have nearly 100% of the hydrocarbon storage capacity.

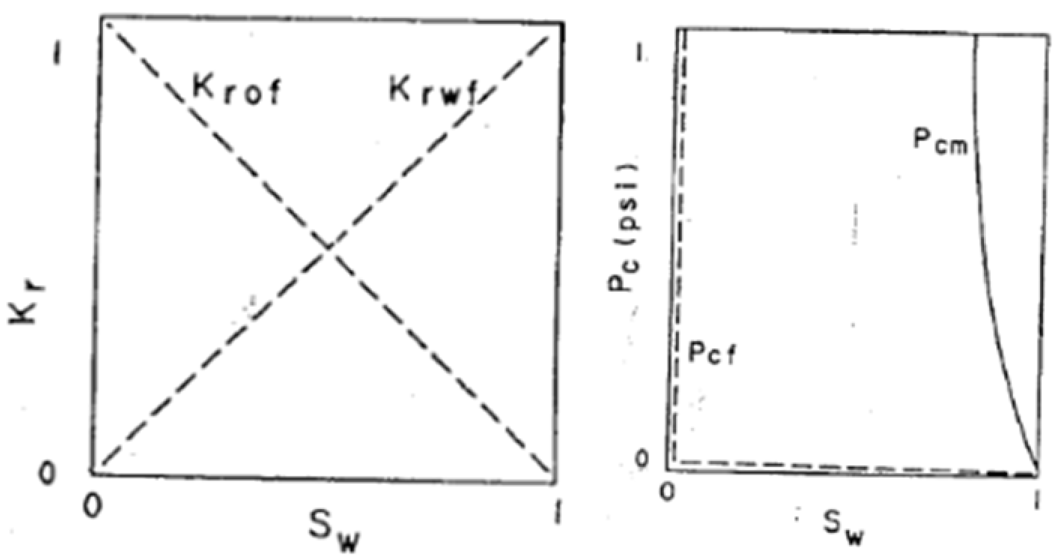


Figure 3.2.3.4 Relative permeability and Capillary pressure curve for Type B2 reservoir (Aguilera, 1995)

Conventional log interpretation in this type of reservoir might have a high value of water saturation due to large amounts of water in the matrix (can be seen in the capillary pressure that water saturation is relatively high).

3. Reservoir Type C

The storage capacity in type C reservoirs are located entirely in the fractures because the matrix porosity is zero, as shown in Figure 3.2.3.5. In this case, the fractures provide the essential porosity and permeability. Reservoirs of this type are generally characterized by initially high production rates that decline to uneconomic limits in a short period of time.

Figure 3.2.3.5 Type C reservoir: all storage capacity are in fractures (Aguilera, 1995)

As the above explanation, each reservoir type has different recovery factors depending on its drive mechanism, as shown in Table 3-1. In general, type C reservoirs have relatively higher recovery than type A or type B because all the hydrocarbon storage is in the fractures. Water drive will enhance the most, compared with other drive mechanism. However, this will come with rapidly increased water cut which must be considered.

Table 3-1 Typical Oil Recoveries from Naturally Fractured Reservoirs as a Percent of Original Oil in Place (Aguilera, 1999).

	Reservoir Type		
Recovery Mechanism	A	B	C
Depletion Drive	10-20	20-30	30-35
Depletion Drive + Gas Injection	15-25	25-30	30-40
Depletion Drive + Water Injection	20-35	25-40	40-50
Depletion Drive + Water Injection + Gas Injection	25-40	30-45	45-55
Gravity Segregation with Counterflow	40-50	50-60	>60
Depletion Drive + Water Drive	30-40	40-50	50-60
Depletion Drive + Gas cap	15-25	25-35	35-40
Depletion Drive + Gas cap + Water Drive	35-45	45-55	55-65

Development of fractured carbonate requires additional data, analysis, reservoir modeling, and different approach to optimize the oil recovery.

3.3 The Characteristic of Reservoir

The data sets are provided by the company's research and field analysis department.

3.3.1 Reservoir Characteristics

In summary, the reservoir characteristics are three low and three complexity.

1. Three Low
    a. Relative low structure amplitude, as shown in Figure 3.3.1.1

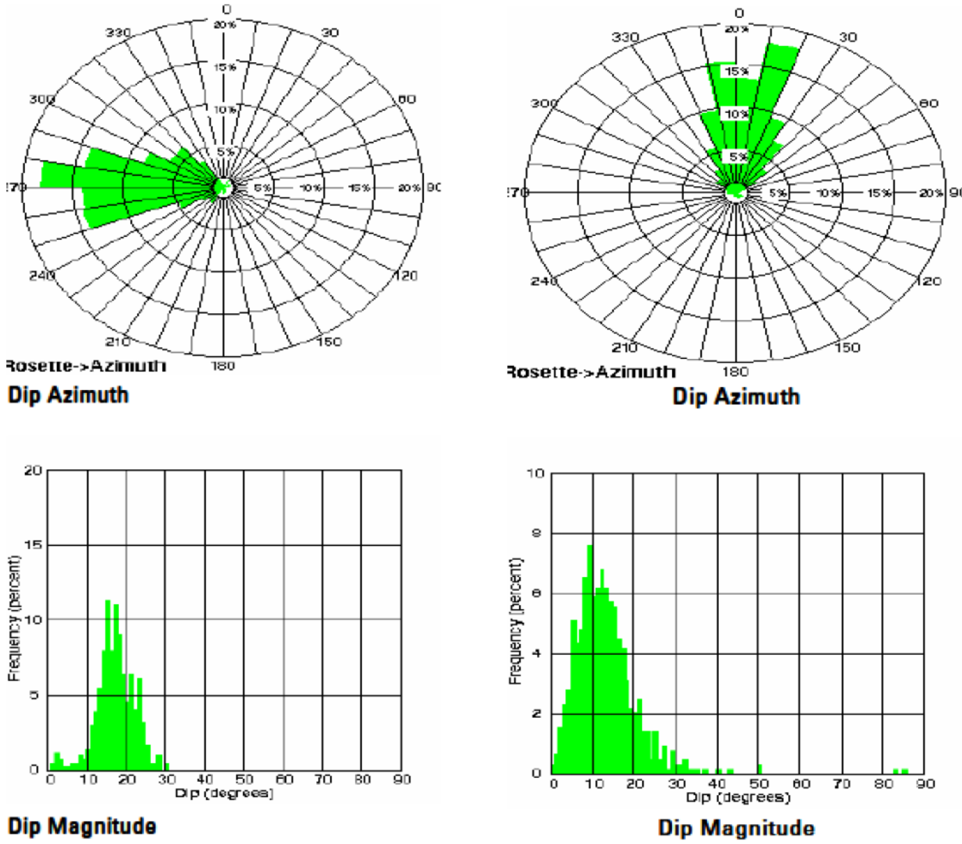


Figure 3.3.1.1 Attitude of well (Integrated Petrophysical Study Report 2009)

The dip is from 10 degrees to 30 degrees on the attitude of the stratum in the well.

b. Low Matrix Porosity and Permeability, as shown in Figure 3.3.1.2 and Figure 3.3.1.3.

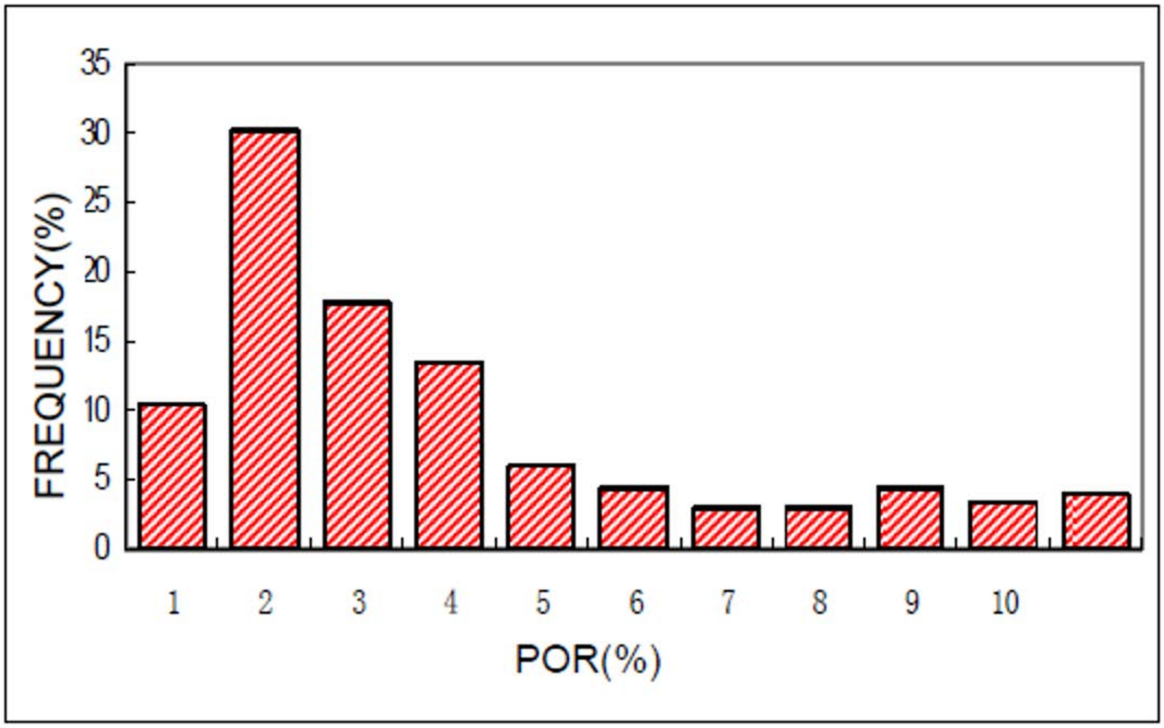


Figure 3.3.1.2 Core porosity diagram (Integrated Petrophysical Study Report 2009)

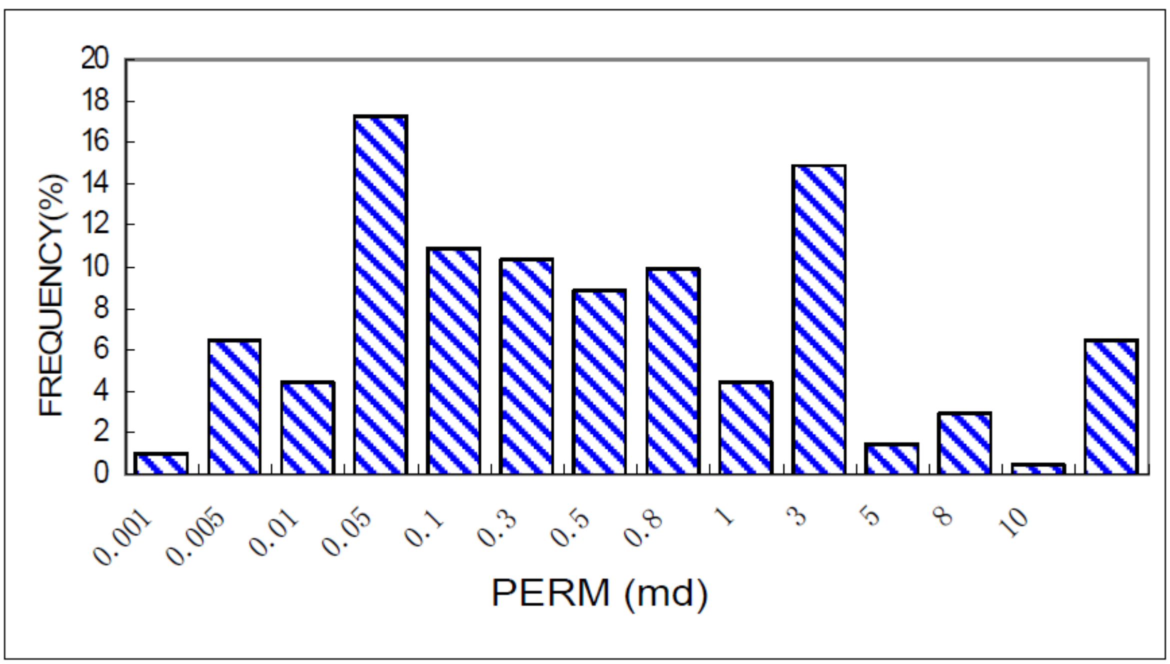


Figure 3.3.1.3 Core Permeability diagram (Integrated Petrophysical Study Report 2009)

The core data shows the porosity is usually less than 5%, and the permeability is less than 1md in most core samples (about 70%).

c. Low oil saturation

The oil saturation data shows the range is around 50%-55% in the reservoir.

2. Three Complexity

a. Complex Rock Fabric

The reservoir contains a lot of rock fabric such as matrix porous, vuggy, fracture, dissolution and so on.

b. Complex Oil-Water System

Past studies on production date indicate that there is no uniform oil-water-contact in the area. The data shows a quick water breakthrough in production.

c. Complex Logging response

3.3.2 The Character of Core Porosity and Permeability Distribution

Statistical analysis was conducted on the physical properties of 5 wells shown in Figure 3.3.2.1. The core samples of the reservoir show good matrix porosity, because the petrogenetic constricted crack is small in unit III and the plug samples show some fractures, therefore the core permeability is better in the third unit.

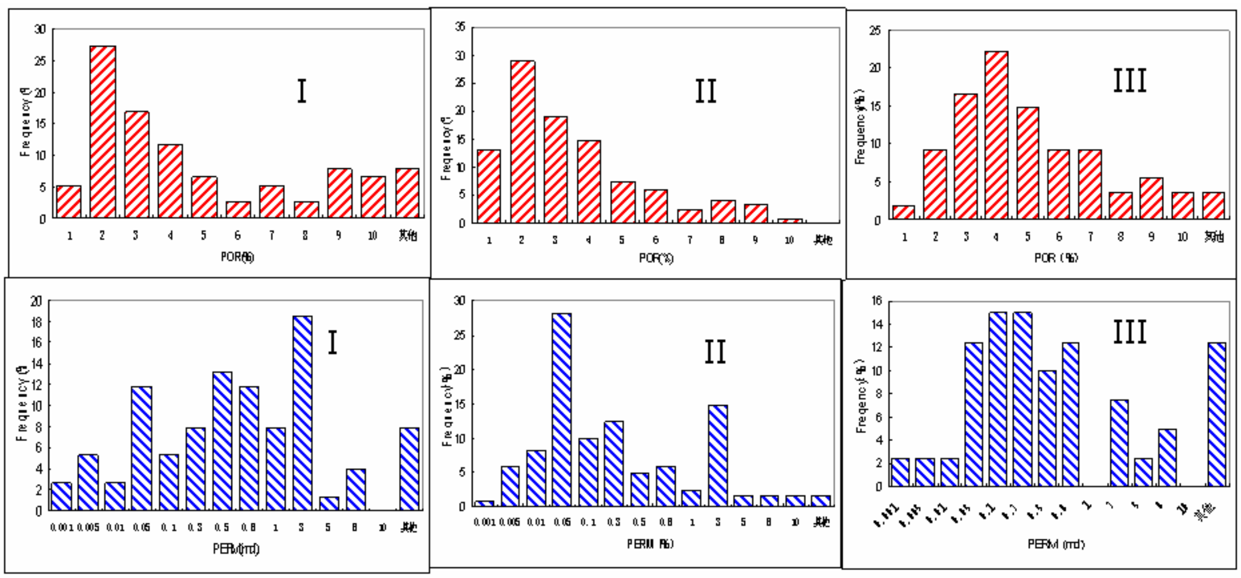


Figure 3.3.2.1 Conventional physical property data statistics map of 5 well (Integrated Petrophysical Study Report 2009)

3.3.3 Lithology and Physical Property

The lithology of the formation is mainly limestone and dolomite. Typical values of the petrophysical properties of the formation are listed in the Table 3-2 below.

Table 3-2 Typical Values of Petrophysical Properties.

Porosity	Matrix 5% to 10% Fracture 3% to 8%
Initial Oil Saturation	50% to 55%
Wettability	Oil - Wet
Thickness	Various, Average 172 ft
Pore Types	Matrix Fracture Vug
Lithology	Limestone, limestone with dolomite and dolomite with limestone, dolomite: (glauconitic and oolitic) stringers, white - off white, hard, dense, brittle, lime mudstone to locally wackestone and marl rich with planktonic (globigerina foraminifera) locally with radiolarian cherts: nodules, very hard, dark brown to black, sometimes grey

The relationship of different porosity and permeability in different cores are exhibited below in Figure 3.3.3.1. This figure shows no correlation between the lithology of the rock and the matrix permeability and porosity. Fracture conducts can also be seen in Figure 3.3.3.1, where the porosity is low (less than 4%) but the permeability is large.

