



**NUMERICAL MODELING OF WATER SHUTOFF
UTILIZING NANOSILICA GEL TREATMENT**

BY

MOHAMMED IBRAHIM HASSAN ALABDRABALNABI

A Thesis Presented to the
DEANSHIP OF GRADUATE STUDIES

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS

DHAHRAN, SAUDI ARABIA

In Partial Fulfillment of the
Requirements for the Degree of

MASTER OF SCIENCE

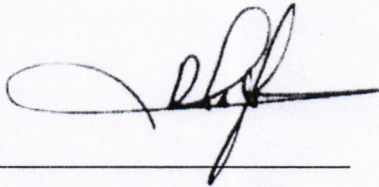
In

PETROLEUM ENGINEERING

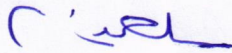
MAY 2024

KING FAHD UNIVERSITY OF PETROLEUM & MINERALS
DHAHRAN- 31261, SAUDI ARABIA
DEANSHIP OF GRADUATE STUDIES

This thesis, written by **MOHAMMED IBRAHIM HASSAN ALABDRABALNABI** under the direction of his thesis advisor and approved by his thesis committee, has been presented and accepted by the Dean of Graduate Studies, in partial fulfillment of the requirements for the degree of **MASTER OF SCIENCE IN PETROLEUM ENGINEERING**.



Dr. Dhafer Abdullah Al Shehri
Department Chairman

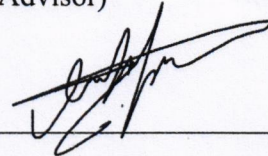


Dr. Suliman Saleh Al-Homidan
Dean of Graduate Studies

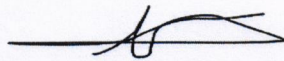
Date



Dr. Murtada Saleh Al-Jawad
(Advisor)



Dr. Mustafa Al-Ramadan
(Member)



Dr. Ayman Mohammed
Almohsin
(Member)



© Mohammed Ibrahim Alabdrabalnabi

2024

|To my beloved parents, wife, son, relatives and friends |

ACKNOWLEDGMENTS

I would like to take this opportunity to express my heartfelt gratitude to everyone who has contributed to this accomplishment. **First and foremost**, I extend my thanks to His Almighty Allah, who has always been my greatest supporter. I am blessed to have been surrounded by wonderful people, all of whom I will acknowledge in the following paragraphs. I am deeply grateful to my esteemed thesis advisor, **Dr. Murtada Al-Jawad**. His unwavering support, invaluable guidance, and continual confidence in my capabilities have been fundamental to the success of this thesis. Dr. Murtada's mentorship and dedication have significantly aided me in overcoming numerous challenges throughout this research journey. I also want to extend my heartfelt thanks to **Dr. Ayman Almohsin**, whose unwavering support and mentorship over the past decade have been invaluable. He has been like an older brother to me, offering guidance and encouragement at every step. His support was pivotal in my decision to pursue my master's degree at KFUPM, and I am profoundly grateful for his role as a member of my thesis committee. Dr. Ayman stood by me during difficult times, offering assistance when I faced struggles, and for that, I am genuinely thankful. His commitment to my growth and success has left a lasting impact on my life and career. My sincere gratitude also goes to **Dr. Mustafa Al-Ramadan**, whose inspiring support and guidance throughout my studies at KFUPM have been invaluable. I appreciate his insightful questions and constructive comments that have enriched my work. I would like to acknowledge the following individuals who have been instrumental in shaping this journey:

My Family: Your unwavering belief in my abilities has been my guiding light. Despite the challenges and setbacks, your encouragement has been invaluable. I also want to honor my father; may Allah bless him and grant him mercy; his love and guidance continue to inspire me daily. **My Wife, Batool:** Thank you for the unwavering patience and unlimited support

throughout my journey at the university. Your remarkable ability to handle all responsibilities at home while I focused on my studies has been invaluable. Your encouragement and understanding have not only motivated me but also made it possible for me to pursue my academic goals. I am truly thankful for your love and dedication, which have been my greatest source of strength.

Hamzah Aboluhom: Special thanks to you for your invaluable support and guidance, which were crucial in developing the numerical model central to my research. Your expertise and encouragement have greatly enhanced my work. I would also like to express my heartfelt appreciation to my friends: **Tariq Almubarak, Ahmad Busaleh, Jawad Al-Darweesh, Ahmed Ali, Mohammed Al-Ameer, Abdullah Al-Adi and Ridha Alabdrabalnabi.** Your tremendous help and guidance during my studies have been invaluable, and your encouragement has been a beacon during this critical phase of my academic journey.

I would like to extend my sincere gratitude to **KFUPM** and the **College of Petroleum Engineering and Geosciences (CPG)** for providing a nurturing academic environment and exceptional resources that have been crucial to my research. The dedication of the faculty and the opportunities afforded to me have contributed significantly to my personal and professional development. Lastly, I extend my heartfelt appreciation to my friends and colleagues at **Saudi Aramco.** Your encouragement, assistance, and camaraderie have made this journey more meaningful. I would like to thank the management at the **EXPEC Advanced Research Center** for their support and for fostering an inspiring environment for my research. I am truly grateful to everyone who has contributed to this endeavor, whether directly or indirectly. Your impact will resonate beyond these pages.

TABLE OF CONTENTS

ACKNOWLEDGMENTS	V
TABLE OF CONTENTS	VII
LIST OF TABLES	X
LIST OF FIGURES	XI
LIST OF ABBREVIATIONS.....	XII
ABSTRACT	XIII
ملخص الرسالة.....	XV
CHAPTER 1 INTRODUCTION	1
1.1 Background	1
1.2 Problem Statement	2
1.3 Research Objectives	3
1.4 Proposed Work	3
CHAPTER 2 A REVIEW OF RECENT DEVELOPMENTS IN NANOMATERIAL AGENTS FOR WATER SHUTOFF IN HYDROCARBON WELLS.....	5
2.1 Abstract.....	5
2.2 Introduction	6
2.3 History of Water Problem:	9
2.3.1 Sources of Water	9
2.3.2 Water Shut-off Methods.....	13
2.4 Utilizing Nanomaterials for Enhancing Gel Treatments:.....	17
2.4.1 Challenges of Gel Treatments:.....	18

2.4.2	The Positive Impact of Nanomaterials on Gel Treatments:.....	25
2.5	Treatment Modelling and Field Cases	39
2.5.1	Gelation Time Modelling	39
2.5.2	Modelling Water Shutoff Performance	41
2.5.3	Limitations of Proposed Models	42
2.5.4	Field Cases in Oil Wells	43
2.6	Research Gap and Future Development.....	47
2.7	Conclusions.....	49
 CHAPTER 3 IN-SITU NANO-BASED FLUID FOR WATER SHUTOFF: A KINETIC STUDY.....		51
3.1	Abstract	51
3.2	Introduction.....	52
3.3	Methodology	55
3.3.1	Materials	55
3.3.2	Experimental Work.....	56
3.3.3	Experimental Design.....	57
3.3.4	Model Development	58
3.4	Results and Discussion	59
3.4.1	Effect of Temperature	59
3.4.2	Effect of Activator.....	62
3.4.3	Gelation Kinetics.....	63
3.4.4	Model Validation	68
3.5	Conclusions.....	70
 CHAPTER 4 AN INTEGRATED 3D MODEL OF WATER SHUTOFF CONSIDERING THE GELATION KINETICS OF NANOSILICA GEL.....		71

4.1	Abstract.....	71
4.2	Introduction	72
4.3	Methodology.....	76
4.3.1	Model Algorithm	77
4.3.2	Mathematical Formulation	78
4.4	Results and Discussion	81
4.4.1	Impacts on Near Wellbore Gel Distribution in 2D.....	82
4.5	Conclusions	90
CHAPTER 5 CONCLUSION, FUTURE WORK, AND RECOMMENDATION		91
5.1	Conclusion.....	91
5.2	Future Work and Recommendation	92
REFERENCES.....		94
VITAE.....		112

LIST OF TABLES

Table 2.1: List of common chemical's structure for water shutoff applications.	16
Table 2.2: Summary of the challenges of in-situ polymer gel, PPG, and silicate gel.....	23
Table 2.3: Successful field applications for gel treatments.	24
Table 2.4: Summary of nanomaterials' impact on gel properties.	37
Table 3.1: Summary of conducted rheological experiments.	57
Table 3.2: Selected nanosilica formulation at 180°F.	64
Table 3.3: Selected nanosilica formulation at varied temperatures.	66
Table 4.1: Input data for the base run.	81

LIST OF FIGURES

Figure 2.1: Flow behind pipe.....	10
Figure 2.2: Tubing Leaks.....	10
Figure 2.3: Rise of water oil contact.....	11
Figure 2.4: Fracture from the injector to producer.....	12
Figure 2.5: Fracture from a water layer.....	12
Figure 2.6: Water coning.....	13
Figure 2.7: Fingering.....	13
Figure 2.8: Chemical water shut-off systems.....	16
Figure 2.9: Review methodology for the impact of nanomaterials on gel treatments.....	18
Figure 2.10: (a) Swelled PAM/Cs PPG, ⁹¹ (b) Distribution of microgel particles. ⁹¹	20
Figure 2.11: ESEM images of enhanced nanosilica gel samples. ¹³²	27
Figure 2.12: Nano Composite PPG. ⁸⁶	33
Figure 2.13: Effect of nano-clay concentration on gel strength. ⁸⁶	34
Figure 3.1: Detection of gelation time by measuring viscosity against time.....	56
Figure 3.2: Temperature effect on gelation behavior and viscosity.....	60
Figure 3.3: Gelation behavior over temperature at different activator loadings.....	61
Figure 3.4: Gelation behavior against varied activator loadings at 200°F.....	63
Figure 3.5: Rate constant (K) against T^{-1} using constant formulation.....	67
Figure 3.6: GT prediction against recorded GT from lab tests.....	69
Figure 3.7: Gelation model validation with lab experiments.....	69
Figure 4.1: Algorithm of the numerical model.....	78
Figure 4.2: Temperature profile at different injection rates.....	83
Figure 4.3: Temperature profile at different shut-in periods.....	84
Figure 4.4: Temperature profile at different treatment volumes.....	85
Figure 4.5: Distribution of gel penetration at different treatment volumes.....	85
Figure 4.6: Radial gel penetration at altered injected fluid temperature.....	86
Figure 4.7: Radial gel penetration at altered activator loadings.....	87
Figure 4.8: Pre-treatment vs post-treatment gel penetration in 3D.....	88
Figure 4.9: Two thief zones vs one thief zone of gel penetration in 3D.....	89
Figure 4.10: Two thief zones vs one thief zone of temperature distribution in 3D.....	89

LIST OF ABBREVIATIONS

2D	:	Two Dimensional in space
3D	:	Three Dimensional in space
ANN	:	Artificial neural network
BC	:	Boundary Condition
BOPD	:	Barrels of oil per day
BWPD	:	Barrels of water per day
CAC	:	Critical association concentration
ESEM	:	Electron scanning electron microscope
FVM	:	Finite Volume Method
GNP	:	Graphene Nano-platelets
GO	:	Graphene oxide
GT	:	Gelation Time
HAHPAM	:	Hydrophobically associated with partially hydrolyzed polyacrylamide
HMTA	:	Hexamethylenetetramine
HPAM	:	Hydrolyzed polyacrylamide
HPHT	:	High-Pressure High-Temperature
HQ	:	Hydroquinone
IC	:	Initial Condition
ICD	:	Inflow control device
LCST	:	Lower critical solution
OWC	:	Oil-water contact
PAM	:	Polyacrylamide
PCGEL	:	personal computer gel simulator
PDE	:	Partial Differential Equation
PLT	:	Production logging tool
PPG	:	Preformed Sized Particle Gels
RPM	:	Relative permeability modifiers
RRF	:	residual resistance factor
SAP	:	Superabsorbent polymers
SEM	:	Scanning electron microscope
UCST	:	Upper critical solution temperature
WOR	:	Water-oil ratio

ABSTRACT

Full Name : [Mohammed Ibrahim Hassan Alabdrabalnabi]
Thesis Title : [Numerical Modeling Of Water Shutoff Utilizing Nanosilica Gel Treatment]
Major Field : [Petroleum Engineering]
Date of Degree : [May 2024]

Water production is a significant hurdle in the oil and gas industry that can severely influence the environment and production economics. Hydrocarbon reservoirs produce water for several reasons, such as the original connate water in the reservoir, induced fractures, and water breakthrough from neighboring formations. Excess water production can cause issues, including declined oil recovery, higher well abandonment rates, and higher operating expenses for handling and environmental impacts.

Chemical and mechanical techniques can be used to minimize the consequences of water production. Chemical approaches can limit water production, including water control chemicals such as polymers and surfactants. Inflow control devices, packers, and gravel packs are examples of downhole instruments used mechanically to regulate water production. Chemical methods such as water shutoff gels can overcome some of the limitations of mechanical techniques. For example, the gels are injected into the formation and then react to form a barrier that blocks water flow from the water zone while allowing hydrocarbons to flow. Despite complex geology and high permeability, water shutoff gels are effective in many reservoirs.

This research proposes a numerical modeling tool as an interphase to predict gel penetration and coverage around the wellbore. For instance, such a tool could optimize water shutoff chemicals' treatment volume and injection rate. The study will capture extensive laboratory experiments at different chemical concentrations and temperatures using Chandler 5550 viscometer to generate a reaction kinetics model of a nano-based fluid system, namely “Nanosilica,” to predict the gelation time accurately. The model will be created using a numerical simulation in three dimensions incorporating fluid flow, heat transfer, and gelation reaction. To the best of my knowledge, there is no model like this in the literature, and it will be one of the first for water shutoff utilizing Nanosilica technology.

ملخص الرسالة

الاسم الكامل: محمد إبراهيم العبدرب النبي

عنوان الرسالة: النمذجة العددية لإغلاق المياه باستخدام تقنية معالجة جل النانوسيليكات

التخصص: هندسة البترول

تاريخ الدرجة العلمية: مايو 2024

يمثل إنتاج المياه عتبة كبيرة في صناعة النفط والغاز يمكن أن تؤثر بشدة على البيئة واقتصاديات الإنتاج. تنتج المكامن الهيدروكربونية المياه لعدة أسباب، مثل المياه المتصلة الأصلية في المكامن، والكسور المفتعلة، واختراق المياه من التكوينات المجاورة. يمكن أن يتسبب الإنتاج الزائد للمياه في حدوث مشاكل، بما في ذلك انخفاض إنتاج النفط، وارتفاع معدلات التخلي عن الآبار، وارتفاع نفقات التشغيل للمناولة والتأثيرات البيئية. يمكن استخدام التقنيات الكيميائية والميكانيكية للحد من عواقب إنتاج المياه. يمكن أن تحد الأساليب الكيميائية من إنتاج المياه، بما في ذلك المواد الكيميائية للتحكم في المياه مثل البوليمرات والمواد الخافضة للتوتر السطحي. تعد أجهزة التحكم في التدفق، وأجهزة التعبئة وحزم الحصى أمثلة على أدوات قاع البئر المستخدمة ميكانيكياً لتنظيم إنتاج المياه. يمكن أن تتغلب الطرق الكيميائية مثل المواد الهلامية المانعة لتسرب المياه على بعض قيود التقنيات الميكانيكية. على سبيل المثال، يتم حقن المواد الهلامية في التكوين ثم تتفاعل لتشكيل حاجزاً يمنع تدفق المياه من منطقة المياه مع السماح للهيدروكربونات بالتدفق. وعلى الرغم من الجيولوجيا المعقدة والنفاذية العالية، فإن المواد الهلامية المانعة لتدفق المياه فعالة في العديد من المكامن. يقترح هذا البحث أداة نمذجة عددية كأداة بينية للتنبؤ بتغلغل الهلام وتغطيتها حول حفرة البئر. على سبيل المثال، يمكن لمثل هذه الأداة تحسين حجم معالجة المواد الكيميائية لإغلاق المياه ومعدل الحقن. تشمل الدراسة تجارب معملية واسعة النطاق بتركيزات كيميائية ودرجات حرارة مختلفة باستخدام مقياس اللزوجة لتوليد نموذج حركية التفاعل لنظام سائل قائم على النانو "النانوسيليكات النانوية" للتنبؤ بزمن التغلغل بدقة. سيتم إنشاء النموذج باستخدام محاكاة عددية ثلاثية الأبعاد تتضمن تدفق المائع، ونقل الحرارة، وتفاعل الجل الكيميائي. بناء على أبحاثنا، لا يوجد نموذج كهذا في الأدبيات قد تم نشره، وسيكون هذا النموذج الأول من نوعه لإغلاق المياه باستخدام تقنية النانوسيليكات النانوية.

CHAPTER 1

INTRODUCTION

1.1 Background

Controlling excessive water production from oil and gas wells is one of the main goals of the petroleum industry. It should deserve great attention as it could minimize the total reserves recovery across the globe. For instance, it causes liquid loading, sand production, fines migration, scale formation, and tubular corrosion. Additionally, the natural drive mechanism to produce oil is no longer sufficient due to the massive water production that prematurely depletes the reservoir and eventually results in well abandonment ^{1,2}.

The two leading causes of increased water production are water leaks and excessive fluid flow. There are several causes of excessive fluid flow in reservoirs, the most common of which is viscous fingering and undesirable heterogeneous permeability. Water leakage can occur because of pipe leaks, channeling behind the casing, or conning within the matrix. In addition, if water is introduced to the oil reservoir as it matures, the water cut can approach 98% of the extracted volume ³⁻⁵.

