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NUMERICAL SIMULATION STUDY OF FACTORS AFFECTING PRODUCTION WELL GEL TREATMENT USING LINEAR MODELS WITH CROSSFLOW

by

KEWEI SHI

A THESIS

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Approved by

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ABSTRACT

Conformance control is an inevitable topic related to water-flooding. Polymer gel has been proved to enhance oil recovery by blocking the existing water-breakthrough channels. Water that is injected subsequently will be directed to the unswept portion of the reservoir, replacing part of the remaining oil and increasing the oil-recovery factor. Prior to pilot tests of polymer gel treatment, laboratory experiments and numerical simulations are used to design the tests. Understanding physical meanings of key parameters that affect polymer gel treatment and relating the parameters from lab data and the simulator benefit field operation design.

This thesis study tries to evaluate gel performance under different conditions using linear models in CMG-STARS. Eight operational and rock/polymer gel interaction properties are considered. Detailed interpretation of each variable and its influence on water and oil production are provided. Effects of blocking water and increasing oil are analyzed both in the ‘effective period’ and ‘in the long run’.

ACKNOWLEDGMENTS

First, I want to show my appreciation to Dr. Bai, without whose guidance in research and life, I would not reach the point where I am. Having the experience of completing a research study brings me not only the feeling of accomplished of finishing a big project, but also a comprehensive mental preparation for living a meaningful life. I’d also like to thank Dr. Wei for her guidance in the research and her generosity of granting me the scholarship to assist me though my graduate study.

There are several other people whom I would like to acknowledge individually. First, my sincere thanks to Dr. Flori, my committee member, for his enthusiasm in educating, patient guidance and the friendly environment that he creates in the department. Second, I would like to thank Dheiaa Alfarge and Jianqiao Leng, who are Ph.D students of the same research group for their engagement in researching, discussing, and sharing opinions about this study.

Last but not least, my special thanks to my family, and Rolla family and friends. Their constant support and encouragement accompanied throughout my study.

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1. INTRODUCTION

1.1. EXCESSIVE WATER PRODUCTION

Water is generally used to flush oil formations to displace hydrocarbon underground. However, this method can leave as much as 2/3 of the oil in the formation due to the heterogeneity of the reservoir and the high mobility ratio caused by the viscosity difference between oil and water. Once the injected water builds channels from the injection well to the production well, it will flow only through the water channel without exploring any new area. In this case, after water breaks through the producer, the process of producing fluids is merely circulating the injected water through the whole reservoir, which can keep the water cut as high as 98% or more.

Due to the high process expenses and environment damages, excessive water production with oil and gas has increasingly drawn attention to the petroleum industry. According to the National Energy Technology Laboratory (2013), generally 21 billion barrels of water are produced along with oil and gas production annually in the United States. The volume ratio of water to oil worldwide is 2:1 to 3:1, while the ratio for the United States is 5:1 to 8:1, which is caused by the long production history of many reservoirs. For many older US wells, the ratio can be above 50:1. When water-to-oil ratio reaches 4:1, the cost of water treatment can reach $1 per barrel (Bailey et al., 2000).

1.2. CHEMICAL METHODS FOR WATER SHUTOFF

Chemicals have been successfully implemented in the oil industry to change interfacial tension, alter wettability, improve sweep efficiency, reduce water production, and enhance oil recovery (EOR). Among all the chemicals used in EOR, polymer flooding surpasses other chemicals by the virtues of low application risk and sustainability at high temperature and high-salinity reservoirs. Dyes (1954) found that the mobility ratio is influenced by adding polymer to thicken the flood water. A thick and viscous polymer solution ought to enter into the low-permeability zones as much as possible to directly displace the remaining oil in the unswept area. However, Seright et al. (2012) proved that after polymer placement, injected water forms water channels solely in the high-permeability layer, as shown in Figure 1.1, which negates the effect of reducing mobility ratio. In polymer-gel injection, gel is injected in the low-viscosity phase to enter into the high-permeability layer as much as possible. Any penetration of gel as a blocking agent to the low-permeability layer will impede or even shut off the consecutive flooding fluids. An ideal case of gel placement for water shut-off and oil enhancement is shown in Figure 1.2. In the order from (a) to (d), gelant has much deeper penetration in the high-permeability layer than the low-permeability layer. Second, sufficient water is injected subsequently to make a distinguishable distance between the gel rear in the high-permeability layer and the gel front in the low-permeability layer, which will be the flowing path of consecutive flooding water followed by gelation and resuming water injection. Ideally, water will cross-flow the intentionally created path and push the oil that is overlapping the gel from the low-permeability layer into the high-permeability layer.

Several limitations of using polymer gel as a blocking agent should be noted. First, gel treatment does not have an effect on the oil, which is beyond the deepest penetration of the gel. Once water in the low-permeability layer flows beyond the gel bank of the high-permeability layer, water will cross-flow back to the more-permeable layer. Second, a successful gel placement is closely related to the gelation time. If the blocking area is targeted away from the injection well, long gelation time, as much as several months, is needed to achieve the addressed depth of penetration. Third, the effect of polymer gel is maximized when the sweep efficiency is low. This is determined by the mechanism by which polymer gel benefits the production. By blocking the high-permeability layer, gel diverts the water flow path to the low-permeability layer, which is not previously swept due to the poor sweep efficiency. If the sweep efficiency before gel treatment is high or the gel penetration in the high-permeability layer is not deep enough, there will not be sufficient area in the low-permeability layer to be flooded by water. Last, the viscosity and resistance factor of the gelant should not be too high for light-oil reservoirs. Viscous gelant will perform like polymer solutions that can penetrate depths similarly in low- and high-permeability layers.

Prior to pilot tests, laboratory experiments and numerical simulations are used for designing the test Xiao et al. (2016), Hadi Mosleh et al. (2016), Temizel et al. (2016), Okeke et al. (2012). Numerical simulator is used to run the same experiments as carried in the lab and to verify the data obtained from the lab. By a successful match between the simulation results and the lab data, properties of sample rock and interactions between the sample rock and chemicals can be determined. These detailed properties are crucial for field operation design.

In this study, eight parameters including operations and reservoir properties that influence the effect of gel placement are analyzed based on reservoir simulation. CMG-STARS, an advanced industrial modelling software of recovery processes for chemicals, is used to simulate the gel behavior on the reservoir performance Okeke et al. (2012).

This study clarifies the parameters in detail and investigates the physical meanings, and it provides a clear description on how to obtain each parameter from either lab data or calculations.

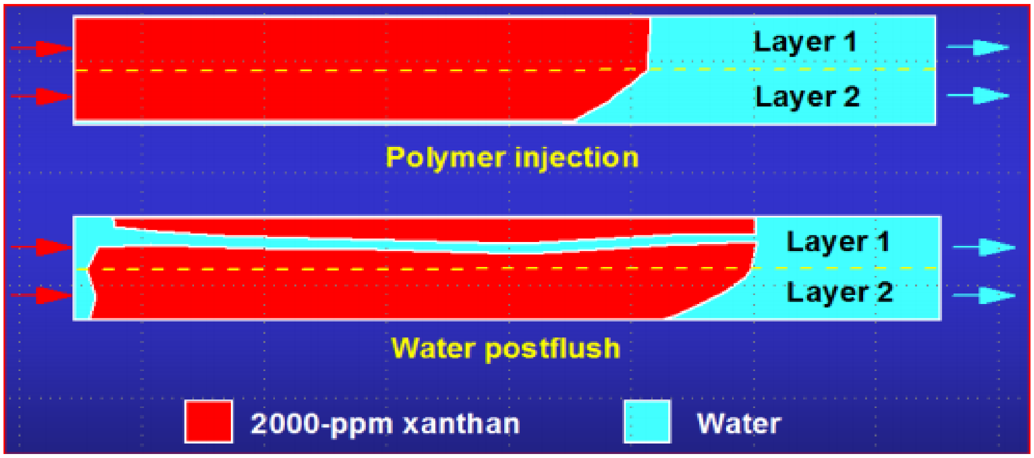


Figure 1.1. Water injection following polymer injection.

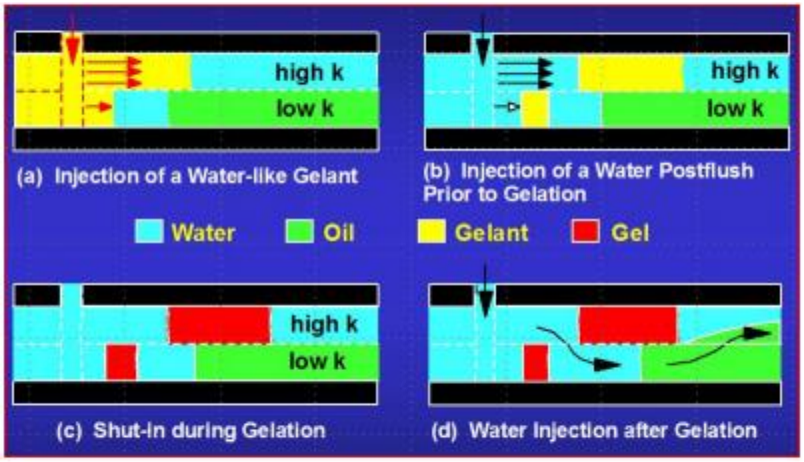


Figure 1.2. An ideal polymer gel injection with post-flushing water.

2. LITERATURE REVIEW

2.1. BASIC CONCEPTS OF WATER-FLOODING RECOVERY

In this section, basic concepts of water-flooding recovery are listed to provide necessary background for using conformance control agent to improve reservoir performance. This section illustrates the importance of mobility ratio, reservoir heterogeneity, and sweep efficiency to production, and the differences between polymer and polymer gel in increasing oil and reducing water production, types and the development of polymer gels.

2.1.1. Mobility Ratio. Mobility of a phase is defined as its relative permeability divided by its viscosity. Mobility ratio is the ratio of mobility between displacing phase and displaced phase. Equations for mobility and mobility ratio are listed as equations (1) and (2):

$$\text{mobility} = \frac{\mathrm{k}}{\mu}, \tag{1}$$

$$\text{mobility ratio} = \frac{\text{mobility}_{\text{displacing}}}{\text{mobility}_{\text{displaced}}} = \frac{\mathrm{k}_{\text{displacing}}\mu_{\text{displaced}}}{\mu_{\text{displacing}}\mathrm{k}_{\text{displaced}}}. \tag{2}$$

Mobility reflects the ability of a phase to flow in the presence of other phases in a porous medium. When the displacing phase has greater mobility than the displaced fluid, it creates fingers. Figure 2.1 (a) shows a fingering problem when water is used to flush oil, due to the significant mobility difference between water and oil. Once water breaks through the producer, the following injected water flows through the existing water pass, leaving a large portion of the reservoir unswept. While when polymer solution is pre-flushed, as it has smaller mobility difference than that of water and oil, the interface between polymer solution and oil is much more rounded and smoother, having a larger swept area, as shown in Figure 2.1 (b). A mobility ratio of 1 implies that the displacing fluid has the same ability of flowing as the displaced fluid. A favorable mobility ratio less than 1 refer to using a fluid that has lesser ability to flow to displace a fluid that has greater ability to flow, leading to a relatively uniform interface between the two fluids.

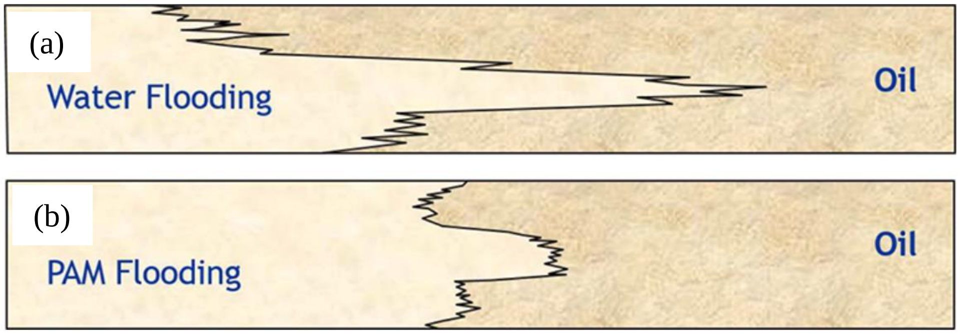


Figure 2.1. Fingering of water (Thomas, 2016)

2.1.2. Reservoir Heterogeneity. Reservoir heterogeneity is the variation in rock properties, such as porosity, saturation, permeability, cation exchange capacity, and clay mineral content in the same reservoir. Heterogeneity is caused by variations in sediment transport and environments that influence mineralogy, organic content, pore size, natural fractures and other geological properties that vary within one reservoir. Alpay (1972) used well logs, lithological descriptions, laboratory core-permeability profiles, and correlation method to describe heterogeneity.

In 1950, Dykstra et al. (1950) created a method of characterizing vertical permeability variations according to data generated from cores in labs. The core data are arranged in the descending order, and a figure related to the core permeabilities is created. Y-axis has the permeability values, and X-axis is percent of values larger than the corresponding Y-axis value. The most commonly used way of describing permeability heterogeneity is known as the Dykstra-Parsons coefficient, which is expressed by equation 3:

$$V = \frac{V_{84.5} - V_{50}}{V_{50}}, \tag{3}$$

where V_{50} is median permeability, and $V_{84.5}$ is permeability mean plus standard deviation of the permeability data. A typical permeability-variation coefficient is shown in Figure 2.2. Larger V implies more heterogeneity. A homogeneous reservoir would have a 0 value for V, which means permeabilities of the reservoir are uniform.

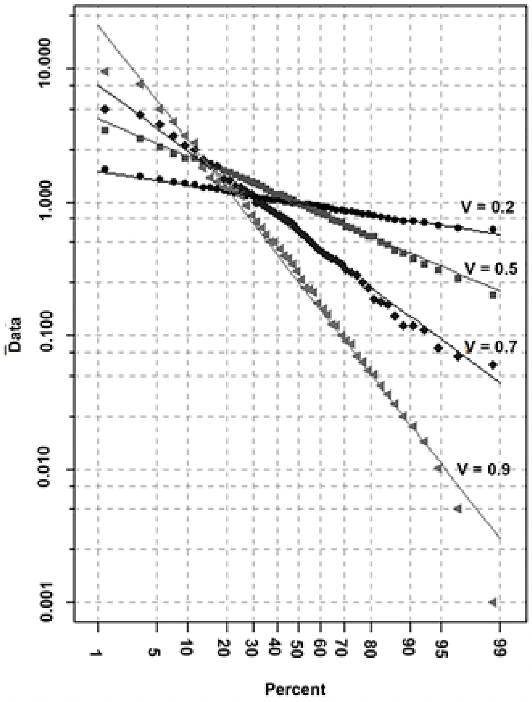


Figure 2.2.A typical figure of Dykstra and Parsons coefficient by Trabelsi et al. (2017)

Jensen et al. (1990) came up with several statistical methods based on the Dykstra-Parsons coefficient, which required more information, but improved the accuracy of description. Sahni et al. (2005) created a heterogeneity simulation model by combining the Dykstra-Parsons coefficient and core measurements.

2.1.3. Sweep Efficiency. Sweep efficiency implies the effectiveness of enhancing oil recovery by increasing the contact area of the injected fluid. The equation for volumetric sweep efficiency is

$$\mathrm{E} = \mathrm{E_A E_l E_D}, \tag{4}$$

where $\mathrm{E_A}$ is areal sweep efficiency, $\mathrm{E_l}$, is vertical sweep efficiency, and $\mathrm{E_D}$ is displacement efficiency. Taking water flooding as an example, the areal sweep efficiency, $\mathrm{E_A}$ is the fraction of a horizontal layer that injected water contacts with. It is dependent on the well pattern, well spacing, fractures, formation dip and dip azimuth, mobility ratio, and directional permeability. Vertical sweep efficiency, $\mathrm{E_l}$, is the fraction of cumulative contact height of injected fluids vertically in the pay zone to the total vertical height of pay zone. $\mathrm{E_l}$ is heavily dependent on mobility ratio, volume of injected fluid, and reservoir heterogeneity. Variations in vertical permeabilities cause irregular fronts that have a huge effect on the vertical displacement efficiency. Fluids flow faster in the high-permeability layers than in low-permeability layers, leaving portions of the low-permeability layers unswept by the injected fluids at the breakthrough. The equation for displacement efficiency is

$$\mathrm{E_D} = (\mathrm{V_{oi}} - \mathrm{V_{or}})/\mathrm{V_{oi}}, \tag{5}$$

where V_{oi} is volume of oil at start of flood and V_{or} is volume of oil remaining after flood. It represents the fraction of oil that is recovered to the initial amount of oil. In some injected fluids flooded areas, oil is trapped by capillary pressure which is related to interfacial tension between oil, the injected fluid, and rock surface. In other words, oil may not be produced even if the injected fluids have flooded the area.

2.1.4. Polymer and Polymer Gel. Because of complex depositional environment, no petroleum reservoirs are ideally homogeneous. Therefore, improving sweep efficiency is always a good strategy to enhance oil recovery**.**

Lake et al. (1986) described polymer flooding as an enhancing oil-recovery method. The goal of polymer injection or polymer flooding is to decrease the injected fluid's mobility by increasing its viscosity and minimize polymer loss due to adsorption. Figure 2.3 shows the effect of using polymer as injected fluid instead of water.

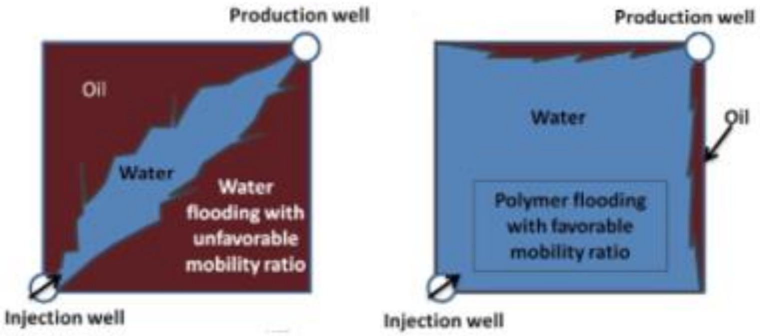


Figure 2.3.Effect of polymer flooding in enhancing sweep efficiency by improving mobility ratio

However, polymer flooding increases water cut quickly at the same time as it improves oil production, making it an inefficient strategy for improving oil recovery. When polymers are used in reservoirs with extremely high permeability streaks or channels, they flow through higher permeability channels like fractures. In such cases where polymer solutions do not work well, polymer gel with greater viscosity that has larger resistance to flow, but the same injectivity to injection wells, are indicated for optimal oil exploitation. By crosslinking and gelling the polymer, its strength and stability can divert flooding water path to increase the sweep efficiency.

2.1.5. Resistance Factor (RF) and Residual Resistance Factor (RRF). RF and RRF are usually used to describe the effect of recovery from chemical flooding. RF is the mobility ratio of injected brine to injected chemical solutions for the same reservoir rock:

$$\mathrm{RF} = \frac{\text{mobility of flooding brine}}{\text{mobility of flooding chemical solutions}} = \frac{(\frac{k_w}{\mu_w})}{(\frac{k_c}{\mu_c})}\,. \tag{6}$$

RRF is the mobility ratio of brine after chemical flooding to that of before chemical flooding. The equation for RRF can be expressed in terms of water mobility, as follows:

$$\mathrm{RRF} = \frac{\text{Final water mobility after chemical flooding}}{\text{Intial water mobility before chemical flooding}} = \frac{(\frac{k_w}{\mu_w})_{\text{Final}}}{(\frac{k_w}{\mu_w})_{\text{Initial}}}\quad . \tag{7}$$

The larger the RRF, the better the blocking effect. An ideal water-shutoff agent should result in a water RRF as large as possible, with an oil RRF as small as possible.

2.2. CHEMICALS FOR DISPROPORTIONATE PERMEABILITY REDUCTION (DPR).

Chan (1988) summarized the qualifications of chemicals for water-control treatment: high salinity and hardness tolerance, compatibility with any water mix, controllable gelation at reservoir temperatures, low viscosity, insensitivity to shear stress, pore-size selectivity, environmental safety, and cost effectiveness.

2.2.1. Polymer Gels for DPR. It has been shown by Liang et al. (1993) that when gels are injected from production wells with perforations in all pay zones, it can reduce water production more than it does to oil or gas production. Although the ideal condition of polymer gel for water shutoff is reducing water production substantially without lessening hydrocarbon production extensively, there are many factors making the DPR effect more realistic. Variations in reservoir conditions, well conditions, well workflow, mixing and injection procedures, and rock mineralogy make it extremely hard to draw conclusions about polymer gel for DPR from field applications Seright (2009). The performance of some polymers and gels is inherently highly variable, even with uniform conditions of reservoir rock. Seright et al. (2002) concluded from numerous core-flood experiments using Berea sandstone that BJ's Aqua Con gelant can modify relative permeability to the effect that the oil residual-resistance factors range from 2.7 to 59, and water residual-resistance factors range from 1.5 to 317. Seright (2006) identified three limitations of using in-situ gels to achieve DPR: significant difference in physical performances of adsorbed polymers and weak gels, restriction of radial flow to oil residual-resistance factor to be less than 2, and larger permeability reduction in low-permeability layers than high-permeability layers.

2.2.2. Gel Types. Lake (1996) classified commercially used polymers for oil industry into two categories: polyacrylamides and polysaccharides. The most widely used ones are Xanthan gum, hydrolyzed polyacrylamide (HPAM), and copolymers of acrylic acid and acrylamide. With the development of gel technology, gelation time and gel strength can be designed in laboratories according to specific oil-field characteristics.

Gel is generally classified by the location where it forms as in-situ gel and preformed particle gel. Bai et al. (2015)categorized polyacrylamide polymer gels in three categories, shown in Figure 2.4, which also takes gel particle size into account: in-situ monomer-based gel, in-situ polymer-based gel, and preformed gel. Based on the cross-linking material, in-situ polymer-based gel can be classified as metal-cross-linked polyacrylamide gel and organic-cross-linked polyacrylamide gel. Based on particle sizes and applicable conditions, preformed gel can be classified as millimeter-sized particle gel, micrometer-sized particle gel, sub micro-sized particle gel, which refers to micro- and nano-particle gels. Each type of gel has evolved according to industry demand. Development history and evaluation of each gel type are presented in the following text.