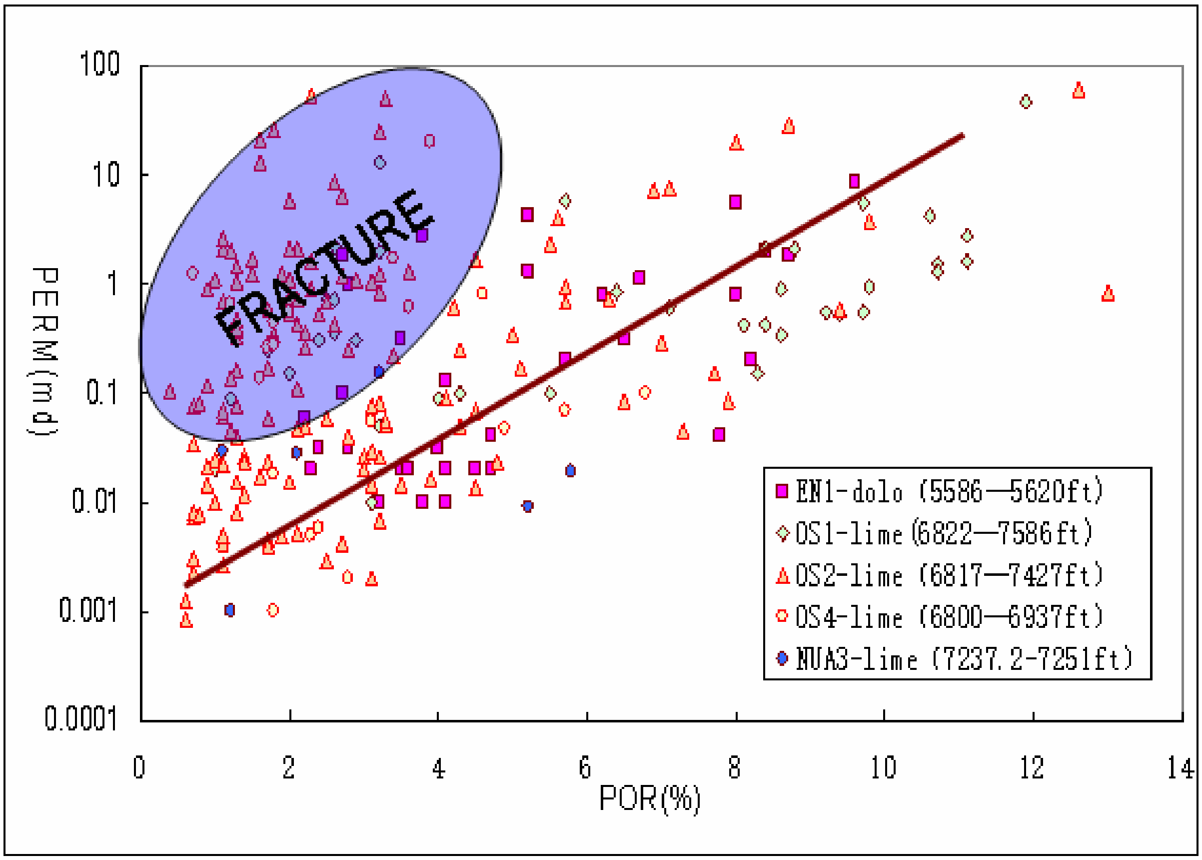


Figure 3.3.3.1 the relationship between POR&PERM of different lithology

3.3.4 Direction Difference of Permeability

The vertical and horizontal permeability has the following characteristic:

1. The majority of the porosity and permeability is due to the vugs and fractures
2. The horizontal permeability is higher than the vertical permeability
3. There is no clear preference for permeability in the horizontal plane (the x direction)

3.3.5 Reservoir Type

There are a lot of methods to identify reservoir types based on the apparent differences in the type of reservoir space in the field. Considering the heterogeneity difference of carbonate formations, the study was done through DST's fluid flow index and permeability with applied special pressure to reservoir accuracy (unit thickness and pressure difference), rather than total reservoir thickness. Under heterogeneous conditions, it is difficult to determine the same reservoir thickness, so comparisons within reservoir thicknesses have not been applied.

$$\mathrm{PI} = 18.291\ \mathrm{Ln(PERM)} - 51.811, R^2 = 0.8938$$

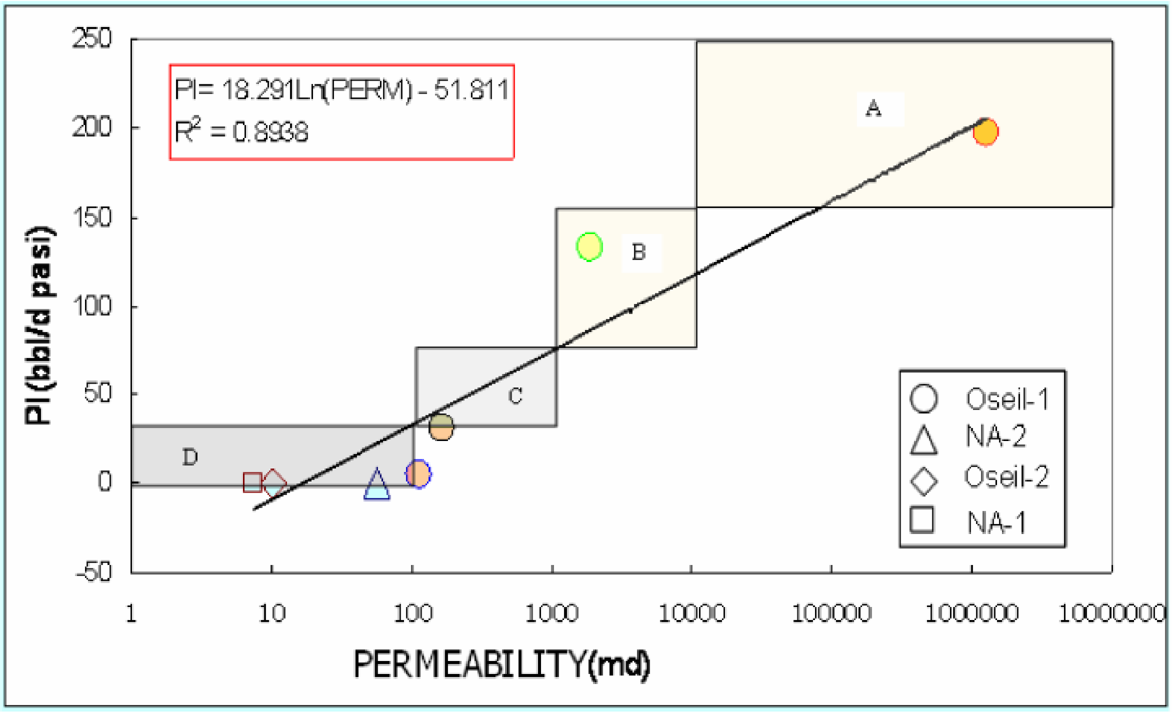


Figure 3.3.5.1 DST permeability vs PI (Integrated Petrophysical Study Report 2009)

On the DST permeability vs PI graph, as shown in Figure 3.3.5.1, the reservoir types are classified. There are four different types of reservoir through the PI and permeability, as shown in Table 3-3: A is not good at developing fractures; B is a fracture-porosity reservoir, with good conditions for fracture development.

Table 3-3 Reservoir Type Table

Calcination	Por (%)	PERM (md)	PI (bbl/d psi)	Rock Fabric Description
A	➢ 7	➢ 10000	➢ 150	Vuggy
B	➢ 7	1000-10000	75-150	Fracture very developed
C	➢ 5	100-1000	30-75	Fracture medium developed
D	➢ 5	1-100	5-30	Fracture undeveloped, mainly matrix Por

3.3.6 Fracture Orientation and Dip Angle

Fracture orientation and dip angle can be obtained with Fullbore formation microimager (FMI) as shown in Figure 3.3.6.1. The Rosette diagram is needed to identify the dominant fracture line that is used to determine the orientation of well trajectory. If a well produces oil from a reservoir that only has a vertical fracture, then the water cut will rapidly increase.

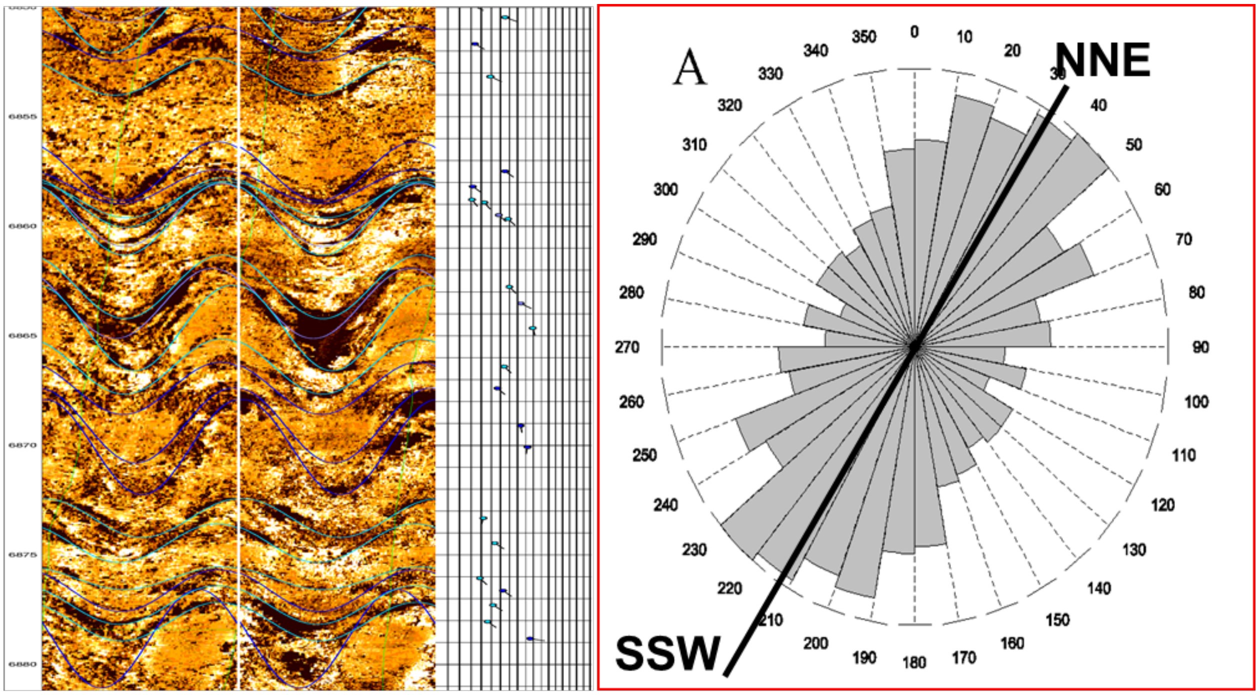


Figure 3.3.6.1 Example of Oil Field Fullbore formation microimager FMI and Rosette Diagram (Integrated Petrophysical Study Report 2009)

3.3.7 Well Testing Analysis

Analysis from well testing will identify the presence of the fracture and measure its permeability, Storativity Ratio (ω), and Interporosity Flow Coefficient (λ). The storativity ratio is a fraction of fracture pore volume to total pore volume. Interporosity flow coefficient is the permeability ratio between matrix and fracture. Typical well test analysis from a fractured reservoir is shown in Figure 3.3.7.1.

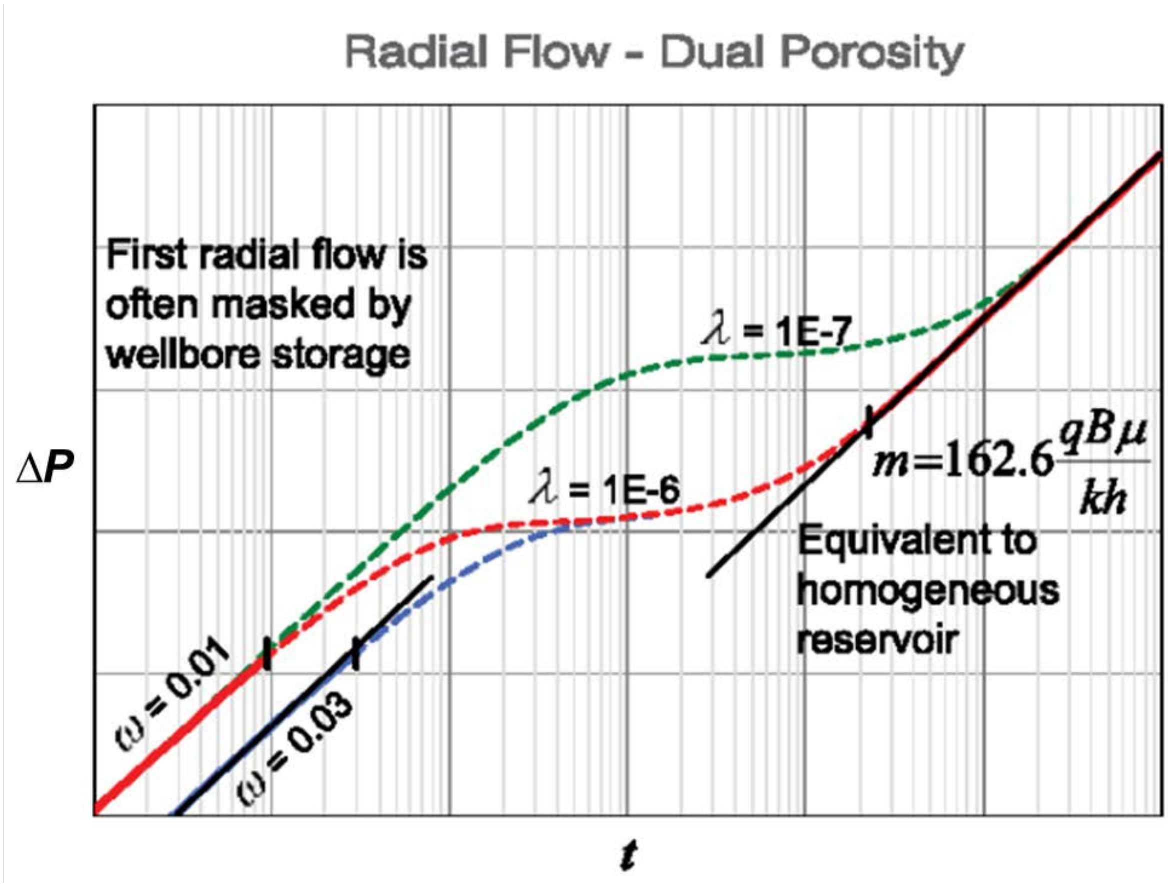


Figure 3.3.7.1 Build Up Curve from a Fractured Reservoir (HIS, 2014)

3.4 Challenges

The Oil field is a highly fractured carbonate reservoir. The fracture system provides high permeability channels that can bring water into the wellbore quickly. The field has very strong bottom water support, which provides ample energy for water to break into wellbores. The crude oil from the field is relatively viscous and contains heavy components, which results in an unfavorable mobility ratio with less advantage of gravity segregation. Therefore, there are two major challenges in the field.

1. The biggest challenge is the high water cut.

Since the oil field is dominated by vertical fractures, which is the high angle fractures, the fracture density of the water section seems to be higher than the fracture density of the oil leg. Non-uniform oil-water contact (OWC) motion caused by vertical fractures connects oil and aquifers. Further drilling and completion plans are needed in this area to avoid vertical fractures.

2. The other challenge is poor matrix contribution.

In typical naturally fractured reservoirs, the storage and flow are dominated by fractures in the reservoir and the poor recovery factor as RF depends on fracture effective porosity and permeability as well. The matrix has varying degrees of contribution to the storage which depends on different reservoir types. According to field study and production data, the matrix seems to play an unimportant role in the reservoir, however the reservoir analysis propose that the matrix has significant potential in field production. A dual porosity model is suggested to the study, as shown in Figure 3.4.1.

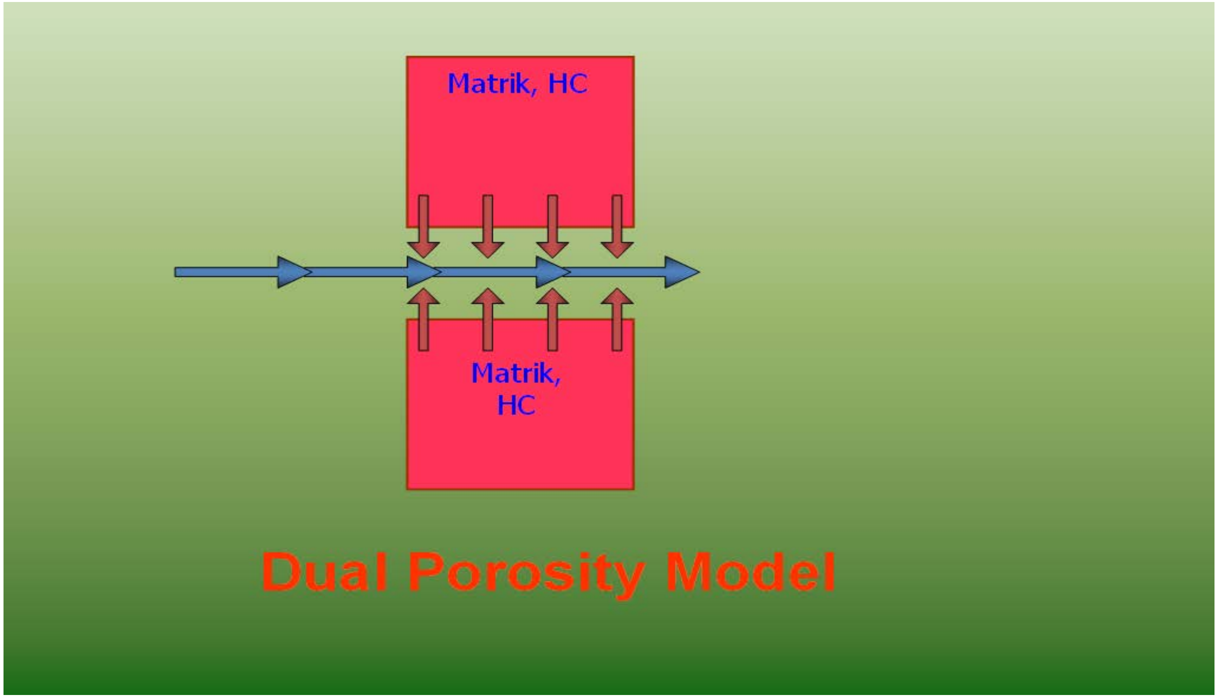


Figure 3.4.1 The Ideal Dual Porosity Model of the oil field

The Well Test Interpretation, as shown in Figure 3.4.2, indicates high permeability of fractures, contrast ratio of fracture perm and matrix perm (low λ) and significant storage in fractures (moderate ω). Therefore, a dual permeability model is suggested to the study as well.