Oil operators commonly utilize water to oil ratio (WOR) to address and quantify the water production to oil production, as shown in **Equation 1.1**:

$$WOR = \frac{Q_w}{Q_o} \tag{1.1}$$

Q_w and Q_o are the flow rates of water and oil, respectively ^{5,6}. Based on the research of Bailey *et al.* ⁷ on a global scale, they claimed that for one barrel of oil, three barrels of water are produced in parallel. Based on the recent analysis from Grand View Research Group ⁸, the cost of water treatment was around 6 billion USD in 2015. Subsequently, this research group estimated the price to hit almost 10 billion USD by 2024. Additionally, the treatment market size has increased gradually due to strict environmental regulations ⁵.

1.2 Problem Statement

Sustainable development and the provision of clean water for human consumption require effective management of water resources. It is common to use water shutoff treatments in the oil and gas industry to prevent unwanted water production from wells that can damage the environment and reduce production efficiency. Optimizing the effectiveness and reducing the cost of water shutoff treatments requires accurate modeling. However, the choice between analytical and numerical modeling methods can significantly affect the model's accuracy, applicability, and simplicity.

Numerical simulation offers several advantages over analytical modeling for water shutoff treatments. First, numerical simulation can be used to accurately describe the complex physical processes involved in water shutoff treatments. Due to the heterogeneity of reservoirs, fluid properties, and fluid-rock interactions, numerical simulations can account for them. Second, numerical simulation can be applied to various conditions, including complex geometries, non-linear behavior, and multiphase flow. This makes numerical simulation a more versatile tool for modeling water shutoff treatments. Third, numerical

simulation can be relatively simple to implement, especially with the availability of modern software tools and computing power.

1.3 Research Objectives

The research objective of this master thesis is to develop a 3D numerical simulation model utilizing MATLAB® software to design and optimize a water shutoff treatment and predict the penetration of the fluid into the formation and gelation time. This will be achieved by:

Develop an accurate reaction kinetic model from rheological experiments at different fluid compositions and reservoir temperatures to predict gelation time.

Create a mathematical formulation that includes reaction kinetics, continuum flow on two scales, and thermal energy transfer.

Generate a numerical 3D simulation model utilizing MATLAB software from the mathematical formulation developed in (1).

Ensure that the numerical model is efficient in terms of computation.

1.4 Proposed Work

The following work shall be carried out to reach the objective mentioned above:

Analyze the data generated from the massive lab experiments and exclude outliers.

Conduct the required rheological tests if the data is insufficient to build a reliable gelation model.

Generate an accurate gelation kinetics model using regression tools from EXCEL or machine learning algorithms from MATLAB if required.

Work on the mathematical formulations and integrate the reaction kinetics, 3D fluid flow, and 3D temperature models into MATLAB software.

Evaluate the model's performance and accuracy.

CHAPTER 2

A Review of Recent Developments in Nanomaterial Agents for Water Shutoff in Hydrocarbon Wells

2.1 Abstract

Reducing water production from hydrocarbon wells is one of the major requirements to prolong the life span of the production wells. Gel treatment is commonly regarded as one of the traditional cost-effective methods for water shut-off applications. Different gel systems have been developed to overcome the challenges of performing a successful water shut-off treatment. Each gel system has its advantages and disadvantages. A new proposed technology is to enhance the gel performance by utilizing nanomaterials in its composition. Nanomaterials such as nano-silica, nano-clay, and graphene can significantly modify gel properties to improve plugging efficiency. This paper provides a brief review of the added value of using nanomaterials in the structure of polymer in-situ gel, preformed particle gel, and nano-silica-based fluid. Nanomaterials such as nano-clay, nano-silica, and nanographene can adjust the properties of in-situ gel, such as control of gelation time (9-10) hours and enhancing gel strength up to 4.5 times. Nanomaterials also improved the swelling ratio of preformed particle gel by up to 400%, accompanied by increased gel strength. Notably, nano-silica-based gels exhibit an exceptional plugging efficiency

(100%). Additionally, the paper discusses how modeling can be used to overcome operational challenges in terms of placement and plugging performance.

¹This chapter is copied from the manuscript: Ali, A.; Alabdrabalnabi, M.; Al Ramadan, M.; Aljawad, M.; Almohsin, A.; Azad, M. A Review of Recent Developments in Nanomaterial Agents for Water Shutoff in Hydrocarbon Wells. *ACS omega* **2024**.

2.2 Introduction

During oil production under an external drive fluid, the driving fluid is targeted to push the oil ahead to the production interval. Conformance measures the flood front efficiency of the driving fluid to push the oil toward the production interval.^{6,9,10} However, the heterogeneity of reservoirs may assist the driving fluid (i.e., water) to move faster than oil, which results in leaving large amounts of oil unswept and leading to co-production of the driving fluid (water or gas).^{6,11} This is called a reservoir conformance problem,^{6,12,13} and it can occur in production or injection wells.¹⁴ Applying any technique to improve the movement of unwept oil is called conformance control.^{9,11,15,16} Water shut-off is classified under conformance control mechanisms by eliminating excessive water production using different strategies, which enhances the oil recovery and extends the production life cycle of the well.¹⁷⁻¹⁹

Undesired water production has received great attention from the petroleum industry to overcome the challenges associated with the produced water and thus improve the economic life of the wells.²⁰ The reservoir rock generally contains connate water and hydrocarbons. In addition to that, some reservoirs are surrounded by vast aquifers. In such

cases, water can flow from different sources into the wellbore and be produced along with hydrocarbons. Immediate treatment is required when the water production rate exceeds the economic level of the water-oil ratio (WOR).²⁰ Problems arise when the water production rate starts to compete with oil production, which means no or little oil is produced.²¹ Some studies reported a large volume of water produced with oil. In 2000, According to Bailey⁷ et al., each barrel of oil was associated with three barrels of water worldwide, and this amounted to approximately 75 billion barrels of water with a disposal cost of \$40 billion. Another study by Veil²² stated that total water production in the USA nearly reached 24.4 billion barrels in 2017. Therefore, water shut-off technologies are introduced to reduce water production, improve recovery efficiency, ensure effective reservoir management, and, in some cases, comply with environmental regulations.⁹ Additionally, the water control technologies enhance profitability for the operator by lowering the lifting cost, extending the productive well life, reducing the well maintenance cost, and minimizing water disposal cost.^{17,20}

The critical parameter in planning a successful water shut-off treatment is conducting an accurate diagnosis of the root cause of water and then applying a suitable treatment for the problem.^{7,10,23-30} Investigation into several ineffective treatments has led to the conclusion that operators often do not perform an appropriate diagnosis in the beginning due to some reasons, such as insufficient time, invested capital, and inadequate knowledge about the range of effectiveness for each method.^{17,31} Diagnosing the water production challenge should include information about the production wells and the field data. Data such as heterogeneity of reservoir, production drive mechanism, production data, and well geometry can help find the water entry point.³² The diagnosis is conducted using

production logging tools, pressure transient analysis, well log analysis, nodal analysis, relative permeability ratio, and production data analysis.³²⁻³⁷

Gel treatments are considered one of the oldest methods to treat water production.^{10,38,39} They have shown their capability to plug the thief zones such as fractures, high permeability layers, etc.^{17,23} However, they face certain challenges that need to be addressed in terms of gelation control, gel stability, and thermal stability.^{40,41} The newly developed improvement is by utilizing nanomaterials such as silica, clay, and graphene in the composition of the gel. These materials have shown the capability to improve material performance for different uses. Over the last few years, there has been a noticeable increase in the usage of nanomaterials in the oil and gas industry.⁴² Nanomaterials are materials manufactured at nanoscale size, their size range from 1 to 100 nanometers. This size allows the material to exhibit unique properties distinct from the Bulk material. It was found that nanomaterials have a huge capability to improve material performance for different applications, such as enhancing oil recovery, formation evaluation, and reservoir imaging.⁴²⁻⁴⁵ Many gel systems suffered from overcoming many challenges during water shut-off treatments, such as gel instability under reservoir conditions, gelation time control, and gel propagation in the reservoir. Therefore, materials such as nano-silica and nano-clay were introduced as a part of gel composition, and an incremental improvement in gel properties was found.

This study aims to discuss the recently developed gel systems that include only nanoparticles of silica, clay, zirconium oxide, or graphene in their composition. The study shows the added value of these materials in the performance of polymer gels and silicate gels in overcoming operational challenges during water shut-off treatments. Besides, the

study demonstrates the capability of gel modeling treatment to enhance water shut-off treatments.

2.3 History of Water Problem:

2.3.1 Sources of Water

Two types of water are produced with oil. Good water is produced naturally as part of the fractional flow process and does not compete with oil production at economically viable rates, so it is left untreated during production to avoid any negative impact on oil production¹⁰ In contrast, Bad water also known as insufficient water hinders oil production. Immediate treatment is necessary for bad water to reduce its negative impact and increase oil production.^{7,10} Many sources have been identified to cause excessive water production. Generally, these can be classified into reservoir-related sources and wellbore-related sources. Below is a list of the most common ones:

2.3.1.a Wellbore-related sources

Flow behind the pipe can occur when there is a channel between the water-bearing layer and the wellbore. The connection could be due to the partially or nonexistent primary cement in the interval between the water layer and production interval, or due to a bad cement job (cement failure). Another reason is the continuous microannulus between the cement and formation or the cement and the casing as illustrated in **Figure 2.1**.^{6,7,14,46}

Casing /Packer/Tubing leak can occur due to corrosion in the casing, tubing, or uninsulated seal of the packer as appeared (see **Figure 2.2**).^{6,24}

Migration of oil-water contact (OWC) can cause undesired water production because of water coning once the OWC starts rising and reaching the perforation of the target zone, as shown in **Figure 2.3**. This can predominantly occur if the perforations are placed close to the OWC, and the reservoir vertical permeability is high.

Barrier breakdowns can occur when fracture breaks through the impermeable layer or when acids are used to dissolve the rocks. This can result in the formation of a new fracture near the wellbore, which will eventually enable the water to migrate to the wellbore due to the pressure difference across the permeable layer.⁴⁷

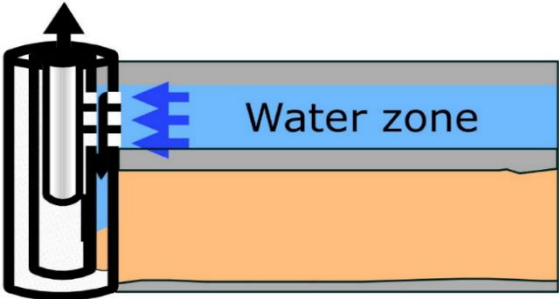


Figure 2.1: Flow behind pipe.

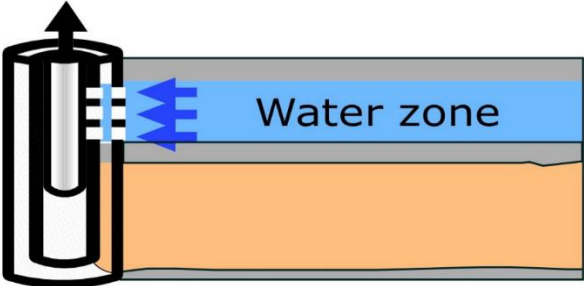


Figure 2.2: Tubing Leaks.

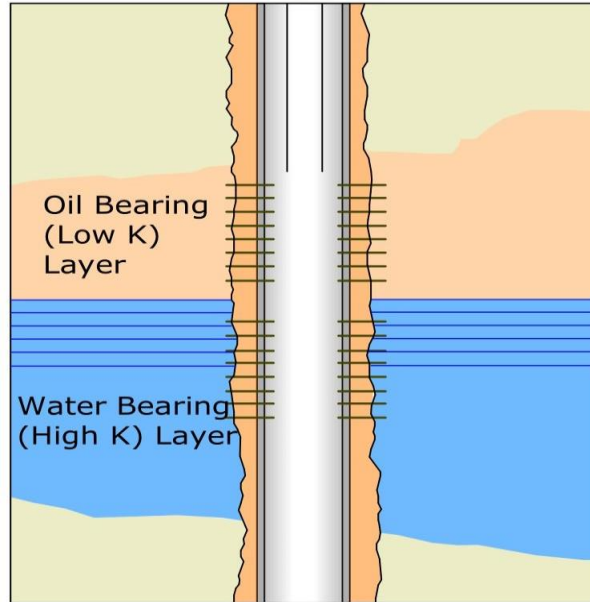


Figure 2.3: Rise of water oil contact.

2.3.1.b Reservoir-related sources

Fracture between the injector and producer can allow water from the injection well to flow into the production well as illustrated in **Figure 2.4**. This is a common problem in waterflooded reservoirs, which leads to unwanted water production in a very short time through the fractures.⁷

Fissure/Fracture from a water layer can provide a path for water flow from the underlying water zone, also hydraulic fracturing can cause this problem (see **Figure 2.5**).¹⁴

Water coning can occur when the water rises up from the bottom of the reservoir and reaches the wellbore. **Figure 2.6** illustrates this phenomenon. This is more likely to happen in wells with high water saturation and low permeability.²⁴

Watered-out layer with and without crossflow can occur when a water-saturated layer is sandwiched between two high permeability layers. Also, water can flow from the

watered-out layer to the production well through the high permeability layers. the water source can be from either an active bottom water or injection well.^{6,7}

Channels through a high permeability zone can allow water to flow more easily through the reservoir, resulting in higher water production rates. This is a common problem in reservoirs with high permeability streaks. This widely happens in reservoirs with either an active water drive or a water-flooding-treated reservoir.⁴⁸

Fingering can occur when water flows along high permeability channels in the reservoir. It is a condition whereby the interface of the oil-water layer creates a fingering profile (see **Figure 2.7**). The water bypasses horizontally a section of the reservoir as it moves. This phenomenon is common in a reservoir with a water injection well and viscous oil. It also can happen in a reservoir with a bottom water drive or gas cap expansion.^{6,20}

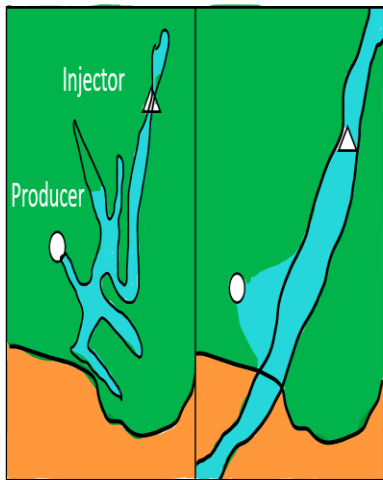


Figure 2.4: Fracture from the injector to producer.

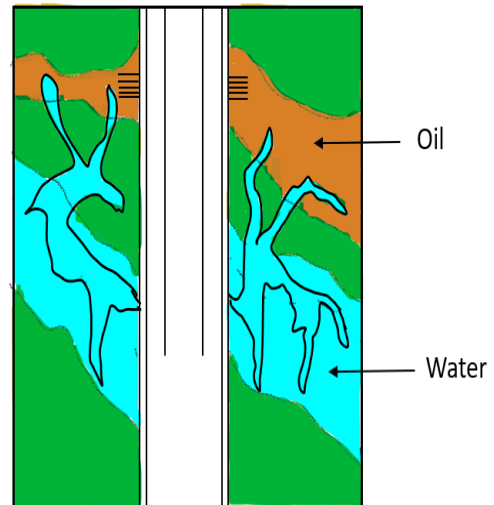


Figure 2.5: Fracture from a water layer.

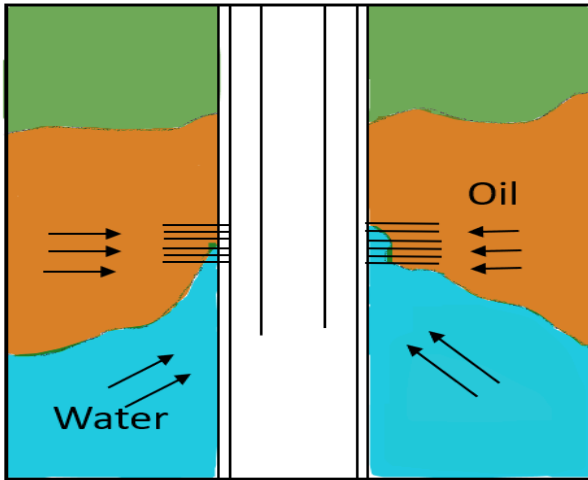


Figure 2.6: Water coning.

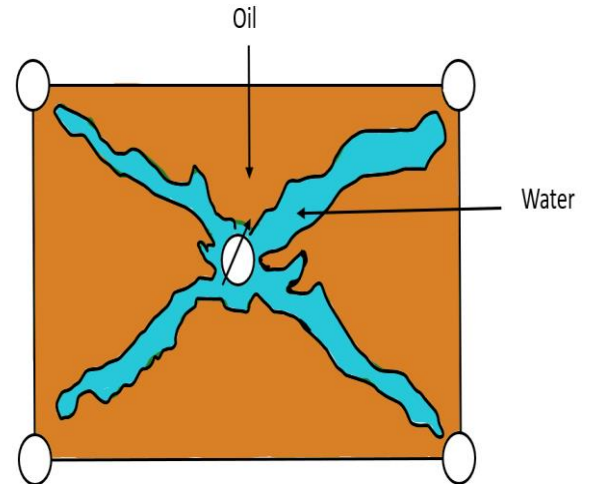


Figure 2.7: Fingering.