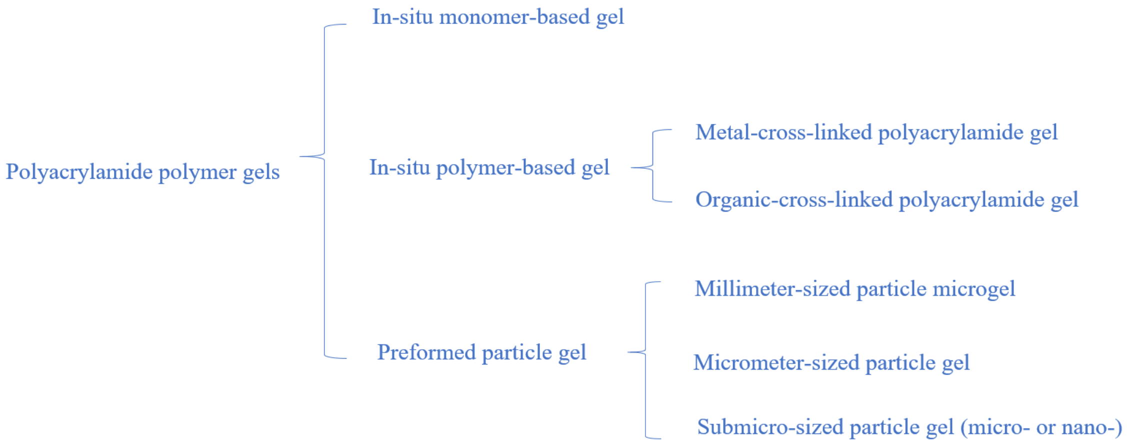
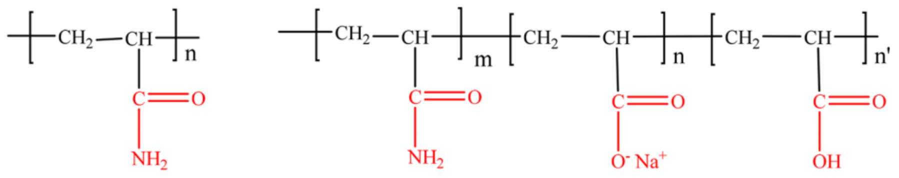


Figure 2.4. Gel classifications according to Bai et al. (2015)

2.2.2.1 In-situ monomer based gel. A solution of monomer and cross-linker, with a viscosity close to that of water, typically between 1 to 1.3, is injected into all perforated layers. Polymerization and gelation occur in the formation. Due to the low viscosity of the injected fluid, monomer gel has the advantage of penetrating deep into the high-permeability layers. According to results of laboratory core experiments by Halliburton, the PermSeal^{TM} gel can reduce matrix permeability from 150 to 0.4 md, and reduce fracture permeability from 3200 to 10.8 md. Little flow was observed, but no extrusion with 1000 psi pressure difference across the 3-in core. This type of gel works best between 4.44°C and 93°C, tolerates temperature as high as 149°C, minimizes environmental effects, as no heavy metal is involved, and resists H_2S, CO_2, or multivalent cations of the formation brines. However, to achieve a good effect with this gel system, a relatively high monomer concentration of 4% to 10% is suggested, which makes the monomer-gel system expensive. An economical gel system will benefit the oil industry more.

2.2.2.2 In-situ polymer-based gel. In 1974, Phillips Petroleum Co. (now ConocoPhillips) first announced a three-slug injection with multivalent cations between polymer solutions to reduce water mobility. A water-resistance factor of 16 to 18 was achieved when calcium, magnesium, or aluminum cations and partially hydrolyzed polyacrylamide or copolymers of acrylamide were used in the three-slug injection, compared with a water-resistance factor of 3 when only a polymer solution is injected. In-situ polymer-based gel works as a diverter by entering the targeted zone as a fluid of viscosity close to that of water and forming solid-like gel in the pores to plug the addressed area. Polymers can be classified as synthetic polymers and natural polymers. Zhu et al. (2017) summarized the commonly used synthetic polymers as polyacrylamides (PAM) or partially hydrolyzed polyacrylamide (HPAM), polyacrylonitrile (PAN), polyvinyl alcohol (PVN), polyvinylamine (PVAm), and copolymers based on acrylamide (AM) monomers. Figure 2.5 shows the chemical structures of the synthetic polymers. Natural polymers used in the oil industry are guar, lignin, and tannin. Cross-linking reactions depend on the bonds between the chemical groups that are on the molecular chains of polyacrylamides and the cross-linkers. Metal cross-linkers form ionic bonds or coordination bonds with the chemical groups, while organic cross-linkers form covalent bonds. In-situ gel is cost-effective and easy to inject, but the gelation time is hard to control and ambiguous with regard to shear degradation or degree of hydrolysis.



(a) Polyacrylamides (PAM) **(b) Partially hydrolyzed polyacrylamide (HPAM)**

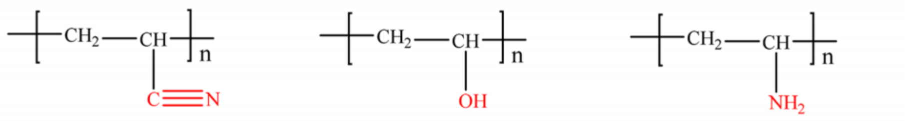


Figure 2.5. Chemical structures of different polymers

2.2.2.3 Organic-cross-linked polyacrylamide gel. In 1984 Falk (58) patented a formula that used PAM (5 million Dalton) and organic cross-linker, including phenol and formaldehyde, in a gel system. The gel strength reached a maximum when gel behavior was solid-like, 8 days after being mixed at 50°C. However, because phenol is toxic and formaldehyde is carcinogenic, this formula was not widely used in enhancing oil recovery. Ahmad Moradi-Araghi (1994) researched compounds that can substitute for phenol and formaldehyde to form stable gels. The replacements for phenol were acetylsalicylic acid, anthranilic acid, phenyl salicylate, salicylamide, and salicylic acid; the only replacement for formaldehyde was hexamethylenetetramine (HMTA). However, HMTA thermally hydrolyzes underground to formaldehyde and ammonia, which restores toxicity to the environment. In later studies, researchers found other substitutes for formaldehyde, either glyoxal or 1,3,5-trioxane, and other substitutes for phenol, which are catechol resorcinol, and hydroquinone (HQ).

2.2.2.4 Preformed gel. By forming gel at surface facilities and injecting it as gel particles, it is a given condition that polymer and cross-linker are fully reacted. Preformed gel overcomes the potential toxicity that in-situ gels has to the environment. Injection preparation is easier with preformed gel as there is only one component. Preformed gel is less sensitive to pH, salinity, multivalent ions, H_2S, temperature, and shear rates. Based on different preformed gel particle sizes, swelling times, and application reservoir conditions, preformed gels are classified as micro-gel and nano-gel. Millimeter-sized particle gel is typically injected at particle concentrations of $2{,}000*10^{-6}$ to $8{,}000*10^{-6}$ (Bai et al., 2007), (Coste et al., 2000); micrometer-sized particle gel is typically injected at a particle concentration around $3{,}000*10^{-6}$ (Chauveteau et al., 2001); micro- and nano-sized particle gels are usually injected at particle concentrations of $1{,}500*10^{-6}$ to $6{,}000*10^{-6}$, with $1{,}500*10^{-6}$ to $2{,}500*10^{-6}$ surfactant (Pritchett et al., 2003), (Frampton et al., 2004).

Although performed particle gels are more stable and environmentally friendly, simulations of preformed particle gel transportation, adsorption, and retention in porous media are difficult because preformed gels have irregular particle shapes and are injected as solid particles. Very extensive laboratory experiments and complicated calculations are required to obtain an algorithm for simulating behavior of preformed particle gel in the formation. The focus of this thesis is reservoir simulation of in-situ gel, which is relatively mature and accurate according to currently available reservoir simulators

2.2.3. Gelation Mechanism. Gelation kinetics are all about the chemicals. HAPm/Cr(III) is a very commonly used system, and it is used to introduce the gelation mechanism according to the following: Shu (1989) put forward that gelation rates and gel properties are strongly related to the structural features of the cross-linker. The cross-linker is a coordinate-covalent-bonded Cr(III) carboxylate complex, and Sydansk (1993) concluded that acetated is the preferred one. According to Sydansk, the cross-linking process is dependent on the pH of the solution. Vossoughi (2000) concluded that chromium as cross-linker enables gelation at pH as high as 9, because when intermolecular cross-linking occurs through Cr(III), there are two carboxylate functional groups on two different acrylamide polymer molecules involved. Lockhart et al. (1994) researched the effect of polymer-solution pH on gel performance. Many gels have an optimum range of pH for the best effect. After gelent is injected into the reservoir, its pH is influenced by that of natural rock. te Nijenhuis (2001) showed a method for analyzing gel kinetics of the HAPm/Cr(III) system in detail. Gelation rate is also strongly dependent on temperature. There have been numerous studies of temperature effect on gelation rate (Bryant et al., 1997); (Lockhart, 1994); (Broseta et al., 2000); (Sydansk, 1993); (A. Moradi-Araghi et al., 1993); (Bartosek et al., 1994); (Sanders et al., 1994); (Prada et al., 2000); (Chiappa et al., 2003). Hurd et al. (1931) noted that the phase change throughout the gelation process is from aqueous solution, experiencing a maximum activity of cross-linking, to a hardening or setting phase, which starts extremely slow. Lockhart et al. (1994) found that gelation time for the HPAm/Cr(III) system can be longer than half a year. te Nijenhuis (2001) proved that gelation time for HPAm/Cr(III) is very long.

When gelation time is determined from lab experiments, apparent activation energy to initiate the cross-linking reaction can be calculated using Hurd and Letteron's model. The Hurd and Letteron model (1932) from Hurd et al. (1931) used the following equation:

$$\mathrm{E_a} = \frac{\mathrm{R}\,\partial(\ln(\text{gel time}))}{\partial(\frac{1}{\mathrm{T}})}, \tag{8}$$

where $\mathrm{E_a}$is apparent activation energy, R is the gas constant 8.314 J/kmol, and T is the absolute temperature (K). Broseta et al. (2000) proposed that apparent activation energy reflects the sensitivity of gelation kinetics to temperature.

2.2.4. Gel Syneresis. Gel syneresis refers to one of the chemical modifications occurs with the HPAm/Cr(III) gel system, such that gel volume shrinks and water is expelled from the gel structure. Syneresis is strongly dependent on the composition (Vossoughi, 2000). Bryant et al. (1997) conducted experiments and found that gel can lose 95% of its initial volume with syneresis. (Gales et al. (1994)) gave an explanation of syneresis. There are two potentials that balance each other when cross-linking happens, elastic potential and mixing potential. At the beginning of cross-linking, elastic potential is lower than mixing potential because of low cross-linking density. As cross-linking proceeds, when elastic potential exceeds mixing potential, syneresis will occur to equilibrate the two potentials.

2.3. GOVERNING EQUATION OF POLYMER-GEL IN THE RESERVOIR SIMULATOR

By using Simulator for Chemical Oil Recovery and Polymer Injection (SCORPIO), CMG STARS can handle up to 10-component chemicals, which can be in aqueous, oleic, or micellar phase. Reaction rates and stoichiometric numbers can be specified to describe the gelation process. SCORPIO can reproduce the effect of gel adsorption and gel transportation caused by velocity dispersion and molecular diffusion.

The differential equation of mass conservation that governs fluid flow in SCORPIO is

$$\nabla \cdot k \sum_{\alpha} \frac{k_{r\alpha}\rho_{\alpha}}{\mu_{\alpha}} C_{\alpha}^{i}(\nabla p_{\alpha} - \rho_{\alpha} g \nabla D) + \nabla \cdot \phi \sum_{\alpha} \rho_{\alpha} S_{\alpha} D_{\alpha}^{i} \nabla C_{\alpha}^{i} + \phi \sum_{\alpha} S_{\alpha} R_{\alpha}^{i} + q_{i} = \partial(\phi \tilde{m}_{i}) / \partial t\,, \tag{9}$$

$$\tilde{m}_{i} = \sum_{\alpha} \rho_{\alpha} S_{\alpha} C_{\alpha}^{i} + \frac{\rho_{R} \Gamma_{i}}{\phi}\,. \tag{10}$$

where i refers to component and α refers to phase. C_{α}^{i} is mass concentration of component i in phase α. D_{α}^{i} is a term representing velocity dispersion and molecular diffusion. $\tilde{m}_{i}$ is mass density of component i, which includes adsorption and transportation, as shown in equation 10. ρ_{α} and ρ_{R} are densities of phase α and rock. R_{α}^{i} is reaction rate, of which the unit is mass of component i in phase α per unit volume per unit time. qi is mass rate of a grid caused by injection or production.

The differential equation of pressure that governs fluid flow in SCORPIO is

$$\frac{\phi}{V_f}\frac{\partial V_f}{\partial p}\frac{\partial p}{\partial t}+\sum_i \frac{\partial V_f}{m_i}\frac{\partial(\phi\tilde{m}_i)}{\partial t}=\frac{\partial\phi}{\partial p}\frac{\partial p}{\partial t}\,. \tag{11}$$

Equation 11 expresses the change of pore volume which is contributed by the change of fluid volume caused by pressure change and the amount of mass change. V_f, fluid volume, is a function of pressure, temperature, and mass of fluid. p is pressure, which is explicitly dependent on temperature.

Temperature is a primary parameter that affects fluid flow, and it is generally assumed that temperature changes in a chemical flooding does not include vapor or gas phase.

3. RESULTS AND DISCUSSION

3.1. RESERVOIR SIMULATION MODEL DESCRIPTION

Eight variables of operational decisions and reservoir properties are analyzed in this study. CMG-STARS, an industrial advanced modelling software for chemical recovery processes is used to simulate the reservoir performance. Dimensions of the model are 100*10ft in I direction, 1*10ft in J direction and 20*1ft in K direction. The base case is a 1-D linear model that has 20 layers with 10 low-permeability layers on top, rock type 1, and 10 high-permeability layers on the bottom, rock type 2 (Figure 3.1). Horizontal permeability for the top layers is 5md and 500md for the bottom layers. Ratio of vertical permeability to horizontal permeability is 0.1. Porosity is 0.22. Pore volume is 44,000ft^3. Initial oil saturation is 0.85 and initial water saturation is 0.15. Initial oil in place is 37,400 ft^3, 6661.23bbl; initial water in place is 6,600 ft^3, 1567.7 bbl. This study uses simplified linear models for running all the experiments. Reservoir temperature is 113°F; water density and oil density are 62.42 lb/ft^3 and 50 lb/ft^3; water viscosity and oil viscosity are 0.5 cP and 1cP. Grid top is 2845ft and reservoir pressure is 1280 psi. Maximum adsorption capacity is 7.36e-8 lb-mole/ft3 for tock type 1, and 3.31e-8 lb-mole/ft3 for rock type 2. Residual adsorption levels for both rock types are set the same as maximum adsorption capacity, which assumes that the base case gel does not desorb. Accessible pore volume for both rock types is set as 1. Accessible resistance factor is 80 for rock type 1 and 40 for rock type 2. The values for the rock properties are set the same as the example from the CMG-STARS tutorial. Reservoir and fluid properties and rock-dependent parameters are shown in Table 3.1 and Table 3.2. One injector is placed at the left end of the reservoir and one producer is placed at the right end, as shown in Figure 3.1. Initial water injection rate is 20 bbl/day. Production rate is kept the same as the injection rate throughout all the experiments. Composition of gelant injected into the reservoir is shown in Table 3.3, which represents a type of gel used in Dr. Bai's lab that is made from 417 ppg of polymer solution.

Table 3.1. Input Data of Reservoir and Fluids Properties

Property	Value
Number of Grid Blocks	I*J*K: 100*1*20
Block Widths	I: 100*10ft; J:1*10ft; K: 20*1ft
Reservoir Temperature (°F)	113
Water Density (lb./ft^3)	62.42
Oil Density (lb./ft^3)	50
Water Viscosity (cP)	0.5
Oil Viscosity (cP)	1
Gel Viscosity (cP)	10
Reservoir Pressure (psi)	1280
Grid Top (ft.)	2845
Number of layers	20
Horizontal Permeability for Top Layers, kh1 (md)	5
Horizontal Permeability for Bottom Layers, kh2 (md)	500
kv/kh	0.1
Porosity	0.22
Initial Oil Saturation	0.85
Initial Water Saturation	0.15

Table 3.2. Rock-dependent parameters

Parameter	Value	Rock Type
Layer	1-10	1
Max. Adsorption Capacity(lb-mole/ft^3)	0.0735537e-06	1
Residual Adsorption Level (lb-mole/ft^3)	0.0735537e-06	1
Accessible Pore Volume	1	1
Accessible Resistance Factor	80	1
Layer	11-20	2
Max. Adsorption Capacity (lb-mole/ft^3)	0.03309e-06	2
Residual Adsorption Level (lb-mole/ft^3)	0.03309e-06	2
Accessible Pore Volume	1	2
Accessible Resistance Factor	40	2

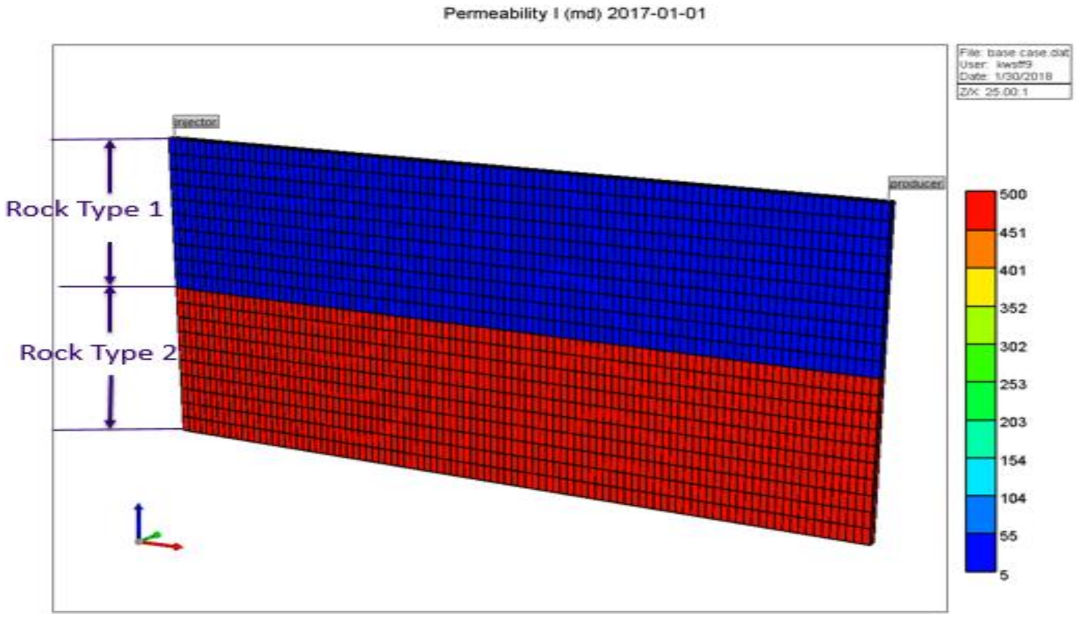


Figure 3.1. Permeability Distribution of Base Case

Table 3.3. Gelent-component concentration

Component	Mole Fraction
Water	0.999995528
Polymer	3.61E-06
X-linker	8.65E-07
Total	1

3.2. PARAMETERS AND DISCUSSIONS

3.2.1. Effect of Gel Injection Starting Time. This variable refers to the timing of gel injection. The starting times of gel injection are to be determined first. Wells workflow for determining the starting times is to inject water into the injection well and produce fluids from the production well with the same fluid flowing rate. Four starting times for gel injection are chosen when water cuts from the production well reach 80%, 90%, 95%, and 98%. Second, shut in the injection well, convert the production well to a gel injection well and inject gel for 5 days. Keep both wells shut in for another 30 days for polymer and cross-linker to process, and then open both wells to resume production. The four starting times for gel injection are noted in Table 3.4. Water injection rate is 20 bbl/day. Gels injection rate is 60 bbl/day. The amount of gel injected into the reservoir is 300 bbl, which is equivalent to 0.045 pore volume.

To evaluate the DPR effect of the variables, length of effective period, water reduction and oil increment in the effective period, average water reduction per day and average oil increment per day in the effective period, and oil recovery factors at 1 year and 2 years after gel injection are compared. The effective period refers to the time from the reopening of the producer to the time when water cut rebounds to the point when the producer was shut in. Effective period can be seen as the length of the days that gel treatment has a visualized influence on water reduction.

Table 3.4. Well events

Water Cut, %	No. of Days to Arrive at the Corresponding Water Cut	Gel Injection Period, day to day	Gelation Time, days	Time to reopen the injector
80	105	105 to 110	30	140
90	133	133 to 138	30	168
95	247	247 to 252	30	282
98	1072	1072 to 1077	30	1107

Result: according to Table 3.5, the later the gel is injected, the longer the effective period, which is also shown in Figure 3.2. According to Figure 3.3, for the case with no gel injection after water breakthrough at day 101, rate of change for water cut decreases with time. Therefore, after reopening the producer, it takes a longer time to reach to a water cut as the value of the water cut increases. However, in terms of reducing production water during the effective period, injecting gel at 90% water cut has the best effect; in terms of increasing production oil during the effective period, injecting gel at 95% water cut can achieve the best result. When gel is injected too early, for instance at 80% water cut, the effective period is 54 days, which is a relatively short to achieve a large water reduction, compared to the effective period of injecting gel at 90% water cut, 85 days. Therefore, when gel is injected too early, the effective period is not long enough to have a large water reduction or a large oil increase. When gel is injected late, for instance at 98% water cut, water saturation in the high-permeability layers close to the production well is much larger than that of injecting gel at an earlier time. Figure 3.4 compares water saturation profiles near the wellbore immediately after the gel injection at different times. Even though the effective period is a substantially longer, compared with an early gel injection, there is not much oil left in the high-permeability layers to be expelled, and water, which occupies most of the pore space, will be expelled instead. This is reflected by the plot of water saturation vs. water cut in Figure 3.5. The derivation of the plot decreases as water saturation approaches 1 at greater values of water saturation. Water flows faster with larger water saturation. Therefore, the later gel is injected, the farther gel can travel from the production well. Regarding average values in the effective period of water reduction and oil increment per day, the best results both happen when gel is injected at 80% water cut. The average values stand for the efficiency of the effects that gel injection makes. The case with gel injection at 80% water cut has substantially better efficiency in reducing water and increasing oil.