$$\lambda = \frac{k_m}{k_f}$$

$$\omega = \frac{\phi_f C_f}{\phi_f C_f + \phi_m C_m}$$

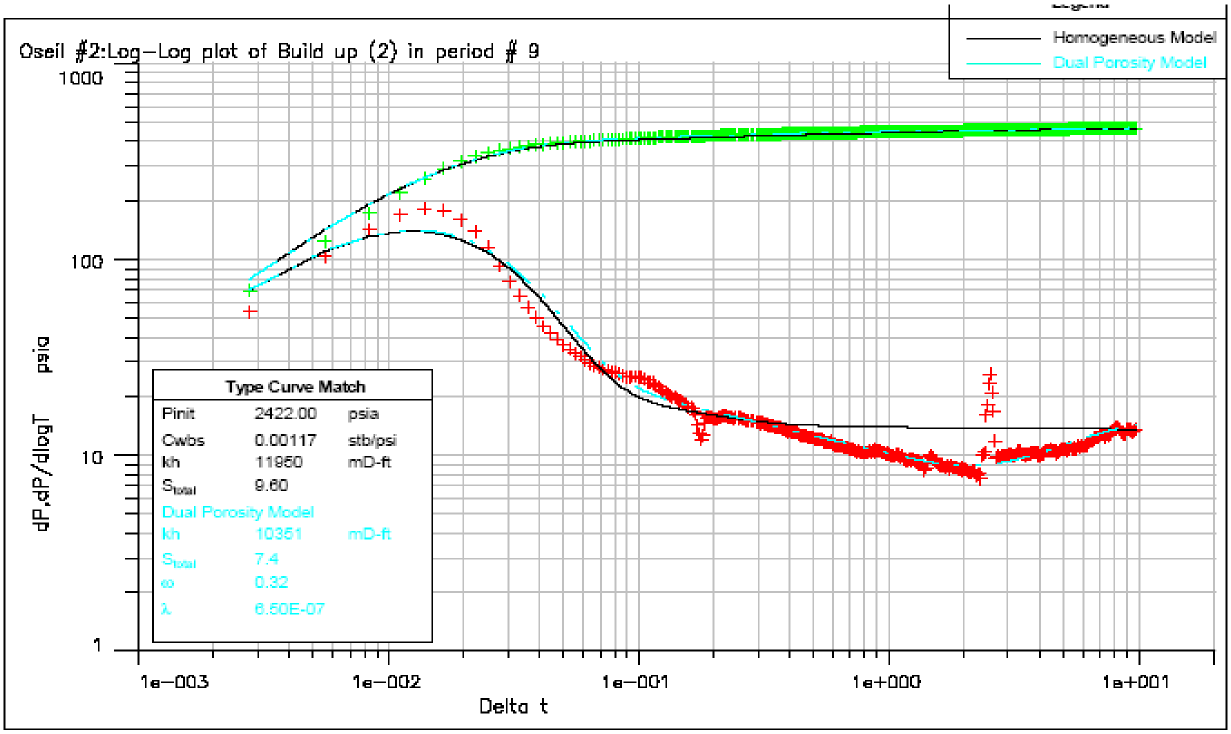


Figure 3.4.2 Well Test Interpretation Graph (Integrated Petrophysical Study Report 2009)

3.5 Statement of Problems

This study is based on numerical simulations and mathematical analysis of the results obtained for the elements of the oil field. The model includes all the major features of this reservoir, such as matrix, fractures, water zones, highly variable petrophysical properties. The principal objectives of this study are as follows:

1. To determine the role of fractures and matrix in a general sense — advantages and disadvantages in promoting low salinity water injectivity and oil drainage.
2. To assess the effect of low salinity water injection schemes and study the effect of low salinity water on reducing water cut.
3. Determine the principal production mechanism of low salinity water injection in carbonate reservoir.
4. To examine the applicability of low salinity injection (LSW) in the model under study in terms of oil and water movement
5. To determine ways of optimizing low salinity water injection performance in different type of reservoir
6. Based on the insight into fluid flow and the drive mechanism gained from the process behavior of all the low salinity injection oil recovery processes simulated and analyzed, to propose a low salinity water injection scheme for this reservoir

Chapter Four: RESERVOIR MODELING

4.1 Naturally Fractured Reservoir

Naturally fractured reservoirs are characterized by the presence of two distinct types of porous media: matrix and fracture. Because of the different fluid storage and conductivity characteristics of the matrix and fractures, these reservoirs often are called dual-porosity reservoirs.

In actual condition, a naturally fractured reservoir can be composed of a rock matrix surrounded by an irregular system of vugs and natural fractures. Warren and Root have observed that a real, heterogeneous, naturally fractured reservoir has a characteristic behavior that can be interpreted using an equivalent, homogeneous dual-porosity model such as that shown in Figure 4.1.1.

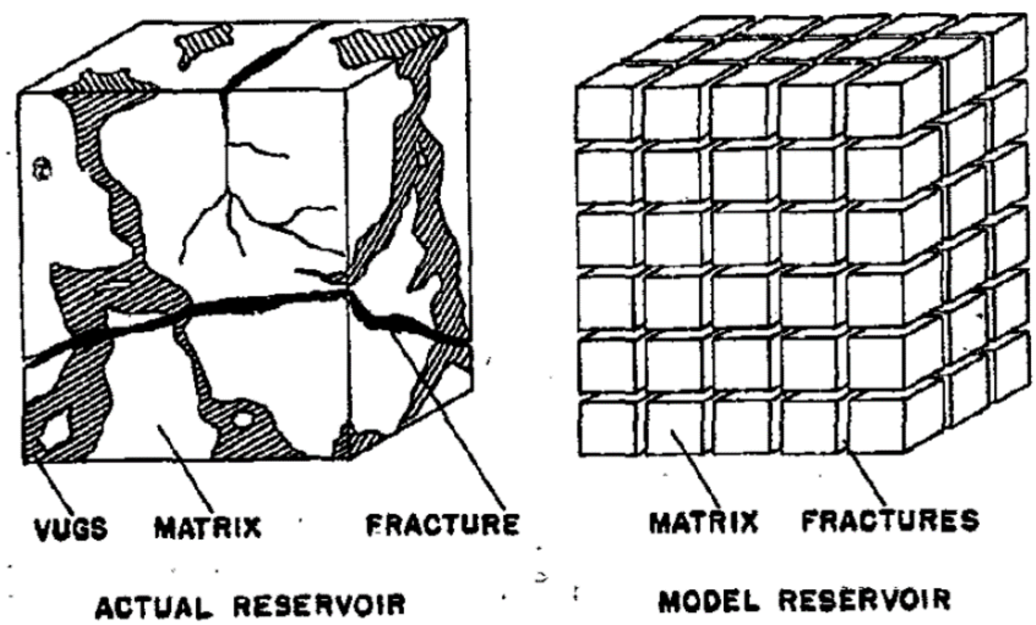


Figure 4.1.1 Modelling of naturally fractured reservoir (Warren and Root, 1963)

Fractured carbonate is categorized as dual porosity system or dual permeability system. Dual porosity systems are characterized by very little matrix flow, thereby making fractures function as the main transport mechanism for fluid to flow. In dual permeability system, there is some fluid flow through the matrix.

Porosity represents the void space in a rock. It can be calculated by dividing the void space by the bulk volume of the rock. Porosity can be classified as primary and secondary porosity. Primary porosity is established when the sediment is first deposited. Thus, it is an original characteristic of the rock. Secondary porosity is the result of geologic process after the deposition of sedimentary rock and has no relation to the form of the sedimentary particles. In general, secondary porosity is due to solution, recrystallization, dolomitization, and fractures.

Porosity is equal to void space divided by bulk volume. Fracture porosity can be attached to single point properties or total bulk properties. As such, fracture porosity is a strongly scale dependent.

a. Fracture porosity attached to single point properties, $\phi 1$.

   Fracture porosity is equal to the void space within fracture divided by bulk volume of the fracture. Therefore, $\phi 1$ is a large number, sometimes close to 100%.

b. Fracture porosity attached to total bulk volume, $\phi 2$.

   Fracture porosity is equal to the void space within fracture divided by total bulk volume. Therefore, $\phi 2$ is usually a small number, in many cases less than 1%.

4.2 Numerical Simulation Model

Numerical simulation is an effective approach to quantify reservoir performance. To accurately represent a real reservoir, the source of data for simulations must be reliable enough to capture the physical characteristics of the target reservoir. In this section, simulation models are used to analyze the feasibility and practicability of low salinity injection applied in a Naturally Fractured Carbonate Reservoir.

From field data, interference and communication signatures were observed within wells which indicate the presence of fractures. For simulation models, naturally fractured reservoirs are divided into matrixes and fractures interacting continuum with superimposed computational grids. Each grid block may contain several fracture and matrix continua (elements) which are lumped together as shown in Figure 4.2.1. When there are substantial matrix heterogeneities, this lumping may lead to erroneous results. Thus, the geological model is built on the dual porosity and dual permeability model, in which the primary continuum for fluid flow is the fracture network and the sink or source to the fracture is the low permeability, high storability matrix system. The tool to build the model is available in Computer Modelling Group Compositional and Unconventional Reservoir Simulation (CMG GEM) to carry out an evaluation. CMG is a reservoir modelling software platform used to make exploration and production decisions and CMG GEM is used worldwide within industry for advanced modelling of recovery processes.

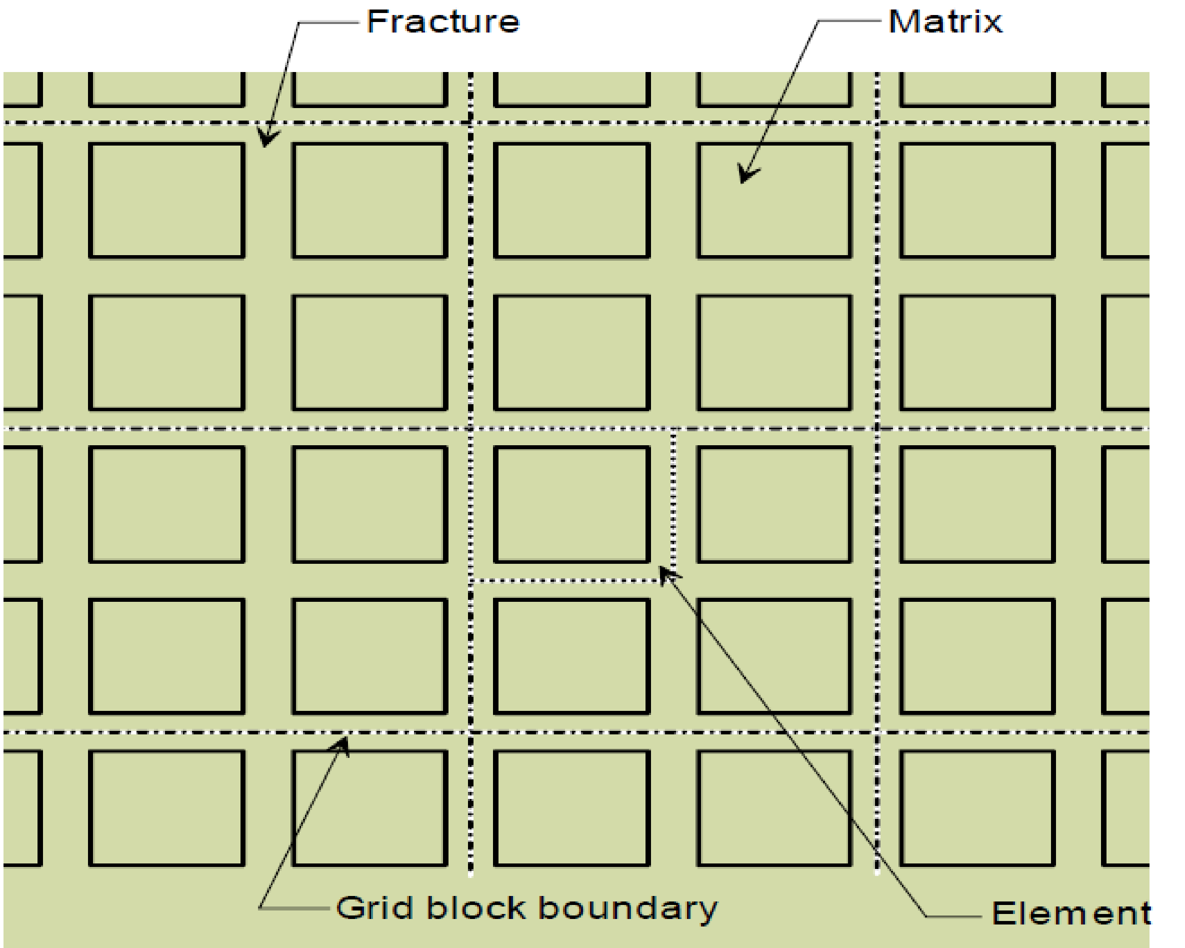


Figure 4.2.1 Fracture and Matrix system in Modeling Naturally Fractured Carbonate Reservoir (CMG, 2017)

In the simulation model, 46 (I-direction) × 69 (J-direction) × 30 (K-direction) grid blocks are built with a grid size of 50 m in length (I-direction), 50 m in width (J-direction) and 1m in thickness (K-direction). The grid top ranges from 4,600 m to 5,082 m and the grid thickness is 7.5 m. Figure 4.2.2 shows the Reservoir Structure of the model. The field structure is suitable for this work given the carbonate structure and vertical refined blocks. The global model is composed of many faults, which some of the faults are relative to reservoir boundaries. The matrix porosity is modelled in the same way with conventional reservoir porosity. Figure 4.2.3 shows the matrix porosity distribution of the model. Each layer has different matrix porosity and the middle-upper layers have better porous media. The formation properties of the model are listed in Table 4-1.

The simulation model is built up as a Type A reservoir, which has a high storage capacity within the matrix. The average matrix porosity is around 0.1903 as listed in Table 4-2. The permeability of the model is stochastically simulated as a function of porosity, using the collocated co-kriging technique. The model contains very thin layers with high permeability and porosity. High vertical heterogeneity in the permeability, synthetic discrete Fracture Network modeling, high flow rates with no indication of barriers, carbonate reservoir of microbial origin, partially dolomitized, PVT data, and intermediate-wet relative permeability are taken into account for the model.

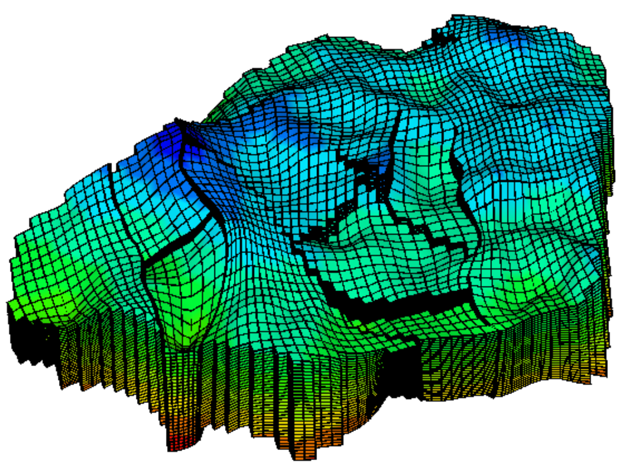


Figure 4.2.2 Reservoir Structure

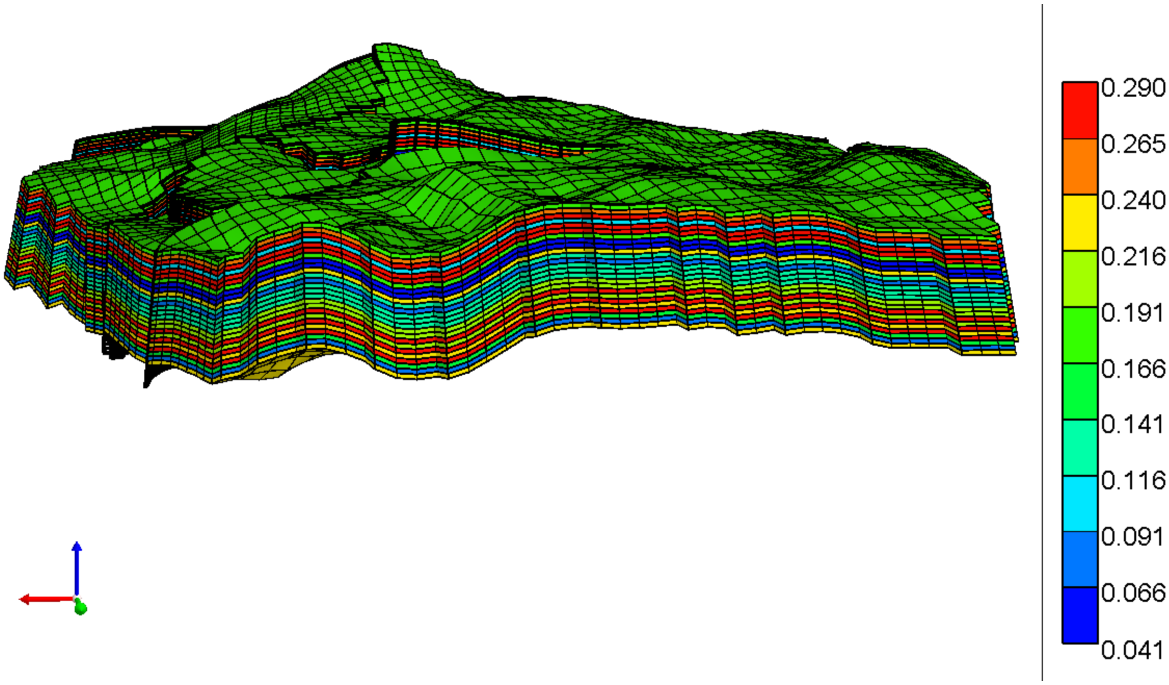


Figure 4.2.3 Matrix Porosity Distribution of the Model

Table 4-1 Formation Properties

Porosity Range	2-30%
Average Porosity	19.1%
Pressure dependence of Formation Porosity and Rock Compressibility of Matrix and Fracture	56.0E-6 1/kPa
Reference Temperature	25 °C
Reference Pressure	450 kPa
Formation Pressure	22063 kPa
Reservoir Temperature	190°F
Oil API	28
Live Oil Viscosity	1.14cP

Table 4-2 Model Matrix Porosity Distribution

Layer	Matrix Porosity
1	0.1836
2	0.242
3	0.2882
4	0.1062
5	0.2796
6	0.2736
7	0.171
8	0.0408
9	0.0522
10	0.237
11	0.1314
12	0.09
13	0.1164
14	0.1338
15	0.135
16	0.2154
17	0.2024
18	0.2792
19	0.2102
20	0.266
21	0.226
22	0.2904
23	0.1422
24	0.0762
25	0.2316
26	0.2178
27	0.2178
28	0.2178
29	0.2178
30	0.2178
Average	0.1903

Table 4-3 Input Uncertainty Date for Reservoir Simulation

	Uncertainty Reservoir Simulation Property (input data)	Nomenclature
Static Properties	Porosity	Poro
	Matrix Permeability	k_x; k_y, k_z
	Fracture Permeability	kf_x; kf_y, kf_z
	Fracture Spacing	$sigma_x$; $sigma_y$; $sigma_z$
	Net to Gross	NG
	Rock Type	rtype
Dynamic Properties	Relative Permeability	kr

The components of the model are generated by CMG Winprop. Since the model is built upon practical geological data and not an ideal simulation model, the existing black oil model template for example, cannot be applied to this model. The input data for Winprop is based on a 'Crude oil Analysis report' from the oil field, in which the report summarizes the oil compositional data from C_1 to C_{34} for the reservoir. Usually, when describing the compositions of crude oil, heavier carbonate components are summarized as, for example, C_7+ to shorten the list of crude compositions. Therefore, more than 70 different compositions of crude oil are summarized and simplified to 13 compositions, these are listed in Table 4-4. The field report and oil analysis report indicate the crude oil API is around 22-32, and the components of the model, which are summarized in Table 4-5, indicates the oil in the reservoir has the proportion of the C_7+ component exceeding 50%. The CMG Winprop regression analysis matches the oil viscosity and API data from the field reports.