2.3.2 Water Shut-off Methods

In general, applying a certain method depends on the type of water problem in the reservoir (wellbore-related sources or reservoir-related sources).⁴⁹ Each method is effective in shut-off only specific water paths, and they could be classified into two types:

2.3.2.a Mechanical Methods

They involve placing a tool of high mechanical strength or cement into the wellbore to shut off the unwanted water source. The mechanical tools involve retrievable and straddle packers,⁴⁹⁻⁵² plugs,⁵³ tubing patches,⁵⁴ and squeeze cementing.⁵⁵⁻⁵⁸ They are preferred for treating near wellbore problems such as channels behind casing or casing and tubing leaks. The advantage of the mechanical methods is that the effect will appear in a short time and is relatively inexpensive compared to other solutions.^{59,60} However, they are not feasible for treating reservoir-related sources such as fractures or high permeability zones.²³

Additionally, incorrect placement of the plugging tool can lead to the loss of the producing oil zone.⁶¹

2.3.2.b Chemical Methods

They involve injecting chemicals, such as gel, into the reservoir section or layer that provides an easy path for water to flow. This is implemented to plug the water-bearing zones and fractures, which can help to reduce water and increase oil production. The propagation of the chemical fluid reduces the water permeability in the targeted zones, and this forces the water to take other paths pushing the oil ahead to the production interval. These methods can also increase the water viscosity which improves the reservoir conformance and sweep efficiency. Their advantage over the mechanical solutions is the ability to treat both near-wellbore and reservoir-related sources. The results could last for months and up to years depending on reservoir characteristics. However, a disadvantage is that the efficiency of the chemical solution is highly affected by reservoir properties and its compatibility with the reservoir temperature and water salinity.^{17,62,63} The study focuses on discussing the chemical techniques that utilize the gels as blocking agents and how nanomaterials such as nano-silica can assist in overcoming some operational challenges during treatment. **Figure 2.8** and **Table 2.1** illustrate the most common chemical systems used for the last century, summarized below:

- **Inorganic gels**⁶⁴: They were discovered in early 1920s for blocking lost circulation zones and zone squeezing. Sodium silicate is the most common type. They have a very low viscosity and can easily be injected into deep reservoirs. They can provide an acceptable plugging efficiency with high thermal stability. Another type,

aluminum, was developed to combat undesired water production in high temperature and low permeability reservoirs.⁶⁵⁻⁶⁷

- **Monomer systems:** **Monomer**-based systems such as acrylamide, can be placed deep in the reservoir matrix. They have low viscosity, and after placement, they polymerize to form a gel with varying strength depending on the monomer type.
- **Polymer gels**⁶⁸: They are composed of polymer and crosslinking agent. Once they are placed into the target zone, they form a rigid 3D gel structure that blocks the water phase. Common types include Polyacrylamide (PAM) and hydrolyzed polyacrylamide (HPAM). Crosslinking agents could be metallic, such as aluminum and chrome, or organic, such as phenol. Additionally, biopolymers such as xanthan can also be crosslinked to form a 3D gel.^{69,70}
- **Ungelled polymers**^{71,72}: It was found that some polymer types can reduce water permeability by a degree higher than oil permeability, which is called relative permeability modifiers (RPM). Polyacrylamide is one of these polymers that have this characteristic.
- **Resins**⁷³: These are thermosetting materials injected with a catalyst (acid or base) that start to react at bottomhole temperature to provide sufficient strength to seal fractures and channels. Phenol and epoxy are among the most common ones.
- **Viscous flooding (polymers)**⁷⁴: In some situations, water production can be caused by an unfavorable mobility ratio, resulting in a poor sweep of viscous oil. Polymer flooding can enhance the mobility ratio and improve sweep efficiency by

increasing the water viscosity during water flooding. HPAM and xanthan polymer are common for this job.

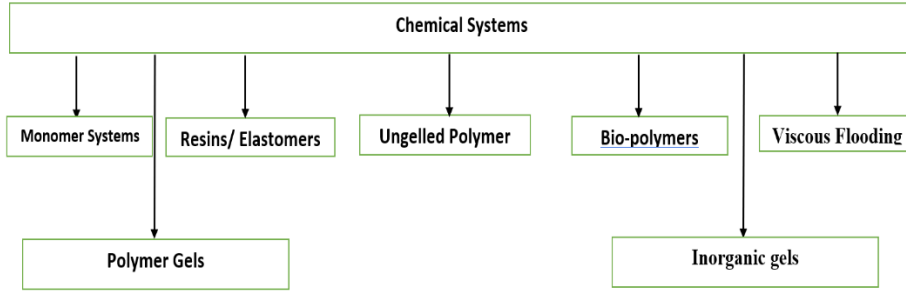


Figure 2.8: Chemical water shut-off systems.

Table 2.1: List of common chemical's structure for water shutoff applications.

Chemical System	Name	Chemical Structure
Inorganic Gels	Sodium Silicate	$\begin{array}{c} \text{O} \\ \\ \text{Na}^+ \text{Si} \text{Na}^+ \\ / \quad \backslash \\ \text{O}^- \quad \text{O}^- \end{array}$
Monomer Systems	Acrylamide	$\text{CH}_2=\text{CH}-\text{C}(=\text{O})\text{NH}_2$
Polymers	Polyacrylamide	$\left[\begin{array}{c} \text{CH}_2 - \text{CH} \\ \\ \text{C} = \text{O} \\ \\ \text{NH}_2 \end{array} \right]_n$
	HPAM	$\left[\begin{array}{c} \text{CH}_2 - \text{CH} \\ \\ \text{C} = \text{O} \\ \\ \text{NH}_2 \end{array} \right]_n \left[\begin{array}{c} \text{CH}_2 - \text{CH} \\ \\ \text{C} = \text{O} \\ \\ \text{O}^- \end{array} \right]_m$

	Xanthan Gum	
Resins	Phenol-formaldehyde	

2.4 Utilizing Nanomaterials for Enhancing Gel Treatments:

The analysis process for this review starts with the initial demonstration of the actual challenges confronting three distinct gel types: in-situ polymer gel, preformed particle gel, and silicate gel. **Figure 2.9** illustrates the systematic approach taken to assess the impact of nanomaterials on gel treatment. The influence of nanomaterials is divided into three distinct categories, each corresponding to a particular gel type. Enhancements in gels properties have been observed, primarily in terms of thermal stability, gelation time, gel strength, and swelling performance. These improvements can be attributed to the application of four key types of nanomaterials, silica, clay, graphene, and zirconium oxide.

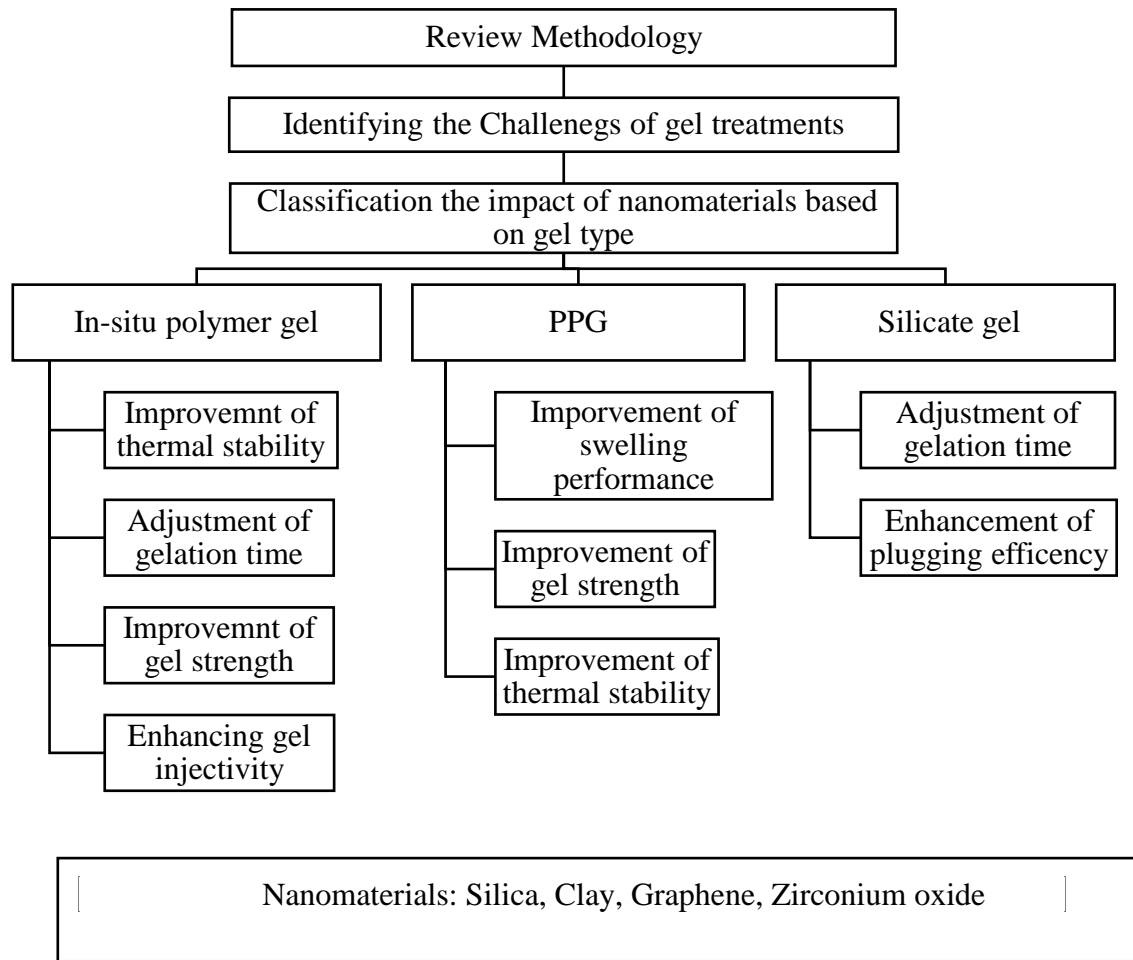


Figure 2.9: Review methodology for the impact of nanomaterials on gel treatments.

2.4.1 Challenges of Gel Treatments:

Gel treatments are one of the most common chemical water shut-off methods. They are effective and economical ways to reduce water production in mature reservoirs.⁷⁵ Polymer Gel can control water mobility by either reducing the permeability or plugging the high permeability zones and fractures.⁷⁶ This property improves the sweep efficiency and increases oil production correspondingly. Based on where the gelation takes place, subsurface or at the surface, the gel can be classified into the following:

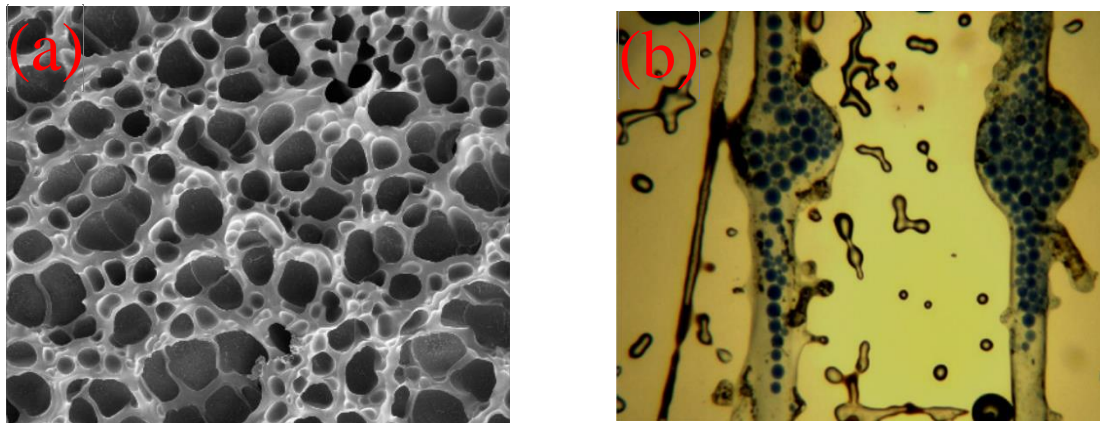
2.4.1.a In-situ Gel

It is a type of gel that forms a downhole in the reservoir.^{77,78} For conventional polymer gel, a mixture of polymer solution, crosslinker, and additives are injected downhole into the target zone. After the expected time and under a certain temperature, the mixture reacts to form a gel that plugs the zone partially or fully.⁷⁷ Despite their popularity, many disadvantages were addressed such as a lack of gelation time control leading to an unpredictable depth of penetration,^{79,80} dilution by formation water,⁸⁰⁻⁸² uncertainty of gelling due to shear in surface facilities and the reservoir,^{41,83,84} and potential damage of low permeability un-swept oil zone.⁸⁵

2.4.1.b Preformed Gel:

Preformed gels (PPG) are a type of gel that is formed at the surface and then injected into the reservoir as particles. It is a new type of well-conformance technology that was first introduced by the Institute of Petroleum Exploration and Development (RIPED), PetroChina in 1996.⁷⁷ They are made from superabsorbent polymers (SAPs), which are three-dimensional hydrophilic crosslinked polymers that swell but do not dissolve due to their inner physical and chemical nature.⁸⁶ PPGs are micro to millimeters in size and are used to plug fractures or channels of high permeability zones of a few decimeters.⁸⁷ Their plugging efficiency depends highly on particle strength and conduit inner diameter.⁸⁸ Another advantage is the performance of plugging is less affected by operation and reservoir conditions such as shear rates, salinity, pH, and temperature.¹¹ However, the application of these gels is limited to high permeable formation (not less than 500 md) and fractures due to particle size constraints.¹¹ Preformed gel types include partially preformed gels^{89,90}, preformed particle gels of millimeter to micro size (PPG),^{38,91,92} microgels,⁹³⁻⁹⁵

pH-sensitive crosslinked polymers,⁹⁶⁻⁹⁹ and Bright Water®.^{100,101} The main differences include the swelling capabilities, particle size, and the preferred reservoir conditions to be used.¹¹ In addition to that, different types of mechanisms were used to combat water production such as partial plugging,^{77,102} relative permeability modification, large pores plugging, mobilizing capillary-trapped oil and monolayer or multilayer adsorption.^{77,94,103} **Figure 2.10** displays SEM images of swelling and aggregation of PPG and microgel in the porous media which will be reflecting on the achieved plugging efficiency. It distinctly demonstrates the contrasting plugging mechanisms between preformed particle gel and microgel when compared to in-situ gel. In preformed gel applications, plugging predominantly occurs due to swelling and aggregation of preformed gel within the pore structure. In contrast, in the case of in-situ gel, the transformation of the gelant solution from a liquid to a solid state within the pore system serves as the primary cause for shutting the water flow.



[Figure 2.10: (a) Swelled PAM/Cs PPG,⁹¹ (b) Distribution of microgel particles.⁹¹]

2.4.1.c Silicate gel

silicate-based gel is one of the oldest methods to tackle reservoir conformance problems.^{6,104} Their mechanism to mitigate water or gas production is similar to other gelling materials such as polymers or phenolic resins. It has the form of brittle gel, formed by the reaction between the silicate solution and an activator.¹⁰⁵ In the old days, HCl was used as an activator, but due to its hazardousness, different types of materials such as NaCl were successfully proved as gelation activators^{106,107}. The gelation happens as the result of chemical bonding between the particles which aggregate to form a semi-solid 3D network of long bead-like strings.¹⁰⁸ In addition, the gelation time of silicate gels is highly affected by temperature and activator concentrations.¹⁰⁸ Sodium silicate is considered the most well-known silica solution.¹⁰⁷ There are many advantages to applying silicate gels for water-shut-off applications. They are environmentally friendly, and the solution viscosity is similar to water, which provides good injectivity.¹⁰⁹ They also provide good thermal stability at elevated temperatures.^{110,111} The cost of applying silicate gels is relatively low, compared to other gel systems.^{110,112–114}

However, they have some drawbacks that have reduced their usage in recent years. The gel strength of silicate gel is less compared to polymer gels. The silicate gel has less gel strength when compared to polymer gels.⁶ Another disadvantage is the gelation time, as it was found that the increase in gelation time could affect the gel strength negatively.⁶

The focus of the study is only on these three gel systems, In situ Polymer gel, preformed particle gel, and silicate gel. These gels have operational common challenges in terms of gel placement and performance. **Table 2.2** summarizes the common challenges that the face operator in the oil field. The challenges facing the three gel systems are diverse. In

situ polymer gel contends with environmental sensitivity, complicated control of gelation time, and the potential for oil zone damage. Preformed gels confront a fundamental limitation, being generally unsuitable for low-permeability formations, necessitating alternative solutions in those cases. Silicate gels challenge precise control due to their rapid gelation and may struggle to maintain optimal gel strength over an extended duration, while their sensitivity to divalent ions can hinder effectiveness. Based on this observation, there is a clear need to improve the performance of the gel by making modifications to its composition. In recent times, three common nanomaterials, namely nano-silica, nano-clay, and nanographene, have been introduced into the gel composition to enhance its properties.

Table 2.2: Summary of the challenges of in-situ polymer gel, PPG, and silicate gel.

Gel system	Mechanism	Challenges	Examples
In situ Polymer gel	Gellant is placed into the target zone and over a certain period, it will be transformed into a solid gel.	<ul style="list-style-type: none"> - Gelation is affected by environmental conditions. - Control of gelation time is difficult. - Possible damage to the oil zone. 	Crosslinked PAM gels ¹¹
PPG	The gel is initially generated at the surface before being injected into the reservoir.	<ul style="list-style-type: none"> - It cannot propagate formation with permeability less than 1 D. - Limited application for the reservoir of an extreme permeability. 	PPG (China) ⁸⁷
Silicate gel	The gel is formed into the formation by the reaction of silicate solution with an activator under a certain temperature.	<ul style="list-style-type: none"> - Rapid gelation time. - The gel strength is low for an extended period. - Sensitive to the formation's minerals (divalent ions). 	Sodium silicate gel ¹⁰⁷

The key to a successful water shut-off treatment lies in accurately diagnosing the root cause of water intrusion and applying suitable remedies.^{7,10,23–30.} Understanding the reservoir's recovery mechanism and tracing the source of the produced water are crucial. Tracers and logging services help identify these sources. Once identified, specific solutions can be applied. **Table 2.3** illustrates some of the previous successful filed applications for gel treatments. In-situ polymer gels and silicate gels are commonly used for near-wellbore issues like casing and tubing leaks, as well as sealing high-permeability zones. Preformed particles are preferred in China for their effectiveness in treating fractures over in-situ gels.

Table 2.3: Successful field applications for gel treatments.