As the four cases have different production times before gels are injected, to compare the effect of oil recovery enhancement, the increments of oil recovery factor after 1-year and-2 years production are used. According to Figure 3.6, simulation results show the earlier the gel is injected, the larger the oil-recovery factor increment for the same period of time after the injection. In field applications, the optimum time to inject gel will be determined by current process of reservoir exploitation, expectations of effective periods, and expectations of water reduction and oil increment after the gel injection. If the goal is to have the longest effective period, and largest oil recovery factor not considering the time length of the production, gel should be injected at a later water cut. However, if the goal is to efficiently reduce water production, increase oil production, and increase oil recovery factor, gel should be injected at an early time. The purpose for this simplified model is to exhibit the tendency of how gel injection time can affect reservoir performance. When determining the time for gel injection for any real case studies, reservoir simulation should be used to forecast the reservoir performance in both effective time and in the long run.

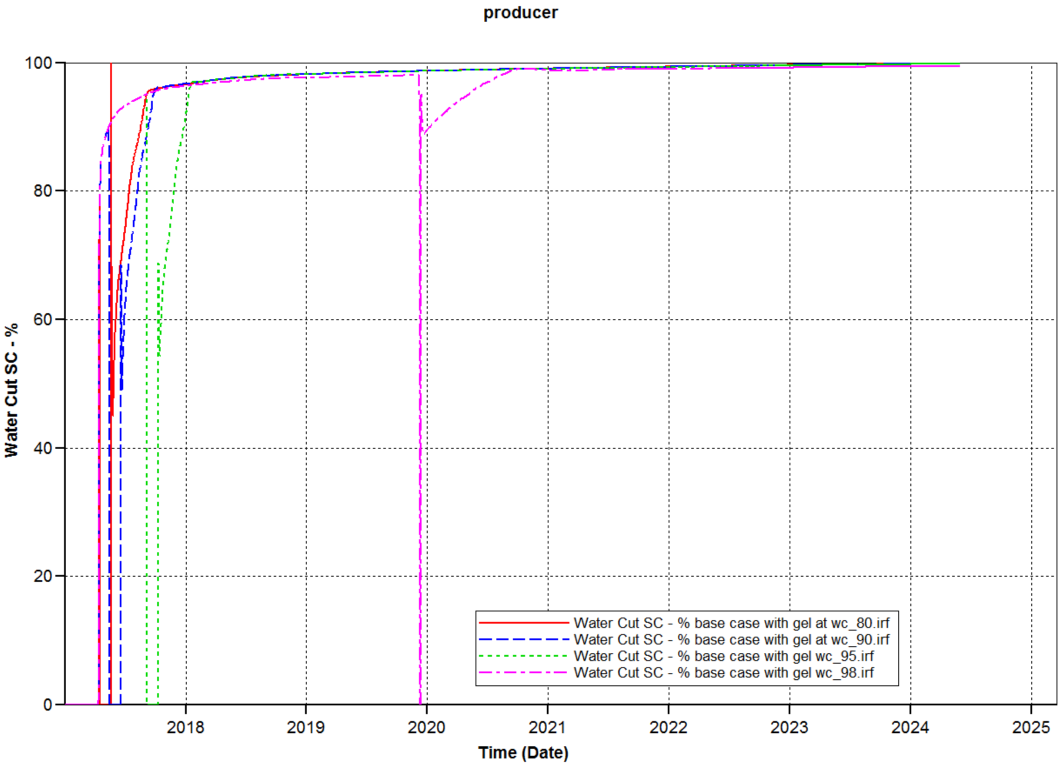


Figure 3.2. Water cuts for gel injection at 80%, 90%, 95% and 98% water cuts

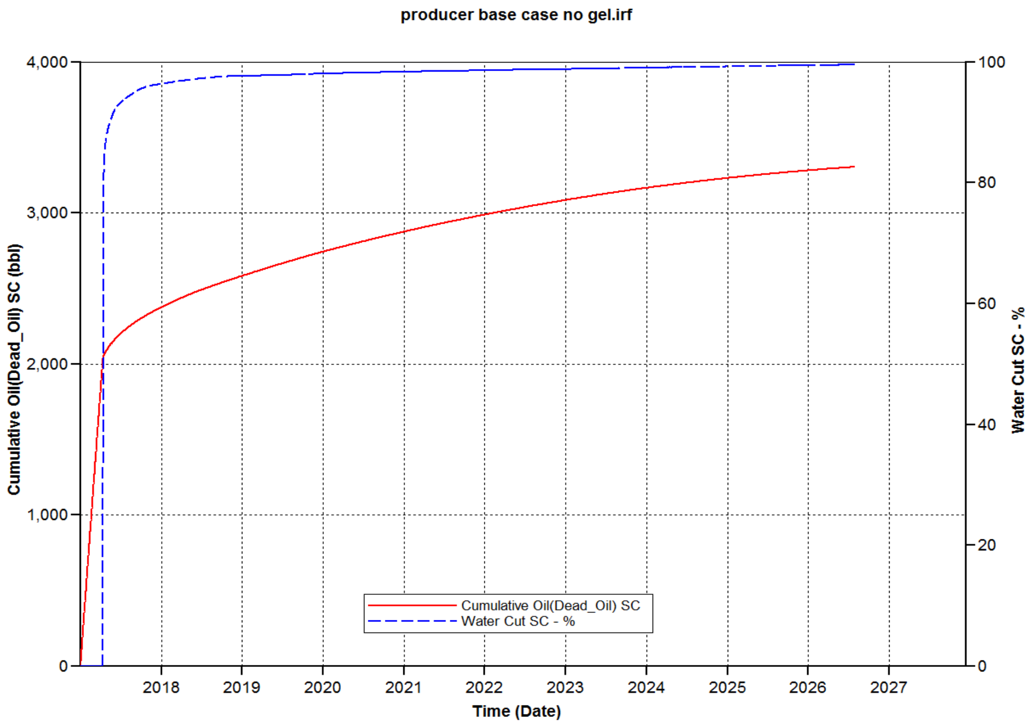


Figure 3.3. Cumulative oil production and water cut for case without gel injection

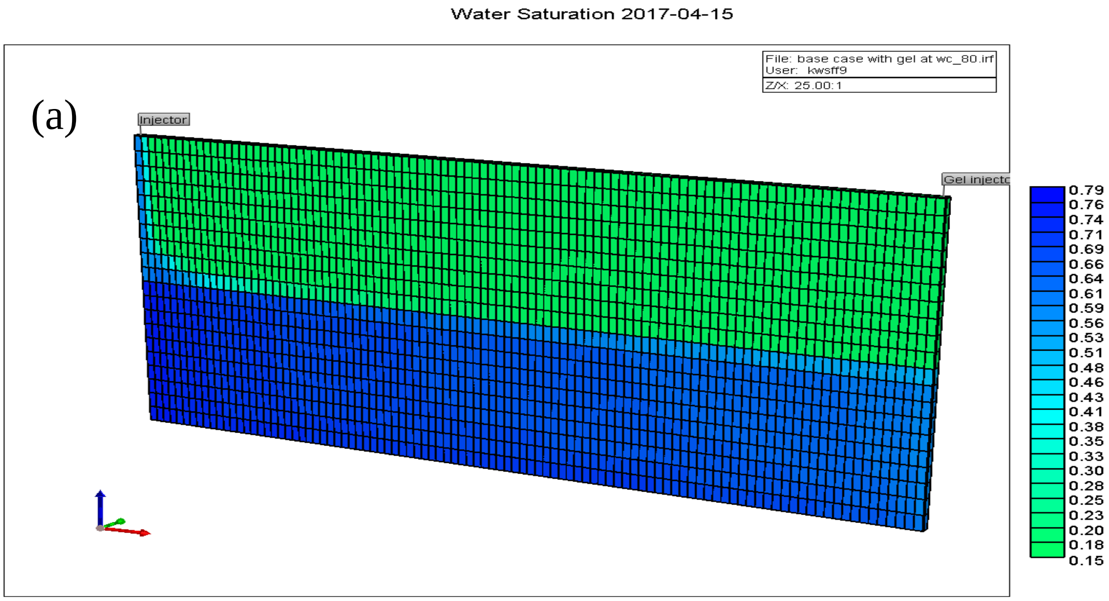
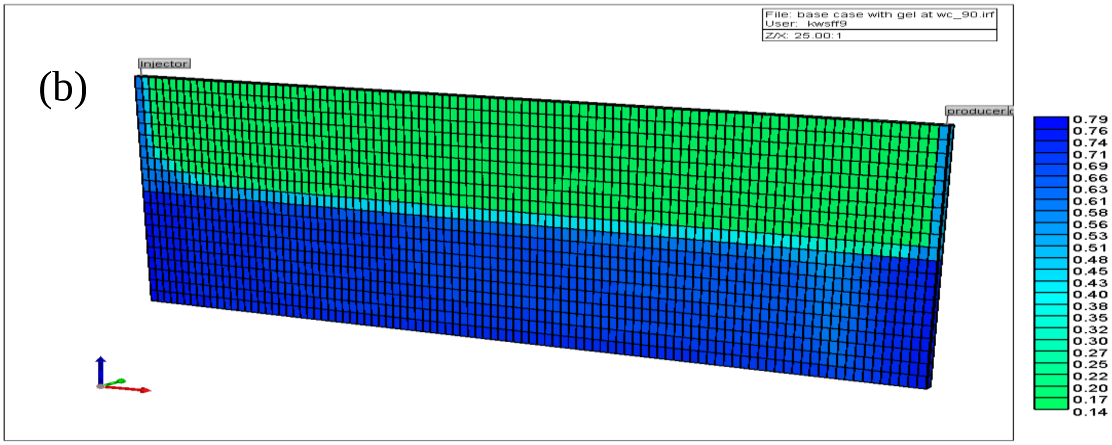
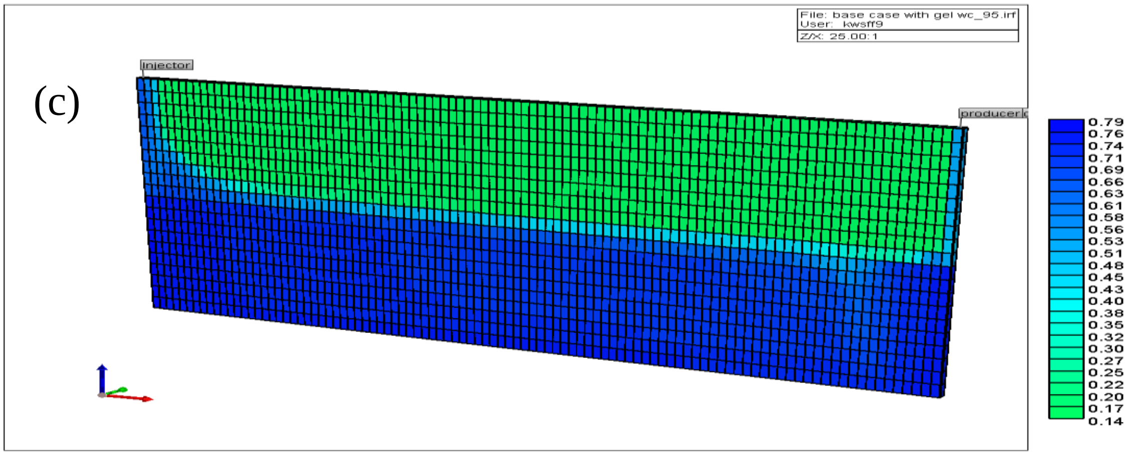


Figure 3.4. (a-d) Water saturation profile immediately after gel injection at 80%, 90%, 95%m and 98% water cuts

Water Saturation 2017-05-18



Water Saturation 2017-09-09



Water Saturation 2019-12-14

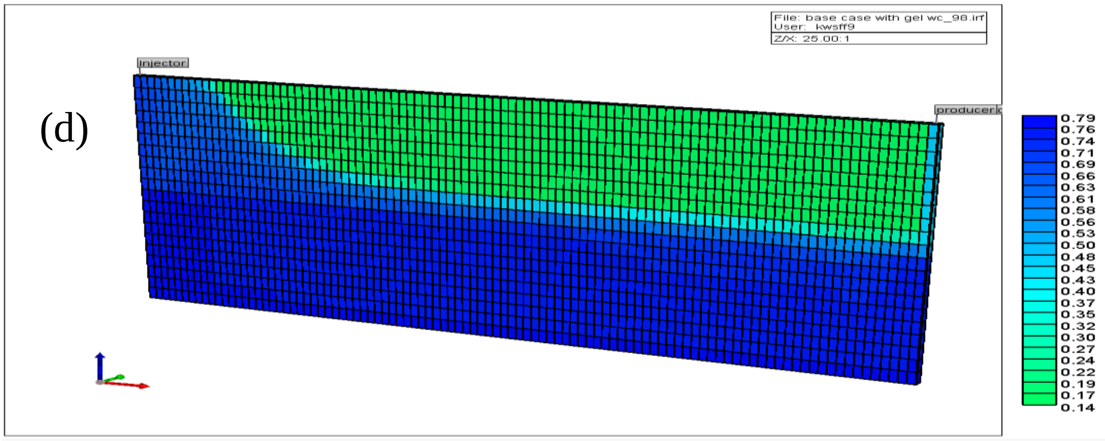


Figure 3.4. (a-d) Water saturation profile immediately after gel injection at 80%, 90%, 95%m and 98% water cuts (cont.)

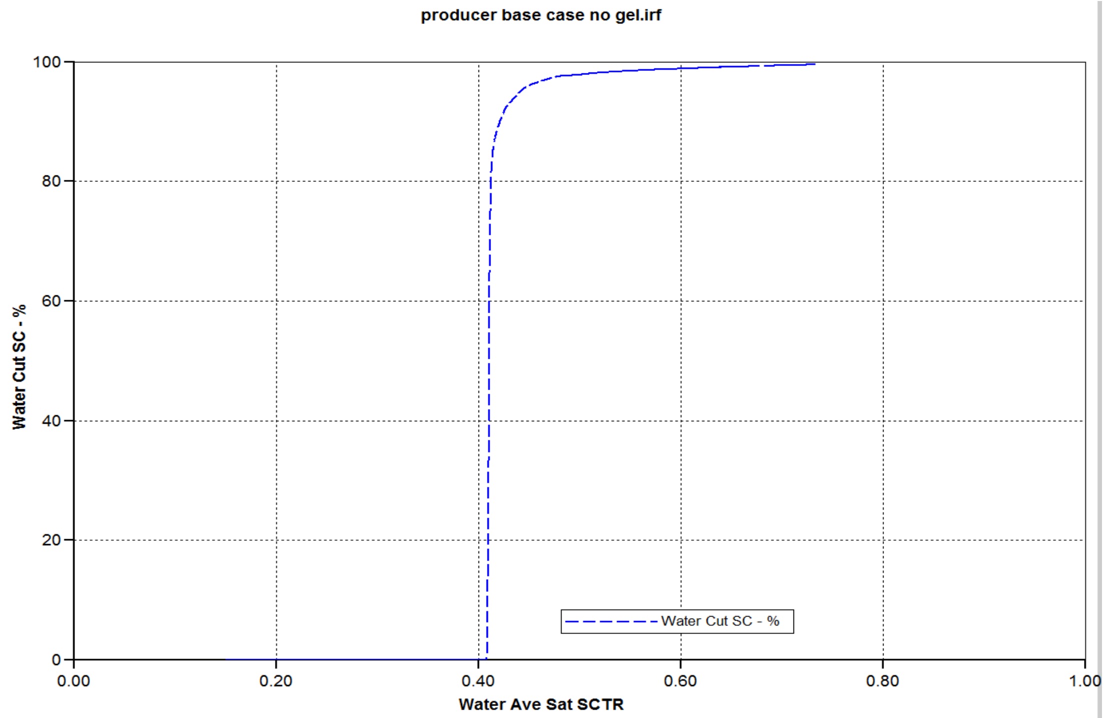


Figure 3.5. Water average saturation vs. water cut for the case without gel injection

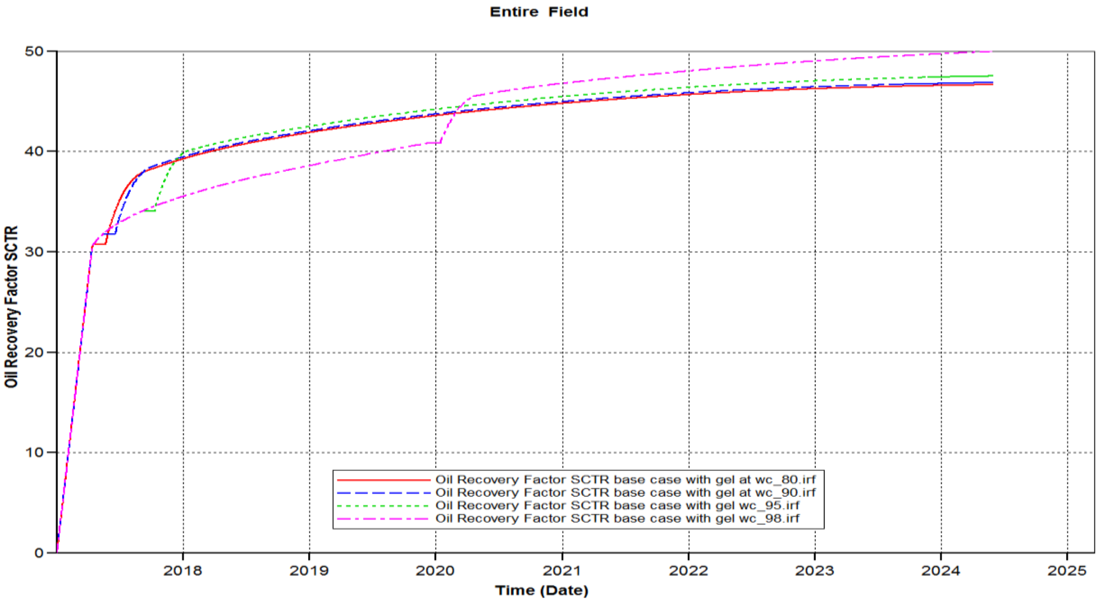


Figure 3.6. Oil recovery factors with gel injection 80%, 90%, 95%, and 98% water cuts

Table 3.5. Results for Effect of Gel Injection at Various Water Cut

Water cut with gel when gel is Injected, %	80	90	95	98
Effective period, days	54	85	92	213
Water production in the effective period without gel, bbl	999.61	1599.12	1767.92	4180.5
Water production in the effective period with gel, bbl	725.12	1277.91	1477.67	4041.7
Reduced water production in the effective period, bbl	274.49	321.21	290.25	138.8
Average water reduction per day in the effective period, bbl/day	5.08	3.78	3.15	0.65
Oil production in the effective period without gel, bbl	80.39	100.89	72.09	79.41
Oil production in the effective period with gel, bbl	354.88	421.55	397.75	224.04
Increased Oil production in the effective period, bbl	274.49	320.66	325.66	144.63
Average oil increment per day in the effective period, bbl/day	5.08	3.77	3.54	0.68
Oil recovery factor with gel for the 1st year treatment, %	9.753	8.8306	7.7725	4.6777
Oil recovery factor with gel for the 2nd year treatment, %	2.128	2.1312	1.8781	1.2561

3.2.2. Effect of Gel Injection Amount. To maximize the economic efficiency of production, current oil price and costs for gel injection should be taken into consideration. By changing the amount of gel injected, the operators are able to adjust the production according to the market. In the simulation models, gels are injected when water cut is 95% and the well workflow complies with this water cut. Model parameters are set the same as those of the base case, the only difference being gel injection amount. Figures and tables are generated to predict the effect of the amount of gel injection, five cases with 100 bbl, 200 bbl, 300 bbl, 400 bbl, and 500 bbl of gel being injected, respectively.

Result: Table 3.6 shows reduced water production, increased oil production and their average changing rates per day for the effective period, and oil recovery factors at 1 year and 2 years after gel is injected. According to Table 3.6, 500 bbl of gel is optimum for this model because it has the longest effective period, the largest average water reduction, the largest oil increment during the effective period, and the largest oil recovery factor at 1 year and 2 years production. Polymer gel increases oil production by blocking fluid flow in the high-permeability layer near the production well, forcing flushing water to the part of the low-permeability layer that is immediately above the gel-placement area, which cannot be swept only by water flooding. The larger the amount of gel being injected, the larger the blocking area in the high-permeability layers close to the production well, as shown in Figure 3.7, which means water flushing a larger unswept area in the low-permeability layers. Oil production increases with increasing amount of gel injection. Oil-recovery factors and water cut of the five cases are shown in Figure 3.8 and Figure 3.9. When the amount of gel injection is small, there is not enough blocking area in the high-permeability layers; therefore, very little unswept area in the low-permeability layers will be flushed. And with gel injection, pressure near the wellbore is raised. When the producer is opened a second time, it produces with a larger pressure difference and with a larger amount of injection. In the simplified model of this thesis report, the most water reduction and the most oil increment average value per day for around the first 7 years are achieved by injecting the most amount of gel, which is 500 bbl in this study.