Table 4-4 Live Fluid and Dead Liquid Combined Analysis

	WT%	MOLE%
N2	0	0
C1	0.059	0.3062
CO2	0.007633	0.079167
C2	0.005567	0.082467
C3	0.050967	0.4999
IC4	0.036533	0.271067
IC5	0.126633	0.762433
C4	0.137633	1.033267
C5	0.1138	0.650533
C6	0.230267	1.1161
BENZENE	0.03835	0.295133
TOLUENE	0.1742	0.6156
C7+	93.04968	77.36597
	g/mol	
Mole Weight of the sample	218	

Table 4-5 Crude Component input to Winprop

Component	Primary % weight
N2	0
CH4	4.753494706
CO2	0.506961616
C2H6	2.970934191
C3H8	8.912802573
IC4	2.22612292
IC5	6.114735264
NC4	8.491038794
NC5	4.639730222
NC6	7.774424374
BENZENE	0.632525258
TOLUENE	1.265050515
C7+	51.71217957
Sum	100

The extremely large CPU times were a limiting factor, and the simulation cases were terminated at various stages. Since the component properties of the model are not input as a template, the model will calculate and interpolate every single component and there are a lot of parameters that will be simulated as a function of the input data, as a result the process takes a large amount of time to run a simulation. The simulation involved many complex operations, this causes each single case to take about 3 to 4 hours to simulate. This makes it necessary to cut the model and select a relatively ideal part of the model for simulation. The top right part of the model is selected for cut.

In this study, the method of five spots pattern is selected, with one central vertical injector surrounded by 4 vertical producers, all of which penetrate through 10 layers. The production wells are located at and go through a high permeability area as shown the Figure 4.2.4, and the shape of the cut model and the well trajectories are shown in Figure 4.2.5.

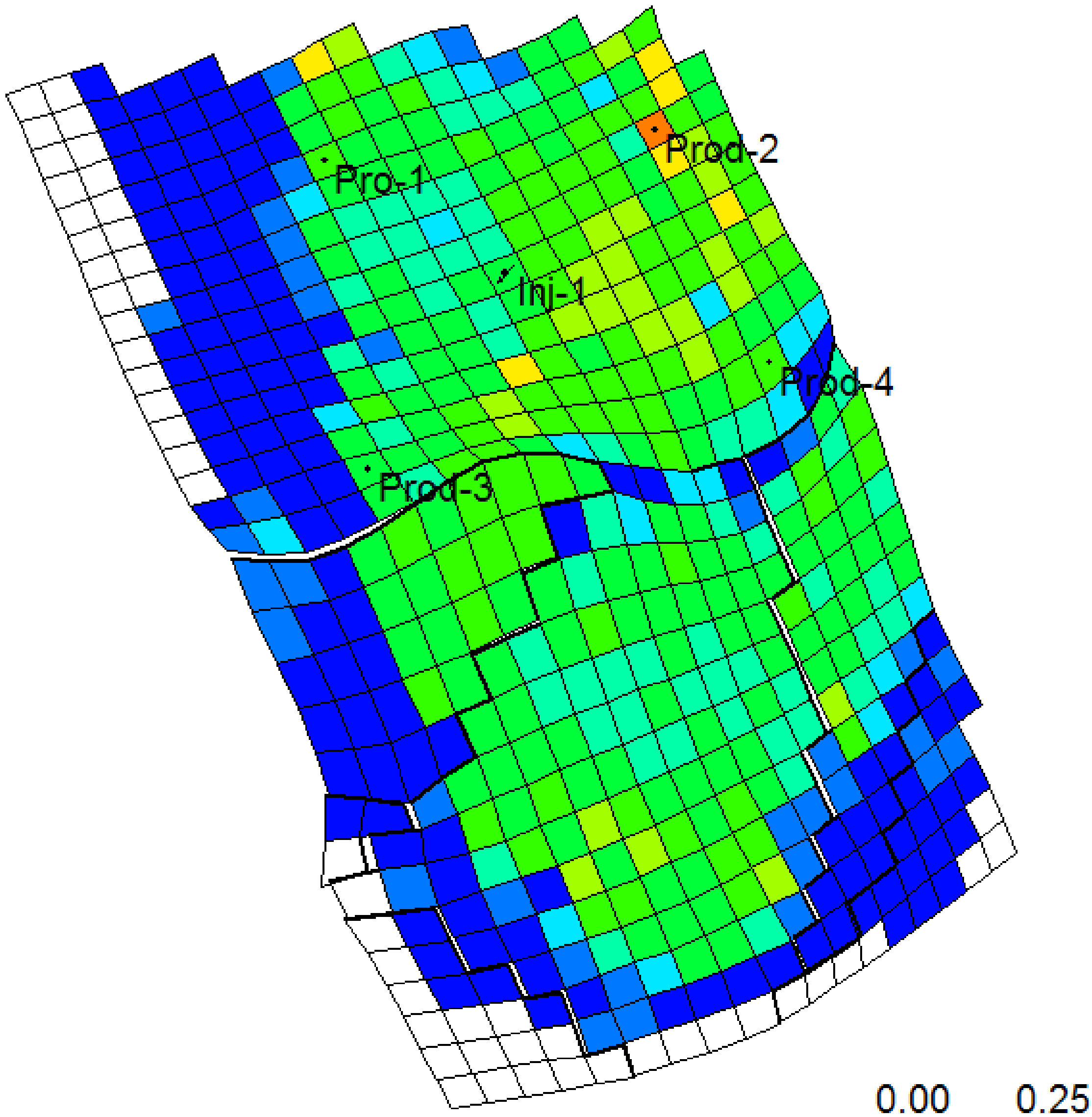


Figure 4.2.4 Production wells locates at and go through high permeability area

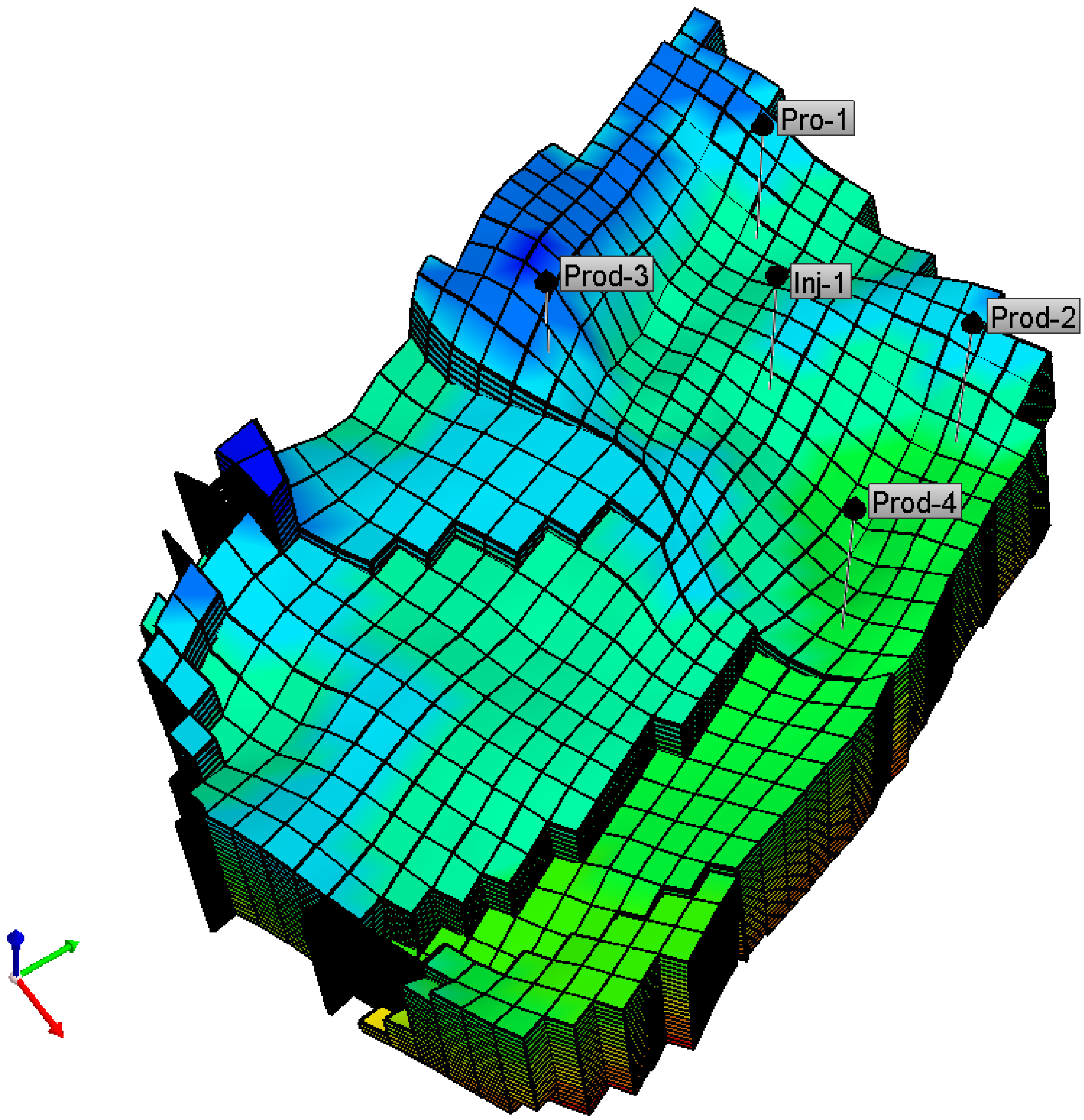


Figure 4.2.5 Shape of cut model and well trajectories

Chapter Five: DISCUSSION OF SALINITY WATERLOOD IN NATURALLY FRACTURED CARBONATE RESERVOIR

5.1 Summary of Study

Carbonate rocks contain more than 50% of the global hydrocarbon reserves. However, there are still many challenges in the development of carbonate reservoir technology because carbonate reservoir void space is mainly composed of caves, vugs, and fractures, which all vary in size and have complex distributions (Deng, 2010). Therefore, the challenge of effectively developing carbonate reservoirs has become one of the important topics today. Compared with fresh water injection methods, Low Salinity Water Flooding can produce up to 10% extra crude oil (Kokal, 2010). There are no expensive chemicals required for Low Salinity Water Flood, this makes Low Salinity Water Flooding a cheap and environmentally friendly technique, and there are no related injection issues. In addition, using Low Salinity Water Flooding to improve the recovery efficiency of the water injection process is economically effective (Sheng, 2013).

5.2 Performance of Different Salinity Water Floods vs. Fresh Water Floods

5.2.1 Injection Salinity

The study involves comparing four different injection fluids to the resulting production in a carbonate reservoir model. The four injection fluids are Fresh Water, Low Salinity Water, Seawater and Initial Formation Water. The components and salinity variations are shown in Table 5-1, which the salinity data is provided by CMG database and the fresh water date is from waterencyclopedia website. (Waterencyclopedia.com, 2020)

The word “Salinity” defined in terms of the Total Dissolved Solids (TDS), which includes monovalent/divalent Anions and Cations. The fluid contains less than 3000 ppm total dissolved solids are classified as Low Salinity Brine, and fluid contains more than 30000 ppm total dissolved solids is classified as Formation Brine. In general, water flooding typically involves the injection of seawater which has a salinity of about 35000 to 40000 ppm. Therefore, the “Sea Water” represents high salinity fluid and the “Initial Formation Water” represents high salinity water with dissolved minerals.

Table 5-1 Table of Injected Fluids Salinity

	Initial Formation Water Composition	Sea Water Composition	Low Salinity Water Composition	Fresh Water Composition
Compoent	Salinity (ppm)=	Salinity (ppm)=	Salinity (ppm)=	Salinity (ppm)=
'H+'	0.005	0	0.000000001	0
CO3--'	0	0	0	0
CO2--'	1300	0	0	0
'SO4--'	0	3150	46.8	2.2
'Ca++'	18492	511	2.34	0.65
'Mg++'	2320	1540	0	0.14
'Na+'	68520	13200	0	0.56
'Cl-'	150060	23400	0	0.57
Total (Salinity)	240692.005	41801	49.14	4.12

5.2.2 Production Performance Comparison of Four Different Injection Fluid, History Match

Figure 5.2.2.1 shows the history match of the filed production data versus simulation production data. The red line represents the real field cumulative oil production and the other colored line represents the simulation cumulative oil production. The difference of three salinity injected fluid is not obvious in the chart because the difference in simulation production of the three salinity fluids is small and the total cumulative production amount is large. However, the figure clearly indicates that the simulation results trend to match real field production. The difference in the first half of the chart is due to the well schedule of the real field during production. The red line is not smooth and the value is smaller than the simulation results, but after year’s production, the real filed production line and simulation production line are similar.

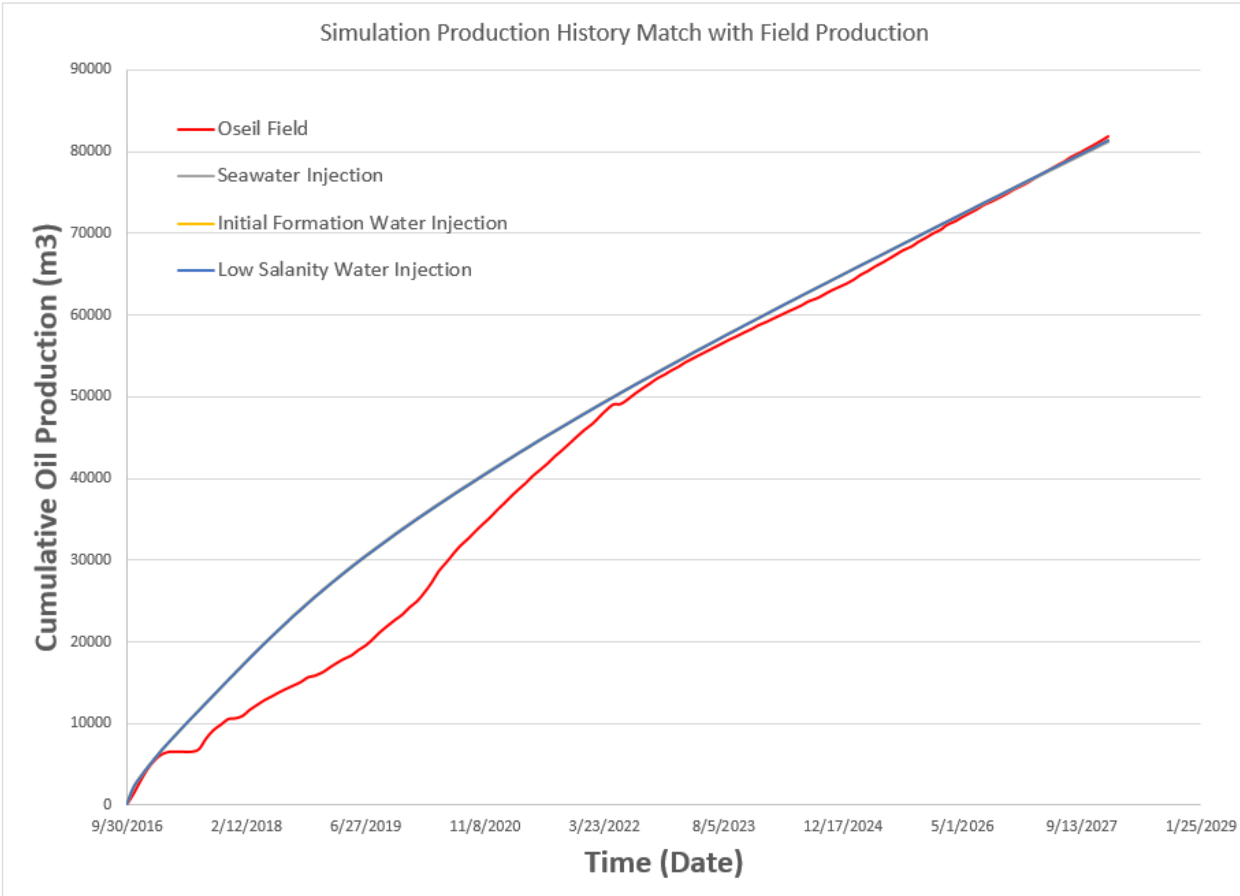


Figure 5.2.2.1 History Match of Field Production Data vs. Simulation Production Data

5.2.2.1 Fresh Water Flood vs. Low Salinity Water Flood

Figure 5.2.2.1.1 compares the cumulative oil production of Low Salinity Water Injection (yellow line) and Fresh Water Injection (blue line). The graph indicates that the final cumulative oil production of Low Salinity Water Injection is around 100,000 cubic meters and 80,000 cubic meters for Fresh Water Injection in a 15 years simulation. The accurate improvement in oil recovery of as much as 29.24% of the Fresh Water Flood is observed through production data. Therefore, the Low Salinity Water Flood has a better effect than fresh water flood in this carbonate reservoir.