Applied chemical system	Cause of Water Problem	Reference
In-situ polymer gel	Casing leaks	10,115
	Tubing leaks	46,115
	High permeable thief zones	116
	2D coning	117,118
	Natural fracture system connected to water zones	119,120
Preformed particle gel	Super permeability channels	121
	Low permeability fractured reservoirs	122
	Communication between the injection and the production wells	77
	High permeable layers	77

Silicate gel	Casing leaks	123
	High Permeable layers	124
	Fault reservoir with extremely high permeability	125,126

2.4.2 The Positive Impact of Nanomaterials on Gel Treatments:

This study will focus on gel properties improvements by utilizing nanomaterials for in-situ gels and preformed gels to combat excessive water production as illustrated below:

2.4.2.a The impact on in-situ polymer gels

Polymer gels are commonly used as a cost-effective technique for reservoir conformance problems.¹²⁷ Due to their nature, polymer gels provide many advantages such as good injectivity, deep penetration in the reservoir, increasing the viscosity of water, and changing the fluid's permeability for different zones. However, several challenges exist in implementing proper gel treatment techniques, such as aggregation to high polymer concentration above critical association concentration (CAC), instability or degradation at high temperature in the reservoir, and insufficient gelation time to place a gel in the target zone. Utilizing nanomaterials has shown an improvement in gel properties as follows:

2.4.2.b Enhancement of thermal stability

Temperature is one of the most important factors that affect the conversion of polymer solution into a solid gel that seals the target zone. In the design of polymer gel, two critical temperatures are significant for gel placement, the lower critical solution temperature

(LCST) and the upper critical solution temperature (UCST). The range between them identifies the transition zone from flowing solution to a solid gel.¹²⁸ Another important factor is the degradation temperature at which the polymer degrades and becomes flexible, affecting negatively sealing performance¹²⁹. Therefore, researchers have been working to illustrate the valuable impact of adding nanoparticle materials to strengthen polymer stability at elevated temperatures and extend the transition zone. Some of these nanoparticles include the following:

Zirconium hydroxide: Zirconium hydroxide ($Zr(OH)_4$) of nanoparticles size that has been investigated to improve the thermal stability of gels. They are highly applicable as a crosslinker agent due to several hydroxyl groups existing in their composition.¹³⁰ These hydroxyl groups can react with the polymer chains in the gel, forming strong bonds that help to prevent the gel from degrading at high temperatures. The usage of nanoparticles of zirconium hydroxide has improved the thermal stability of PAM crosslinked with hydroquinone (HQ) and hexamethylenetetramine (HMTA).¹³¹ The thermal stability increased by 3 or 5 °C and reached up to 187 °C compared to the gel without nanoparticles. The new interaction between the hydroxyl group and amide group led to a stronger gel with limited gel mobility that required more energy to break the gel structure.

Nano-silica & Nano-clay: Nano-silica (SiO_2) and nano-clay have shown their capabilities to improve the thermal stability of gels. Nano-silica has a high specific surface area and can absorb heat, which helps to prevent the gel from degrading at high temperatures. Nano-clay has a high thermal conductivity, which helps to transfer heat away from the gel, which also helps to prevent the gel from degrading. Lie¹³² et al. observed that adding nanoparticles

of silica improves the strength of polyacrylamide crosslinked with HQ and HMTA. **Figure 2.11** illustrates two gel structures for the gel, with and without nano-silica particles. The ESEM images clearly demonstrate the massive aggregations and arrangements of silica nanoparticles that existed in uniformly distributed three-dimensional network structures of the gel. These are new arrangements assist in creating stronger structure, reflected in the higher gel strength for gels incorporating nano-silica particles.

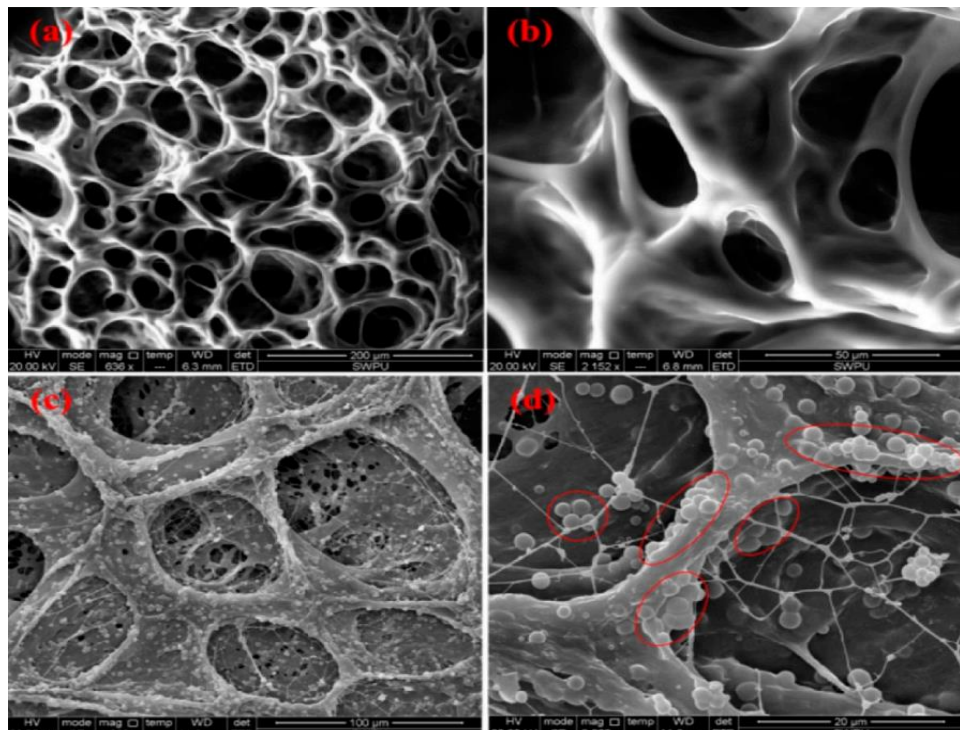


Figure 2.11: ESEM images of enhanced nanosilica gel samples.^{132]}

Asadizadeh¹³³ et al. obtained the same results when analyzing the effect of SiO₂ on the a gel composed of hydrolyzed polyacrylamide crosslinked with chromium (III) acetate. The gel showed significant flexibility, elongating to 1150% at remarkably high temperatures. Furthermore, the recorded inflection temperature for a gel with nano-silica was higher than the one without nano-silica particles.

Despite these advantages, the usage of nanoparticles silica is limited to its compatibility with the polymer type. Nano-clay also has been addressed by some researchers. It has improved the performance of gel at high temperatures in many studies. In a study performed by Cheraghian¹³⁴ et al., adding nano-clay to PAM hydrogel increased the oil recovery by 5.8% at elevated temperatures (80 °C).

The use of nano-silica and nano-clay to improve the thermal stability of gels is a promising new technology for combating water production in oil reservoirs. This technology can help to extend the life of gels and improve their performance at high temperatures.

Nano-Graphene: Graphene is a carbon-based material that can be used at the nanoscale. It has very acceptable mechanical and thermal properties that improve the performance of nanocomposite gel. An experimental study was conducted by Shen¹³⁵ et al. to investigate the effect of Graphene Oxide on polyacrylamide hydrogels. The results showed an increase in the thermal stability of the nanocomposite gel due to a denser structure caused by the increased cross-linking density.

Adjustment of gelation time:

The gelation time is the time it takes for a gel to form. It is important to be able to control the gelation time so that the gel can be injected into the reservoir and gel at the right location. Nanoparticles can be used to adjust the gelation time of gels. Nanoparticles can aggregate and connect to the polymer chains, forming a 3D network that is stronger with adjustable gelation time.

In the same study performed by Lie¹³² et al., nanoparticles of silica have improved the gelation time of polyacrylamide crosslinked with hydroquinone and hexamethylenetetramine. Another study was conducted by Singh¹³⁶ et al. by utilizing nano fly ash with PAM polymer crosslinked with chromium acetate. The results of the study showed an increase in the gel strength with a reduction in gelation time (9-10) hours. In addition, the low activation energy supported rapid gel formation.

Improvement of gel strength

The gel strength is the ability of a gel to withstand shear forces. It is important for gels to have high gel strength so that they can withstand the shear forces in the reservoir and be effective at plugging water production zones. Nanoparticles can be used to improve the strength of gels. Nanoparticles can form a network that strengthens the gel and makes it more resistant to shear forces.

Nano-silica: Lie et al¹³² investigated the effect of nano-silica on PAM hydrogel. The results showed that the increase in the concentration of silica nanoparticles led to an increase in gel strength and storage modulus of nanocomposite gel. Chen¹³⁷ et al. also added nano-silica to PAM/PEI hydrogel to investigate the impact on gel syneresis, plugging efficiency, and stability at elevated temperatures. It was found that a high decrease in the degree of syneresis caused further improvement in gel strength. The classification of the gel strength code has changed from class F (highly deformable non-flowing gel) to class I (rigid gel). In addition to that, the results of sand pack experiments illustrate a high residual resistance factor which reflects the high plugging efficiency.

Nano-Graphene: Graphene was observed to add an improvement in the strength of the gel, Shen et al.¹³⁸ investigated the effect of graphene oxide (GO) nanoparticles on PAM

hydrogel. The increase in crosslinking density led to a denser structure with a higher modulus when compared to the original gel without nanoparticles. Similar results were observed by Lie¹³⁸ et al., the nanocomposite GO-PAM had tensile strength higher by 4.5 times and more than 300% elongation.

In another study, Almohsin¹³⁹ et al. introduced a nanocomposite PAM by including graphene-based zirconium oxide, a superb mechanical strength was observed at elevated temperatures. The structure of the gel was homogenous and stable, and it shows the capability to trap the water even at elevated temperatures.

Enhancing gel injectivity

The evaluation of gel injectivity stands as a pivotal criterion for the effective deployment of gels in field applications, necessitating rigorous assessment prior to field trials. In a study conducted by Almohsin¹³⁹ et al., the injectivity of a developed polyacrylamide (PAM) gel incorporating graphene and zirconium oxide nanoparticles, was examined through core flooding experiments. Six pore volumes of the gelant were injected at a temperature of 320 °F. Throughout the injection process, a minimal increase in pressure was observed, stabilizing at 28 psi, indicative of the favorable injectivity characteristics exhibited by the nano-based gel formulation.

Pereira¹⁴⁰ et al. explored the effectiveness of HPAM gel integrated with nanoparticles for water shut-off purposes. They assessed injectivity by measuring gelant viscosity at varying shear rates. The viscosity of gelant, with and without clay nanoparticles, ranged from 18.0 to 19.1 mPa·s at a shear rate of 300 s⁻¹. At lower shear rates, viscosity values were between 67.5 and 76.9 mPa·s. These findings suggest that the addition of nanoparticles minimally affects gel injectivity. Ali¹⁴¹ et al. also investigated gel injectivity using sulphonated PAM

gel incorporating Fe₂O₃ and NiO nanoparticles. Their study revealed that the gel with nanoparticles experienced a minimal pressure drop during the initial 2 pore volumes compared to the gel without nanoparticles. However, as the injection progressed, the nano-based gel exhibited a higher pressure drop. This phenomenon can be attributed to the aggregation and adsorption of nanoparticles within the core samples. Consequently, the study suggests using nanoparticles of a size that matches the expected treated pore size to optimize gel injectivity.

Impact on preformed particle gel

Preformed particle gels are composed of dried crosslinked polymers in the form of adjustable particle sizes.⁸⁷ The injection process of these gels is simpler than the in-situ gels as the aqueous solution is composed of one component. When PPGs come in contact with water, they absorb it and expand to a few hundred times their original size.⁷⁷ The swelling ratio depends mainly on its composition along with the surrounding environmental conditions such as salinity, pH, and temperature⁷⁷. As they are prepared on the surface, this helps prevent some drawbacks of in-situ gels such as lack of gelation time control, dilution by formation water, and gelation variation caused by shear degradation.⁷⁷ The new proposed technology is to enhance particle gels performance by incorporating some nanomaterials into their composition, below is the list of some types:

Improvement of swelling performance and thermal stability:

Nano-silica and Nano-clay: Khoshkar¹⁴² et al. reported the advantages of using nanomaterials in preformed particle gel composition and their positive effects on serving water shut-off objectives for the fractured reservoir. In their study, a small amount of nano-clay and nano-silica were added to 9 PPG samples of different compositions (which are

called N-PPG). To investigate the effectiveness and performance of N-PPG, static bulk tests, dynamic good tests, and micromodel model tests were performed to examine various parameters such as swelling capacity, pH value, temperature, and particle size.

Their results showed that the existence of nanomaterials improved the maximum swelling ratio and lesser syneresis rates compared to PPG without nanomaterials added. In a comparison of N-PPG and PPG made without nanomaterials, the swelling capacity of N-PPG was not affected by a pH value in the range of 3 – 10, which opens a potential usage of N-PPG for a wide range of pH values. They recommended that for any specific reservoir, the optimum particle size and the injection rate should be identified to obtain effective water shut-off treatment.¹⁴²

Graphene Nanoplates: Paprouski¹⁴³ et al. conducted laboratory experiments to investigate the effect of new additives on the swelling performance and thermal stability of preformed particle gel. The additive is composed of sodium silicate solution and Graphene Nano-platelets (GNP). Compared to the base synthesized PPG, it provides an acceptable swelling performance as well as higher thermal stability and dehydration resistance. The results showed that the samples that had a combination of silicate sodium and Nano graphene had a higher storage modulus compared to the base samples without nano-graphene. Over the wide range of frequencies, the values of G' were greater than G'' , which illustrates the elasticity of the composed gel. In addition to this point, it was found that the addition of nano-graphene along with the presence of silicate sodium has shown small sensitivity to temperature and time.

Improvement in gel strength and thermal stability:

Nano-clay: a study by Tongwa and Bai⁸⁶ proposed a new Preformed Particle Gel using a nanomaterial in the main composition, called nanocomposite hydrogel. The proposed gel is composed of [monomer](#), initiator, crosslinker, additives, and nano-clay called laponite XLG (L-XLG) which does not exist in the conventional hydrogel (see **Figure 2.12**).

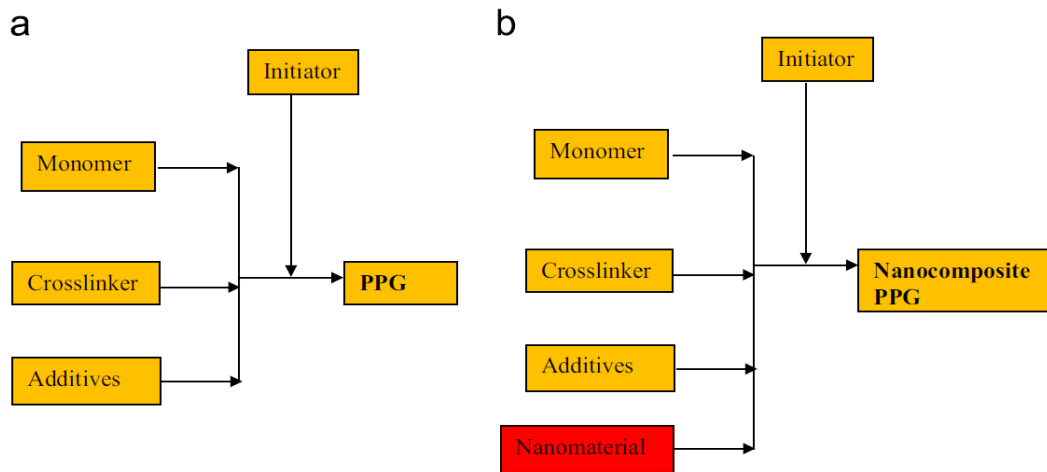


Figure 2.12: Nano Composite PPG.⁸⁶

Viscoelastic properties, such as elastic moduli, were used to evaluate the mechanical performance of nanocomposite preformed particle gel. A significant increase in elastic modulus was noticed along with an increase in the concentration of nanomaterials, leading to further improvement in gel strength properties as illustrated in **Figure 2.13** which shows the changes in elastic modulus with increase in concentration of LXLG concentration. The lowest value for the elastic modulus was for the gel without nanomaterials (800 Pa), and it greatly increased with the addition of nanomaterials.

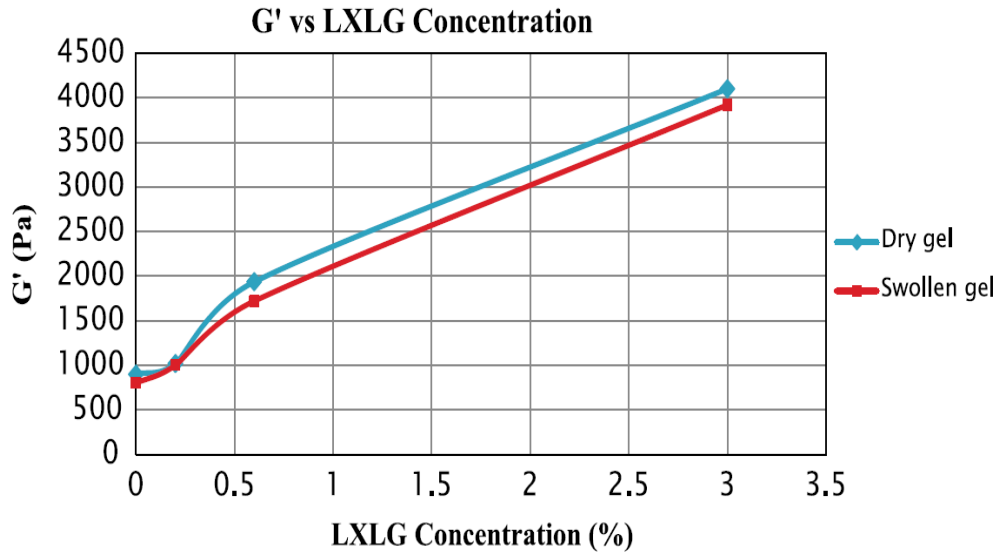


Figure 2.13: Effect of nano-clay concentration on gel strength.⁸⁶

The swelling performance was also evaluated in formation water and 1% brine solution. The results showed an obvious increase in the swelling kinetics of gel with nanomaterials information water, the swelling ratio was 180%, and in 1% brine solution (NaCl), it exceeded 400%.