Table 3.6. Results for effect of gel injection amount

Amount of gel injection, bbl	100	200	300	400	500
Effective period, days	67	78	92	107	121
Water production in the effective period without gel, bbl	1286.35	1498.15	1767.92	2057.02	2327.42
Water production in the effective period with gel, bbl	1104.84	1233.48	1441.67	1674.08	1891.77
Reduced water production in the effective period, bbl	181.51	264.67	326.25	382.94	435.65
Average water reduction per day in the effective period, bbl/day	2.71	3.39	3.55	3.58	3.60
Oil production in the effective period without gel, bbl	53.65	61.85	72.09	82.81	92.59
Oil production in the effective period with gel, bbl	234.87	326.05	397.75	465.14	527.33
Increased oil production in the effective period, bbl	181.22	264.2	325.66	382.33	434.74
Average oil increment per day in the effective period, bbl/day	2.70	3.39	3.54	3.57	3.59
Oil recovery factor with gel @ 1 yr	39.90	41.06	41.83	42.59	43.34
Oil recovery factor with gel @ 2 yr	42.14	43.13	43.71	44.29	44.89

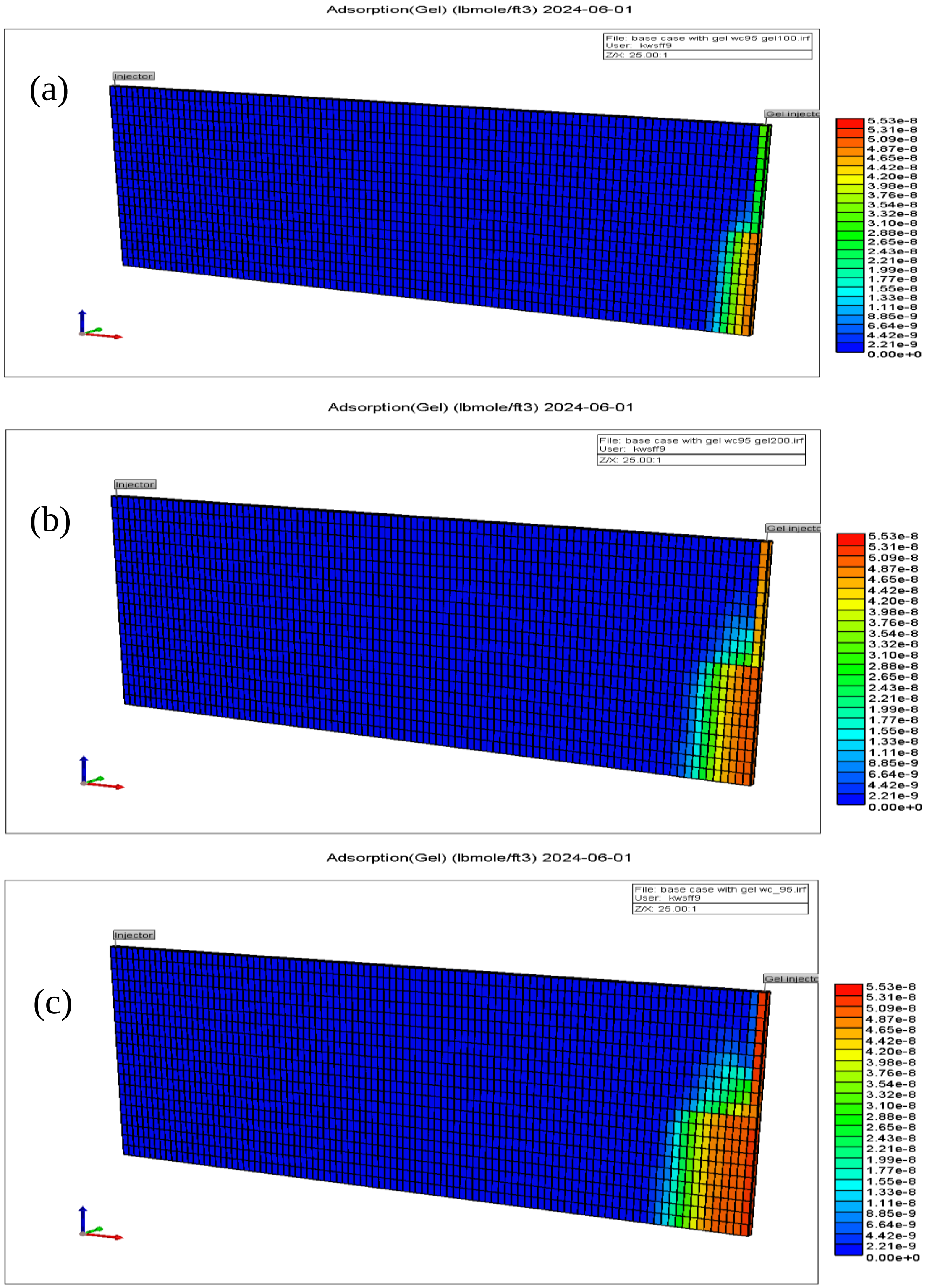


Figure 3.7. (a-e) Comparison of gel adsorption profile with 100bbl, 200bbl, 300bbl, 400bbl, and 500bbl

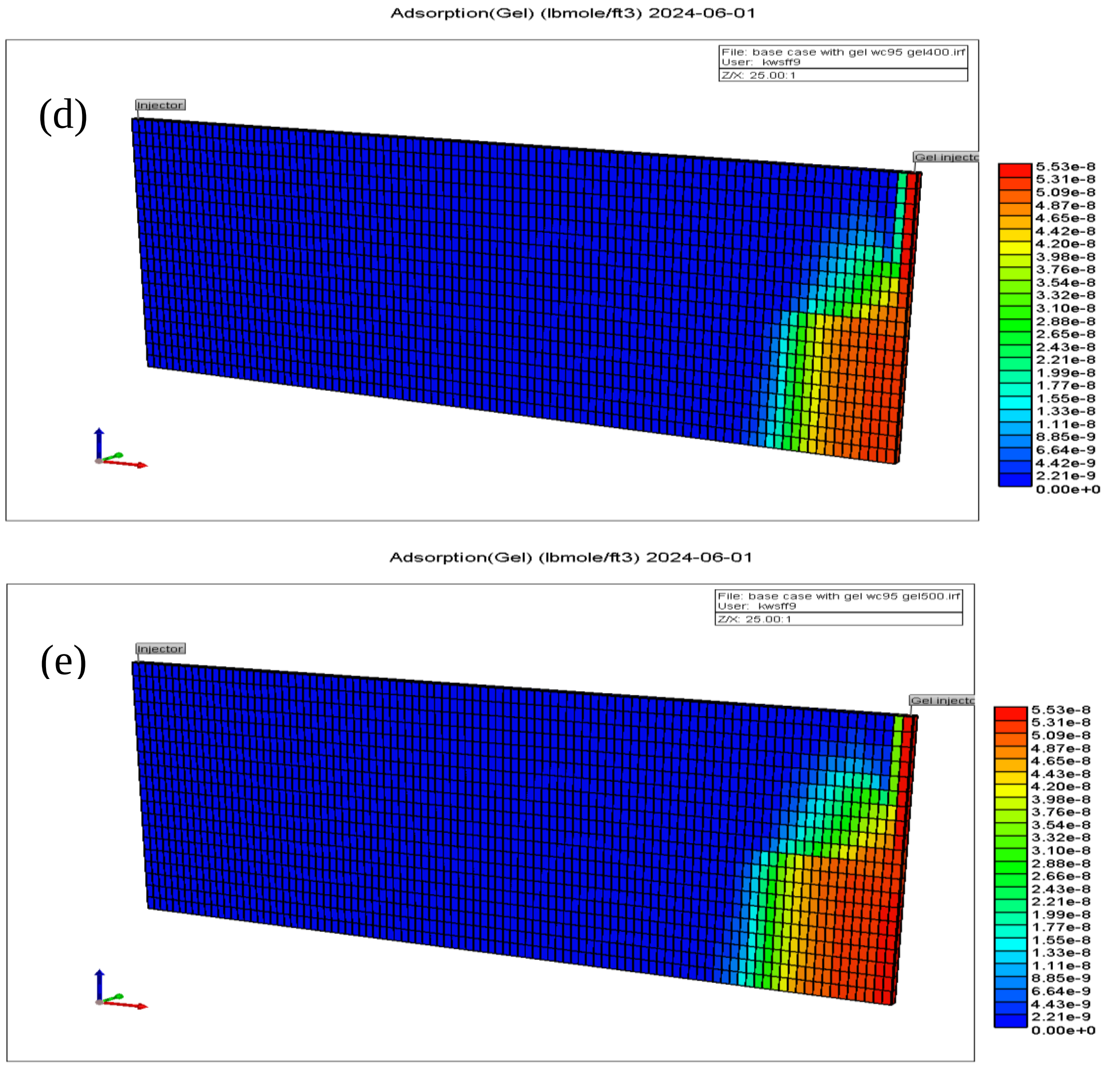


Figure 3.7. (a-e) Comparison of gel adsorption profile with 100bbl, 200bbl, 300bbl, 400bbl, and 500bbl (cont.)

3.2.3. Effect of Drawdown. Drawdown pressure at the production well influences oil production in the long run. The way to set different drawdown pressures to the production well in this case is to set different production ratea as 5 bbl/day, 10 bbl/day, 15 bbl/day, 20 bbl/day, 25 bbl/day. The corresponding drawdown pressures are 721 psi, 1,313 psi, 1,763 psi, 1,989 psi, and 2,118 psi. Water flooding rate from the injection well is kept the same as the production rate. Water-flooding rate influences the volume of water used for displacing oil and for reservoir-pressure maintenance. By lowering the water-flooding rate, less viscous force is applied on the reservoir fluids and less volume of fluid to replace oil. Gels are injected when water cut is 95% and the well workflow conforms with this water cut. Model parameters are set according to those of the base case, the only difference being water-injection rate and the corresponding fluid-production rate. Figures and tables are generated to predict the effect of the water-flooding rate after gel injection.

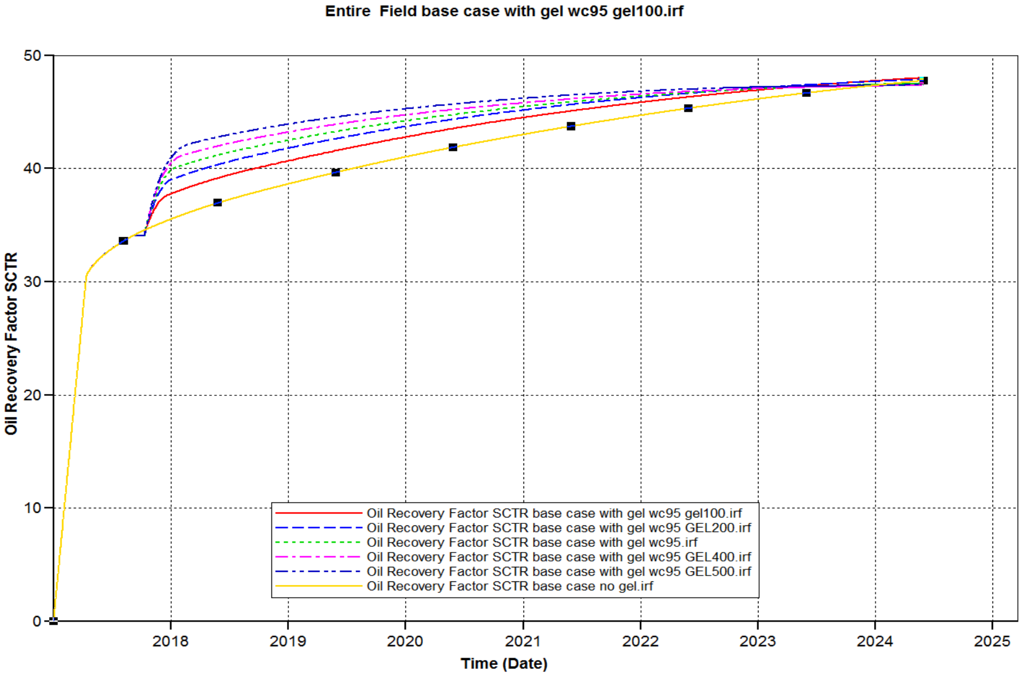


Figure 3.8. Oil recovery factors of cases with 100bbl, 200bbl, 300bbl, 400bbl, and 500bbl gel injection

Result: according to Table 3.7, the lower the drawdown pressure of the production well, the lower the water-flooding rate applied on the injection well after gel injection, the lower the water cut and the lower the oil production. Effects on water cut and oil production are the same for the effective period, and 1 year and 2 years after the producer is reopened. Reducing water-flooding rate lowers water cut, water production and oil recovery factor, as shown in Figure 3.9, Figure 3.10 and Figure 3.11. According to Figure 3.12, oil-recovery factor of the case with no gel injection surpasses the cases with gel injection, starting from surpassing the case of water-flooding rate at 5 bbl/day at the year 2020. This is due to the fact that gel reduces water and oil permeabilities at the same time, to different degrees. Therefore, with continuous production, the case without gel injection will have a higher oil recovery factor compared with the cases with gel injection. However, with the drawdown pressure applied to the production well, 1,989 psi, for the first 7 years of production, as gel reduces water permeability more than it does to oil permeability, oil recovery is substantially larger with gel treatment. An optimum scenario requires balancing the market for oil and the increased operational fees and maintenance fees incurred with water production.

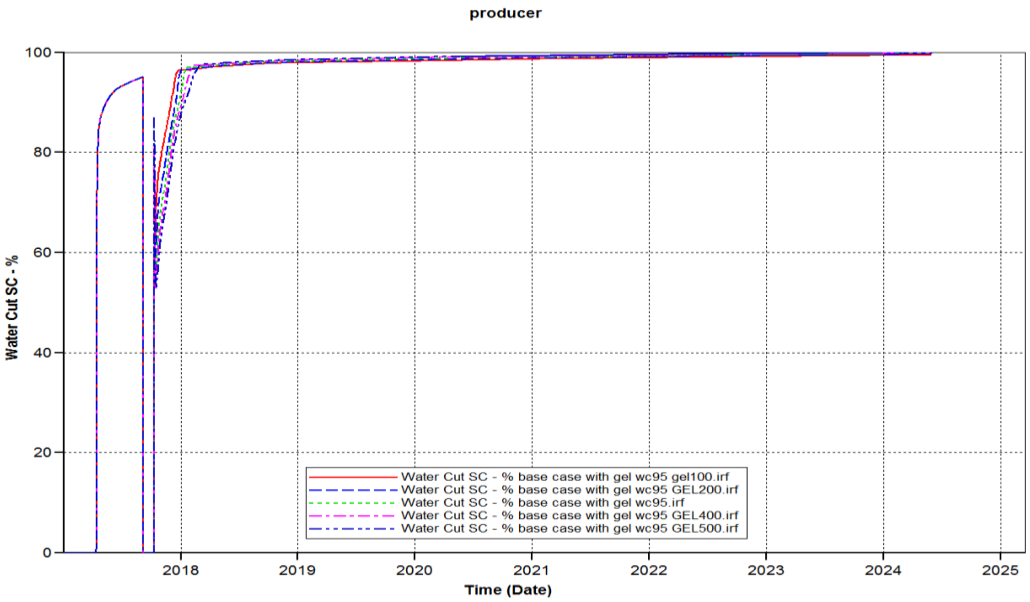


Figure 3.9. Water cuts of cases with 100bbl, 200bbl, 300bbl, 400bbl, and 500bbl gel injection

Table 3.7. Results for effect of water-flooding rate after gel injection

Water rate, bbl/day	5	10	15	20	25
Drawdown pressure, psi	721	1313	1763	1989	2118
Effective period, days	428	190	123	92	72
Water production in the effective period without gel, bbl	8296.35	3662.32	2366.04	1767.92	1382.61
Water production in the effective period with gel, bbl	1730.48	1500.35	1447.73	952.72	1403.25
Reduced water production in the effective period, bbl	6565.87	2161.97	918.31	815.20	-20.64
Average water reduction per day in the effective period, bbl/day	15.34	11.39	7.47	8.86	-0.29
Oil production in the effective period without gel, bbl	263.68	137.68	93.97	72.09	57.39
Oil production in the effective period with gel, bbl	410.5	399.62	397.21	397.75	396.5
Increased oil production in the effective period, bbl	146.82	261.94	303.24	325.66	339.11
Average oil increment per day in the effective period, bbl/day	0.34	1.38	2.47	3.54	4.71
Oil-recovery factor with gel @ 1 yr	39.70	40.67	41.28	41.83	42.30
Oil-recovery factor with gel @ 2 yr	40.78	41.93	42.88	43.71	44.40

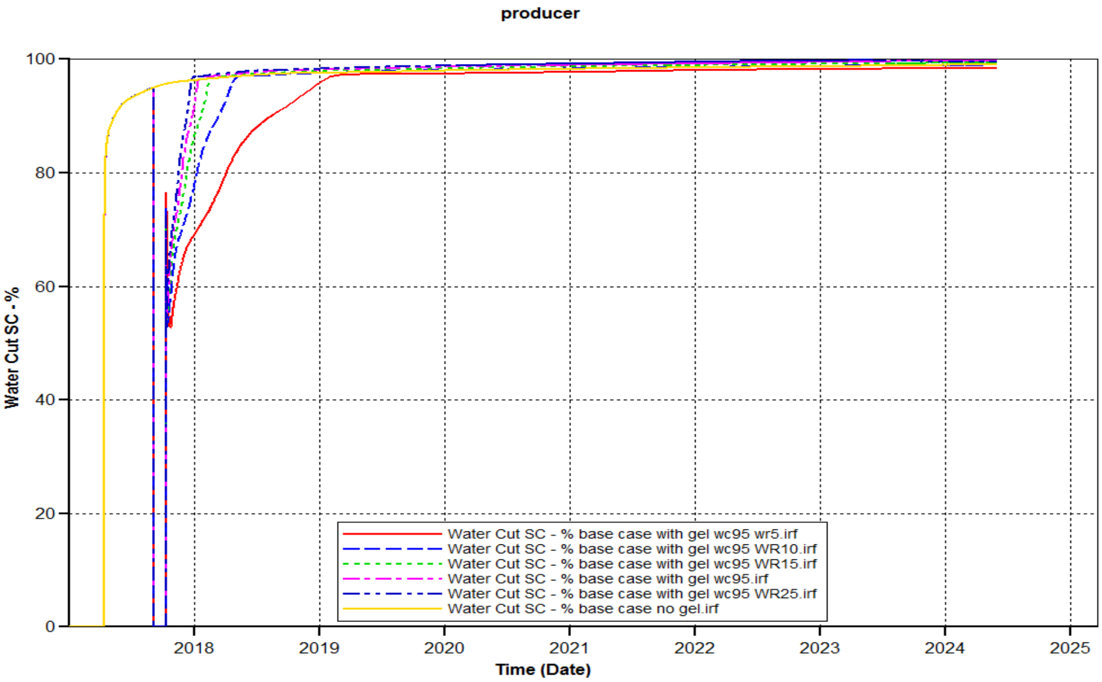


Figure 3.10. Water cuts of cases with 5 bbl/day, 1 0bbl/day, 15 bbl/day, 20 bbl/day and 25 bbl/day

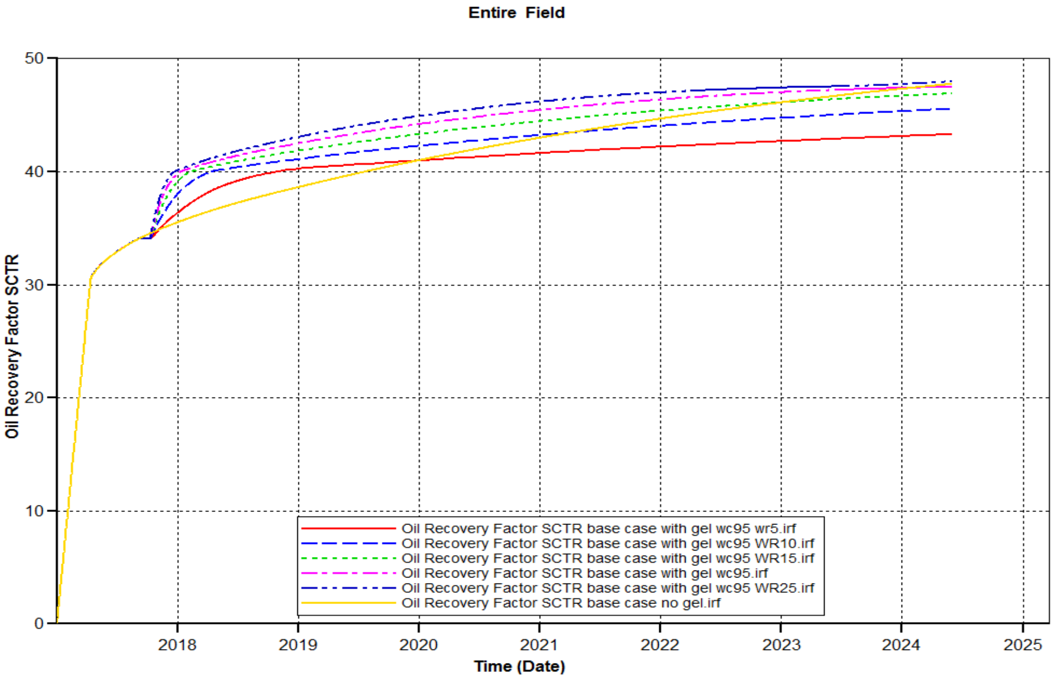


Figure 3.11. Comparison of oil-recovery factor for cases with various water-flooding rate of 5 bbl/day, 10 bbl/day, 15 bbl/day, 20 bbl/day and 25 bbl/day after gel injection and no gel injection

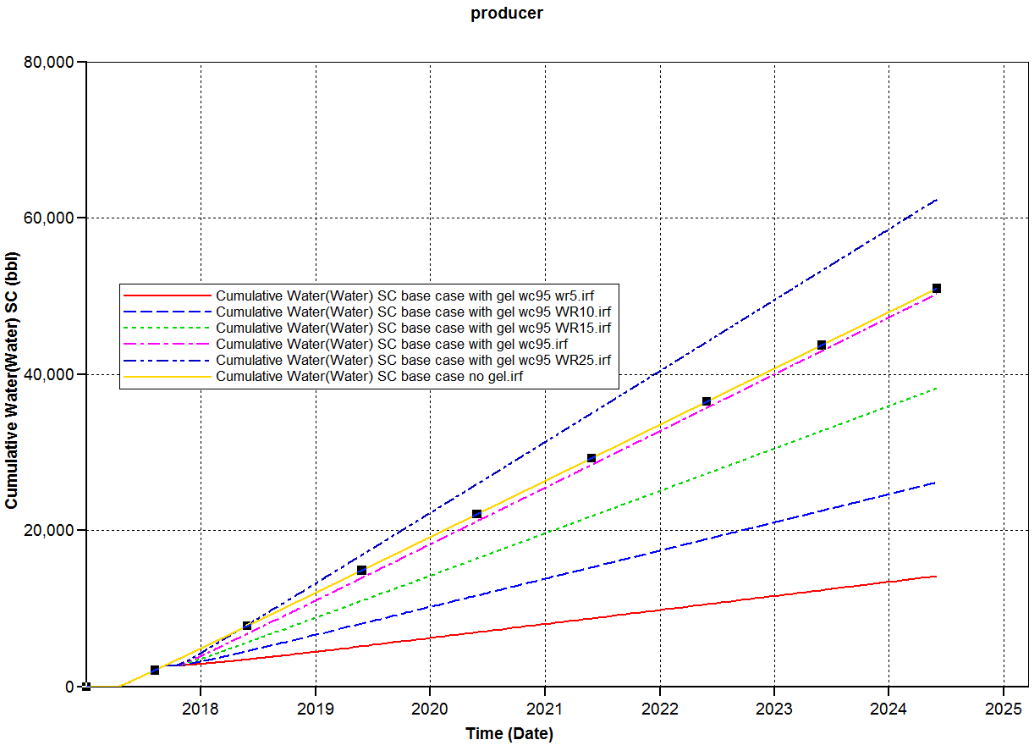


Figure 3.12. Cumulative water production with various water-flooding rate of 5 bbl/day, 10 bbl/day, 15 bbl/day, 20 bbl/day and 25 bbl/day.