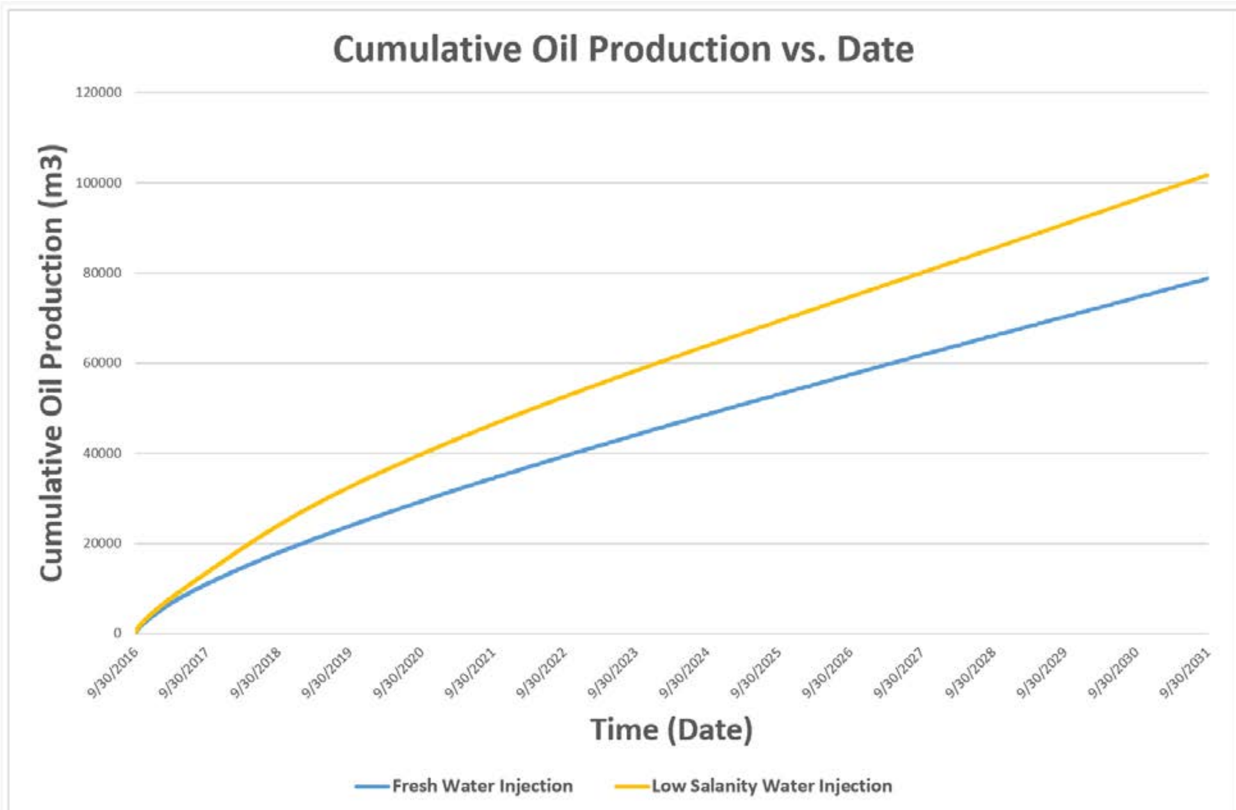


Figure 5.2.2.1.1 Production Performance Comparison of Fresh Water Injection and Low Salinity Water Injection

Salinity Water Flooding has the ability to change the wettability of the formation, thereby allowing better production performance than traditional fresh water flooding. Researchers such as Tang and Morrow have shown that relative water and oil permeability will change through Low Salinity Water Injection and rock wetting conditions tend to be more water wet. Therefore, at a given water saturation, the relative permeability of the oil will increase, decreasing the likelihood of oil to be trapped in the pore structure. The original fresh water relative permeability curve of the model is shown in Figure 5.2.2.1.2, and the relative permeability curve with Low Salinity Water involved is shown in Figure 5.2.2.1.3. The relative permeability data is provided by the company's laboratory work. From the comparison of the two figures, it is easy to see that after Low Salinity

Water is applied to the reservoir, the relative permeability curve of the model changes, which the cross point move to right. The comparison states that the injection of Low Salinity Water will make the rock wetting condition tends to be more water wet. As Atthawutthisin mentioned that the complexity of the composition of the minerals, oil, and water phases in carbonate reservoirs creates severe conditions for explaining the reasons for the observation (Atthawutthisin 2012), but one thing to confirm is if Low Salinity Water has an effect on changing formation wettability.

Different physical and chemical mechanisms have been proposed to verify if Low Salinity Water Flooding has an effect on salting out, multiple ion exchange (MIE), fine particle migration, electric double layer (EDL) expansion, mineral dissolution and pH adjustment (Purswani et al. 2017) to enhance oil recovery. Simulation results hinted at a possible explanation as to why Low Salinity Injection enhances oil recovery more than fresh water flooding methods. These results indicated that the Low Salinity Water Floods can change the ionic component or brine salinity, which will lead to enhanced oil recovery.

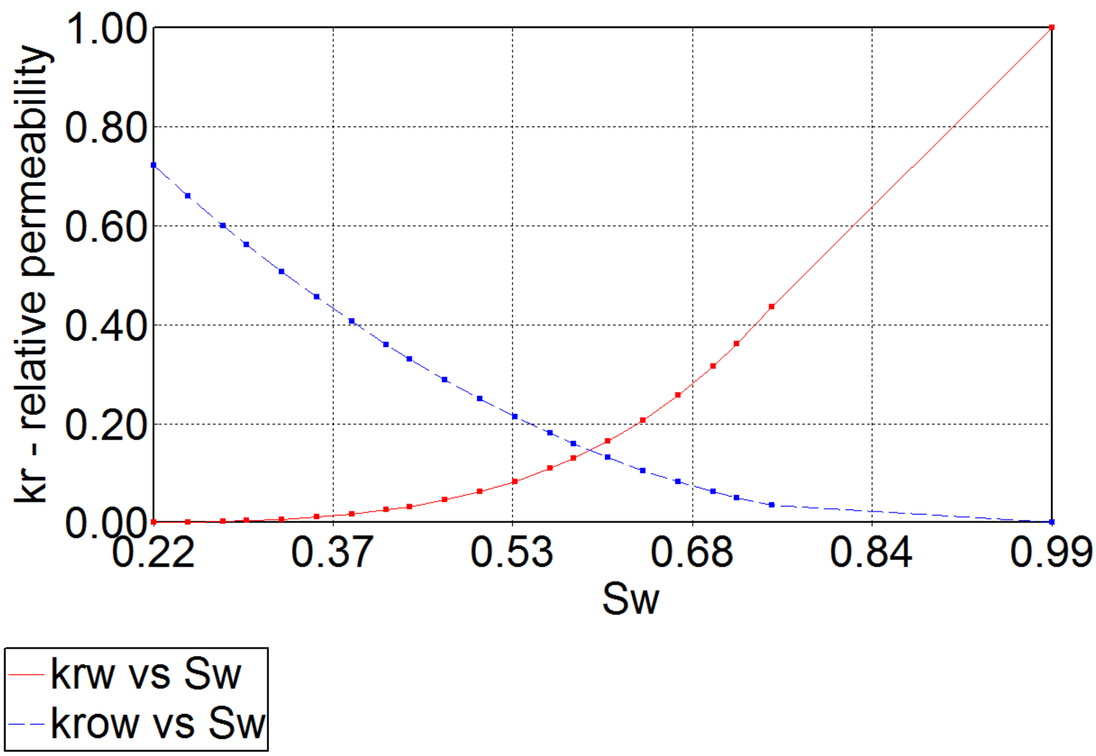


Figure 5.2.2.1.2 Relative Permeability Curve of fresh water

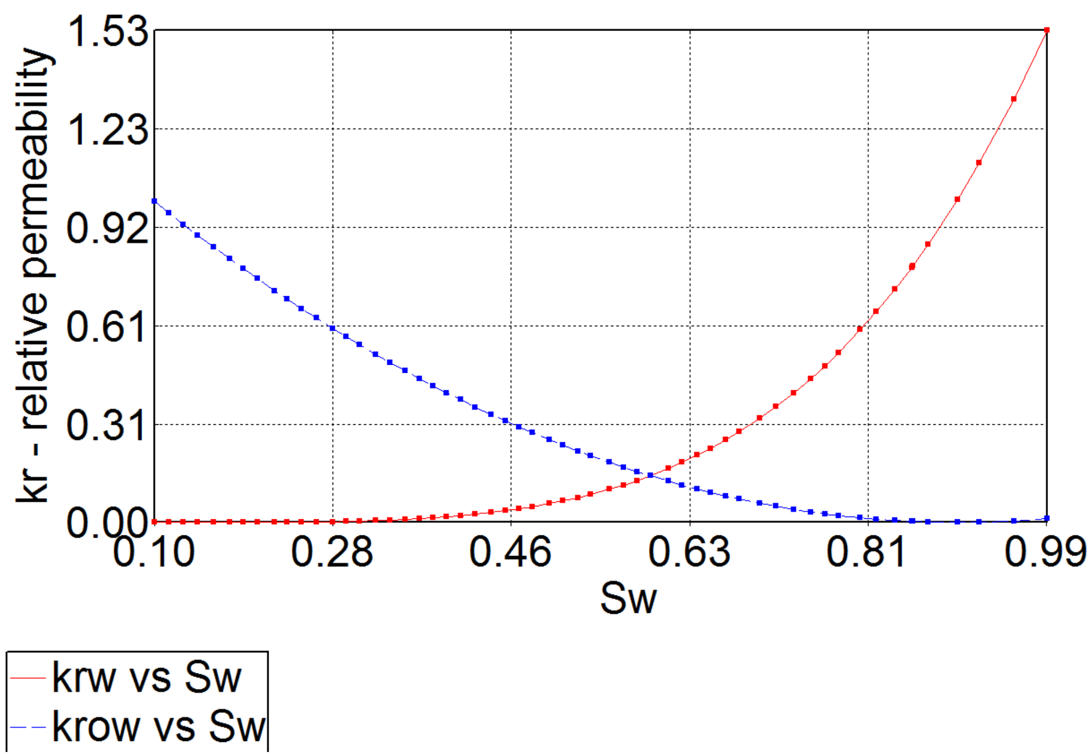


Figure. 5.2.2.1.3 Relative Permeability Curve with Low Salinity Water Involved

5.2.2.2 Low Salinity Water vs. Seawater vs. Initial Formation Water

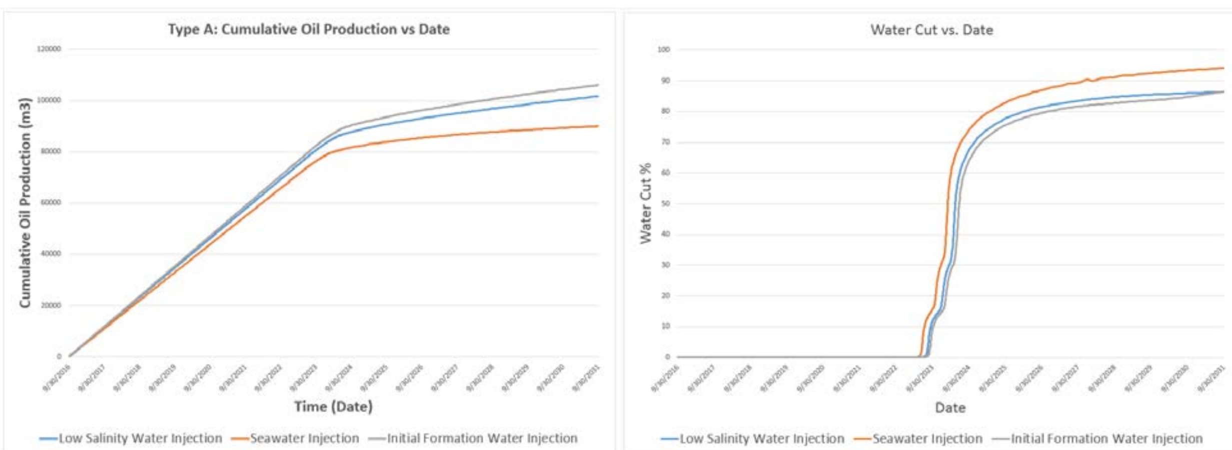
Figure 5.2.2.2.1 (A) compares production performance between three different salinity injections. It indicates the Sea Water Injection has the worst production performance of the three brine injections and the Formation Water Injection has a slightly better effect on producing oil than Low Salinity Water Flooding. The initial production of the three brine injections are approximately the same until they reach the middle of simulation time. Figure 5.2.2.2.1 (B) indicates the water cut difference between the three different brine injections. At the end of the production cycle, the initial water injection line tends to overtake the Low Salinity Injection line – in terms of a higher water cut.

The three different salinity water injections have approximately the same production performance at the beginning until the middle of the production cycle. The cumulative oil production graph indicates that the Low Salinity Water Flooding has better oil recovery than the Sea Water Injection. According to the Sea Water components listed in Table 5-1, the Sea Water can be classified as a high salinity fluid which contains large amounts of "Na+" and "Cl-" compared with the Low Salinity Water's components. The simulation results in the carbonate reservoir showing that the Low Salinity Water Flooding has higher oil recovery than High Salinity Water Flooding in the study. The specific factor of enhanced oil recovery is 7.39%.

A research of Zhang states that based on experiments and research, the Lower Salinity Brine Injection improves recovery factor by about 29% more than Higher Salinity Brine Injection (Zhang et al., 2007), as shown in Figure 2.3.1. The simulation result shows a suboptimal conclusion compared to Zhang's research. The simulation result indicates that the Initial Formation Water which contains high salinity components has slightly better oil recovery than Low Salinity Water Injection.

However, carbonate reservoirs have more complex structures and more uncertain factors, so the effect of Low Salinity Water Flooding may not be as significant as in a sandstone reservoir. In addition, the divalent ion content in the formation water affects the presence of divalent ions (Ca2+, Mg2+) which are necessary for clastics to combine with $SO4^{2-}$ for carbonates. Based on extensive laboratory researches on carbonate reservoirs, the presence of Mg2+, Ca2+ has proven to be potentially decisive ions that will increase oil production during brine waterflooding (Bader 2007; Puntervold et al. 2007; Shariatpanahi et al., 2010; Strand et al., 2008; Zhang et al., 2007a). Table 5-1 shows that the Initial Formation Water injected to the reservoir contains large amount of “Ca2+” components. Formation water with high content of calcium ions (Ca2+) has potential for an average increase in oil recovery of 10% by injecting into the reservoir (Mamonov, Strand, & Puntervold, 2019). In addition, a reasonable explanation of why Initial Formation Water has a slightly better effect on enhancing oil recovery than Low Salinity Water is the simulation reservoir has heavier crude components as mentioned in Chapter 4. The average mole weight of the crude used in the simulation is 218 g/mol and the primary weight of C7+ exceeds 50%. Therefore, the Initial Formation Water, with large amount of “Ca2+” and “Mg2+”, has a good effect on enhancing oil recovery in medium type crude.

A study of water drive behavior analysis related to this carbonate formation is introduced. There are two very representative water cut trends of Carbonate Reservoirs, the “S” type and the “Γ” type, as shown in Figure 5.2.2.2.2.(B). The shape of the “S” type water cut represents a reservoir with a productivity index that is favorable, and a water cut that is slow due to low pressure draw down. The shape of the “Γ” type water cut indicates that in general, the well has no water free production period and the low water production period is short. Therefore, comparing to the “S” type water cut, the reservoir productivity index of “Γ” type water cut is unfavorable and the pressure draw down is higher. Figure 5.2.2.2.1 (B) indicates a typical “Γ” type water cut, which the water cut goes up in a short time. Since Carbonate Reservoirs with homogeneous fracture networks can offer a relative stable oil production and large cumulative production, the homogenous micro-fracture is much more favorable than the macro-fracture in the simulation reservoir. A combination of macro-fracture and micro-fracture will result in rapid water invasion during the initial production period. Increasing the pressure draw down will trigger oil in the micro-fractures, therefore the cumulative oil production will increase.



A B

Figure. 5.2.2.2.1 Production Performance Comparison of Low Salinity Water Injection, Seawater Injection and Initial Formation Water Injection (A) and Water Cut Comparison of Low Salinity Water Injection, Seawater Injection and Initial Formation Water Injection (B)

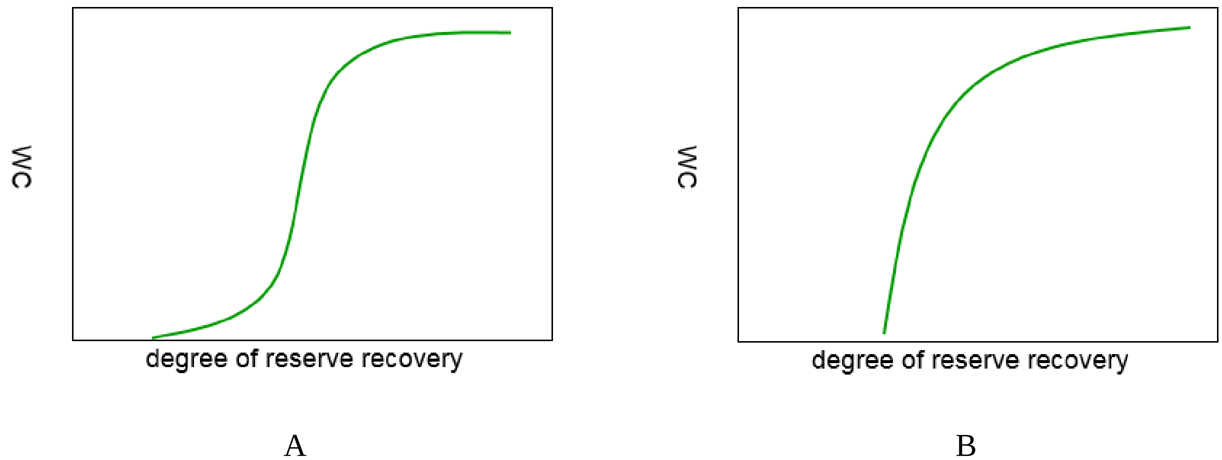
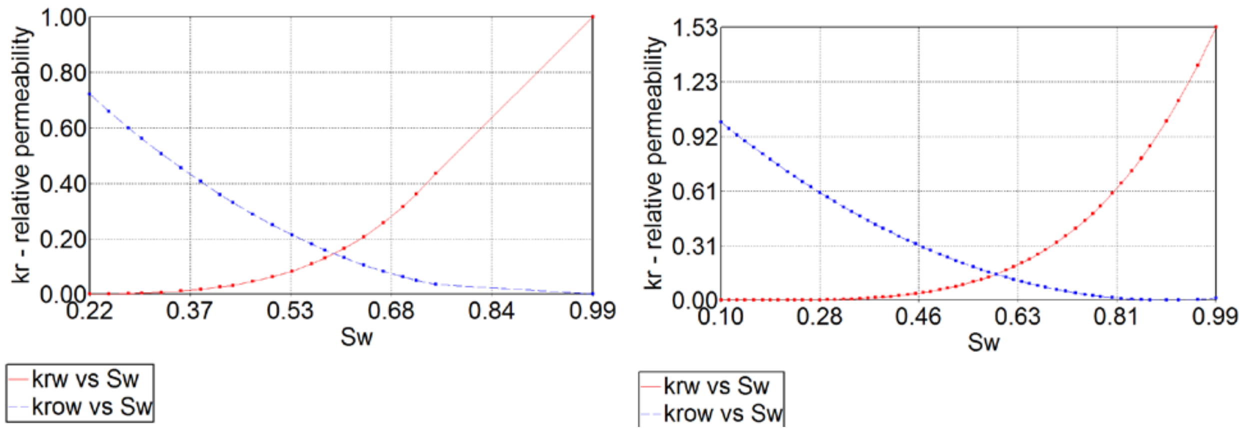