For thermal stability, a significant increase in thermal stability for a long period was obtained for a gel with nanomaterial (up to years). This improvement supports the idea of adding nanomaterial to gel composition to serve water shutoff objectives for an extended period. However, it was noticed that after degradation, there was a substantial increase in viscosity. The viscosity of nanocomposite gel was 4,437 cp, which is much higher than the viscosity of gel with no nanomaterial (170 cp). This suggests that nanocomposite gel can be used first to plug the thief zones and then after degradation, form a high viscous polymer solution that boosts water and polymer flooding.⁸⁶

Pandit et al.¹⁴⁴ conducted a study to assess a newly formulated PPG reinforced with bentonite nano-clay and nano-silica. The system demonstrated exceptional thermal stability over a two-year period at 120 °C. Moreover, the research examined the plugging efficiency of the gel, revealing a high rate of 97.6% for a 1 wt.% reinforced preformed particle gel. These results suggest promising opportunities for utilizing the developed material in water shut-off applications.

Silicate Gel:

Recently, Nano-silica based fluids were introduced to the industry as an alternative to sodium silicate gels. Many studies investigated temperature limitation, activator concentration, and plugging efficiency. The real challenges for applying the silicate gel is the rapid gelation time along with maintaining a good plugging efficiency over an extended period. Through utilizing nano-silica solution, a better performance was observed and can be illustrated as below:

Adjustment of Gelation Time

Boul¹⁴⁵ et al. conducted experiments using different sizes and shapes of nano-silica to examine their effect on gelation time under a temperature range from 50 to 150 °F. Three tests were conducted on six nano-silica samples with different initial activity and shapes; the tests included the inversion test which measures the approximate gelation time of the different samples, Small-Amplitude Oscillatory Shear (SAOS), and Turbiscan™ tests that both confirm the gelation time precisely. The results led to the conclusion that nano-silica of non-spherical shapes could provide superior gelation time at temperatures as low as 50 °F, and also the samples with high aspect ratio built stable gels in a shorter period than the spherical ones.

Almohsin¹⁴⁶ et al. performed lab experiments to examine certain chemical properties that assist in evaluating the performance of nano-silica based systems for water shut-off applications. In their study, the authors examined the effect of temperature on gelation time as well as how to adjust it by modifying the concentration of the activator. The results of experiments showed that the increase in temperature greatly accelerates the gelation time, as the gelation time is required to be sufficient for successful gel placements. In addition to this point, increasing activator concentration led to a shorter gelation time under a wide range of temperatures from 50 to 200 °F.

Karadkar¹⁴⁷ et al. also performed lab experiments on using nano-silica based fluid for water shut-off applications. To examine the rheology behavior, they conducted experiments on rheology tests with different concentrations of activator at 200 °F. Using the viscosity buildup against time, it was found that gelation time was less sensitive to a higher concentration of 24% and 25% and was susceptible at a lower concentration from 21% to 23%. It was possible to optimize the gelation time from 125 to 490 mins.

Enhancing the Plugging Efficiency

Karadkar¹⁴⁷ et al. conducted core flooding experiments to assess the injectivity and stability of the gel after placement (endurance test), the results were convenient as there was only a 10 psi increase for injection of five pore volume, this indicates the gel has a convenient injectivity. After placement, both N₂ and brine could not flow through the core plug (confirming excellent plugging efficiency).

In a study conducted by Almohsin¹⁴⁶ et al. to evaluate the injectivity and endurance of the nano-silica solution, core flooding experiments were conducted on Brea-Sandstone outcrop

cores, four pore volumes were injected with a small increase in differential pressure, and by the continuous increase in the differential pressure until 4,000 psi a small leak off was recorded 0.0018 cm³/min. Microscope and SEM were used to examine the sliced pieces of the cores to determine the depth of invasion of the fluid, and they both confirmed that nano-silica-based fluid was capable of invading all the samples.

Based on these experimental studies on different types of gel, it is obvious that nanomaterials such as nano-silica, nano-clay, and graphene can enhance gel performance for water shut-off treatments. In addition to that, **Table 2.4** summarizes the impact of nanomaterials on improving the performance of these gels in terms of gel strength, gelation time, and thermal stability.

Table 2.4: Summary of nanomaterials' impact on gel properties.

Nanomaterial	Gel Type	Gel System	Impact	Reference
Silica		PAM crosslinked with HQ and HMTA	Increasing the maximum temperature of the stable gel from 137.8°C to 155.5°C by adding 0.3% nano-silica.	132
	In situ Polymer gel	HPAM crosslinked with chromium (III) acetate	Elevating the stable gel's maximum temperature from 140.8 to 157.9 by incorporating 2000 ppm of SiO ₂ nanoparticle.	133
	PPG	Acrylamide, AMPSNa (2-Acrylamido-2-methyl-1-propane sulfonic acid sodium salt monomer) with linking agent polyethylene glycol diacrylate	Enhancing the swelling ratio with lesser syneresis. The gel becomes more temperature-durable.	142

		Nano-silica based fluid	Accelerating gelation time at low temperatures as 50° F. 145
	Silicate Gel	Nano-silica solution with activator	Adjust the gelation time at a wide range of temperatures between 50 °F and 200 °F. 146
			Achieving 100% plugging efficiency with acceptable injectivity.
		Achieving 100% plugging efficiency for both water and nitrogen. 147	
Clay	PPG	Acrylamide crosslinked polyethylene glycol diacrylate	Increasing Young's modulus of the gel enhances the gel strength. 86
			Increasing the long-term thermal stability of the gel for up to 12 months.
Graphene		PAM crosslinked by N,N-methylenebisacrylamide (BIS)	Increasing the thermal stability of the hydrogel by building a strong interaction between graphene sheets. 135
			Enhancing the gel strength by increasing the cross linking density.
	In situ polymer gel	PAM cross-linked with N,N'-methylenebisacrylamide	Increasing the gel tensile strength by 4.5 times more than 300% elongation. 138
		PAM crosslinked with Metal Oxide/Two dimensional Nanosheets ZrO ₂ /RGO	Providing a superb mechanical strength was observed at elevated temperatures. 139
	PPG	PPG	Increasing the gel strength with superior rheological properties. 143

Fly ash	In situ Polymer gel	PAM crosslinked with Chromium (III) acetate	Enhancing the gel strength with a higher thermal stability.
Zirconium hydroxide	In situ Polymer gel	PAM crosslinked with hydroquinone and hexamethylenetetramine	Improving the thermal stability of the gel to temperature up 187 °C.

2.5 Treatment Modelling and Field Cases

2.5.1 Gelation Time Modelling

Gelation time (GT) is one of the essential parameters for designing successful water shutoff treatments. Most mathematical models for polymer gels fundamentally include one dependent variable, “GT,” and three independent variables, temperature, polymer concentration, and crosslinker concentration.^{148,149} To study the gelation kinetics of water shutoff in-situ gels, steady shear rate measurements have been widely used.^{1,150–152}

The Arrhenius equation¹⁵³ (Equation 2.1) represents the effect of absolute temperature on reaction rate. It details the mechanism of a chemical reaction, and it applies to most of the chemical reactions. Hurd and Letteron¹⁵⁴ developed an empirical model (see Equation 2.2) correlating the gelation time of silicic acid gels with temperature close to the Arrhenius equation. They validated this correlation using experimental data with some assumptions. Below are the beliefs they followed to develop the model¹⁴⁸:

- The gelation reaction is classified as an ordinary chemical reaction with the n^{th} -order rate law.

- The experimental data matches the Arrhenius equation.
- The reacted silica at the gelation point remains the same at all reaction temperatures.

$$\ln k = \ln A - \frac{E_a}{R} \frac{1}{T} \quad (2.1)$$

$$\ln t = \ln c - \ln k - (n - 1) \ln a \quad (2.2)$$

Where a is the fractional conversion, c is simply a constant depending on the value of a , n is the reaction order, t is the gelation time, and k is the rate constant.

The developed model by Hurd and Letteron¹⁵⁴ was verified by Jordan et al. Jordan¹⁵⁵ et al. using PAM/Cr(III) gel system to examine the effect of temperature on GT. They proved that many chemical reactions can be analyzed using the Arrhenius equation.

From the Arrhenius-type equation, Broseta¹⁵⁶ et al. similarly validated the relationship between GT and temperature. His research focused on the PAM/Cr (III) acetate system. He investigated that the GT is a function of multiple parameters: temperature, polymer and crosslinker concentrations, brine salinity, and degree of hydrolysis. Additionally, he verified that temperature has the highest impact on GT compared to other parameters, and it followed the Arrhenius equation. Marfo¹⁵⁷ et al. studied a water shutoff gel consisting of an acrylamide-acrylate copolymer crosslinked with a polyamine crosslinker. Using statical analysis software, he developed a predictive GT model (Equation 3) for temperature, crosslinker concentration, and water salinity.

$$GT = 38.4333 - \frac{13}{75}T + \frac{19}{30}S - \frac{67}{30}C + \frac{1}{100}TC - \frac{1}{300}TS \quad (2.3)$$

Equation (2.3) was very efficient ($R^2 \sim 98\%$) where GT is in hours, T in °F, S is the salinity of mixed water (%) and C is the crosslinker concentration (wt.%).

2.5.2 Modelling Water Shutoff Performance

Xianchao¹⁵⁸ et al. predicted the water shutoff performance in horizontal wells utilizing the gel flow physics during and after gel treatment by modifying the personal computer gel (PCGEL) simulator that involves black oil and in situ gel models. The degradation process of the gel was considered using viscosity and the time-varying residual resistance factor (RRF) models. They also integrated the non-Newtonian fluid behavior within pressure drop calculations along the wellbore. After that, the coupled model was solved numerically. Finally, the coupled model presented outstanding and reliable prediction results utilizing an actual horizontal water shutoff treatment field scenario.

Alghazal and Ertekin¹⁵⁹ proposed an artificial neural network (ANN) as a machine learning module for deep polymer gel conformance treatments in fractured reservoirs. This module was benchmarked with commercial simulators as it minimizes the complexity of a simulation module. The developed ANN module outperformed commercial simulators with higher processing speed and less computational complexity. In addition, the module utilizes reference simulation modules to construct the dataset for the ANN module. Additionally, the module involves the chemical reaction of Polyacrylamide-based polymer with a Chromium Acetate crosslinker. The physical properties of the polymer and produced gel were generated from experimental data. The ANN module included various parameters based on reservoir properties and conformance design factors. After injecting the gel

treatment, the predicated model has two indicators that rely on oil and water rate profile enhancement.

Meshalkin¹⁶⁰ et al. presented a three-dimensional computer model that simulates the process of water shutoff performance within high water cut oil zones. The model considers the geophysical characteristics of the bottomhole formation zone, as well as the rate and amount of water control solutions that are injected in it. The model's effectiveness was validated by comparing the calculated values of water cut and oil production rate with actual well performance data after water shutoff treatment. This confirms that the model is sufficiently accurate and can be applied to increase energy and resource efficiency in oil production.

The study by Ferreira¹⁶¹ et al. focused on the creation, training, and validation of a neural network model that can predict the performance of wells following gel treatment injection. This model is designed to rank wells that are candidates for water shutoff treatments based on potential production results, thereby enhancing the design of future treatments, and optimizing the use of economic resources. The researchers explored various configurations of the neural network, including adjustments to the number of layers, neurons, and transfer functions, to enhance the model's accuracy.

2.5.3 Limitations of Proposed Models

The existing coupled numerical models in the literature for water shutoff using gel treatments emphasize on simulating conventional black oil or compositional multi-phase flow and account for the water treatment process by basically modifying the production index or permeability around the wellbore. For instance, these models do not fully integrate

a dynamic model between the wellbore and the reservoir. They lack a wellbore model that can handle the non-Newtonian flow behavior of gels, coupled with a gel-blocking prediction model in the reservoir that simulates gel propagation and blocking. The current state-of-the-art in coupled modelling does not fully address or integrate these two key aspects. The existing coupled models simplify the gel blocking effects and do not capture the complete dynamic interactions involved.^{158,162,163}

Despite the availability of numerical simulation tools for designing water shutoff treatments, there exists a gap between prediction accuracy and field performance due to inadequate consideration of fluid composition and reservoir properties during the design and optimization stage. Consequently, this can significantly impact the efficiency of the treatment and, eventually, the project's economic viability.

2.5.4 Field Cases in Oil Wells

Water production in oil and gas wells is a common challenge faced by the petroleum industry. Water breakthrough can reduce the productivity of the well, increase the risk of formation damage, and lead to environmental problems. To mitigate the adverse effects of water breakthrough, various water shutoff treatments have been developed and implemented. This section analyzes field cases focusing on the utilization of polymer gels (preformed gels, foamed gels, in-situ crosslinked gels), resins, and Nano-silica. The treatments are compared based on their advantages and disadvantages, considering the reservoir temperature for each case.

Polymer Gels

In-situ crosslinked gels offer the advantage of being pumped as a low-viscosity fluid and then subsequently crosslinked in the reservoir to form a gel. In-situ crosslinked gels have been successful in high-temperature reservoirs of more than 150 °C, but they may face challenges related to gel degradation and incomplete gelation.^{18,46,164}

A modified organically crosslinked polymer gel was successfully field tested in an oil producer located in the Meleiha concession in Egypt's Western Desert. The well initially produced 1900 BOPD with a 30% water cut, but production declined over time and the well was shut in due to low productivity. The well was produced from two intervals in a sandstone reservoir. The upper interval was depleted to 777 psi, while the lower interval maintained 3300 psi due to a strong aquifer. The polymer gel was selected to treat the upper depleted interval using coiled tubing to achieve a treatment penetration radius of 3 ft by having eight hours of gelation time. This zone had a temperature of 200°F. After pumping the treatment, the well was shut in for two days. The upper interval was then positive pressure tested to 3500 psi. The lower interval was opened and had an initial oil rate of 2500 BOPD with zero water cut.¹⁶⁵

Preformed particle gel (PPG) technology has been effectively employed in many mature oil fields across China, including Daqing, Zhongyuan, Liaohe, Shengli, Tuha, Dagang, and Jidong. These fields exhibit a range of challenging conditions such as high salinity and temperature in Zhongyuan, severe channels and high temperature in Dagang, and natural fractures in Tuha. By 2007, around 2,000 wells across Chinese oil fields had been treated using PPG, with the amount of dried PPG per treatment ranging from 3,000 to 40,000 kg. All PPG injection operations were conducted without issues of reduced injectivity.^{81,88,166}

In 1999, the first successful treatment using preformed particle gels (PPGs) was implemented in the SINOPEC reservoir, located in the Zhongyuan oilfield, China.^{77,167,168} Since then, PPGs of millimeter size have been extensively utilized in China, with over 4000 wells benefiting from their application for conformance control and the reduction of permeability in fractures and highly permeable channels.^{16,166}

Foamed gels provide improved mobility control during injection and have shown success in water shutoff applications. The foaming process enhances gel placement and distribution. Their thermal stability allows for application in reservoirs with temperatures more than 100 °C. However, challenges exist in maintaining gel stability and overcoming issues related to foam generation and transport.^{169,170}

A gel foam water shutoff system was tested in Huoshaoshan fractured oilfield Well H1304 on November 11, 2005. The treatment was successfully tested in an oil producer in a fractured reservoir with low permeability and a temperature of 55°C. Since January 2009, oil production has increased by 7800 m³, demonstrating good economic benefits. In this well, the fluid production rate did not decrease while the water cut decreased greatly because of the treatment.¹⁷¹

Resins

Resins, such as phenol-formaldehyde and epoxy-based resins, have been employed for water shutoff treatments. They exhibit excellent mechanical strength and chemical resistance, making them suitable for harsh reservoir conditions. Resins can withstand high temperatures (e.g., up to 150 °C) and are effective in treating highly permeable zones. However, they can be challenging to inject due to their high viscosity, and the curing process may take an extended time, limiting their applicability.^{172,173}

A phenol-formaldehyde system was successfully trial tested in a vertical oil producer located in the GA field in western India. The reservoir was characterized by extremely low permeability, a high temperature of 130-150 °C, and highly consolidated, homogeneous, thin sandstone with high gravity oil. The pre-treatment flowback experienced a 100% water cut with 317 BWPD of water production. The main factors were determined to be a rise in oil-water contact (OWC) and water coning. The planned gel volume was 16 m³. Because of low injectivity, the actual injected volume was around 5 m³. It effectively blocked about a 4.5-meter radius of the formation. The treated well produced around 200 barrels of oil per day for several months after the treatment. The water cut dropped from 100% to 48%.^{174,175}

Nano-silica gel

Nano-silica particles can be used as water shutoff additives and fluid-based systems due to their ability to reduce water permeability. They have been effective in both low and high-temperature reservoirs, with varying particle sizes and concentrations. Nano-silica is an eco-friendly material that has been utilized by oil producers for water and gas shutoff applications.^{176,177} Nano-silica treatments can be easily injected and exhibit good thermal stability up to 350 °F.^{146,178,179}

Nano-silica was successfully field tested in a horizontal oil producer. The well was drilled across a carbonate formation with 3,000 ft of reservoir contact including seven compartments with 38 ICDs. Before treatment injection, the well was thoroughly diagnosed utilizing noise log, and temperature survey. The pre-job analysis confirmed that excess water production was coming from the middle compartment which impacted the integrity of mechanical packers resulting in cross-flow behind the casing. The length of

this compartment was 500 ft which contains six ICDs. The water shutoff treatment was pumped through coiled tubing after setting an inflatable packer above the compartment and a bridge plug below it. The post-treatment analysis (PLT, noise, and temperature logs) and flowback have proven the increase in oil production from the other compartments and an 80% reduction in water production.¹⁸⁰

Nano-based particulate gel

The Southeast Kuwait field has been produced from sandstone formation. A production test was conducted on a cased hole oil producer and indicated 90% of water cut out of 300 BPD of total produced liquids. The test revealed that water came from a 12 ft section of the perforated interval. A decision has been made to isolate the water zone through coiled tubing utilizing a particulate gel as a single nano-additive. The post-treatment flowback showed an increment in oil production to 1,000 BOPD and only 1% of water cut. This particulate gel has been considered a reliable and cost-effective fluid to seal off the water zone layer. The system was smoothly mixed and injected into the targeted zone.^{181,182}

2.6 Research Gap and Future Development

Water shutoff treatments in oil and gas wells utilize various techniques and materials, each with its advantages and limitations. Polymer gels, resins, and Nano-silica have been applied in a wide range of reservoir temperatures. Preformed gels offer thermal stability but require careful placement. Resins exhibit excellent mechanical strength but may have limited injectability. Nano-silica treatments are versatile and can be applied in ultra-high temperatures. Further research and field studies are necessary to optimize water shutoff treatments based on specific reservoir conditions. The advancement in the utilization of

nanomaterials can play a major role to enhance gels' performance, some of future challenges can be illustrated as below:

(1) In-situ and preformed particle polymer gel:

- While studies have demonstrated the positive impact of nanomaterials like nano silica, nano-clay, and nano-graphene, future research should explore a wider range of nanomaterial approved their applicability in EOR applications, such as Aluminum Oxide (Al_2O_3), Titanium dioxide (TiO_2) and Zinc Oxide (ZnO). The compatibility with different polymers and compositions is also an area of research that needs further investigation. Understanding the most effective nanomaterial-polymer combinations can enhance the applicability of these gels.
- Long-term stability and performance, as well as potential degradation, are areas demanding further investigation. Understanding how these gels behave over extended periods within reservoirs is essential. This includes assessing the longevity of gel stability and identifying potential degradation mechanisms to ensure the continued effectiveness of these gels in preventing water flow.
- Nanomaterials significantly enhance the mechanical properties of the gel while ensuring thermal stability. This makes them a viable solution for applications in harsh environments, including temperatures exceeding 300°C and environments with high salinity levels. Further investigations are needed in this area.
- The transition from laboratory experiments to field applications is a critical research gap. Extensive lab work and field trials are needed to validate the practicality and effectiveness of nanomaterial-enhanced gels in actual reservoirs with different characteristics.