3.2.4. Effect of Maximum Adsorption Capacity. Maximum adsorption capacity (ADMAXT) is the maximum amount of adsorption gel that each reservoir grid can hold. Units for ADMAXT can be g-mole/m^3, lb-mol/m^3, or g-mol/cm^3. Adsorption properties such as ADMAXT, residual-resistance factor, and accessible pore volume can be influenced significantly by reservoir heterogeneities. Adsorption of each grid is a function of component concentration and temperature, as well as well location. The relationship between adsorbed moles of component under temperature T, concentration C, and at grid block I per unit pore volume, ad(C,T,I), and the maximum adsorption capacity at grid block I, ADMAXT(I) is expressed by the following equation:

$$\mathrm{ad(C,T,I) = ADMAXT(I) * ad(C,T)/AD_{max,T1}}. \tag{12}$$

where $\mathrm{AD_{max,T1}}$ is the first parameter of the adsorption isotherm; tad1, following *ADSLANG, which stands for the maximum obtainable adsorption at the specific set temperature. An example of using key word ADSLANG in this study would be *ADSLANG 0.183601 0 5.5485E+06, meaning at 113°F reservoir temperature, the maximum obtainable adsorption of the assigned grids is 0.183601 gmol/cm^3. With larger ADMAXT, the amount of adsorption gel in each grid increases, meaning more gel is required for the same area compared to low ADMAXT. With smaller ADMAXT, the same amount of gel requires more pore spaces as shown in Figure 3., which means better gel placement and a larger affected area in the low-permeability layers.

Permeability reduction factor of grid I is a function of RRF and ADMAXT, expressed by

$$\mathrm{RK(I) = 1 + (RRF - 1) * ad(C,T)/ADMAXT}\ , \tag{13}$$

where $\mathrm{ad(C,T)}$ is the adsorbed moles of component in concentration of C and temperature of T. Phase permeability of grid I with adsorption of ad(C,T) is expressed by equations 14 to 16

$$\mathrm{AKW(I) = AK(I) * krw/RKW(I)} \tag{14}$$

$$\mathrm{AKO(I) = AK(I) * kro/RKO(I)} \tag{15}$$

$$\mathrm{AKG(I) = AK(I) * krg/RKG(I)} \tag{16}$$

where AK(I) is the absolute permeability of grid I. Mobility equals permeability divided by viscosity. Therefore, the mobility of a phase with adsorbed component is determined by the phase viscosity, as well as RRF and ADMAXT.

The equation for converting adsorption from lab units to mole units is:

$$\mathrm{Ad_{gel}} = \mathrm{Ad_{gel_{lab}}} * \frac{\rho_r(1-\Phi)}{\Phi} * \mathrm{M}\ (1.6018e4) \tag{17}$$

where $\mathrm{Ad_{gel}}$ is the adsorption used in STARS in lbmol/ft^3, $\mathrm{Ad_{gel_{lab}}}$ is adsorption obtained in laboratory in mg polymer/100 g rock, ρ_r is rock density in g/cm^3, M is molecular weight of gel, Φ is porosity, and 1.6018e4 is the conversion factor between gmol/m^3 to lbmol/ft^3.

CMG assumes that gel adsorption is caused solely by polymer adsorption. One assumption of using Langmuir equation is that there is only one layer of monomer adsorbed on the rock surface. Permeability reduction affects the phase related to the component; therefore, in this case the permeability reduction will have effect on water only. The new effective water permeability is found by equations 18 and 19:

$$\mathrm{R_{k\alpha}} = 1 + (\mathrm{RRF_\alpha} - 1) * \frac{\mathrm{Ad_{cell}}}{\mathrm{ADMAXT}} \tag{18}$$

$$\mathrm{k_{ef\alpha}} = \frac{\mathrm{k_{\gamma\alpha} k_{abs}}}{\mathrm{R_{k\alpha}}}\,. \tag{19}$$

where $\mathrm{R_{k\alpha}}$ is the permeability reduction factor, $\mathrm{RRF_\alpha}$ is the residual resistance factor to phase α, $\mathrm{k_{ef\alpha}}$ is the effective permeability of phase α, $\mathrm{k_{\gamma\alpha}}$ is the relative permeability of phase α, and $\mathrm{k_{abs}}$ is the absolute permeability of the rock.

Following is an example of obtaining the new relative-permeability curve for grid 100,1,20, corresponding to the I,J,K coordination, which is the grid at the bottom of the production well. By the end of production, on 2024-06-01, $\mathrm{RRF_w}$ is 82.64. $\mathrm{RRF_o}$ is 1. $\mathrm{Ad_{cell}}$ is $6.07*10^{-7}$. ADMAXT is $0.033*10^{-6}$. The new relative-permeability curve can be calculated by inserting the known parameters into equations 18 and 19 as in the following.

Table 3.8 lists the original relative permeabilities as Krw and Krow, and the new relative permeabilities after gel adsorption as Kefw and Kefo. Comparison of original and new relative-permeability curve is shown as Figure 3.13.

$$\mathrm{R_{kw}} = 1 + (82.64 - 1) * \frac{6.07*10^{-7}}{0.033*10^{-6}} = 1502.68$$

$$\mathrm{k_{efw}} = \frac{\mathrm{k}_{\gamma\alpha} * 500}{1502.68}$$

Table 3.8. Relative permeabilities of water and oil before and after gel adsorption

Sw	Krw	Krow	Kefw
0.25	0	0.9	0
0.283125	0.001172	0.741577	0.00039
0.31625	0.004688	0.60293	0.00156
0.349375	0.010547	0.482739	0.003509
0.3825	0.01875	0.379688	0.006239
0.415625	0.029297	0.292456	0.009748
0.44875	0.042188	0.219727	0.014037
0.481875	0.057422	0.160181	0.019106
0.515	0.075	0.1125	0.024955
0.548125	0.094922	0.075366	0.031584
0.58125	0.117188	0.047461	0.038993
0.614375	0.141797	0.027466	0.047181
0.6475	0.16875	0.014063	0.05615
0.680625	0.198047	0.005933	0.065898
0.71375	0.229687	0.001758	0.076426
0.746875	0.263672	0.00022	0.087734
0.78	0.3	0	0.099822

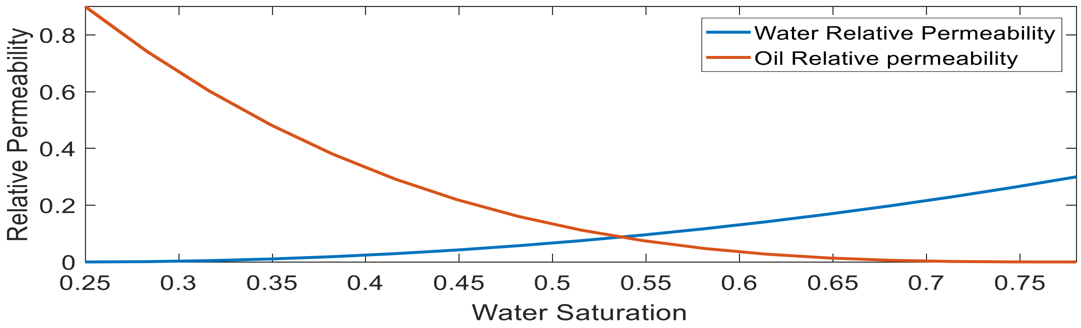


Figure 3.13. Comparison of relative-permeability curves before and after gel adsorption

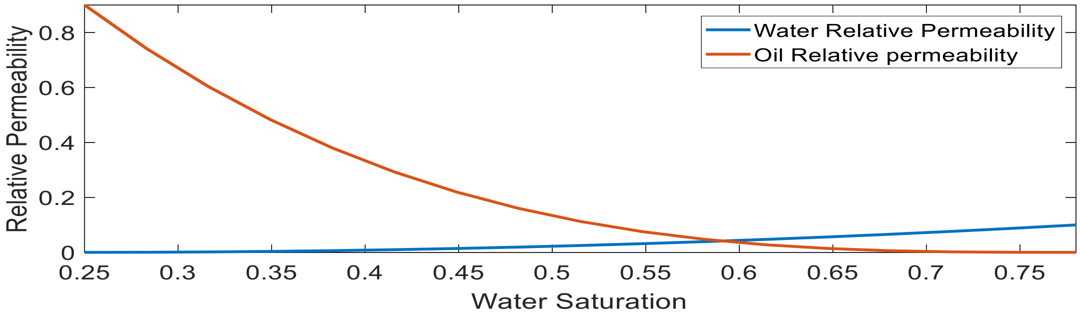


Figure 3.13. Comparison of relative-permeability curves before and after gel adsorption (cont.)

According to equations 18 and 19, the smaller the ADMAXT, the lower the effective permeability of the water phase, meaning better blocking effect of the water phase. Which phase is blocked more depends on the residual-resistance factor. A suitable polymer gel as a DPR agent should have a large residual-resistance factor of water and a small residual-resistance factor of oil, so that, based on equation 18 and 19, the adsorption will reduce water permeability more than oil permeability.

Result: Based on Figure 3.16, the smaller the ADMAXT, the larger the penetration difference between high permeabilty and low permeability layers. According to Table 3.9, the highest oil-recovery factor at 1 year and 2 years occur with the lowest ADMAXT. The largest water reduction and oil increment in the effective period also corresponds to the lowest ADMAXT, which is 7.36e-11/3.31e-11. However, taking effective periods into account, the average water reduction and average oil increment during the effective period peak in the case with the largest ADMAXT. This is because larger ADMAXT causes larger effective relative permeability of water, leading to a much shorter effective period than with cases of smaller ADMAXT. Therefore, the case with the largest ADMAXT has the best average water reduction and oil increment in the effective period, while the case with the smallest ADMAXT has the best total water reduction and oil increment in the effective period and the best oil recovery factor at 1 year and 2 year production. Figure 3.14 and Figure 3.15 are the cumulative water production and oil recovery factor of cases with various ADMAXT. The differences are not obvious according to the plot, but they can be read in the results (Table 3.9).

Table 3.9. Results for effect of maximum adsorption capacity

Maximum adsorption capacity, 0.0736ex /0.0331ex	x = -11	x = -10	x = -9	x = -8	x = -7
Effective period, days	97.00	96.00	96.00	89.00	69.00
Water production in the effective period without gel, bbl	1864.32	1845.03	1845.03	1710.09	1324.85
Water production in the effective period with gel, bbl	1480.78	1462.12	1463.21	1342.13	1018.41
Reduced water production in the effective period, bbl	383.54	382.91	381.82	367.96	306.44
Average water reduction per day in the effective period, bbl/day	3.95	3.99	3.98	4.13	4.44
Oil production in the effective period without gel, bbl	75.69	74.97	74.97	69.91	55.15
Oil production in the effective period with gel, bbl	458.71	457.35	456.26	437.37	361.08
Increased Oil production in the effective period, bbl	383.02	382.38	381.29	367.46	305.93
Average oil increment per day in the effective period, bbl/day	3.95	3.98	3.97	4.13	4.43
Oil recovery factor with gel @ 1 yr	42.71	42.70	42.69	42.54	41.93
Oil recovery factor with gel @ 2 yr	44.45	44.42	44.40	44.30	43.76

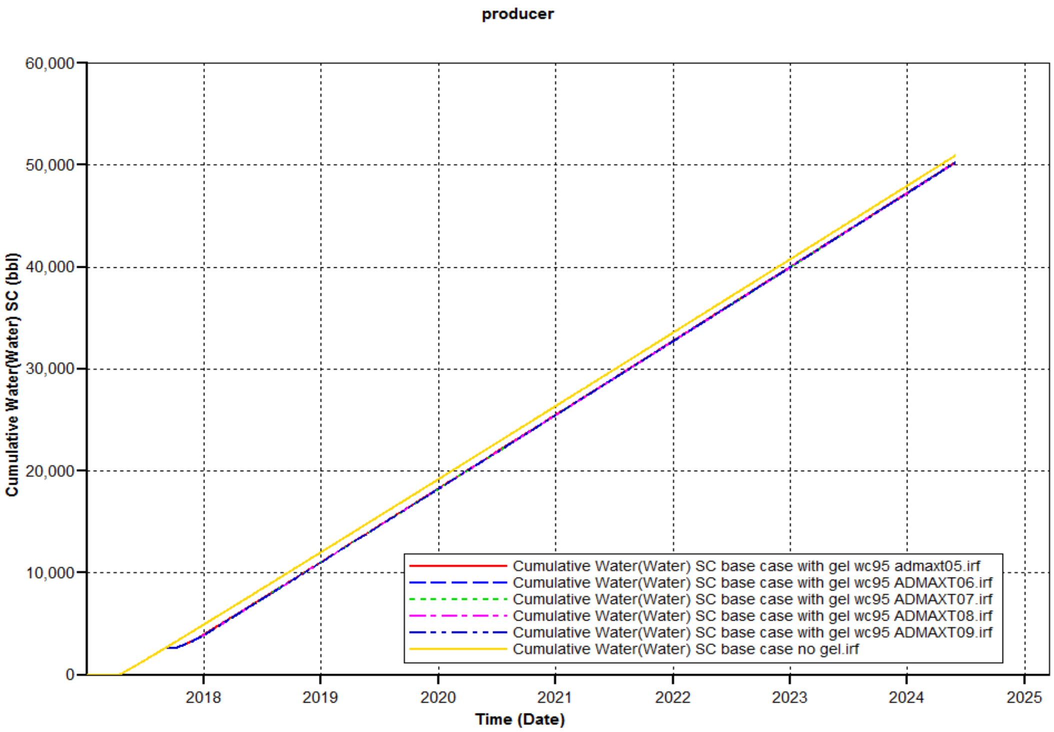


Figure 3.14. Cumulative water production of cases with gel injection and without gel injection

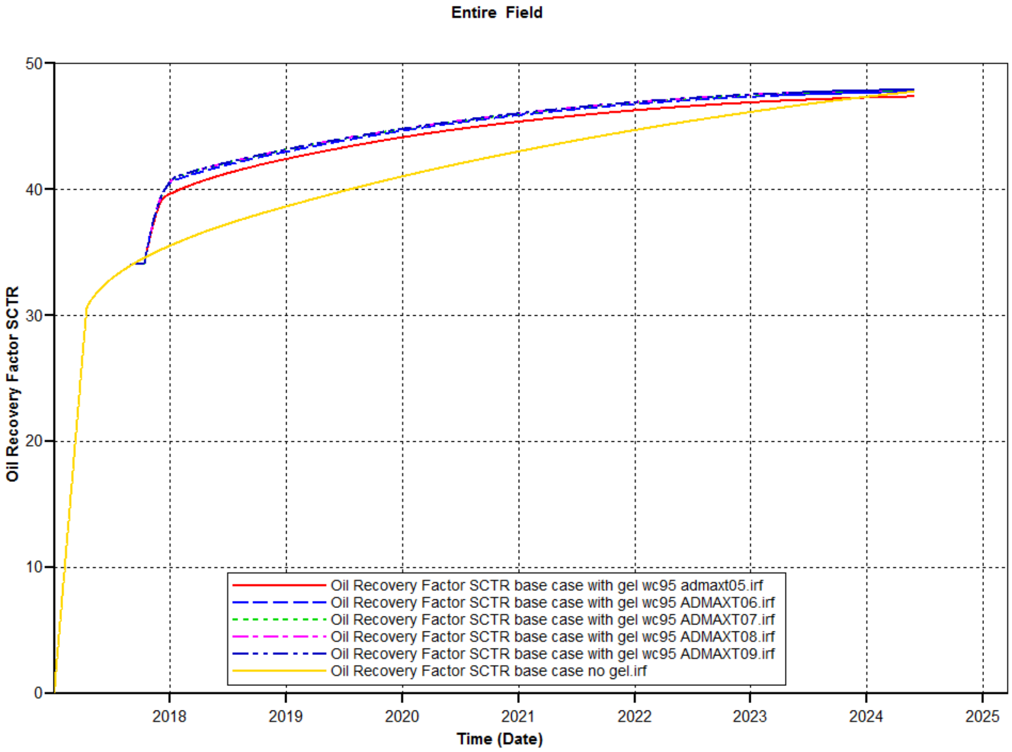
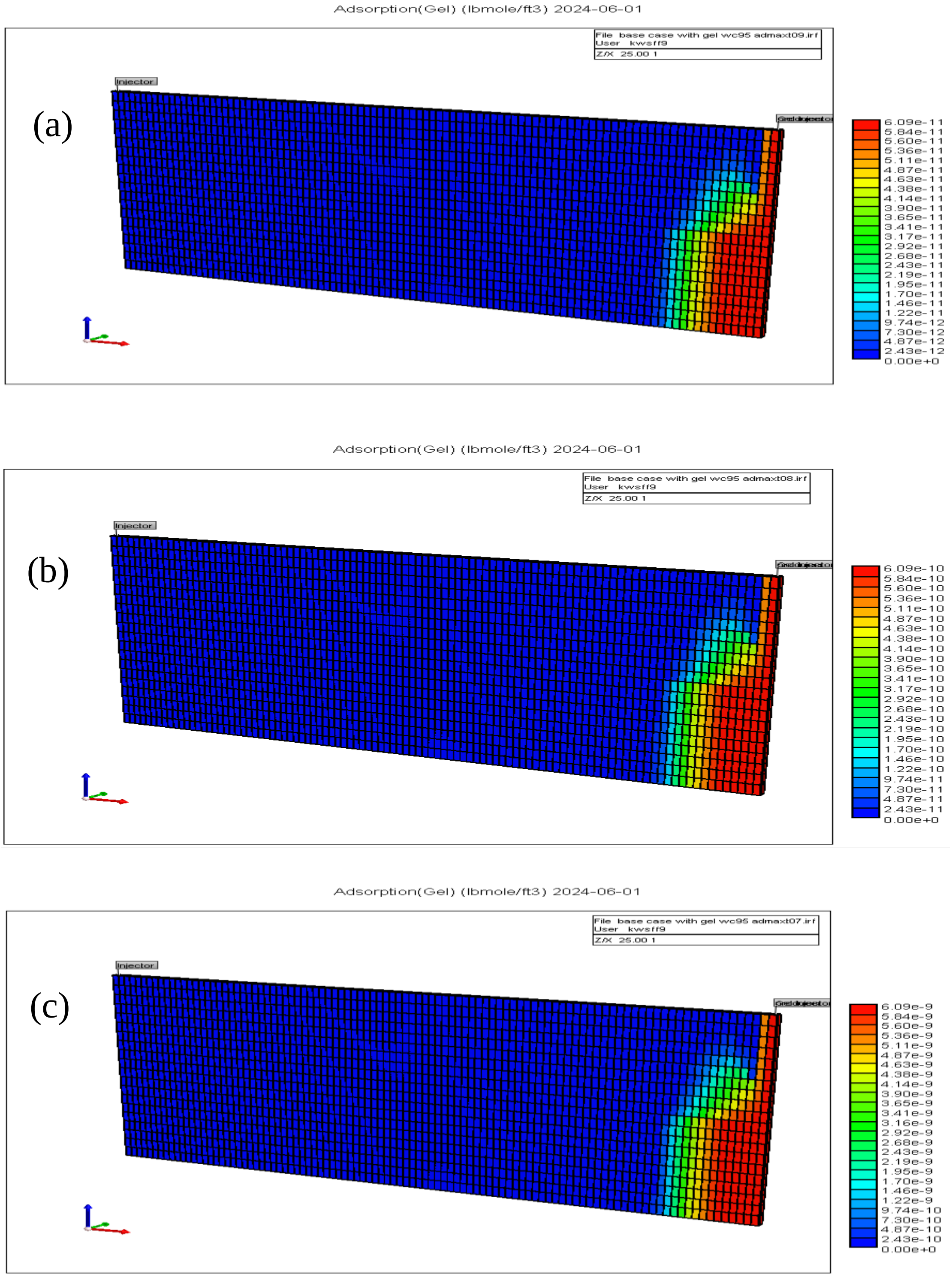


Figure 3.15. Oil-recovery factor of cases with gel injection and without gel injection


Adsorption(Gel) (lbmole/ft3) 2024-06-01

Adsorption(Gel) (lbmole/ft3) 2024-06-01

Adsorption(Gel) (lbmole/ft3) 2024-06-01

Figure 3.16. (a-e) Comparison of gel adsorption with various amount of maximum adsorption capacity of 7.36e-11 /3.31e-11, 7.36e-10 /3.31e-10, 7.36e-9 /3.31e-9, 7.36e-8 /3.31e-8, and 7.36e-7 /3.31e-7