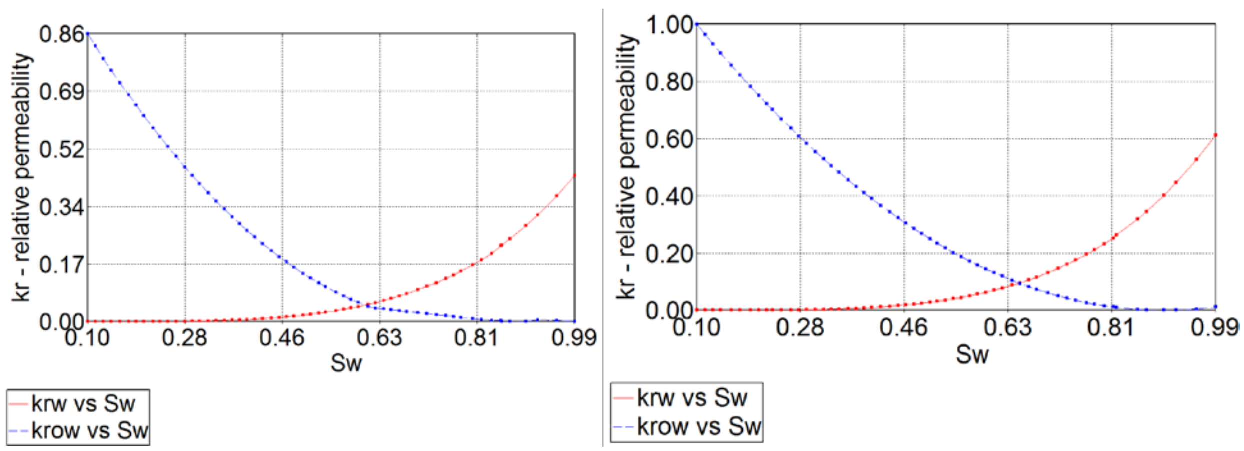
Figure 5.2.2.2.2 "S" type water cut (A) and "Γ" type water cut (B)

Figure 5.2.2.2.3 (A) shows Relative Permeability Curve of fresh water; Figure 5.2.2.2.3 (B) shows Relative Permeability Curve of Low Salinity Water Involved; Figure 5.2.2.2.4 (A) shows Relative Permeability Curve with Seawater Involved; Figure 5.2.2.2.4 (B) shows Relative Permeability Curve of Initial Formation Water Involved. The relative permeability data is provided by the company's laboratory work. After comparing the model relative permeability curve with different salinity water involved, besides Low Salinity Water Injection, the Sea Water and Initial Formation Water have significant effects on changing the wettability of reservoir rock. Due to the Sea Water and Initial Formation Water containing very high salinity components, the effects of these two fluids on reservoir wettability tend to be unified, this changes the rock wetting conditions tend to be more water wet. Salinity Water contains active ions with different relative concentrations compared to Formation Water. Research shows that the carbonate rock wetting condition can be altered by increasing the concentration of divalent anions (Austad et al., 2011).



A B

Figure.5.2.2.2.3 Relative Permeability Curve of fresh water (A) and Relative Permeability Curve with Low Salinity Water Involved (B)



A B

Figure.5.2.2.2.4 Relative Permeability Curve with Sea Water Involved (A) and Relative Permeability Curve with Initial Formation Water Involved (B)

5.2.3 Production Performance Comparison of Type A, Type B and Type C Reservoirs

The study involves three different types of reservoir: Type A, Type B, and Type C. Type A reservoir has a high storage capacity in the matrix but a low storage capacity in the fractures. The storage capacity in the matrix porosity is larger than the storage capacity in the fractures due to small porosity fracture contribution to the rock. Type B reservoir has about equal storage capacity in the matrix and the fractures. The storage capacity in the type C reservoir is all within the fractures because the matrix porosity is almost zero.

5.2.3.1 Matrix Property of 3 Type Reservoirs in Simulation

Table 5-2 shows the approximate matrix porosity of Type A, Type B and Type C Reservoirs, which the data set are provided by the company's report. The matrix porosity for Type A, B and C reservoirs used within the simulation are listed in Table 5-3. The average matrix porosity is within the Type range. The Type A reservoir of the simulation has large matrix porosity, so the matrix should play an important role in oil recovery. The Type B reservoir of the simulation is a type B2 reservoir, which is not an ideal reservoir rock. Consequently, the fractures have only a fraction of the total porosity, but they might have nearly 100% of the hydrocarbon storage capacity. The Type C reservoir of the simulation has zero matrix porosity, so the fractures provide the essential porosity and permeability

Table 5-2 Approximate Matrix Porosity in 3 type of reservoirs (Aguilera, 1995)

	Type A	Type B	Type C
Matrix Porosity	10%-35%	3%-7%	0

Table 5-3 Matrix Property used in Simulation for Each Layer of type ABC Reservoir

	Type A	Type B	Type C
Layer	Matrix Porosity	Matrix Porosity	Matrix Porosity
1	0.1836	0.0306	0
2	0.242	0.057	0
3	0.2882	0.0647	0
4	0.1062	0.0177	0
5	0.2796	0.0466	0
6	0.2736	0.0456	0
7	0.171	0.0285	0
8	0.0408	0.0068	0
9	0.0522	0.0029	0
10	0.237	0.079	0
11	0.1314	0.0219	0
12	0.09	0.003	0
13	0.1164	0.0194	0
14	0.1338	0.0223	0
15	0.135	0.0045	0
16	0.2154	0.0359	0
17	0.2024	0.0504	0
18	0.2792	0.0632	0
19	0.2102	0.0517	0
20	0.266	0.061	0
Average	0.1827	0.035635	0

5.2.3.2 Simulation in Type A Reservoir

Figure 5.2.3.2.1 shows the comparisons of cumulative oil production between Low Salinity Water Flooding, Seawater Flooding, and Initial Formation Waterflooding in a Type A Reservoir. The Seawater Injection has the worst oil recovery out of the 3, and the Initial Formation Water Injection has a slightly higher oil recovery than Low Salinity Water Injection. The Low Salinity Water

Injection has 13.04% increased oil recovery than Seawater Injection, and the Initial Formation Water Injection has 4.2% increased oil recovery than the Low Salinity Water Flooding.

The study indicates that both Low Salinity Water Flooding and Initial Formation Waterflooding have good effects on enhancing oil recovery in this Carbonate Oil Reservoir.

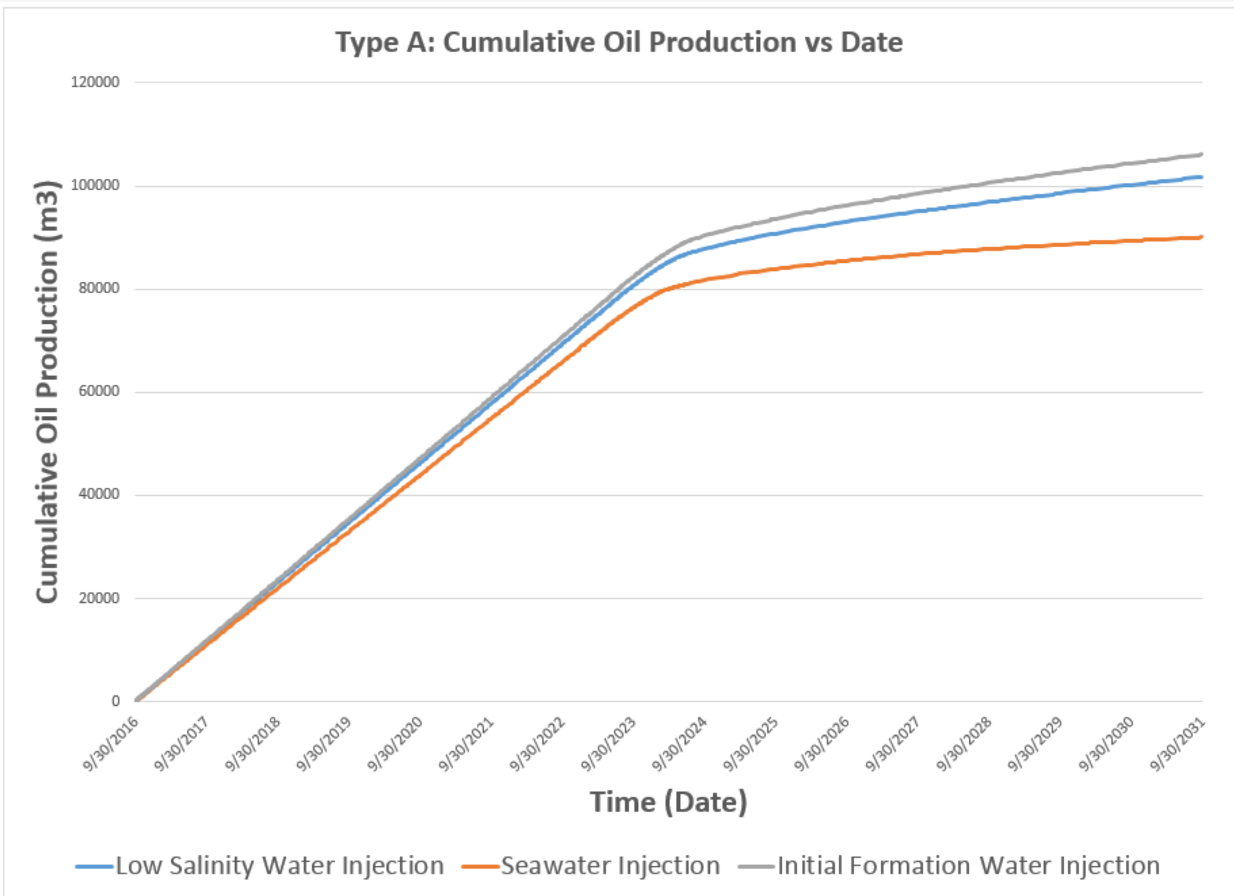


Figure 5.2.3.2.1 Different Salinity Water Injection in Type A Reservoir.

5.2.3.3 Simulation in Type B Reservoir

Figure 5.2.3.3.1 shows the comparisons of cumulative oil production between Low Salinity Water Flooding, Seawater Flooding, and Initial Formation Waterflooding in the Type B Reservoir. It indicates that the Low Salinity Water Injection has the best oil recovery in Type B Reservoirs compared to Seawater Injection and Initial Formation Water Injection. The Seawater Injection and Initial Formation Water Injection have approximated the same ultimate effect on enhancing oil recovery. Figure 5.2.3.3.2 provides a clearer perspective to observe the difference between the different salinity water injection effects on oil production. The Seawater Injection and Initial Formation Water Injection in Type B reservoirs are slightly different in value of cumulative oil production, in which the Seawater Injection has worse production performance than the Initial Formation Water. The Low Salinity Water Injection has 7.95% increased oil recovery than Seawater Injection.

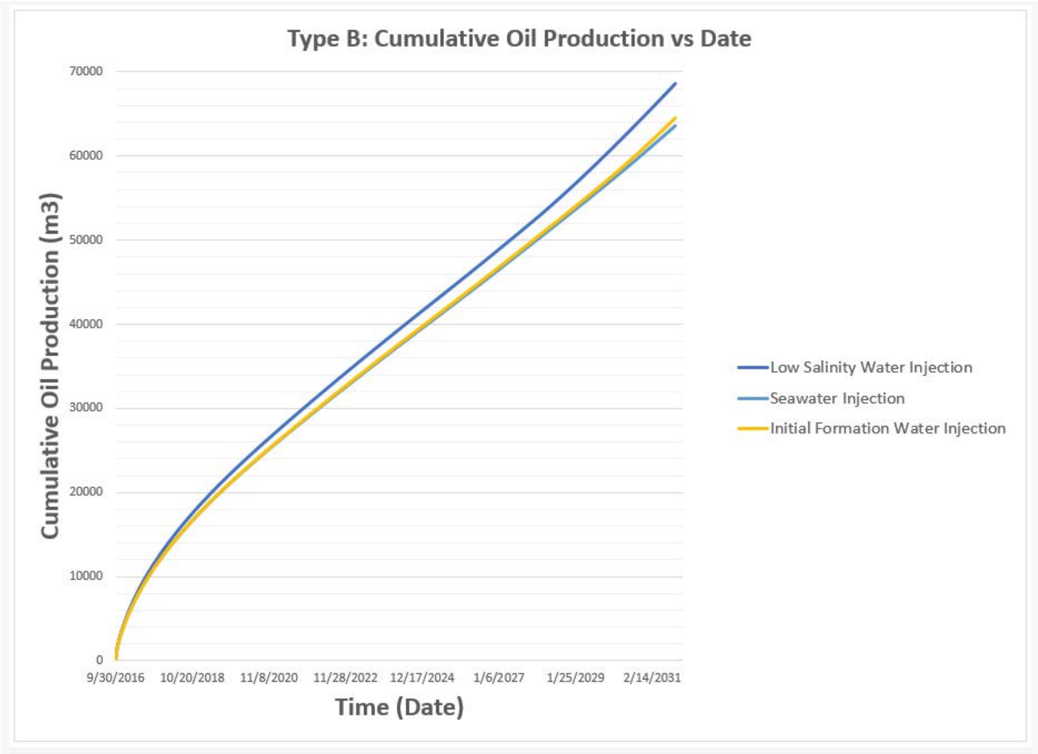


Figure 5.2.3.3.1 Different Salinity Water Injection in Type B Reservoir.

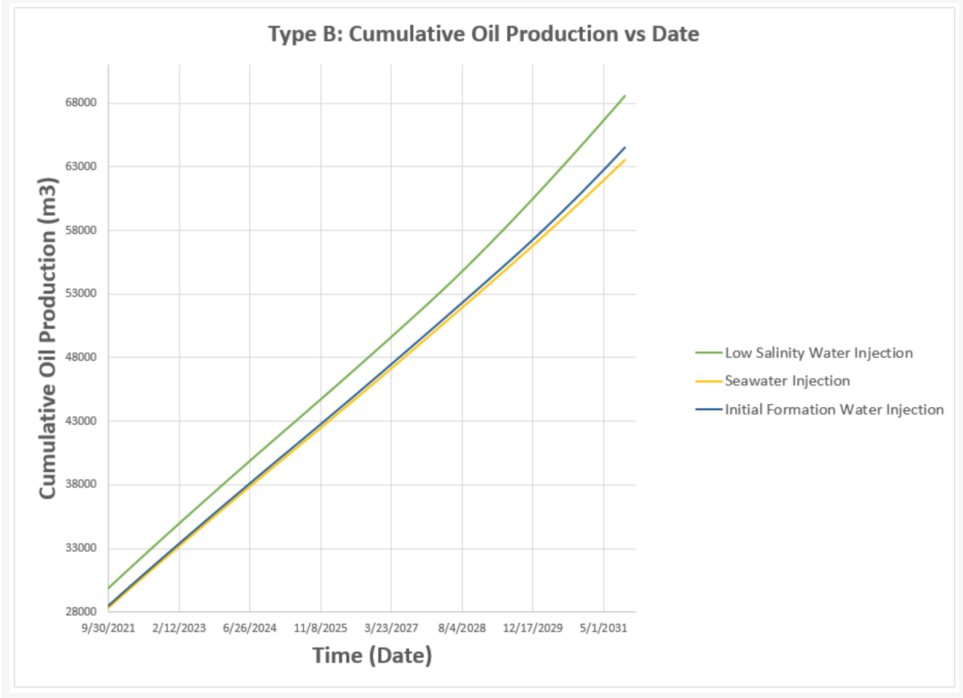


Figure 5.2.3.3.2 Detailed Difference between Different Salinity Water Injection in Type B Reservoir at the end of production period.

Comparing to the simulation results of Type A reservoir, the simulation results of Type B reservoir implicate significant lower oil recovery than Type A reservoir, due to the decrease of matrix porosity. Since the permeability of the model is stochastically simulated as a function of porosity, the decrease of matrix porosity will lead to several model properties to change. The Low Salinity Water Flooding in Type A reservoir has 48.4% increased oil production than in Type B Reservoir, 49.2% increased oil production of Seawater Flooding, and 61.1% increased oil production of Initial Formation Water.

The study indicates that the Low Salinity Water Flooding has a remarkable effect on increasing the oil recovery in Carbonate Reservoirs with about equal storage capacity in matrix and fractures, as well as in reservoirs with a relatively high water saturation, especially for matrix system containing large amount of water.

5.2.3.4 Simulation in Type C Reservoir

Figure 5.2.3.4.1 shows the comparisons of cumulative oil production between Low Salinity Water Flooding, Seawater Flooding, and Initial Formation Waterflooding in the Type C Reservoir. The figure indicates that the Initial Formation Water Injection has the best oil recovery in the Type C Reservoir compared to Seawater Injection and Low Salinity Water Injection. The Seawater Injection and Initial Formation Water Injection have almost identical effects on enhancing oil recovery in the Type C reservoir within this figure.