(2) Nano-silica based gel:

- Studies have indicated that gelation time is sensitive to temperature variations. Future work can work deeper into the mechanisms underlying this

sensitivity and explore additives to mitigate the impact of temperature on gelation time. This is essential for ensuring that silicate gels can be placed successfully over a wide range of temperatures.

- While the research has confirmed that nano-silica can enhance the plugging efficiency of silicate gels, additional studies can focus on the long-term stability and endurance of these gels under reservoir conditions. This includes assessing their injectivity, stability, and plugging efficiency over extended periods to confirm their effectiveness in preventing unwanted water flow.
- Given its outstanding plugging efficiency of 100%, nano-silica gel presents itself as a viable alternative to polymer in-situ gels. Notably, its low viscosity and environmental friendliness further enhance its appeal for various scientific applications.

2.7 Conclusions

Polymer and silicate gels are considered the most widely applied chemical systems for water shut-off applications. The use of nanomaterials in water shut-off applications has the potential to significantly improve the efficiency and effectiveness of these treatments. The placement process is highly affected by the gelation time as a critical factor along with the impact of the reservoir characteristic. Therefore, modelling treatment will assist in improving agents' performance as water shut off agents. Eventually, the impact of nanomaterials could be concluded to:

1. Nanomaterials such as nano-clay, nano-silica, and nanographene, can play a major role in adjusting the properties of in situ gel such as control of gelation time (9-10) hours, enhancing gel strength up 4.5 times, and maintaining thermal stability at high temperature (187 °C).
2. Adding nanomaterials to the composition of PPG could help to adjust swelling ratio by percentage up to 400% and improve the strength of the formed gel to withstand the reservoir conditions (elastic modulus 4,437 Pa).

3. The experimental results of nano-silica gel showed improvement in the plugging efficiency up to 100%, which enhances the idea of potential usage as a plugging material along with other advantages of silicate systems.

CHAPTER 3

In-Situ Nano-based Fluid for Water Shutoff: A Kinetic

Study

3.1 Abstract

Innovative ways to address challenges in the oil and gas industry, such as unwanted water production, are urgently needed to achieve specific goals. In this work, we present advanced nanosilica, an environmentally friendly, cost-effective, and promising new approach for water shutoff applications. This research aims to study the reaction kinetics of a nanofluidic in-situ gel system namely Nanosilica that can be deployed in a targeted zone that could have vugs, natural or induced fractures, and a high permeability streak. To systematically assess this nano-based fluid, the chemical properties prior to, during, and following the gelation reaction at a specific reservoir condition must be examined to accurately predict the gelation time and avoid pre-mature gelation during fluid injection. This study evaluated the gelation reaction of the nanosilica system by monitoring viscosity development using a high-pressure/high-temperature (HPHT) viscometer. This study investigated the effect of temperature and activator concentration on gelation time. The results of the experiments led to the development of a robust kinetic model, which was validated by lab experiments. The study revealed that the gelation time is exponentially related to temperature and activator concentration. The reaction order of nanosilica was higher than the activator. The developed gelation kinetic mode is given as:

$GT = \frac{C_{Ai}}{6.3297 \exp\left(-\frac{126,430}{RT}\right) C_N^{23.44} C_A^{16.18}}$. The model has a significant impact on optimizing and designing nanosilica treatment prior to field execution based on the predicted gelation time at specific bottomhole temperatures.

3.2 Introduction

As oilfields mature, it becomes very common to start acquiring water production. Additionally, enhanced oil recovery methods introduce large volumes of water downhole to provide pressure support, which eventually becomes part of the production profile in producer wells. The problem with produced water is the associated decline in oil production rates. Moreover, water production raises a variety of issues in the oilfield, such as inorganic scale precipitation, bacteria, sand production, emulsion, fines migration, and corrosion. This increase in water production rate, in many cases, presents additional expenses to process and dispose of this water, deems the operation uneconomical, and requires technologies to reduce or stop it ¹⁻⁴.

Conventional water control methods include blocking the water pathways physically by using mechanical tools such as packers or bridge plugs ⁵. They can easily be applied if the water-producing zone is separate from the oil-producing zone. Other mechanical methods include the use of special completions that contain inflow control devices (ICDs). These devices act as downhole chokes restricting drawdown. They work well in long section horizontal wells to delay the water coning effect and, therefore, reduce water breakthrough. However, when the water production source is from the same zone that is producing oil, these isolation methods will not work, as they would hinder oil production rates. For such cases, chemical methods can be used to either modify relative permeability or ease the flow

of oil compared to water. Other chemical methods include the generation of a permanent gel in the water zone in the hope of eliminating or stopping water production ⁶⁻¹¹.

The main difference between both methods is that the mechanical means allow for complete isolation in the wellbore but are unable to control the water from channeling or finding an alternative pathway to reach the wellbore ¹²⁻¹⁴. Moreover, mechanical methods are limited if they cannot reach the desired location, seal properly, or set in the correct position. Accidental mistakes in mechanical methods can easily be remediated by pulling out the plug and placing it in the correct location. However, chemical methods are harder to deal with since they are more permanent and will cause significant losses in oil production rate if not placed properly. They are also subject to sensitive placement conditions such as temperature and salinity. It also requires the wellbore to have minimum contamination ¹⁵⁻¹⁷.

Chemical methods can be deployed in areas that are hard to reach or inside the water formation. However, they require a controlled gelation process. It entails sufficient crosslinking delay duration to successfully pump the fluid deep into the water zone. Chemical methods typically utilize polymers such as partially hydrolyzed polyacrylamides ^{18,19}. These polymers are crosslinked with metallic or organic crosslinkers. Some examples of metallic crosslinkers include the use of aluminum or chromium to bind through the acrylic acid side groups. On the other hand, organic crosslinkers typically utilize polyethyleneimine to bind through the amine side chains of acrylamide monomers ²⁰. These polymeric gels face toxicity concerns with organic crosslinkers and a variety of issues with metallic crosslinkers that include a relatively short crosslinking delay duration, high pumping viscosity, sensitivity to pH and formation water salinity, syneresis when

excessive crosslinker is used, and thermal degradation of the polymer at elevated temperatures²¹⁻²³.

Alternative to in-situ formed gels are preformed-sized particle gels (PPG), pH-sensitive gels, bright water, and micro/sub microgels²⁴⁻²⁸. More recently, nanoparticles have found applications in the oil and gas industry for water control. The fluid system contains a surface-modified nanosilica and an activator²⁹⁻³¹. This system exhibits a low viscosity and can be pumped as a single-phase solution. Although many factors are thought to influence the gelation time of nanosilica, such as pH and salinity, various literature studies on this system noted that the system gelation time could be controlled by tuning the composition and is mainly controlled by temperature^{2,32-34}.

In that regard, a gelation kinetics model is needed to understand the behavior of the system. It is critical to be able to simulate the influence of changing the composition and conditions of this system rapidly and accurately for field implementation. Gelation time with nanosilica is highly correlated to Arrhenius law³⁵. This law states that the activation energy and temperature are related to the rate constant k , as seen in the following Arrhenius equation:

$$k = A \exp (-Ea/RT)$$

Where k is the rate constant, A is a frequency factor, \exp is the mathematical quantity, e , Ea is the activation energy, R is the gas constant, and T is the temperature in Kelvin.

Literature has shown that the system exhibits an exponentially faster gelling time with the increase in temperature³⁶.

This is the first study to investigate the gelation kinetics of modified nano-silica-based chemical, which has applications in water control in the oilfield. The article discusses the materials and equipment utilized in this work. The methodology involves estimating the gelation time by conducting several rheological experiments using HPHT rheometer to examine the effect of temperature and activator loadings on gelation reaction. Next, it shares the variables taken into consideration and how the Arrhenius law was utilized for this model. After that, the work attempts to check the validity of the model by comparing the simulation result with experimental lab tests to confirm the ability to predict the behavior of the nanosilica system for field implementation. The article presents a cutting-edge predictive gelation model for the gelation reactions within a nanosilica system that have never been developed before for such a system.

3.3 Methodology

3.3.1 Materials

The water shutoff fluid is composed of two main chemicals: nanosilica and sodium silicate solutions. The nanosilica consists of colloidal silica nanoparticles dispersed in an aqueous solution, having a viscosity of ~ 6 cP at ambient conditions. The particles have an average size of ~ 10 nm, carry a negative surface charge, and have a spherical shape. The specific gravity of the nanosilica solution is ~ 1.25, and the pH is ~ 7.7. The sodium silicate solution has a specific gravity of 1.34 and pH 11.4 and carries positive charges. It is termed the “activator” as it activates the gelation reaction of the in-situ nanosilica-based fluid system.

3.3.2 Experimental Work

Rheological experiments have been conducted using the Chandler 5550 rheometer. All tests were performed at a fixed shear rate of 10 1/s and pressure around 500 psi. The nanosilica fluid was prepared by adding the required amount of activator (wt.%) into a predetermined amount of colloidal nanosilica solution (wt.%) at room temperature (25°C). Then, the mixture was blended using magnetic stirrer at 300 RPM for ten minutes to have proper mixing and miscible fluid. After that, around 52 ml of the nanosilica fluid is poured into the cup of the HPHT viscometer. Next, the rheology test was initiated by measuring the viscosity against time. The fluid temperatures starts to build up gradually until reaching the targeted temperature within 15 minutes. The gelation time was identified once the viscosity rises dramatically typically above 1000 cP as presented in **Figure 3.1**.

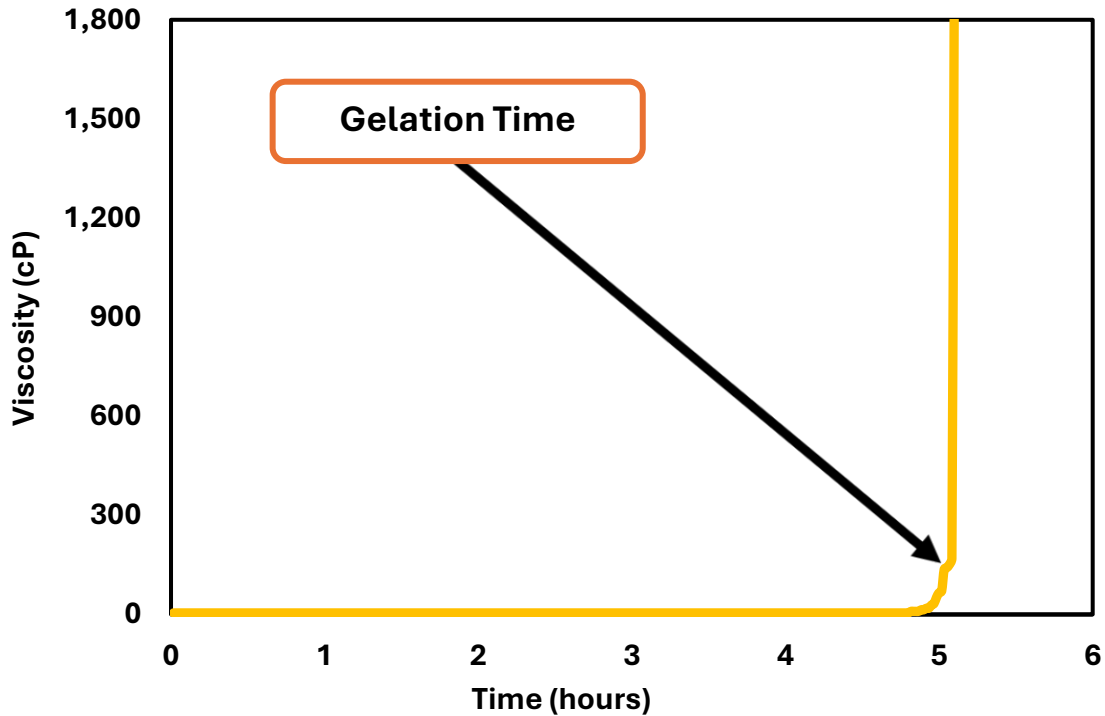


Figure 3.1: Detection of gelation time by measuring viscosity against time.

3.3.3 Experimental Design

There are two primary factors that influence the gelation time of the nanosilica system: temperature and concentration of the activator. In this research, the rheological experiments were performed to examine three main variables which are: temperature, activator concentration, and gelation time. The temperature was chosen since it is a critical parameter that changes during water shutoff injection from surface to the targeted zone and subsequently will disturb the gelation reaction. The activator loading is vital to optimize and design the nanosilica treatment based on the fluid temperature and anticipated gelation time. Conclusively, the temperature and activator concentration variables are compulsory to develop the gelation time model. **Table 3.1** captures the conducted 25 rheology tests to study the effects of temperature and activator concentration on gelation time and to estimate the gelation kinetics parameters.

Table 3.1: Summary of conducted rheological experiments.

Test No.	Activator (wt. %)	Activator (mol/L)	Nanosilica (mol/L)	Temperature (F)	Gelation Time (hours)
1	19%	0.33	6.81	230	5.5
2	21%	0.36	6.65	220	4.0
3	21%	0.36	6.65	210	7.0
4	21%	0.36	6.65	200	14.0
5	23%	0.39	6.55	210	3.5
6	23%	0.39	6.55	200	9.0
7	24%	0.40	6.47	210	2.2

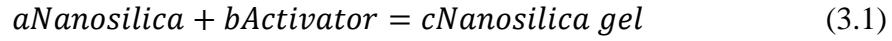
8	25%	0.43	6.35	210	1.5
9	25%	0.43	6.35	200	2.5
10	25%	0.43	6.35	190	5.0
11	25%	0.43	6.35	180	10.8
12	25%	0.43	6.35	170	18.5
13	26%	0.45	6.27	180	8.3
14	30%	0.52	5.95	210	0.3
15	30%	0.52	5.95	200	0.8
16	30%	0.52	5.95	190	1.7
17	30%	0.52	5.95	180	3.0
18	30%	0.52	5.95	170	5.1
19	30%	0.52	5.95	160	8.0
20	32%	0.55	5.78	175	2.6
21	35%	0.61	5.54	170	2.4
22	40%	0.69	5.13	160	3.0
23	40%	0.69	5.13	180	1.1
24	40%	0.69	5.13	170	1.9
25	40%	0.69	5.13	150	4.8

3.3.4 Model Development

To develop the kinetic reaction model of the Nanosilica system, which is an essential input for a numerical simulation, rheology experiments were utilized to build the model. The

Nanosilica gel comprises two components, a modified Silicon Dioxide (SiO₂) and an activator (Sodium Silicate), which are the chemicals to be applied for this reaction.

Therefore, this reaction could have been simplified by **Equation 3.1**:



Where a, b, and c are the stoichiometric coefficients. The reaction between those two components is described in terms of the power law model as follows in **Equation 3.2**:

$$r = kC_N^n C_A^m \quad (3.2)$$

Where C_N is the concentration of Nanosilica in mol/L, *n* is the reaction order of Nanosilica, C_A is the activator concentration in mol/L, *m* is the activator reaction order, and *r* is the reaction rate. According to the Arrhenius equation³⁵, the reaction rate constant is not a constant but rather an exponential function of temperature, as presented in **Equation 3.3** :

$$k = A \exp\left(-\frac{Ea}{RT}\right) \quad (3.3)$$

At which A is the pre-exponential factor, R ~ 8.314 is the universal gas constant in J/(mol . K), T is the temperature in Kelvin [K], and Ea is the activation energy in J/mol.

The reaction rate can be obtained utilizing rheology data by conducting lab tests at varied concentrations of C_N and C_A at different temperatures to estimate A, Ea, *n*, and *m*.