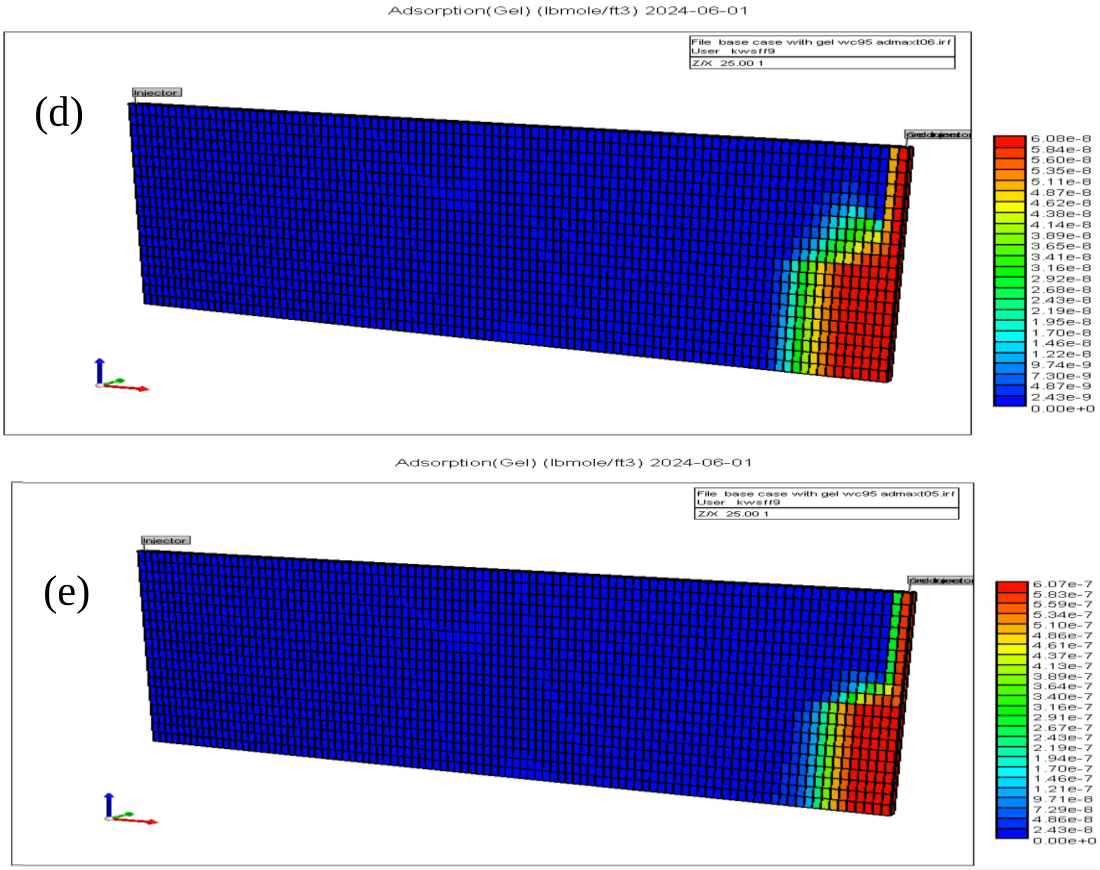


Figure 3.16. (a-e) Comparison of gel adsorption with various amount of maximum adsorption capacity of 7.36e-11 /3.31e-11, 7.36e-10 /3.31e-10, 7.36e-9 /3.31e-9, 7.36e-8 /3.31e-8, and 7.36e-7 /3.31e-7 (cont.)

3.2.5. Effect of Reaction-Frequency Factor. Reaction frequency factor is a constant factor in the expression for reaction time (STARS User Guide). Procedures for obtaining this constant from laboratory measurements are as follows:

In a simple kinetic model, it is assumed that the polymer and cross-linker are in stoichiometric ratios, so that if initial polymer concentration is C_1 ppm by weight, and initial cross-linker concentration is C_2 ppm, then the product gel is (C_1+ C_2) ppm. Set $t_{1/2}$

as the time required for half of the reactants to be converted. The reaction rate, K, can be achieved by equation 20:

$$t_{1/2} = \frac{1}{KC1C2} \tag{20}$$

$t_{1/2}$ can be obtained from the laboratory titration of the cross-linker. When chromium is the cross-linker, under a certain temperature, procedures for obtaining $t_{1/2}$ are: 1) Sequestration: Set a group of times for the reaction and freeze the mixture at those timings. 2) Titration: Add oxidizing agent to each mixture sample to produce chromium oxide. Part of the chromium has been cross-linked with polymers. Only the remaining chromium will oxidize and be precipitated. CrO_3 is dark red, Cr_2O_3 is light- to dark-green. According to the amount of oxidizer used, the remaining chromium concentration by weight can be calculated. Take at least 5 time points and note the corresponding amount of remaining chromium. Make a plot like Figure 3.17 from the time points vs. the amount of remaining chromium. 3) Read the time point that corresponds to 50% of remaining chromium. That time should be the $t_{1/2}$ in equation 1.

The rate constant, K, is a function of temperature and is given by the Arrhenius equation:

$$K = A * e^{\frac{-Ea}{RT}}\ , \tag{21}$$

where A is the reaction-frequency factor, R is the gas constant with a value of 8.314 J/mol-K, T is the temperature in degrees Kelvin, and Ea is the activation energy of the reaction. To obtain the value of Ea, take the ln function on both sides of this equation, which yields equation 23. A linear relationship between 1/T and ln(K) is shown in Figure 3.18. Use number sets of K and 1/T in equation 4 to get Ea.

$$\ln K = \frac{-Ea}{R}\left(\frac{1}{T}\right) + \mathrm{Ln}A\ . \tag{22}$$

$$\ln\left(\frac{K1}{K2}\right) = \frac{-Ea}{R}\left(\frac{1}{T1} - \frac{1}{T2}\right). \tag{23}$$

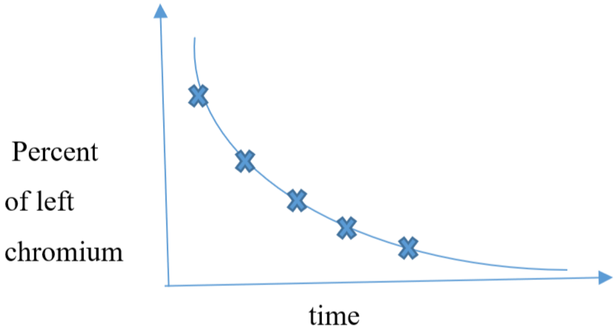


Figure 3.17. Time vs. percent of remaining chromium

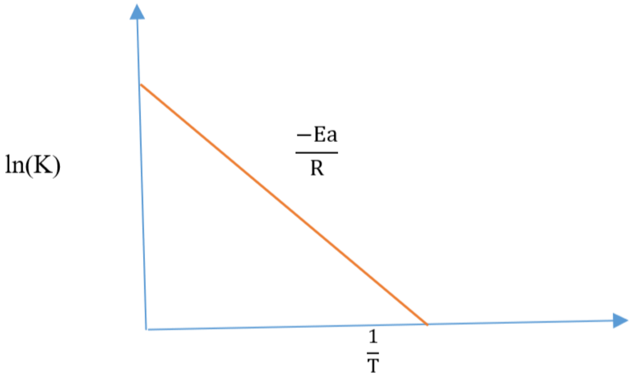


Figure 3.18. Plot of 1/T vs. ln(K)

After obtaining Ea, the reaction frequency factor A can be obtained from equation 23. Therefore, to obtain the reaction-frequency factor of a polymer gel, the work that should be done in the lab is to obtain Figure 3.18 for various temperatures. Then a set of reaction rate K and temperature T can be used for calculating reaction-frequency factor A.

Gels are injected when water cut is 80% and the well workflow conforms with this water cut. Models are those of the base case, the only difference being the reaction-frequency factor. Four cases with $3.24*10^1$, $3.24*10^2$, $3.24*10^3$, and $3.24*10^4$ reaction-frequency factor are run, and figures and tables are generated to predict the effect of the water-flooding rate after gel injection.

Result: Table 3.10 shows that when reaction-frequency factor is under $3.24*10^2$, there is no effective period. In other words, this chemical treatment is not working with a reaction-frequency factor lower than $3.24*10^2$. When the reaction-frequency factor reaches $3.24*10^3$, both water reduction and oil increment and the average values during the effective period increase with the increasing reaction-frequency factor. Low RFF means crosslinking reaction between polymer and cross-linker is too slow that they are not fully processed in the fixed reaction time, which is 30 days for this case. Increasing the reaction-frequency factor from $3.24*10^2$ to $3.24*10^3$, water reduction and oil increment ranges from 0 to observed for the effective period and the long run. Figure 3.19 and Figure 3.20 are water cuts and oil-recovery factors of the four cases. They show that with increasing reaction-frequency factor, water cut is lower and oil-recovery factor is higher. Figure 3.21 shows gel distribution of the four cases. The larger the reaction-frequency factor, the larger gel concentration and larger penetrated area. When using gel in the oilfield, the gelation time changes with needs. On one hand, gelation time must be long enough to keep injectivity for the gel to be placed to the targeted area. On the other hand, gelation time is economically sensitive in the process of production. Once gel reaches the targeted area, ideally chemical reactions should be as fast as possible to minimize the shut-in period. Accurate calculations of an optimum gelation time are needed before gel is used as a plugging agent in an oilfield. Then formulations of gel will be experimentally tested in the laboratory to achieve the optimum gelation time.

Table 3.10. Results for effect of reaction-frequency factor

Reaction frequency factor	32.40	324.00	3240.00	32400.00
Effective period, days	0.00	0.00	153.00	114.00
Water production in the effective period without gel, bbl	0.00	0.00	2945.88	2192.28
Water production in the effective period with gel, bbl	0.00	0.00	2834.68	1964.73
Reduced water production in the effective period, bbl	0.00	0.00	111.20	227.55
Average water reduction per day in the effective period, bbl/day	0.00	0.00	0.73	2.00
Oil production in the effective period without gel, bbl	0.00	0.00	115.00	87.73
Oil production in the effective period with gel, bbl	0.00	0.00	223.53	314.18
Increased Oil production in the effective period, bbl	0.00	0.00	108.53	226.45
Average oil increment per day in the effective period, bbl/day	0.00	0.00	0.71	1.99
Oil recovery factor with gel @ 1 yr	37.00	37.73	39.46	40.94
Oil recovery factor with gel @ 2 yr	38.97	39.87	41.42	42.83

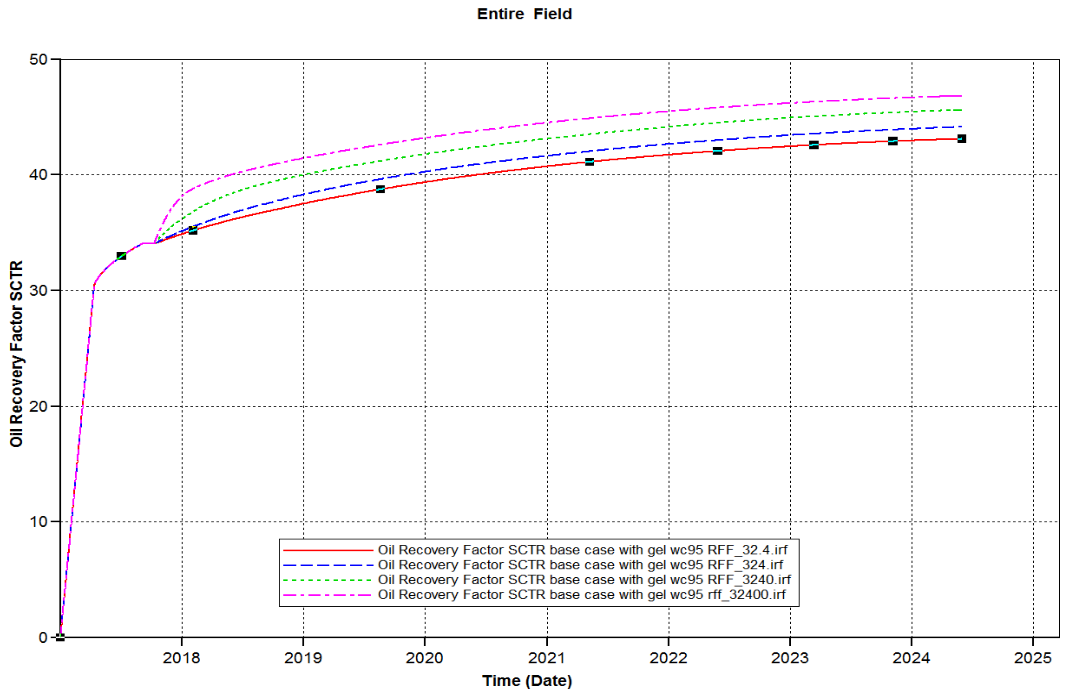


Figure 3.19. Oil-recovery factors of cases with reaction-frequency factors of $3.24*10^1$, $3.24*10^2$, $3.24*10^3$, and $3.24*10^4$

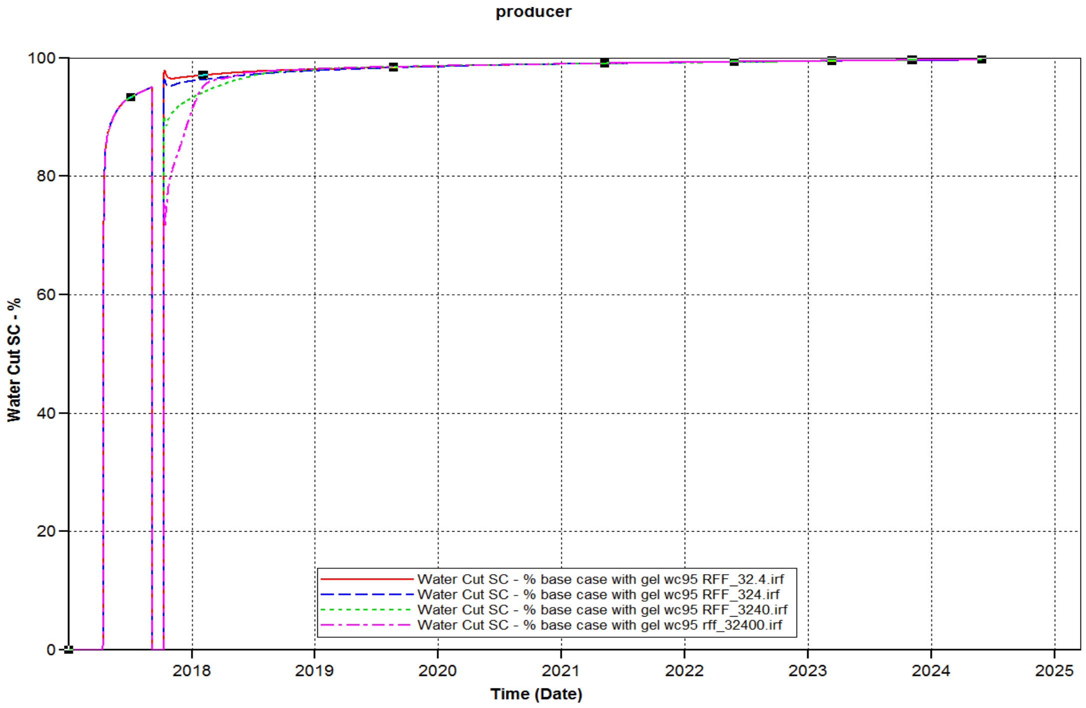


Figure 3.20. Water cuts of cases with reaction-frequency factors of $3.24*10^1$, $3.24*10^2$, $3.24*10^3$, and $3.24*10^4$

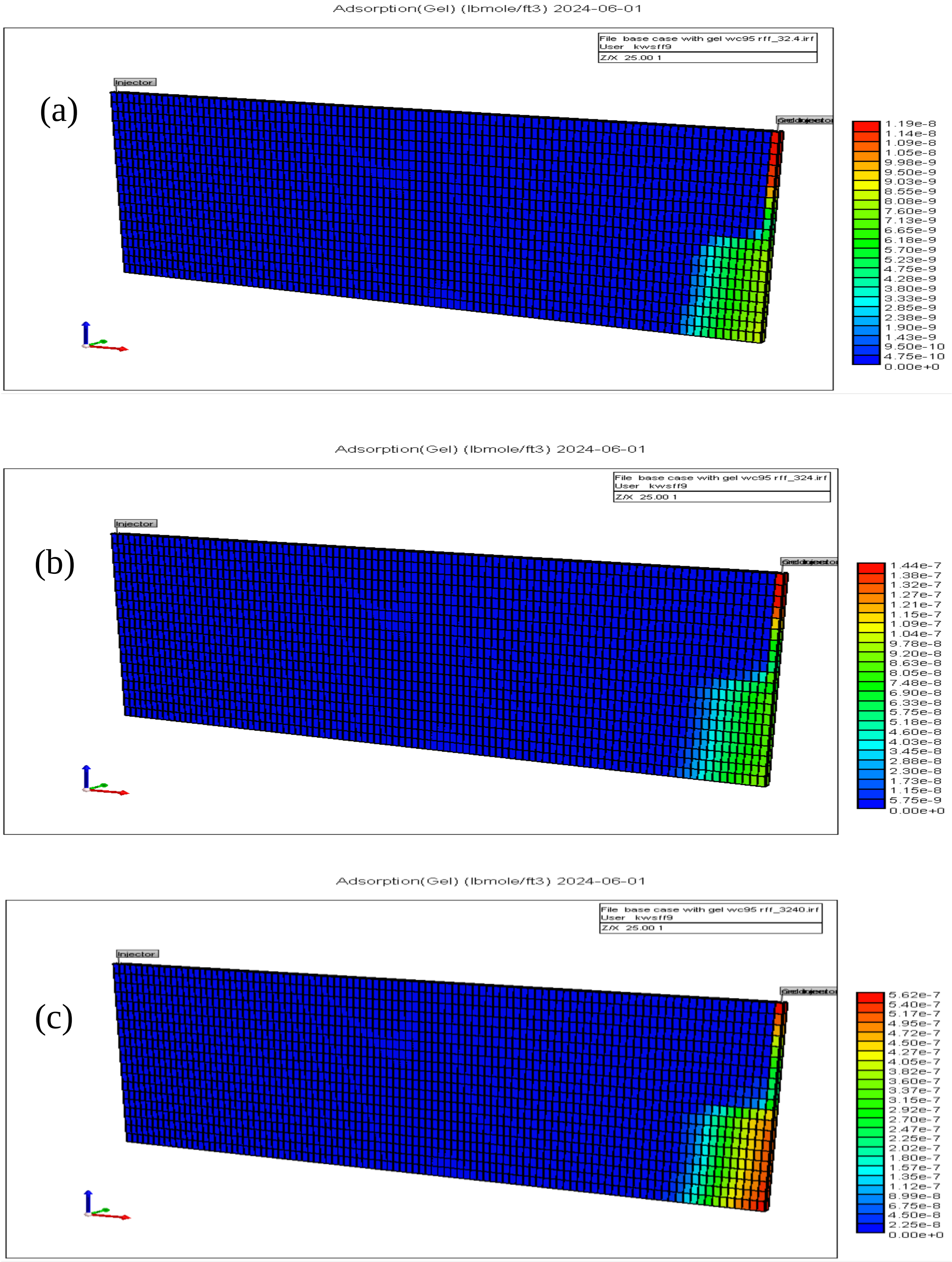


Figure 3.21. (a-d) Comparison of gel adsorption profiles with reaction-frequency factors of 3.24*10^1, 3.24*10^2, 3.24*13^1, and 3.24*10^4

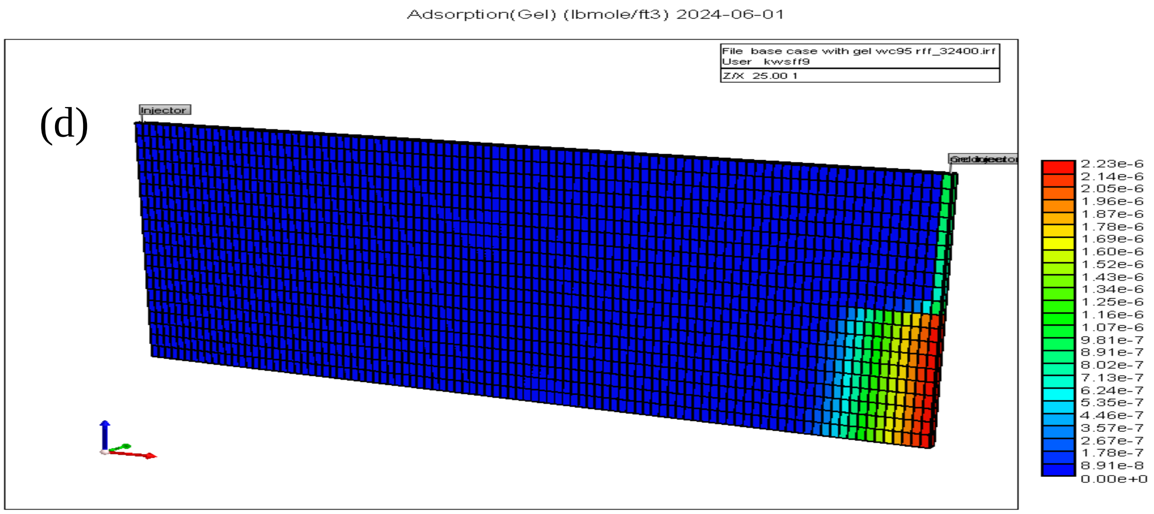


Figure 3.21. (a-d) Comparison of gel adsorption profiles with reaction-frequency factors of $3.24*10^1$, $3.24*10^2$, $3.24*13^1$, and $3.24*10^4$ (cont.)