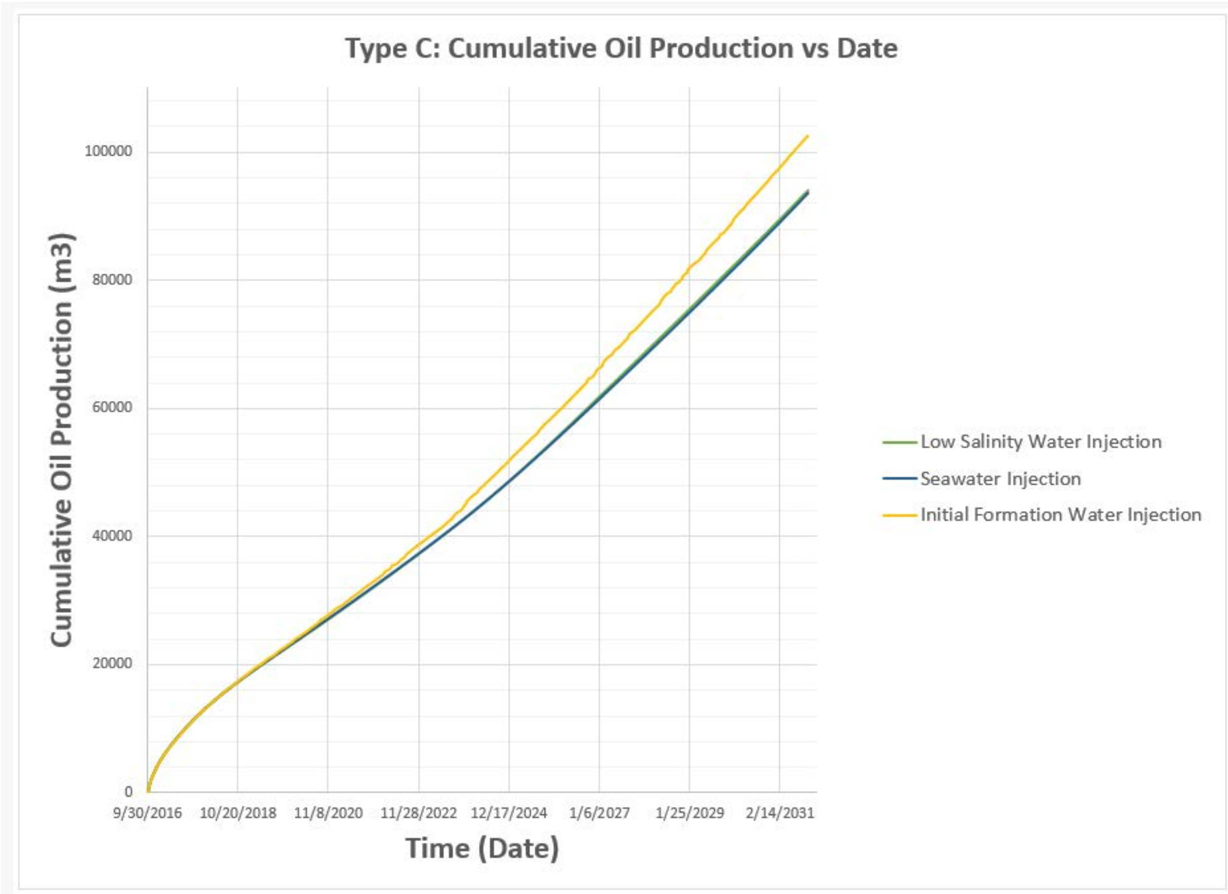


Figure 5.2.3.4.1 Different Salinity Water Injection in Type C Reservoir.

Comparing to the simulation result of the Type A reservoir, the simulation results of the Type C reservoir approaches the Type A reservoir. In both cases, the Initial Formation Water Injection has the best production performance, and the Seawater Injection provides the worst performance among the three different salinity injections. Besides, in the high matrix porosity condition, the effect of the Low Salinity Water Flooding on enhancing oil recovery is close to the best performance which is the Initial Formation Injection, however, in the no matrix porosity condition, the effect of Low Salinity Water Flooding is close to the worst performance which is the Seawater Injection. The three different salinity fluids lead to approximately the same production from the beginning for simulation in Type A and Type C reservoirs. Numerical representation of the simulation results indicates that the oil recovery factor of Initial Formation Water Flooding in Type C reservoirs is bigger than in Type A reservoirs. The result is in line with Aguilera's conclusion that in general, Type C reservoirs have relatively higher recovery than type A or type B because all the hydrocarbon storage is placed within fractures.

The study suggests that the Initial Formation Waterflooding has a remarkable effect on increasing oil recovery in Carbonate Reservoirs with either major matrix porosity conditions or major fracture porosity conditions. In addition, the oil is mainly produced from fractures in Type A Reservoirs because the cumulative oil production curves of Type A and Type C reservoirs are similar, as well as the results that the Initial Formation Water has the best performance among different salinity injections. In the meantime, it is concluded that the matrix dominates oil recovery in the Type B reservoirs by comparing the simulation results in all three different types of Carbonate Reservoirs. The Low Salinity Water Flooding has the best performance only in equal matrix and fracture porosity systems. A reasonable explanation is that the Low Salinity Water Flood changes the wettability of the matrix rock, leading to increased oil recovery.

5.2.3.5 Comparison of Low Salinity Water Flooding, Seawater Flooding, and Initial Formation Waterflooding in Type A, Type B, and Type C Reservoirs.

The Figure 5.2.3.5.1 shows the different production results of Low Salinity Water Flood in Type A, Type B, and Type C Reservoirs. Within this figure, it is clear that the Low Salinity Water Flood has the best performance in a high matrix porosity reservoir. Although the Low Salinity Water Flood has less cumulative production in a low matrix porosity reservoir, it is the best injection method among the three different salinity injections. The figure also indicates the Low Salinity Water Flood has a good effect on applying to Naturally Fractured Reservoirs with about equal storage capacity in the matrix and fractures.

The Low Salinity Water Flooding influences the wettability of the formation, and it presents better production performance than water flooding in this Naturally Fractured Carbonate Reservoir.

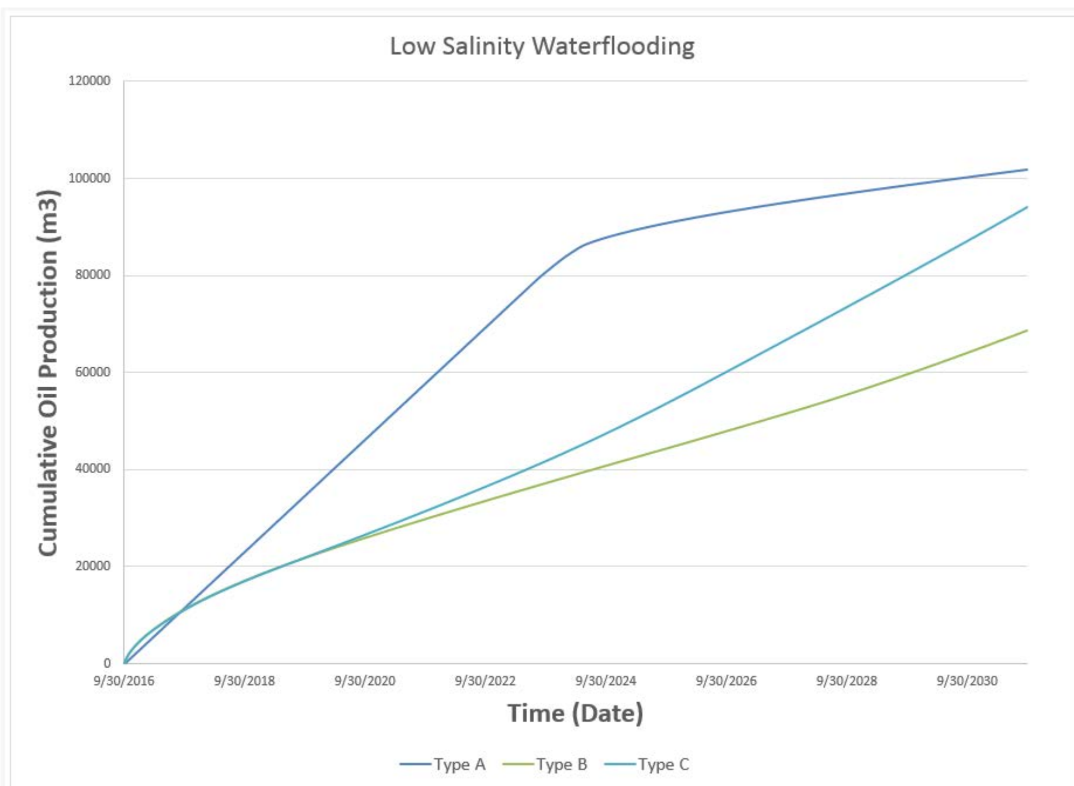


Figure 5.2.3.5.1 Different Production of Low Salinity Water Flooding in Type A, Type B, and Type C Reservoirs.

Figure 5.2.3.5.2 illustrates the different production results of Seawater Flooding in Type A, Type B, and Type C Reservoirs. Although the comparisons indicate that Seawater Flooding provides the worst performance among the three different salinity injections, it has significantly better oil recovery than fresh water flooding. Since this oil field is near the ocean, there are sufficient sea water resources that can be used for oil and gas development.

Seawater also influences the formation wettability, which can increase the oil recovery factor of Naturally Fractured Carbonate Reservoirs. Therefore, the Seawater will be a feasible option in developing the oil field besides Low Salinity Water Flooding.

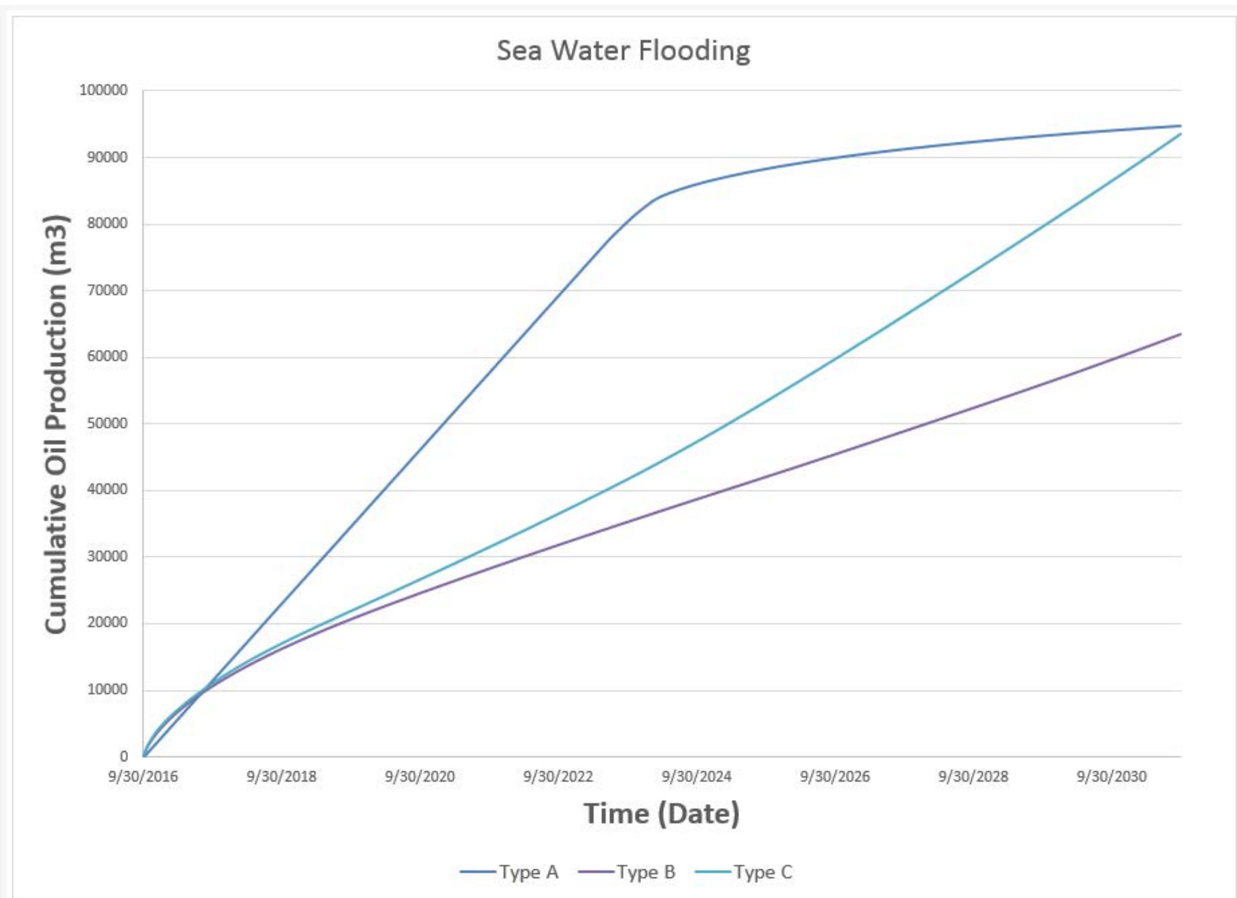


Figure 5.2.3.5.2 Different Production of Seawater Flooding in Type A, Type B, and Type C Reservoirs.

Figure 5.2.3.5.3 shows the different production results of Initial Formation Waterflooding in Type A, Type B, and Type C Reservoirs. In Type A and C cases, the abundant matrix porosity condition and no matrix porosity involved condition, the Initial Formation Waterflood has the best enhanced oil recovery effect compared to the other two salinity injection. Since the cumulative oil amount is about the same in Type A and Type C reservoirs, the fracture system dominates the oil recovery in those two types of reservoirs. The consequence suggests that Initial Formation Water, which contains high amount of potentially decisive "Ca+" and "Mg+" ions, tends to react effectively with $SO4^{2-}$ ions in the reservoir leading to increased oil production during brine waterflooding. Proper composition of Initial Formation Water will improve the productivity of the oil field and increase the oil recovery.

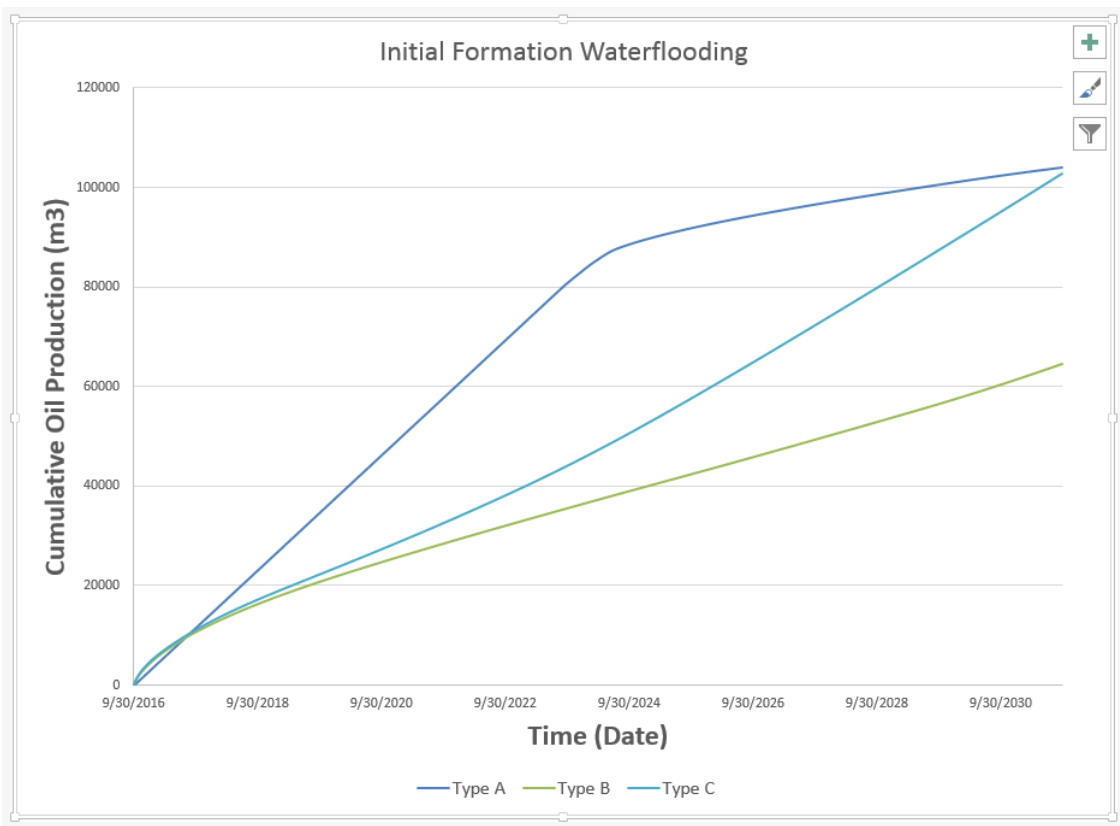


Figure 5.2.3.5.3 Different Production of Initial Formation Waterflooding in Type A, Type B, and Type C Reservoirs.

5.2.4 Fluid Flow Characteristic

The presence of fractures in a reservoir induces fluid flow different from that of more conventional, non-fractured reservoirs. Fractures produce a variety of effects on fluid mobility in a reservoir that must be considered to understand and predict reservoir production behavior. Reservoir fluid will flow from matrix to fracture and then to the wellbore as shown in Figure 5.2.4.1.