3.4 Results and Discussion

3.4.1 Effect of Temperature

Temperature plays a crucial role in the gelation reaction. For instance, as the temperature elevates over time, the gelation time decreases. **Figure 3.2** depicts six rheological

experiments utilizing a system of 40 wt. % of activator and 60 wt. % of Nanosilica. The tests were performed at altered temperatures ranging between 160°F and 210°F. In general, the viscosity builds up dramatically above 200°F. However, it builds up gradually below 170°F. At 210°F and 200°F, the viscosity profiles almost overlap, indicating close gelation time values around 30 min.

Furthermore, as the temperature diminishes, the gelation time rises exponentially. For instance, the captured gelation values at 180°F, 170°F, and 160°F were 77, 120, and 184 minutes, respectively. Consequently, the gelation time is vital to be accurately estimated as the temperature cools down during pumping operations of water shutoff treatment.

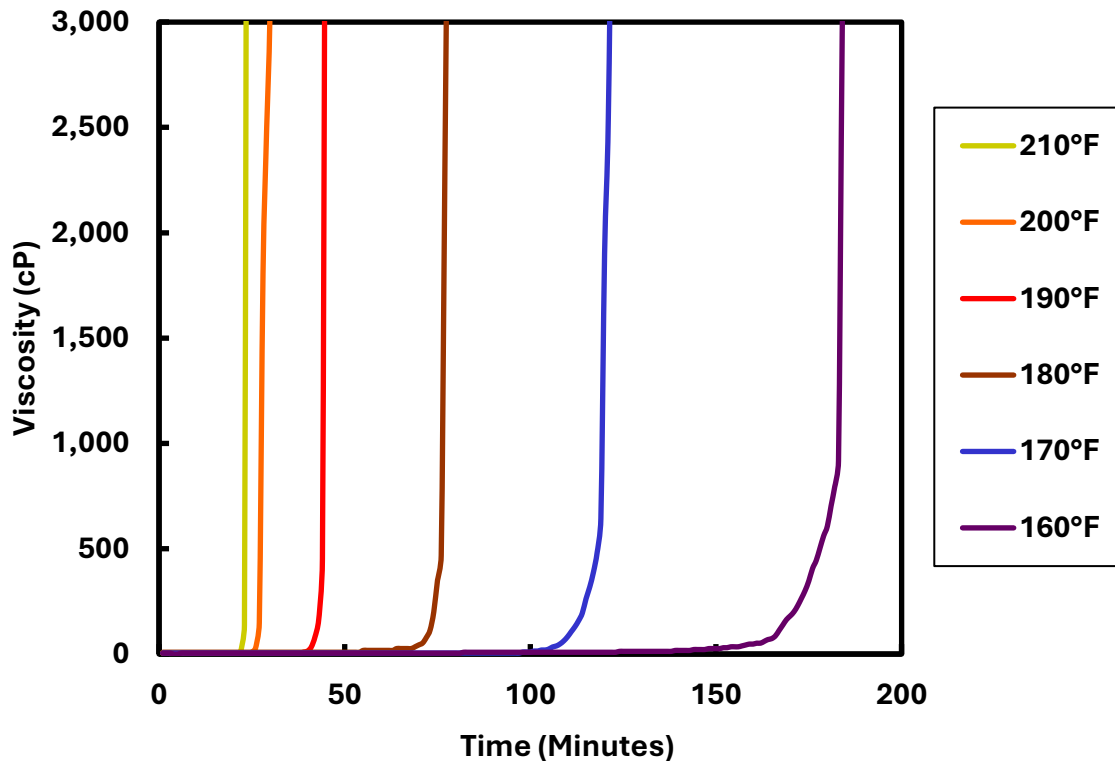


Figure 3.2: Temperature effect on gelation behavior and viscosity.

The gelation time was investigated further by running extensive rheology tests using various activator concentrations at altered temperatures, ranging between 160°F and 210°F.

For example, **Figure 3.3** represents three plots of gelation behavior against temperature; each graph refers to a specific activator loading (25, 30, and 40 wt.%). It can be stated from the plots that gelation time is exponentially related to temperature. At 210°F, the gelation time for the three samples was below two hours and almost identical for the 30 and 40 wt.%. As for 160°F, it was 27, 8, and 3 hours for the samples with activator loading of 25, 30, and 40 wt.%, respectively. The figure is beneficial to understanding the cooling effect of water shutoff treatment during injection and can be utilized to predict the gelation behavior based on the expected reduced temperature.

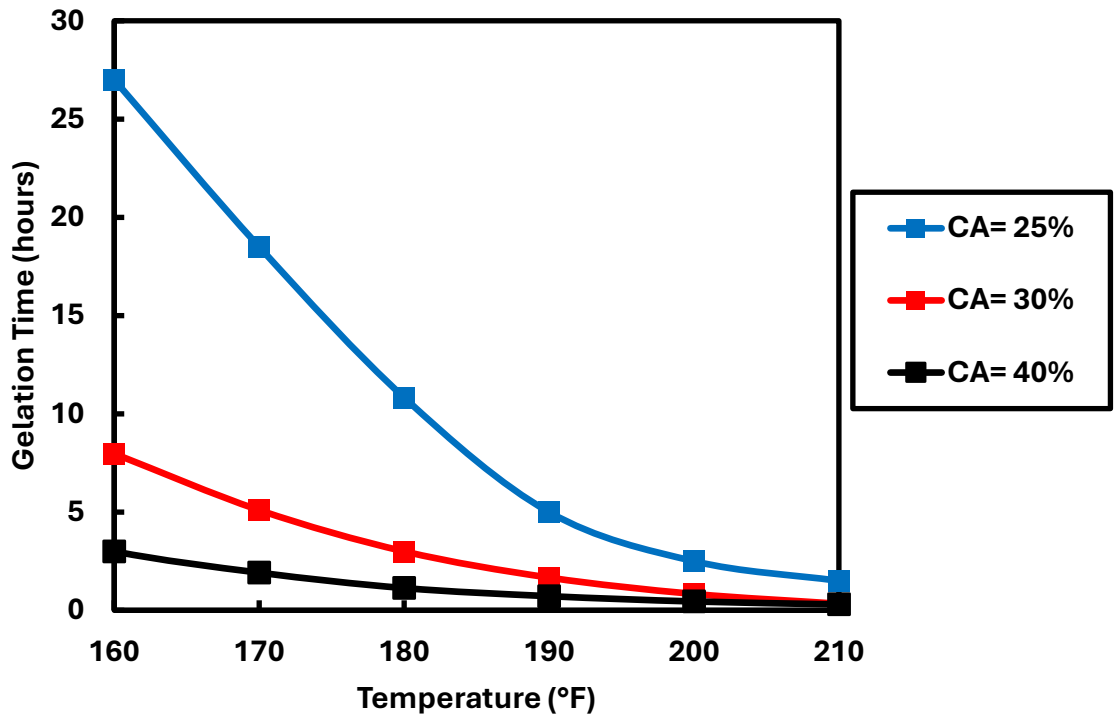


Figure 3.3: Gelation behavior over temperature at different activator loadings.

3.4.2 Effect of Activator

Activator concentration is essential in formulating the nanosilica system to avoid any gelation that might occur in the wellbore during treatment injection. Additionally, lower activator loadings are normally selected at the beginning of the treatment for deeper gel penetration. During treatment injection, the temperature drops due to the injected nanosilica fluid and hence, more activator required to control the delayed gelation. From the rheology tests, the gelation for each nanosilica system was determined at 200°F and plotted in **Figure 3.4**. As illustrated in the figure, the gelation increased marginally from 0.5 hours to two hours between 40 and 26 wt.% of activator concentrations. The gelation shifted from a steady to exponential trend below 25 wt.% of activator loading. Generally, more activator is favored at the last stage of the treatment to guarantee near-wellbore zonal isolation.

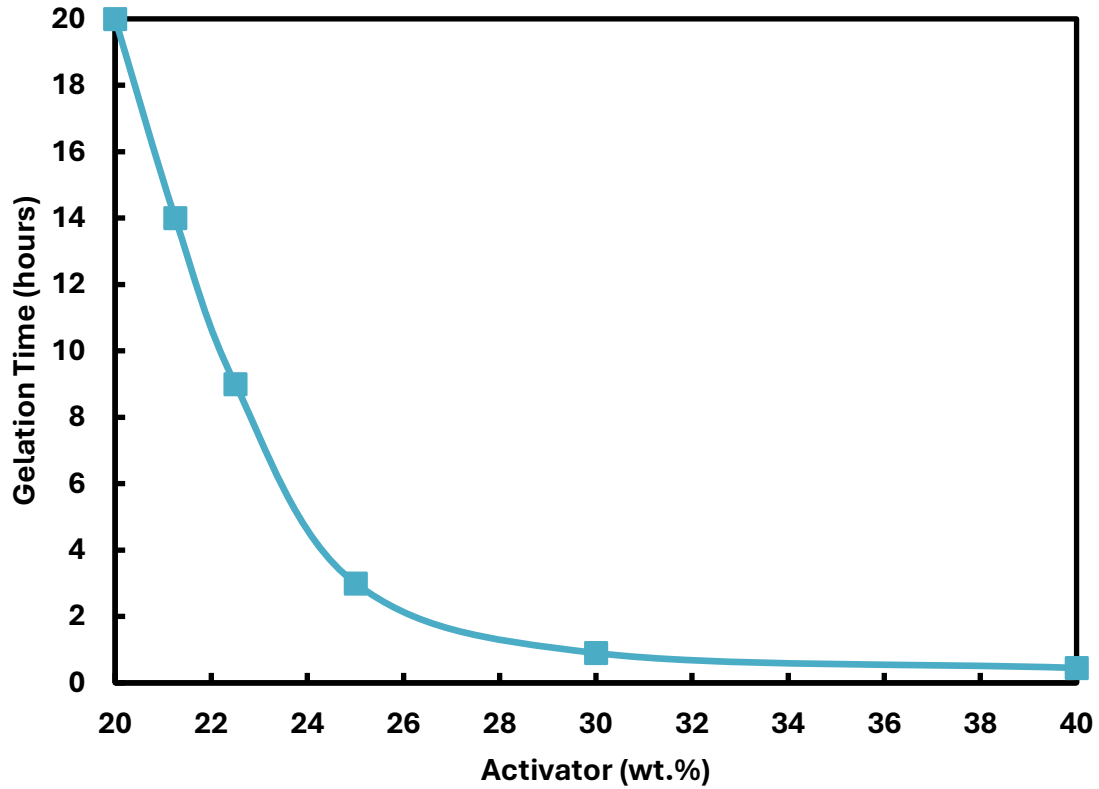


Figure 3.4: Gelation behavior against varied activator loadings at 200°F.

3.4.3 Gelation Kinetics

The reaction kinetics of the nanosilica system was studied utilizing the experiments conducted by the HPHT rheometer. The Nanosilica gel is produced by the reaction of two reagents: Colloidal Silica (C_N) and Sodium Silicate (C_A), as presented in **Equation 3.1**. Therefore, the rate expression of the consumed activator (C_A) is shown in **Equation 3.4**.

$$-\frac{dC_A}{dt} = r = k C_N^n C_A^m \quad (3.4)$$

Where r and k are the reaction rate and rate constant, consequently. To simplify the problem and find the reaction order ($\mathbf{n} + \mathbf{m}$) by estimating the value of exponents \mathbf{n} and \mathbf{m} , we let

$\frac{dC_A}{dt} \sim \frac{\Delta C_A}{\Delta t}$, as shortened in **Equation 3.5**:

$$\frac{dC_A}{dt} \sim \frac{\Delta C_A}{\Delta t} = \frac{C_{Af} - C_{Ai}}{t_f - t_i} = \frac{0 - C_{Ai}}{GT} = -\frac{C_{Ai}}{GT} \quad (3.5)$$

Where: $\frac{dC_A}{dt}$ is the rate of disappearance of activator reactant, ΔC_A is the change of C_A , Δt is the change of time equivalent to the gelation time (GT), C_{Ai} and t_i refer to the initial activator concentration and initial reaction time, and C_{Af} and t_f refer to the final activator concentration and final reaction time. Hence, after evaluating **Equation 3.5** in **Equation 3.4** we get **Equation 3.6** and **3.7**.

$$r = \frac{C_{Ai}}{GT} = k C_N^n C_A^m \quad (3.6)$$

$$GT = \frac{C_{Ai}}{k C_N^n C_A^m} \quad (3.7)$$

To quantify the exponents \mathbf{n} and \mathbf{m} , we need at least four data sets collected at the same temperature (T) and hence the same rate constant (k). For example, **Table 3.2** depicts four experiments conducted at varied reactant ratios at 180°F.

Table 3.2: Selected nanosilica formulation at 180°F.

<i>Test No.</i>	<i>C_N (mol/L)</i>	<i>C_A (mol/L)</i>	<i>r (mol/L.s)=C_A/GT</i>
1	6.35	0.43	1.10E-05
2	5.95	0.52	4.79E-05

3	5.13	0.69	1.71E-04
4	6.27	0.45	1.49E-05

To find the exponents, two systems of equations are required to be solved by substituting and dividing the two values of **Table 3.2**. The simplification steps are presented in the **Equations: 3.8, 3.9, and 3.10**. Same steps applied for test number 3 and 4 as shown in **Equation 3.11**.

$$\frac{r_1}{r_2} = \left(\frac{C_{N1}}{C_{N2}}\right)^n \left(\frac{C_{A1}}{C_{A2}}\right)^m \quad (3.8)$$

$$\ln\left(\frac{r_1}{r_2}\right) = \ln\left[\left(\frac{C_{N1}}{C_{N2}}\right)^n \left(\frac{C_{A1}}{C_{A2}}\right)^m\right] \quad (3.9)$$

$$\ln(r_1) - \ln(r_2) = n \ln\left(\frac{C_{N1}}{C_{N2}}\right) + m \ln\left(\frac{C_{A1}}{C_{A2}}\right) \quad (3.10)$$

$$\ln(r_3) - \ln(r_4) = n \ln\left(\frac{C_{N3}}{C_{N4}}\right) + m \ln\left(\frac{C_{A3}}{C_{A4}}\right) \quad (3.11)$$

After solving the systems of **Equations: 3.10 and 3.11**, the estimated value for **n** was **23.44**, and the value for **m** was **16.18**. Hence, the overall **reaction order** was around **39.62**. Then, the reaction constant can be calculated from **Equation 3.12** and then plotted against T^{-1} to find A and E_a for Arrhenius **Equation 3.3**.

$$k = \frac{r}{C_N^{23.44} C_A^{16.18}} \quad (3.12)$$

For instance, **Table 3.3** presents the selected pairs of temperature and rate constant having fixed C_A and C_N .

Table 3.3: Selected nanosilica formulation at varied temperatures.

<i>Test No.</i>	<i>T(F)</i>	<i>T⁻¹(K⁻¹)</i>	<i>Rate Constant (K)</i>
1	210	2.69	9.54E-03
2	200	2.73	5.72E-03
3	190	2.77	2.86E-03
4	180	2.81	1.32E-03
5	170	2.86	7.73E-04

Figure 3.5 proves that the nanosilica system follows the Arrhenius equation. From

Figure 3.5, the pre-exponential factor (**A**) equals **6.3297** and $E_a/R = 15207$; hence, the activation energy **$E_a = 126.43$ KJ/mol**.

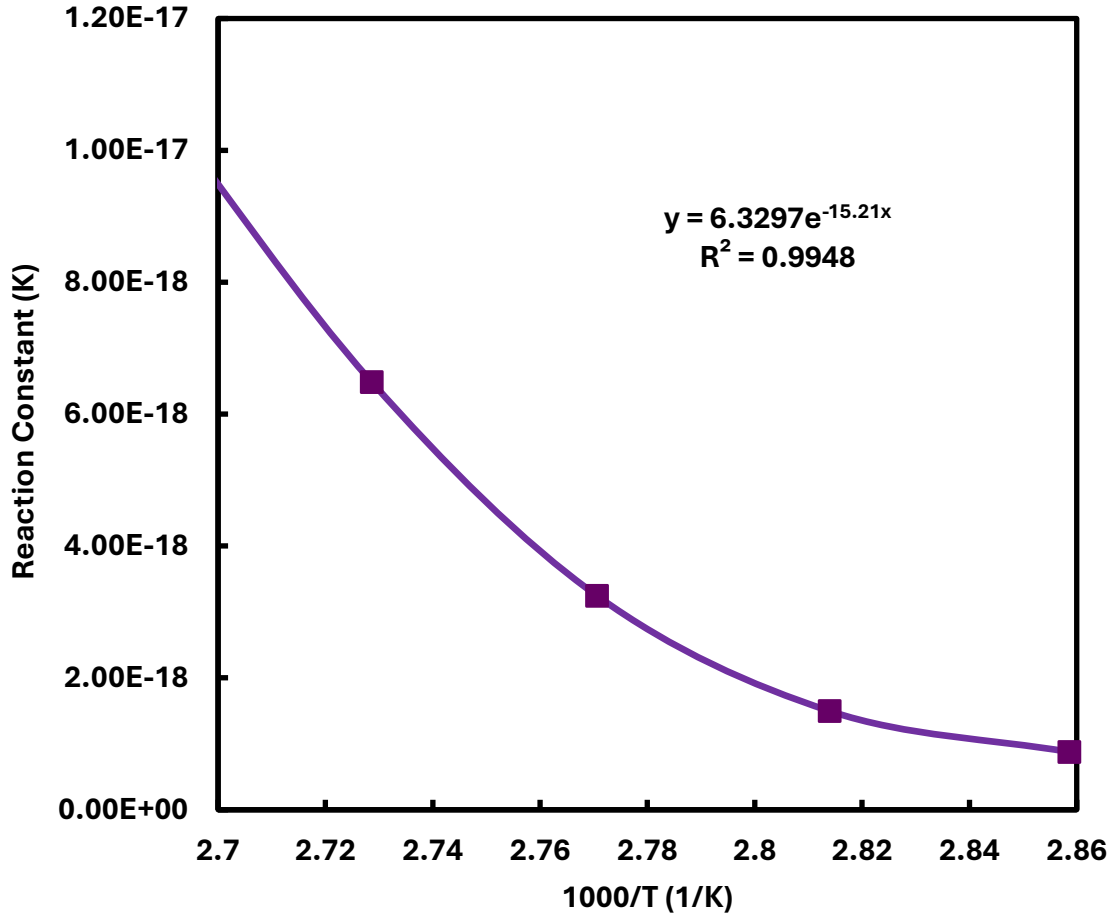


Figure 3.5: Rate constant (K) against T^{-1} using constant formulation.