3.2.6. Effect of the Residual-Adsorption Level (ADRT). ADRT denotes the residual-adsorption level (g-mol/m^3, lb-mol/ft^3, g-mol/cm^3) whose range is from 0 to ADMAXT. 0 implies that the adsorption is completely reversible; ADMAXT implies that the adsorption is completely irreversible. The fraction of ADRT to ADMAXT expresses the stability of the gel adsorption. The ideal situation would expect gel to be unconditionally irreversible to provide the effective blockage.

Result: Results for various ratios of ADRT to ADMAXT for this simplified model, as shown in Table 3.11, imply that the larger the ratio of ADRT to ADMAXT, the better the water reduction and oil increment before the ratio reaches 0.8, as well as the average values and the oil recovery factor at 1 year and 2 years. When the ratio exceeds 0.8, the differences of water cut and oil-recovery factor as shown in Figure 3.22 and Figure 3.23 can be neglected. Figure 3.24 shows the gel-adsorption profile by the end of production, showing that the gel penetration is deeper with larger concentrations as residual adsorption level increases.

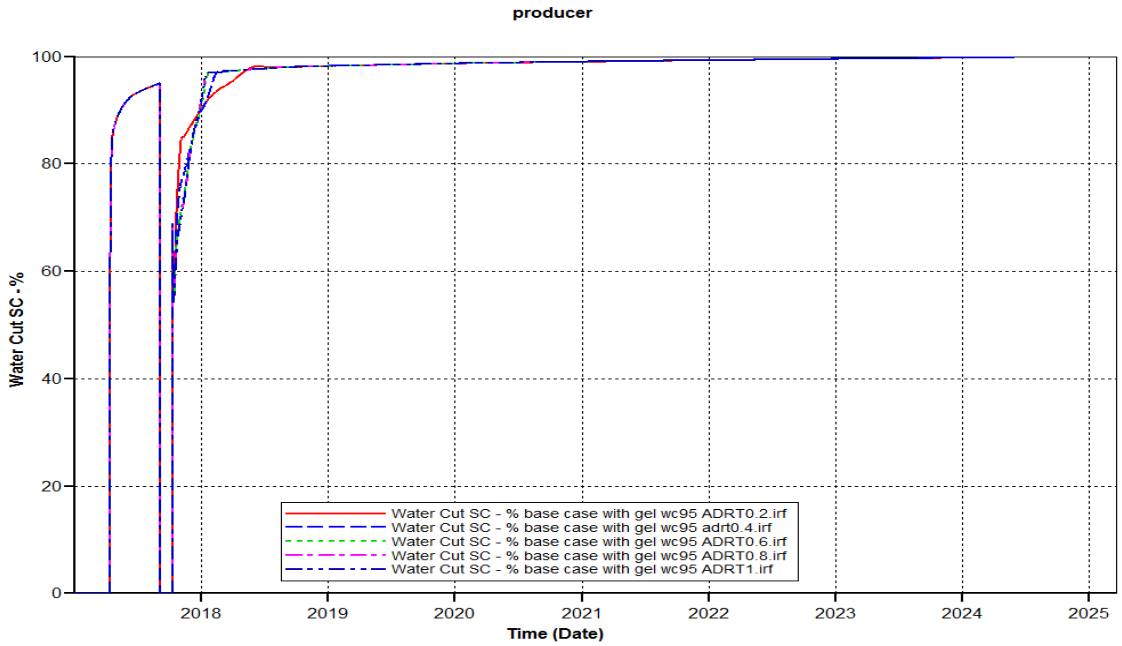


Figure 3.22. Water cuts for various ADRT to ADMAXT ratios of 0.2, 0.4, 0.6, 0.8, and 1

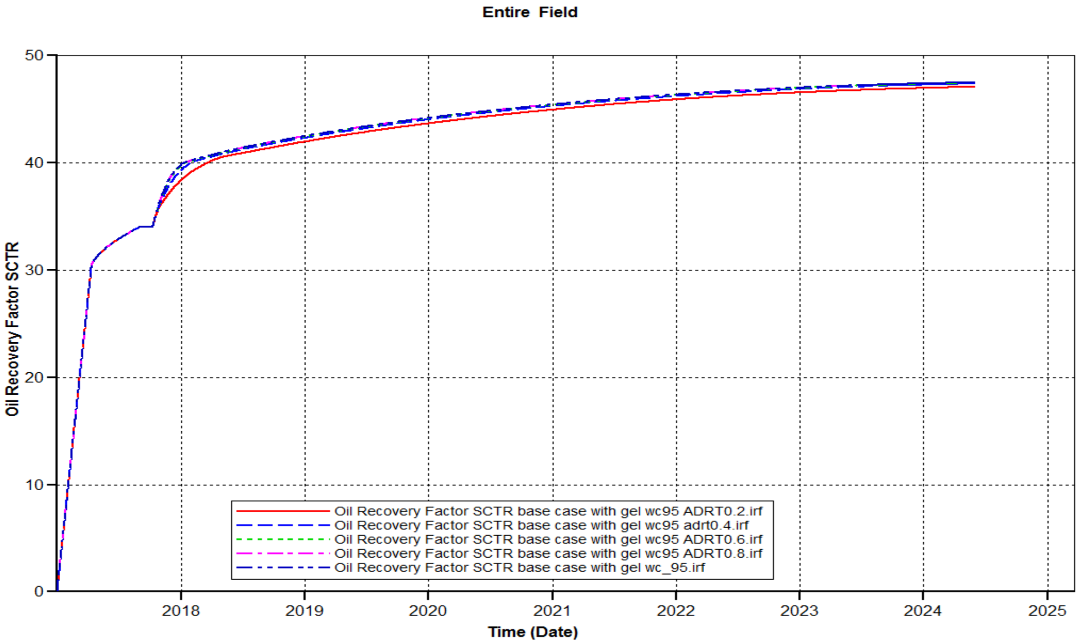


Figure 3.23. Oil recovery factors for various ADRT to ADMAXT ratios of 0.2, 0.4, 0.6, 0.8, and 1

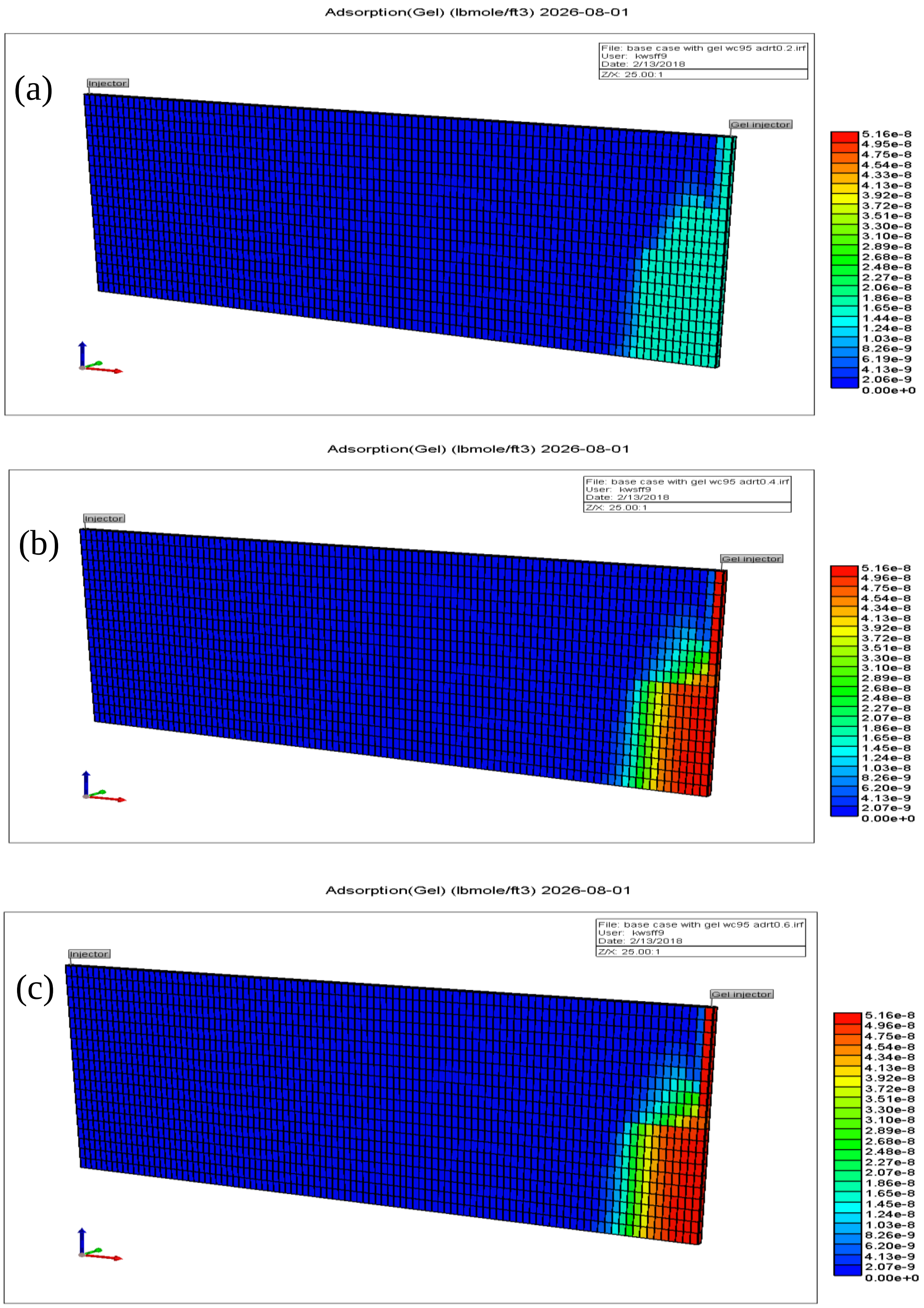


Figure 3.24. (a-e) Gel-adsorption profiles for various ADRT to ADMAXT ratios of 0.2, 0.4, 0.6, 0.8, and 1

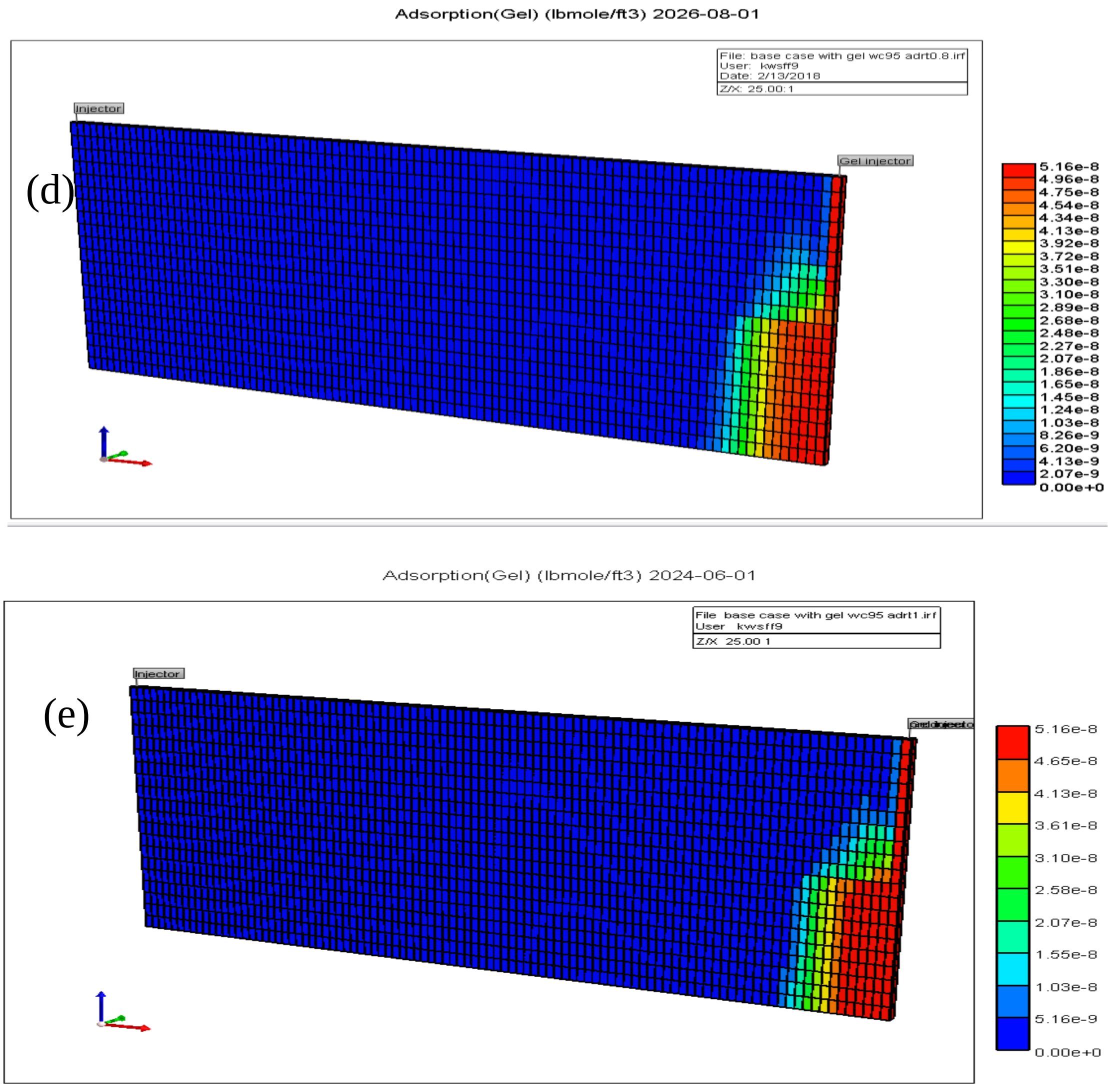


Figure 3.24. (a-e) Gel-adsorption profiles for various ADRT to ADMAXT ratios of 0.2, 0.4, 0.6, 0.8, and 1 (cont.)

3.2.7. Effect of Accessible Pore Volume (PORFT). PORFT denotes the fraction of pore volume available for polymer gel to the total pore volume, ranging from 0 to 1. With lower PORFT, the same amount of gel requires greater pore spaces, which means deeper penetration in the high-permeability layers and larger unswept area in the low-permeability layers, as shown in Figure 3.27.

Result: Table 3.12 is generated from Figure 3.25 and Figure 3.26, which are the water cuts and oil-recovery factors of the cases with various accessible pore volumes. According to the results in Table 3.12, water reduction and oil increment with smaller PORFT are higher than that of with larger PORFTs.

Table 3.11. Results for effect of residual-adsorption level

Ratio of ADRT to ADMAXT	0.20	0.40	0.60	0.80	1.00
Effective period, days	164.00	115.00	95.00	92.00	92.00
Water production in the effective period without gel, bbl	3158.73	2211.58	1825.75	1767.92	1767.92
Water production in the effective period with gel, bbl	2849.10	1898.41	1502.33	1441.67	1441.67
Reduced water production in the effective period, bbl	309.63	313.17	323.42	326.25	326.25
Average water reduction per day in the effective period, bbl/day	1.89	2.72	3.40	3.55	3.55
Oil production in the effective period without gel, bbl	121.28	88.42	74.25	72.09	72.09
Oil production in the effective period with gel, bbl	400.72	401.08	397.08	397.75	397.75
Increased Oil production in the effective period, bbl	279.44	312.66	322.83	325.66	325.66
Average oil increment per day in the effective period, bbl/day	1.70	2.72	3.40	3.54	3.54
Oil recovery factor with gel @ 1 yr	41.52	41.89	42.01	42.05	42.05
Oil recovery factor with gel @ 2 yr	43.35	43.70	43.80	43.85	43.85

Table 3.12. Results for effect of accessible pore volume

PORFT	0.20	0.40	0.60	0.80	1.00
Effective period, days	107.00	118.00	105.00	98.00	92.00
Water production in the effective period without gel, bbl	2057.20	2250.19	2037.90	1864.32	1767.92
Water production in the effective period with gel, bbl	1583.48	1847.38	1684.82	1545.95	1477.67
Reduced water production in the effective period, bbl	473.72	402.81	353.08	318.37	290.25
Average water reduction per day in the effective period, bbl/day	4.43	3.41	3.36	3.25	3.15
Oil production in the effective period without gel, bbl	82.81	89.81	82.10	76.40	72.09
Oil production in the effective period with gel, bbl	565.94	483.98	435.11	413.95	397.75
Increased Oil production in the effective period, bbl	483.13	394.17	353.01	337.55	325.66
Average oil increment per day in the effective period, bbl/day	4.52	3.34	3.36	3.44	3.54
Oil recovery factor with gel @ 1 yr	44.50	42.87	42.19	41.98	41.83
Oil recovery factor with gel @ 2 yr	46.54	44.76	44.05	43.85	43.71

3.2.8. Effect of Accessible-Resistance Factor. Accessible resistance-factor (RRFT) refers to the maximum residual resistance factor that each grid of the model can attain. RRFT of each grid is a variable number, depending on many factors, including the current saturations, fluid-flooding rate, gel adsorption, and time of production.

Result: A larger accessible-resistance factor of the rock implies less effective water permeability after gel treatment. Based on the results in Table 3.13 from Figure 3.28 and Figure 3.29, an enhanced water blocking-effect is obtained with a larger residual-resistance factor. Lower RRFT leads to better water-blocking effect and oil-increment effect. Figure 3.30 shows gel adsorption profiles with various accessible resistance-factor.

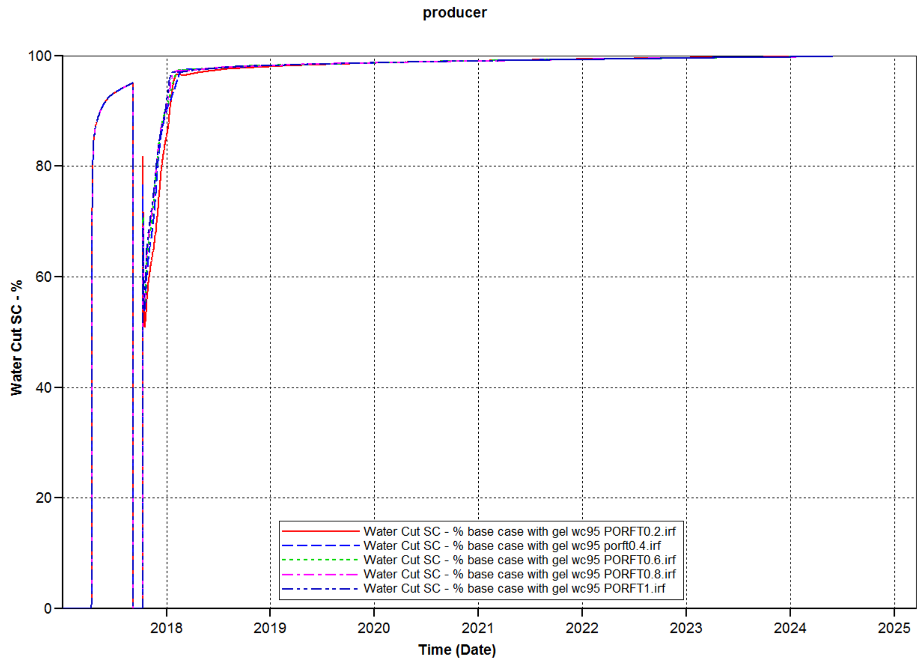


Figure 3.25. Water cuts for cases with accessible pore volumes of 0.2, 0.4, 0.6, 0.8 and 1

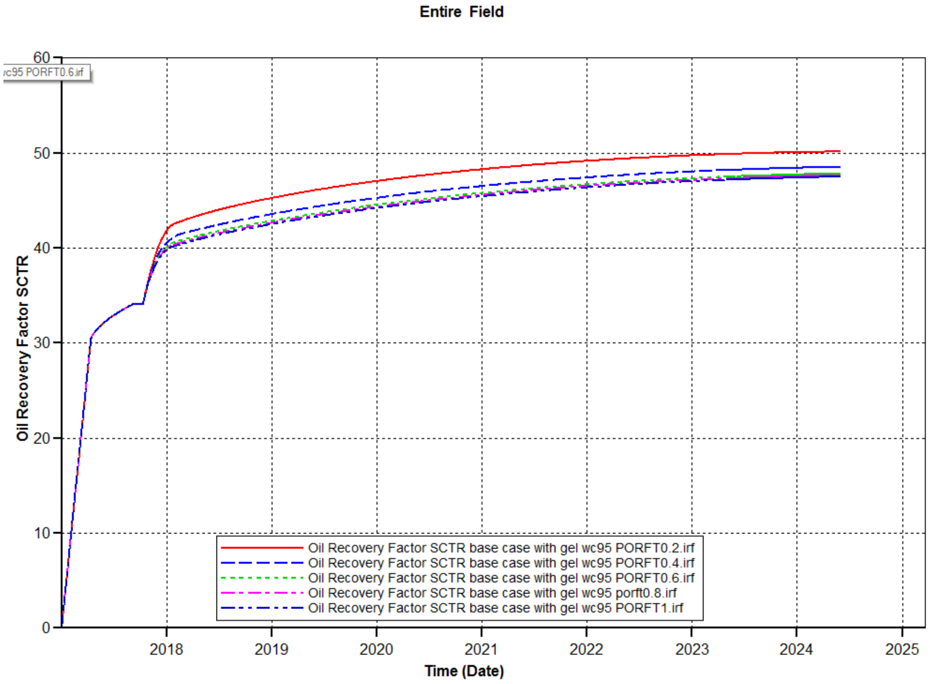


Figure 3.26. Oil recovery factor for cases with accessible pore volumes of 0.2, 0.4, 0.6, 0.8, and 1