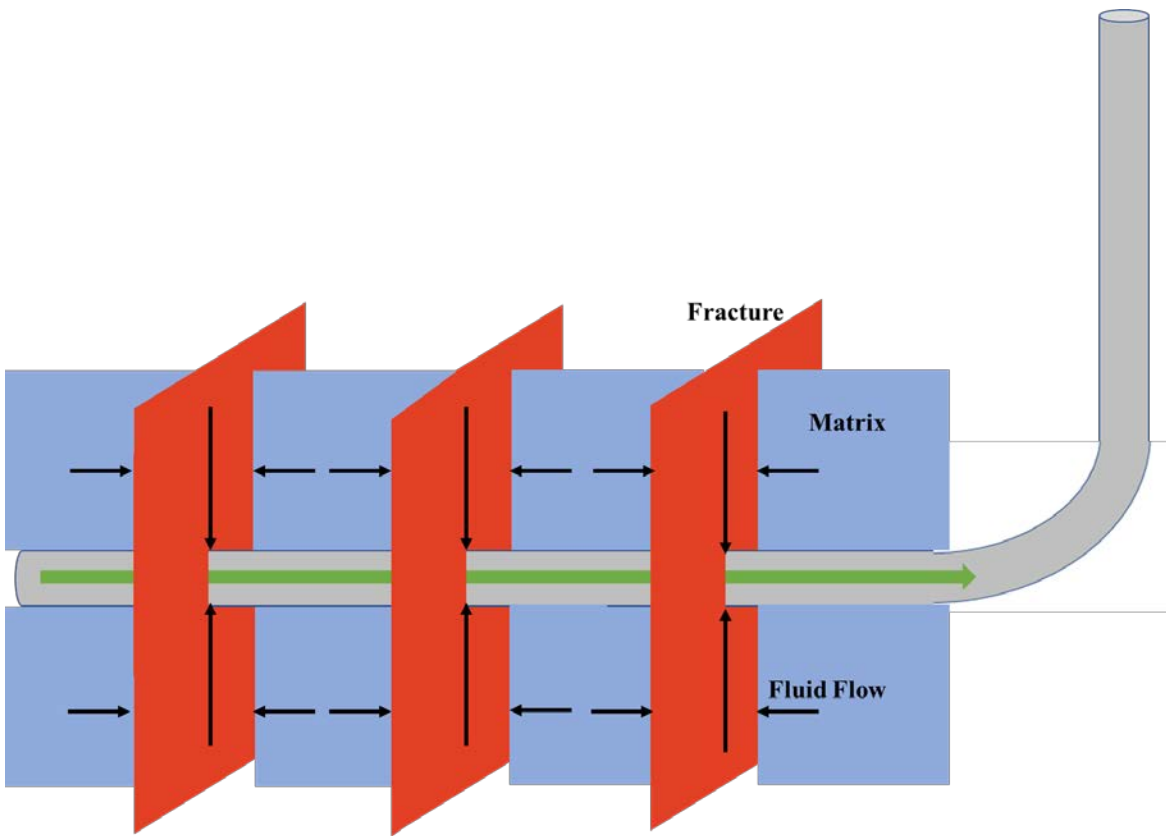


Figure 5.2.4.1 Fluid flow direction in naturally fractured reservoir.

Naturally fractured reservoirs that produce at high initial rates decline drastically after a short period of time because the producible oil stored in the fracture system gets produced quickly and initially. In this initial period, fluid flow to the well is controlled by fractures and it is called the “fracture flow control period”. This initial flow period is what distinguishes fractured reservoirs from non-fractured reservoirs which occurs due to the fracture’s system higher conductivity compared to that of the matrix. Fractures have an essential permeability to flow reservoir fluids at first time production. If not analyzed correctly, the predicted oil rate production would be overestimated. The matrix will contribute later to the production and shows a different production trend compared to the fractures as shown in Figure 5.2.4.2.

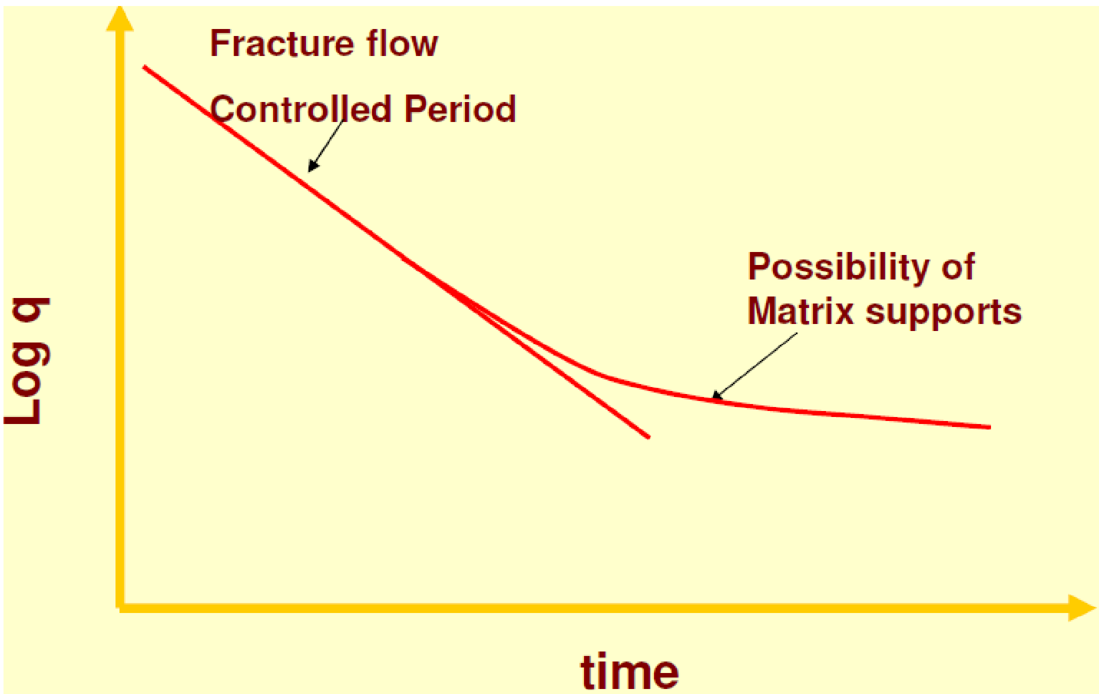


Figure 5.2.4.2 Typical oil production rate in fractured carbonate.

When a fractured reservoir is produced by a vertical well and the fracture is connecting the wellbore and water zone, it can cause a rapid water coning to the well. If the well is a horizontal well, then water level movement is slower than the vertical well and called water cresting as shown in Figure 5.2.4.3.

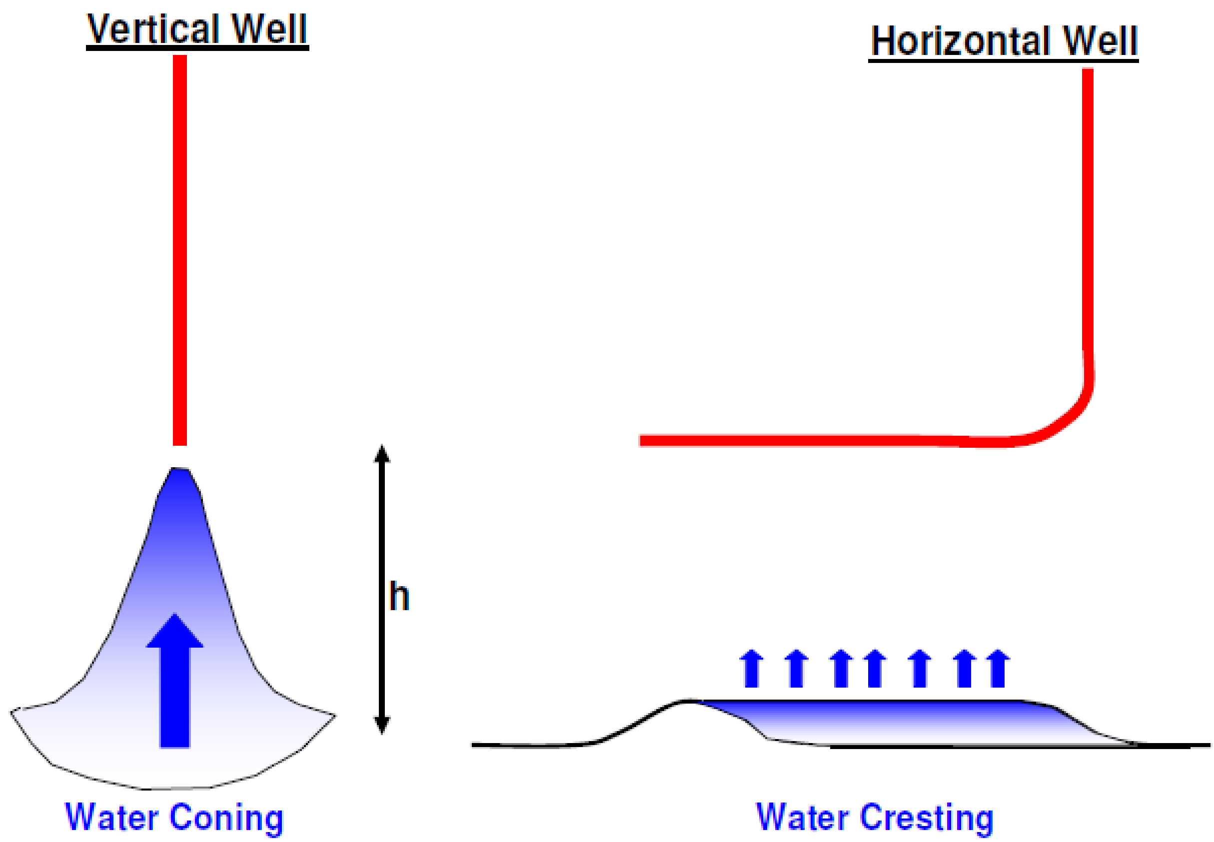


Figure 5.2.4.3 Water coning and Water cresting illustration.

Production performance in fractured carbonates could also be analyzed with decline curve analysis. Decline curve analysis is an analysis of declining oil production rates obtained from field data to forecast future performance of wells, layer, or field and get the estimated ultimate recoverable reserves (EUR). The method is to fit a line through the production history and assuming this same trend will continue in future performance if there are well operations.

5.2.5 Simulation Mineral Reaction Rate with Temperature

The Reaction rate of minerals in the simulation are calculated from the correlations below.

$$r_\beta = \hat{A}_\beta k_\beta \left(1 - \frac{Q_\beta}{K_{eq,\beta}}\right), \beta = 1, \dots, R_{mn}$$

$$k_\beta = k_{0\beta} \exp[-\frac{E_{a\beta}}{R}(\frac{1}{T} - \frac{1}{T_0})]$$

The reaction rate dependency on Temperature for Calcite mineral reaction is:

$$\text{Calcite}\,(\text{CaCO}_3) + (H^+) = (CA^{++}) + (HCO_3^-)$$

Figure 5.2.5.1 shows the reaction rates increase with temperature increase, and the higher the molality of Ca2+ the higher the reaction rate. Figure 5.2.5.2 shows each component in the calcite mineral reaction with Ca2+ Molality. When Ca2+ molality increases, the Calcite reaction rate decreases and Ca2+ reaction increases, and the reaction is going forward and therefore mineral dissolution will occurs.

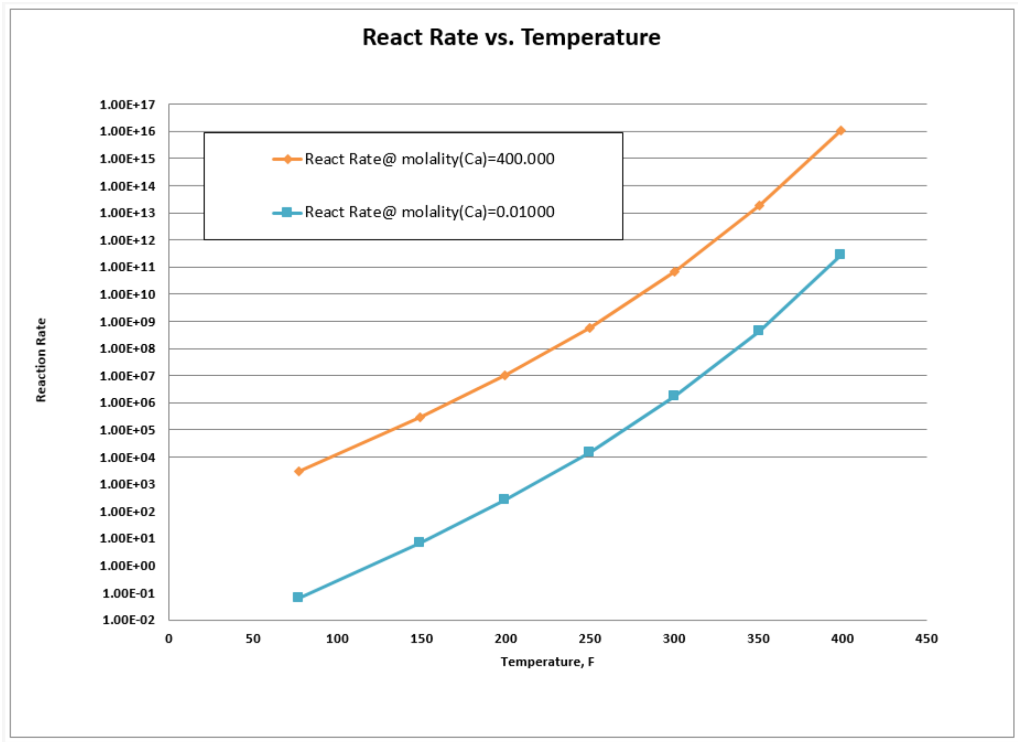


Figure 5.2.5.1 React Rate vs. Temperature

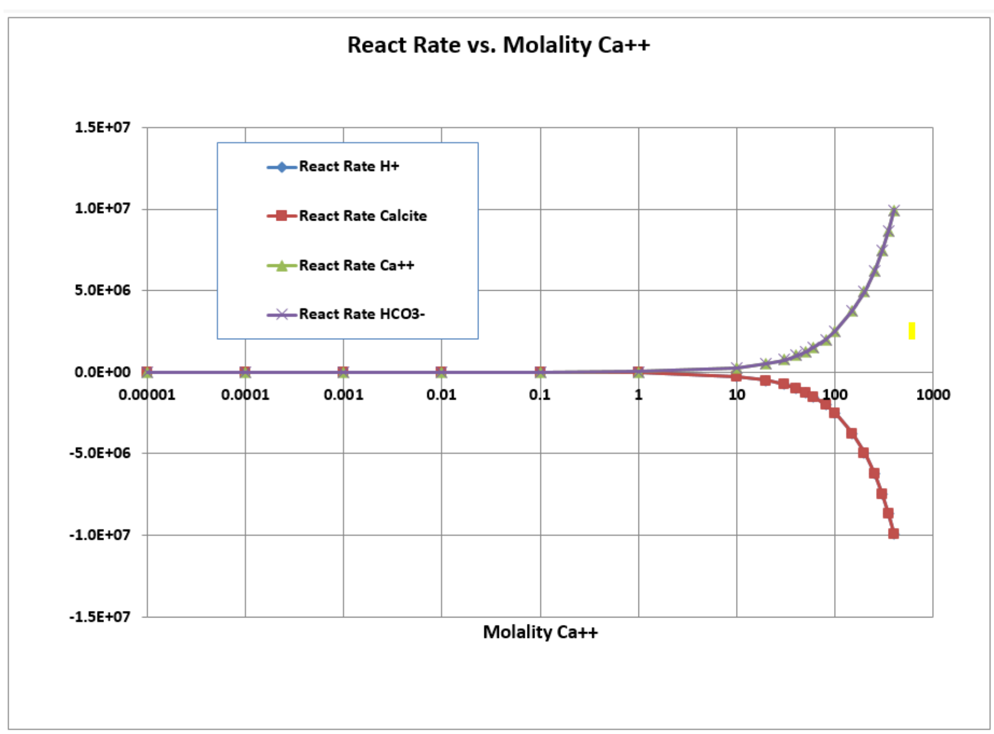


Figure 5.2.5.2 Reaction Rate vs. Molality Ca2+

Chapter Six: CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Reservoir Simulation is the best method for providing insight into the effects of different strategies before implementing the strategy in the real world. In this chapter, a comparison of Waterflooding, Low Salinity Waterflooding, Seawater Flooding and Initial Formation Waterflooding performances is conducted by running simulations in a Naturally Fractured Carbonate Reservoir model; an investigation of applying different salinity waterflood in Type A, Type B and Type C Naturally Fractured Carbonate Reservoirs is completed. The following conclusions are made:

- All three of the different salinity waterfloods - Low Salinity Waterflood, Seawater Flood and Initial Formation Waterflood - have increased production performance as compared to the Conventional Waterflood in the simulation. The study implicates that all the three different salinity waterfloods have a positive effect on enhancing oil recovery in the Naturally Fractured Carbonate Reservoir of the study.
- The Low Salinity Waterflood has a positive effect on changing the wettability of the formation, especially for matrix, because the relative water and oil permeability will change through Low Salinity Water Injection, and rock wetting conditions tend to be more water wet, resulting in an increased oil recovery in the Naturally Fractured Carbonate Reservoir, as well as the Seawater Flood and Initial Formation Waterflood.
- The Initial Formation Water with large amounts of “Ca++” and “Mg++” has effects on enhancing crude with heavy components (prefer C7+ components) recovery in Naturally Fractured Carbonate Reservoir.

- The Low Salinity Waterflooding has remarkable effects on increasing oil recovery in Naturally Fractured Carbonate Reservoirs with about equal storage capacity in the matrix and fractures (Type B Reservoir), as well as in reservoirs with relatively high water saturation, especially for matrix system contains large amount of water because more water contained with low salinity involved will lead to more salinity change, which will lead to better production performance.
- The Initial Formation Waterflooding has notably positive effects on increasing oil recovery in Naturally Fractured Carbonate Reservoir with either major matrix porosity conditions (Type A Reservoir) or major fracture porosity conditions (Type C Reservoir).
- The matrix dominates oil recovery in the Type B reservoirs; whereas fracture dominates oil recovery in the Type A and Type C reservoirs.
- Results indicate that Low Salinity Waterflood is the best method to solve high matrix contribution in this field.
- The reaction rates of minerals increase with slightly increase in formation temperature.
- The homogenous micro-fractures are much more favorable than the macro-fractures in the Naturally Fractured Carbonate Reservoir. A combination of macro-fracture and micro-fractures will result in rapid water invasion during the initial production period. Increasing the pressure draw down will trigger oil in micro-fractures, resulting in a cumulative oil production increase.

6.2 Recommendations

The recommendations for future developing the oil field and the advancement of the study are as follows:

- The relationship between the amount of salinity fluid injected to the formation and production performance needs to be examined for future study.
- The timing of the low salinity fluid injection in this oil field is open to question. The proper injection rate and time will improve the performance of Low Salinity Waterflood in Naturally Fractured Carbonate Reservoir.
- Seawater injection has a significant effect on changing formation wettability and increasing oil recovery in this Naturally Fractured Carbonate Reservoir. It is also beneficial that the oil field is close to the sea and has sufficient sea water resources, therefore the Seawater injection will be a feasible option in developing the oil field.
- The effect of the salinity of the injected liquid on the crude oil of different compositions needs further study.
- Proper composition of Initial Formation Water will improve the productivity of this oil field that contains heavy components and increase the oil recovery effectively.
- The pH value and temperature also affects the performance of salinity waterflooding in Naturally Fractured Carbonate Reservoir. Further research on pH will benefit future development of the oil field.

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