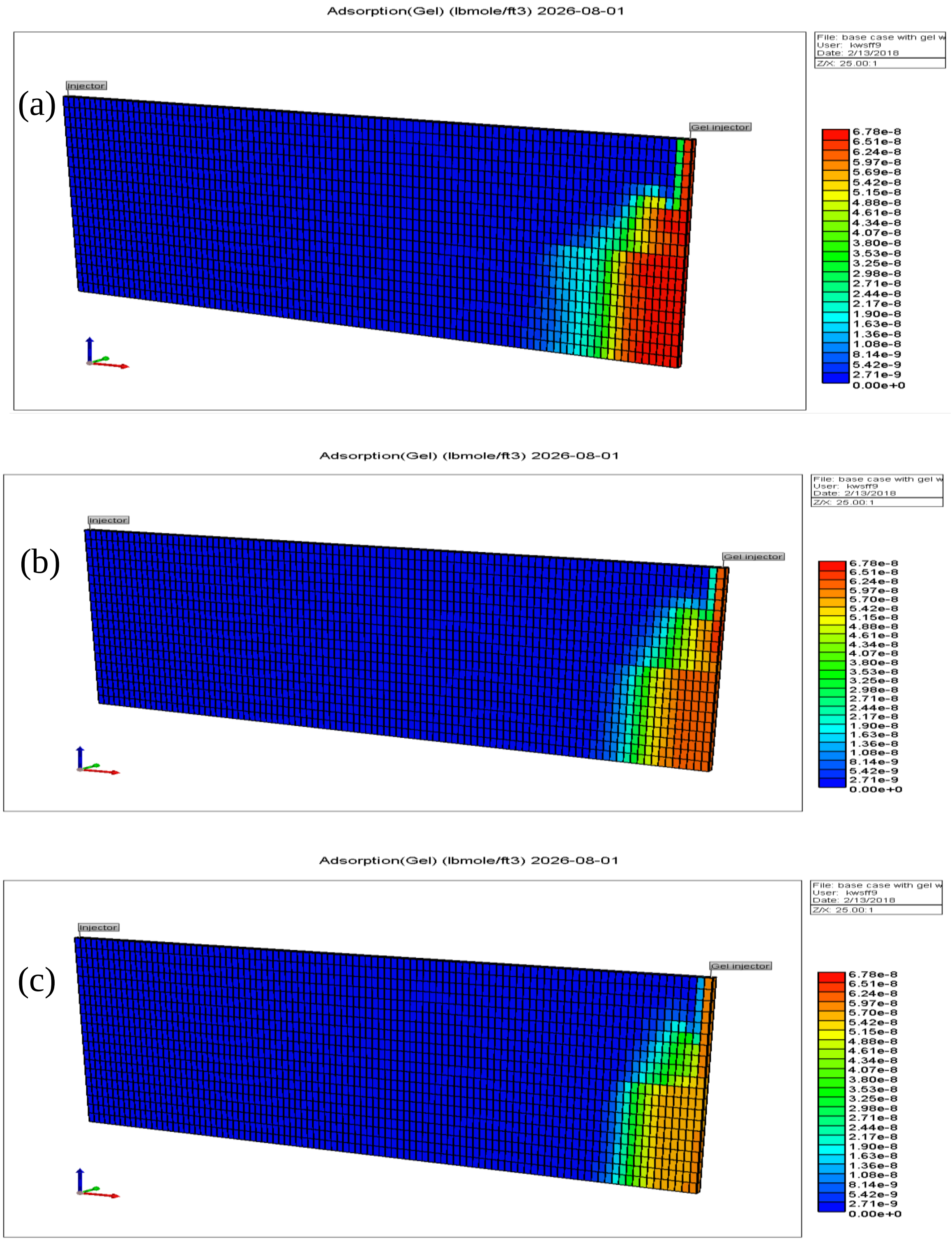


Figure 3.27. (a-e) Gel adsorption profiles for cases with accessible pore volumes of 0.2, 0.4, 0.6, 0.8, and 1

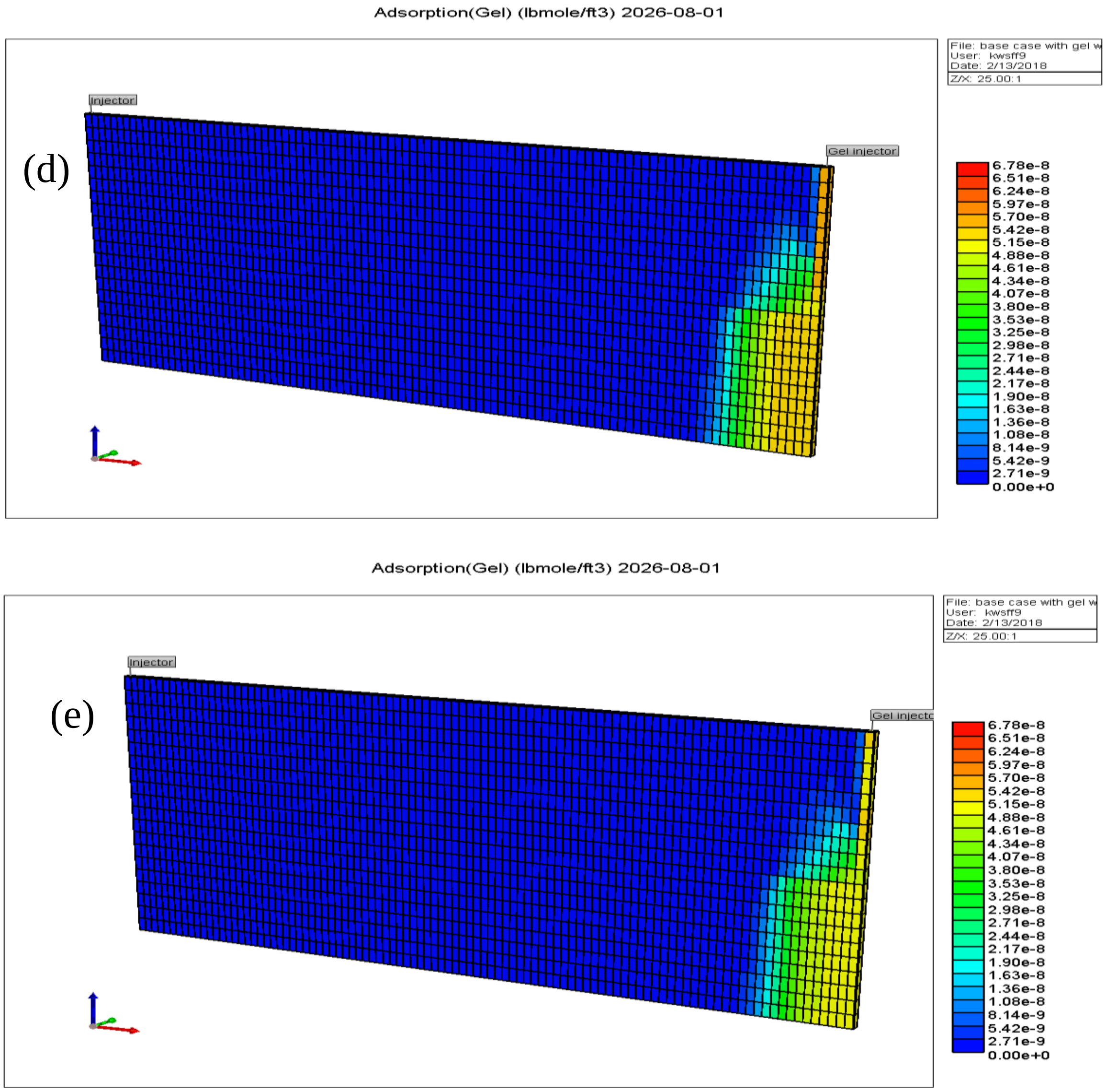


Figure 3.27. (a-e) Gel adsorption profiles for cases with accessible pore volumes of 0.2, 0.4, 0.6, 0.8, and 1 (cont.)

Table 3.13. Results for effect of accessible resistance-factor

RRFT	50	100	150	200	250
Effective period, days	110	83	71	65	60
Water production in the effective period without gel, bbl	2115.08	1594.47	1363.36	1247.86	1151.65
Water production in the effective period with gel, bbl	1812.69	1259.75	1011.95	872.11	782.76
Reduced water production in the effective period, bbl	302.39	334.72	351.41	375.75	368.89
Average water reduction per day in the effective period, bbl/day	2.75	4.03	4.95	5.78	6.15
Oil production in the effective period without gel, bbl	84.92	65.53	56.65	52.14	48.36
Oil production in the effective period with gel, bbl	386.66	400.22	408.04	414.10	417.22
Increased oil production in the effective period, bbl	301.74	334.69	351.39	361.96	368.86
Average oil increment per day in the effective period, bbl/day	2.74	4.03	4.95	5.57	6.15
Oil recovery factor with gel @ 1 yr	37.77	41.94	42.16	42.29	42.38
Oil recovery factor with gel @ 2 yr	40.29	43.81	44.00	44.13	44.20

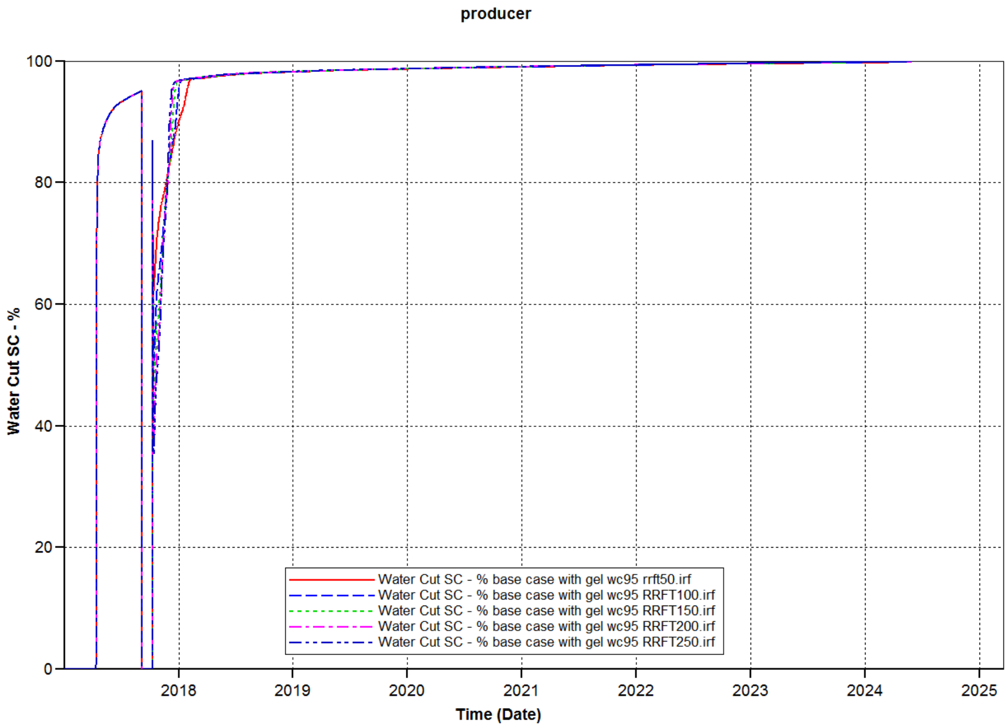


Figure 3.28. Water cuts for cases with accessible resistance factor of 50, 100, 150, 200, and 250

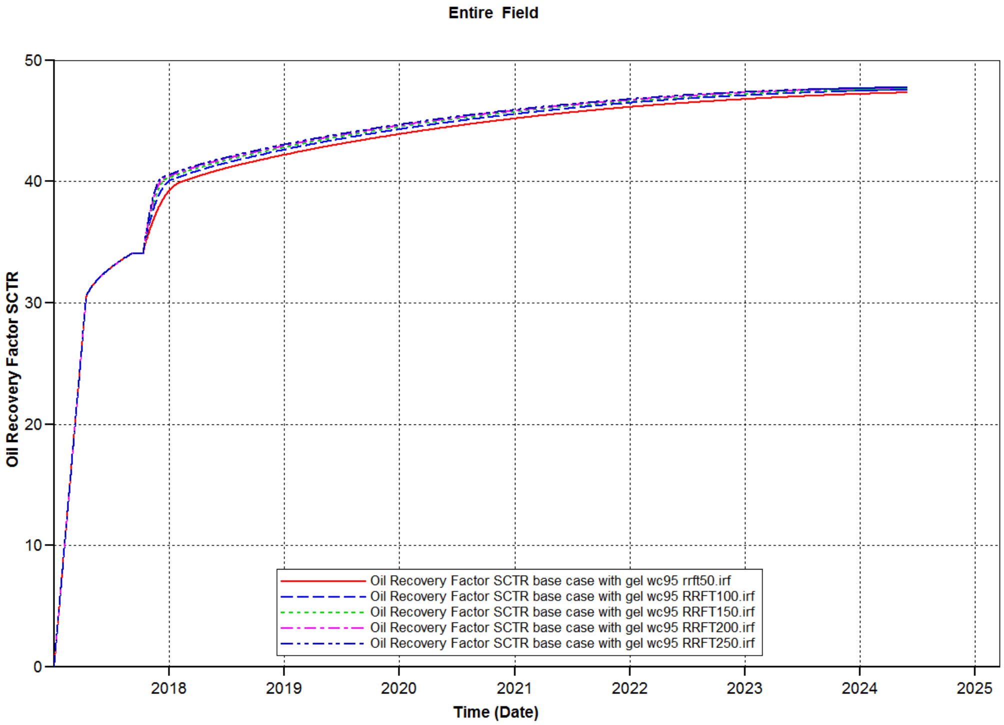


Figure 3.29. Oil recovery factors for cases with accessible resistance factor of 50, 100, 150, 200, and 250

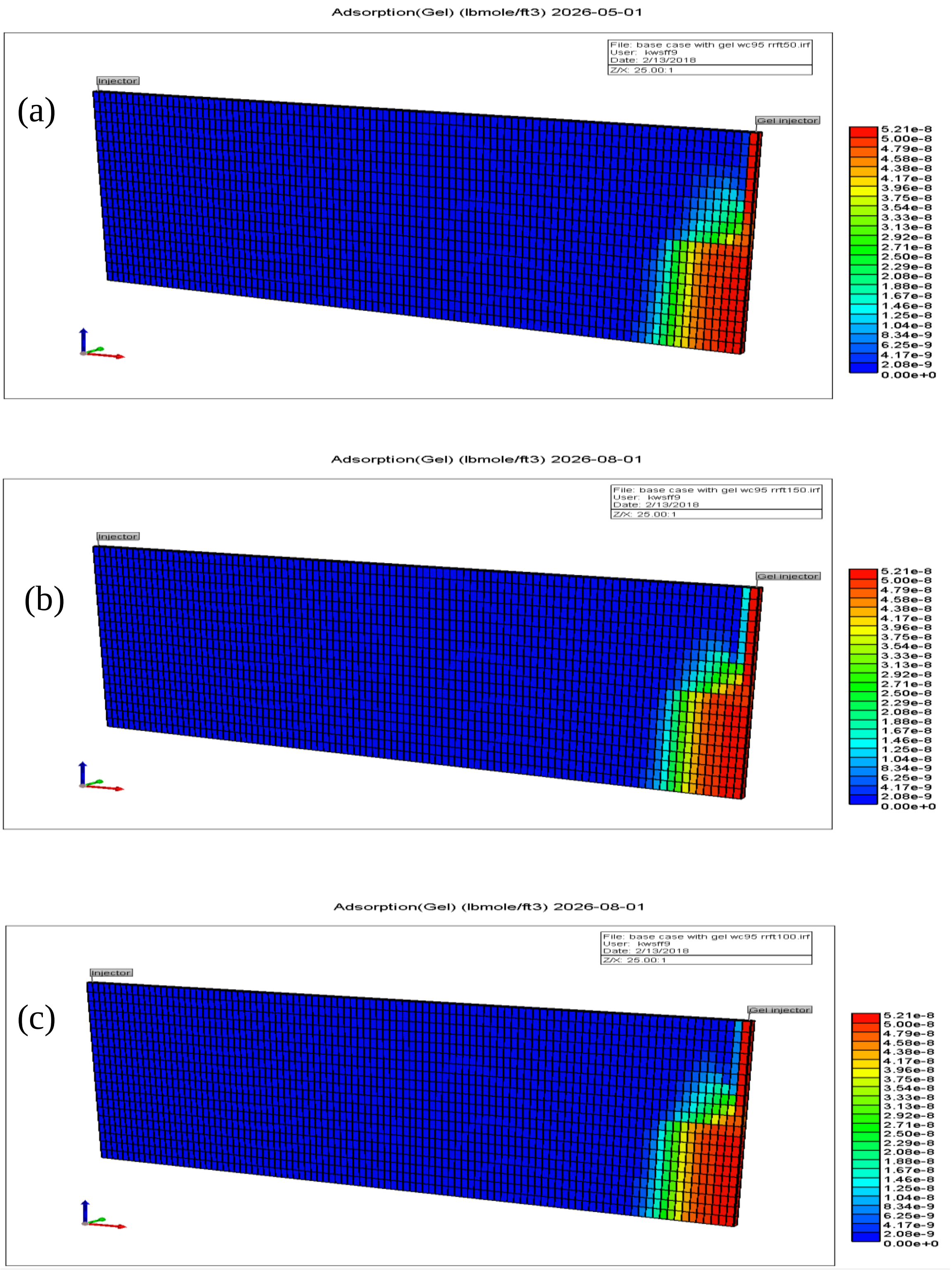


Figure 3.30. (a-e) Gel adsorption profiles for cases with accessible resistance-factors of 50, 100, 150, 200, and 250

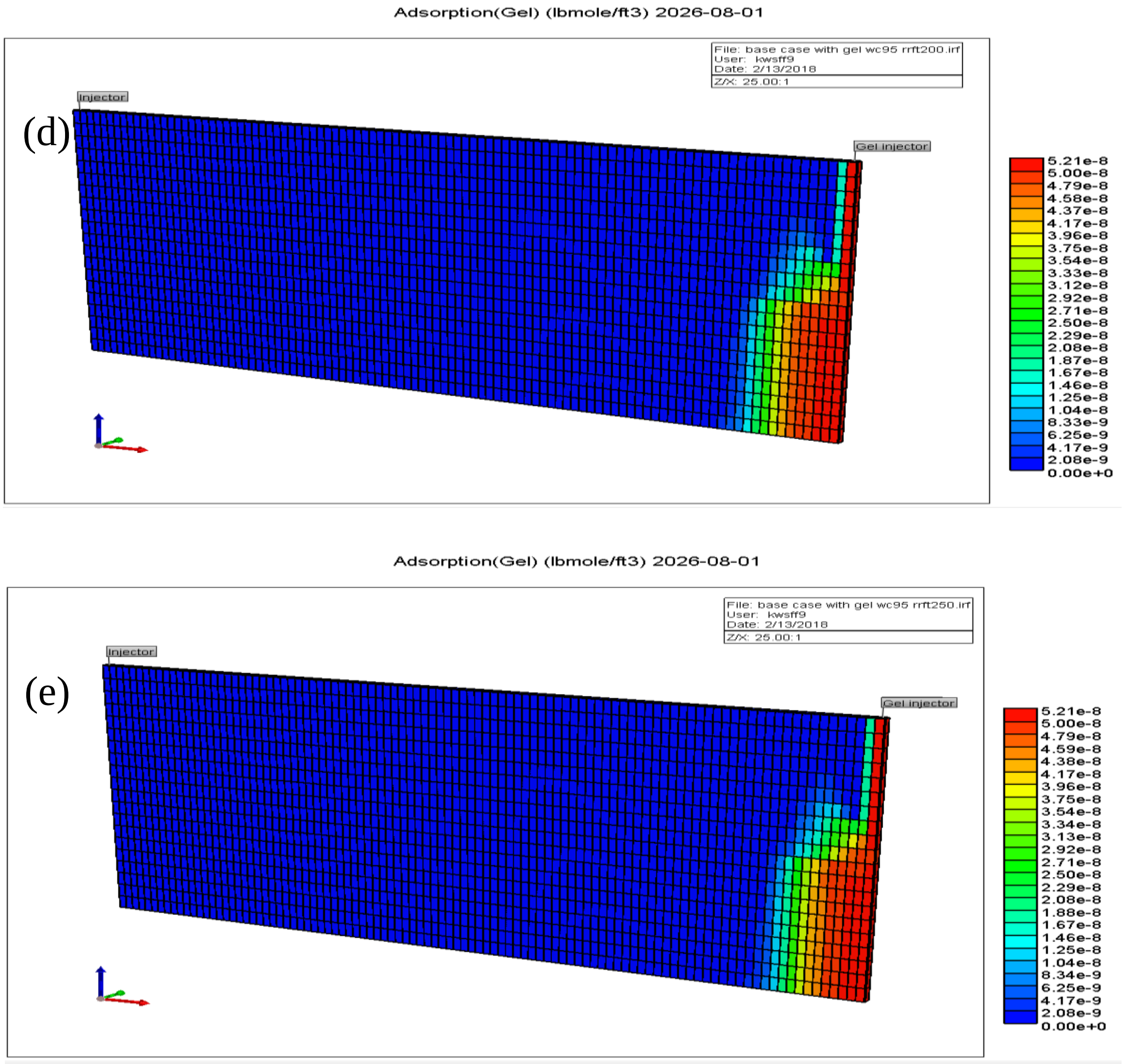


Figure 3.30. (a-e) Gel adsorption profiles for cases with accessible resistance-factors of 50, 100, 150, 200, and 250 (cont.)

4. CONCLUSIONS

To fill up gaps between laboratory experiments and numerical simulations for polymer gel treatment, this study builds the connections between laboratory measurements and simulation inputs for 2 parameters: maximum adsorption level and reaction frequency factor.

To understand physical meanings of key parameters that affect DPR of polymer gel treatment, eight parameters including operation decisions and rock/polymer gel interaction properties are analyzed using sensitivity analysis method.

Conclusions of this study are specific to the simplified model. This study provides the methods of analyzing parameters that influence polymer gel for water shutoff. Reservoir-simulation results on oilfield cases may differ from the conclusions of this study.

Water reduction and oil increment in the effective period is positively affected by early gel injection, gel volume, RFF, ADRT, and RRFT; it is negatively affected by ADMAXT and PORFT.

Average water reduction and average oil increment per day in the effective period is positively affected by early gel injection, gel volume, ADMAXT, RFF, ADRT, and RRFT; it is negatively affected by PORFT.

Water cut is negatively affected by early gel injection, gel volume, and ADMAXT; water cut is positively affected by water-injection rate after treatment, RFF, ADRT, and RRFT.

Oil recovery factor (ORF) is positively affected by early gel injection, gel volume, water-injection rate after treatment, RFF, and ADRT; ORF is negatively affected by ADMAXT, and PORFT.

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