Hence, the developed gelation kinetic model is presented in **Equation 3.13**.

$$GT = \frac{C_{Ai}}{6.3297 \exp\left(-\frac{126,430}{RT}\right) C_N^{23.44} C_A^{16.18}} \quad (3.13)$$

Where GT is the gelation time in seconds, C_{Ai} is the initial activator concentration in mol/L, T is the fluid temperature in Kelvin.

3.4.4 Model Validation

The gelation model was validated by comparing it with estimated gelation data from 25 rheology experiments. **Figure 3.6** depicts the comparison between the captured GT from rheology tests and predicted GT from the model. The coefficient of determination (R^2) was **0.9229** proving that the gelation model exhibited a strong relationship with lab data. Moreover, all data indicated that the absolute error of GT was below an hour except a few tests experienced variance less than and around three hours for experiments with extended GT above five hours. Furthermore, **Figure 3.7**, presents a portion of the model validation using 30 wt.% of activator concentration at altered temperature. It is clear from the figure that the plots almost match each other except at 160°F; that could be due to a human error in selecting the optimum gelation time. Subsequently, the developed GT correlation was robust and validated in predicting the gelation at a wide range of temperatures ranging from 140 to 220°F. There were many human errors that might affected the quality of data such as improper preparation of the sample, identifying the gelation time, uncalibrated viscometer, and quality of the sample.

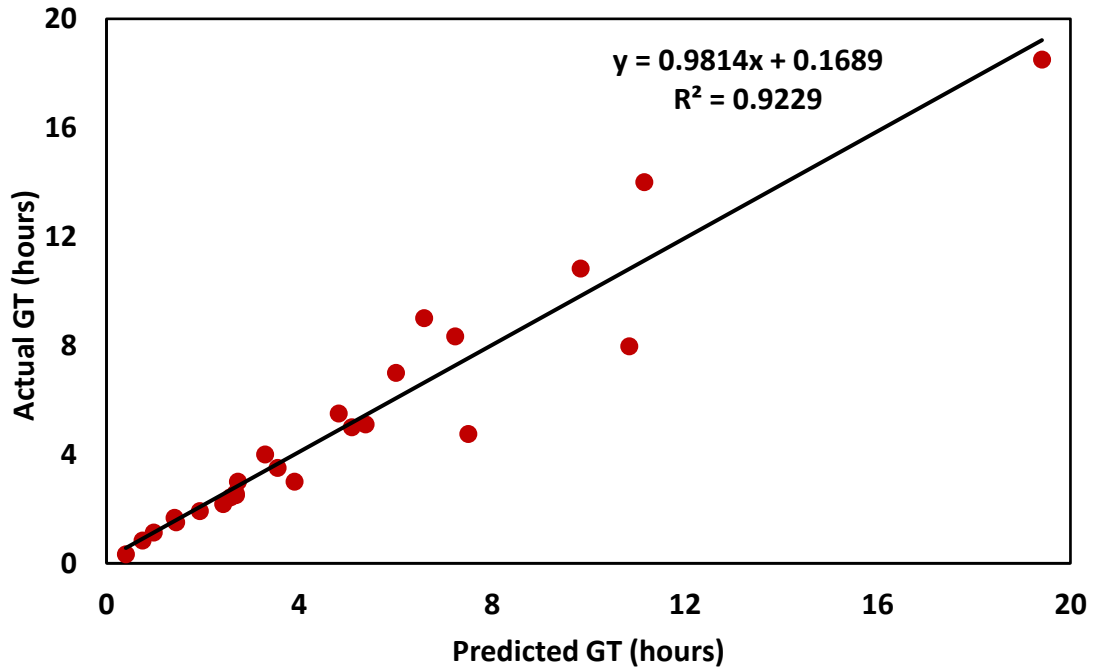


Figure 3.6: GT prediction against recorded GT from lab tests.

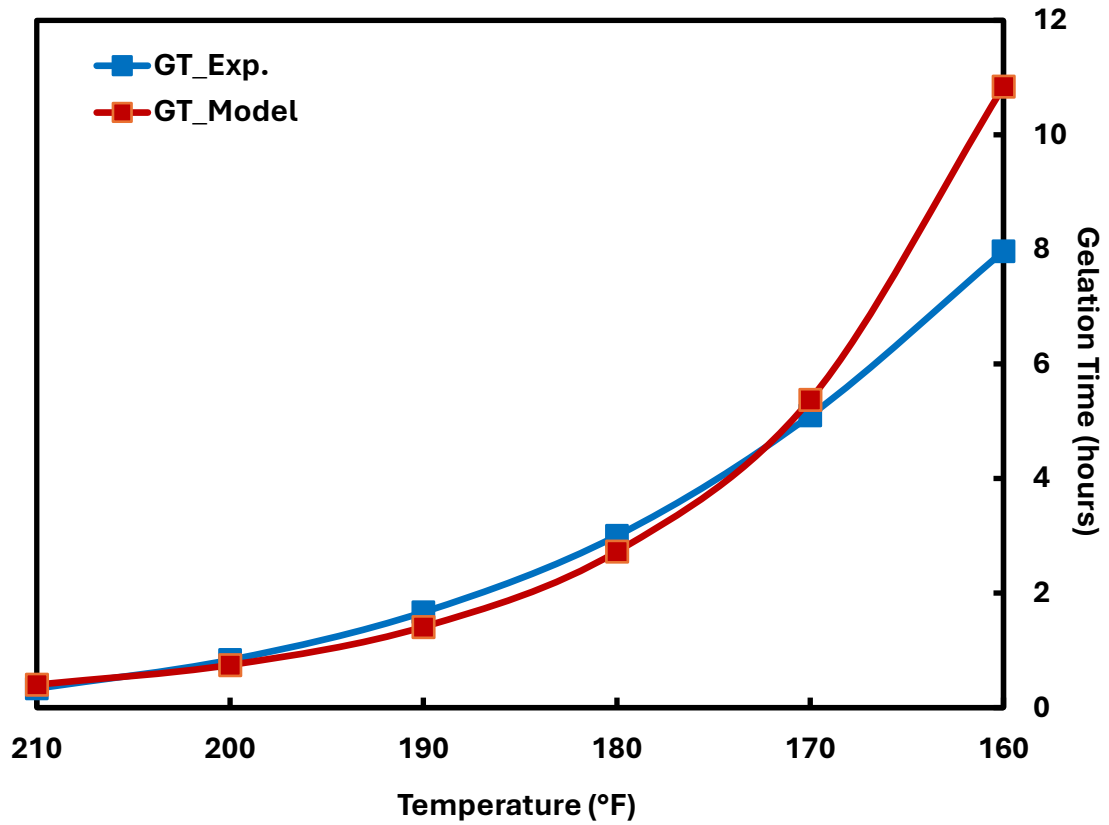


Figure 3.7: Gelation model validation with lab experiments.

3.5 Conclusions

Reducing undesired water production from oil and gas wells is highly vital in the petroleum industry. This will boost the economic viability of mature wells and necessitate the use of new and innovative technologies. In this research, we introduced nanosilica system as a promising, cost-efficient, and environmentally friendly water control fluid. The objective of the study was initially to examine the impact of fluid temperature and activator concentration on gelation reaction. Then, the research tapered into investigating the reaction kinetics of nanosilica as a water shutoff chemical. First, the results from the impact of temperature cooldown during water shutoff injection, illustrated that by utilizing an activator concentration of 40 wt.%, the gelation reaction could be delayed from 30 minutes to 180 minutes if the temperature was reduced from 210°F to 160°F respectively. Furthermore, the effect of cooldown temperature increases by decreasing the activator loading. For instance, the gelation time at 160°F using 25 wt.% of activator was found to be around 27 hours and 40 minutes at 210°F.

Additionally, the effect of activator concentration on gelation reaction, specifically at 200°F, demonstrated that the activator loading had an exponential relationship to gelation time. The gelation time drops dramatically from 20 to 3 hours at 20 and 25 wt.% of activator concentration, respectively. Based on the gelation kinetic findings, the order of nanosilica was higher than the activator. The kinetic model was validated and found to be dependable for optimizing the water shutoff formulation for field application.

CHAPTER 4

An integrated 3D Model of Water Shutoff Considering the Gelation Kinetics of Nanosilica Gel

4.1 Abstract

Effective water shutoff remains a significant challenge in oil and gas fields, with current methods often hindered by inefficient gel placement and inadequate zonal isolation. Numerical simulations play a vital role in designing and optimizing water shutoff treatments but are frequently limited by oversimplification of gel behavior and neglect of formation heterogeneity. Recent advances in nanosilica gel technology offer promising solutions yet require sophisticated modeling approaches to harness their potential fully. To address these challenges, this study introduces an integrated 3D model for simulating water shutoff operations using Nanosilica gel. By combining experimental data, mathematical formulations, and computational simulation, the model captures the relationships between injection rate, fluid temperature, treatment volume, activator concentration, and formation properties. Simulation results underscore the critical importance of balancing competing factors – including gel penetration, temperature cooldown, and gelation time – to optimize treatment outcomes. Moreover, the model highlights the profound impact of formation heterogeneity on gel distribution and performance, demonstrating the value of accounting for localized permeability and porosity variations in design phases. This innovative

approach offers a powerful tool for maximizing treatment success and reducing water management costs in oil and gas fields.

4.2 Introduction

Water shutoff operations are a crucial technique in the oil and gas industry. They aim to mitigate excessive water production and enhance hydrocarbon recovery.¹ One common approach is the use of in-situ gels, which involve injecting a gel-forming fluid into the formation, where it undergoes a gelation process to block the flow of unproductive water.^{2,3} The effectiveness of water shutoff operations using in situ gels depends on several factors, including the gel's ability to penetrate and fully block the water-bearing zones. However, this process can be challenging due to the complex nature of the subsurface environment and the behavior of the gel-forming fluid.⁴ The ability to form in situ gels that block water pathways has made these systems a valuable tool in the oil and gas industry.

Due to their unique properties, nanosilica systems have emerged as a viable solution for water shutoff applications. These systems typically consist of colloidal silica mixed with activators, usually inorganic salts, which can form a gel that plugs pore spaces in the reservoir, thereby reducing water production. Nanosilica fluid demonstrated high thermal stability up to 350°F with low initial viscosity after mixing that can be easily pumped to the formation.⁵⁻⁸

Almohsin⁹ et al. explored how temperature cooldown affects gelation time in nanosilica systems. Their findings indicate that the gelation process is significantly influenced by temperature changes, with elevated temperatures leading to a more rapid increase in

viscosity compared to cooler conditions. This temperature dependence is crucial for tailoring treatment applications, as it affects how quickly the gel can form and, thus, its effectiveness in blocking water pathways. Additionally, Alabdrabalnabi⁷ et al. conducted an experimental investigation into the gelation kinetics of a nanosilica system designed to mitigate water production. They found that the gelation time and properties of the nanosilica could be effectively manipulated by varying the concentration of nanosilica and the type of activator used at altered temperatures. This research underscores the critical importance of gelation kinetics in optimizing nanosilica formulations for water shutoff applications, enhancing their performance in field conditions.

Field applications of nanosilica systems have shown promising results in enhancing oil production while minimizing water influx. Almohsin^{8,10,11} et al. reported successful implementations of nanosilica-based fluids in real-world scenarios, demonstrating their effectiveness in reducing undesired water production or even gas production and improving overall well performance.

One of the main challenges is the reservoir's heterogeneity, which can lead to uneven gel placement and potential breakthroughs in the water flow.¹² Additionally, the gelation kinetics and the rheological properties of the gel can significantly influence its ability to penetrate and effectively block the water-bearing zones.¹³ To address these challenges, researchers have explored various solutions, including the development of improved gel formulations, optimized injection strategies, and numerical simulation models to predict and optimize the gel penetration process. Numerical simulation models have become a valuable tool in understanding and predicting the behavior of in-situ gels during water shutoff operations. These models aim to incorporate the complex physical and chemical

processes involved, such as the gelation kinetics, fluid flow, and the interaction between the gel and the porous media.^{14,15}

Several studies have focused on predicting the performance of water shutoff treatments using various modeling approaches. In 2014, Xianchao¹⁶ et al. initially employed a conventional model to simulate gel formation but found it inadequate for predicting the performance of horizontal wells. They then developed a reservoir model that successfully simulated viscosity and pressure changes within the well over time, even in the presence of polymer gels. Numerous studies have explored polymer gel and reservoir-well modeling using various software and models. PCGEL software, for instance, can simulate both black oil and polymer gel behavior simultaneously.¹⁷ Commercial software like UTCHEM¹⁶ and CMG¹⁸ are also capable of incorporating polymer gel properties and behaviors into simulations. Researchers such as Canbolat and Parlaktuna¹⁹ and Khamees²⁰ et al. have investigated the performance of CMG software in this context. Meshalkin²¹ et al. presented a three-dimensional computer model that simulates the water shutoff performance within high water cut oil zones, considering the geophysical characteristics of the bottomhole formation zone and the rate and amount of water control solutions injected. The model's effectiveness was validated by comparing the calculated values of water cut and oil production rate with actual well performance data after water shutoff treatment, confirming its accuracy and potential for increasing energy and resource efficiency in oil production. Additionally, researchers have explored mathematical modeling of wells and reservoirs to simulate polymer gel behavior.²²⁻²⁴

Artificial intelligence (AI)-based models, specifically artificial neural networks (ANN), have emerged as a promising approach to overcome the limitations of conventional

numerical models. For example, Alghazal and Ertekin²⁵ proposed an ANN as a machine learning module for deep polymer gel conformance treatments in fractured reservoirs. The ANN module outperformed commercial simulators with higher processing speed and less computational complexity, and it included various reservoir properties and conformance design factors. The predicted model had two indicators based on oil and water rate profile enhancement after gel treatment. Ferreira²⁶ et al. focused on creating, training, and validating an ANN model to predict the performance of wells following gel treatment injection. The model is designed to rank wells that are candidates for water shutoff treatments based on potential production results, enhancing the design of future treatments and optimizing the use of economic resources. The researchers explored various configurations of the neural network to enhance the model's accuracy.

Other machine learning models have been employed to predict polymer gel behavior, including Jeziorny, Mo, Rate, and SVR-based models.^{27,28} However, these AI-driven models often lack physical interpretability and may struggle to generalize to new, unseen scenarios.^{24,29}

The current body of literature exhibits significant gaps concerning accurate predictions of water shutoff treatment performance under realistic operating conditions. Most models neglect the effects of temperature cooldown, gelation kinetics, and heterogeneous reservoir properties on gel placement and penetration. Moreover, limited efforts have been devoted to integrating comprehensive reaction kinetics of nanosilica gel systems into numerical or AI frameworks.

A novel approach has been undertaken to bridge these knowledge gaps by developing a cutting-edge numerical simulation framework capable of capturing the intricacies associated with water shutoff operations employing nanosilica gel systems. An integrated 3D and 2D model, built using MATLAB software, accurately captures the nonlinear interplay among gelation kinetics, temperature variation, and fluid flow near the wellbore. Two primary objectives drive this investigation: first, advancing fundamental comprehension of the mechanisms driving nanosilica gel placement and propagation; second, establishing a flexible decision-making support platform to facilitate optimal treatment plan designs suited to distinct rock environments and operational constraints.

4.3 Methodology

In this study, the numerical model involves solving the fluid flow, mass transfer, and heat transfer models. Under the fluid flow equation, the fluid is assumed to behave as a Newtonian and incompressible fluid due to having a very low viscosity of around five cP. Consequently, the fluid is anticipated to follow Darcy's law, which is a simplified equation that represents the key behavior of the fluid penetration before gelation. The thermal (heat transfer) model is considered due to the temperature impact on gelation reaction during temperature cooldown while injecting the fluid and temperature warm back during the shut-in period.

4.3.1 Model Algorithm

The numerical model employs the finite volume method (FVM) to focus on each finite volume within a grid structure. This method involves a series of computational steps to solve equations that describe the physical processes being modeled. The model algorithm is illustrated in **Figure 4.1**, where the two dashed rectangles bound the major model components, which were solved numerically using the FVM. First, the model starts reading the input data that is depicted in **Table 4.1**. Next, the model generates fine mesh grids where the porosity and permeability values are populated, assuming a normally distributed heterogeneous domain.

The model provides numerical solution of the water shut off process during injection and shut-in stages As depicted in **Figure 4.1**, The first stage is on the left within the dashed rectangle during treatment injection The second part is on the right, under the dashed rectangle during shut-in time. The first section solved each mathematical model sequentially to predict the temperature cooldown and distribution of the fluid while injecting until reaching the final pumping time based on the selected pumping rate and volume. For instance, the model starts solving the diffusivity equation to find the pressure solution from which the velocity profile is obtained and utilized for the mass and heat transfer models. Solving the nanosilica activator's mass transfer gives the concentration distribution, and solving the thermal model generates a temperature profile. As for the second part, the model predicts the warm back temperature and gel penetration based on the desired shut-in time. The gel penetration is estimated based on a gelation kinetics formula that was developed in this study. Once the shut-in time exceeds the gelation time

value, the permeability is set to zero in that specific grid. The shut-in algorithm was developed to stop once the time-step equals the selected shut-in time duration.

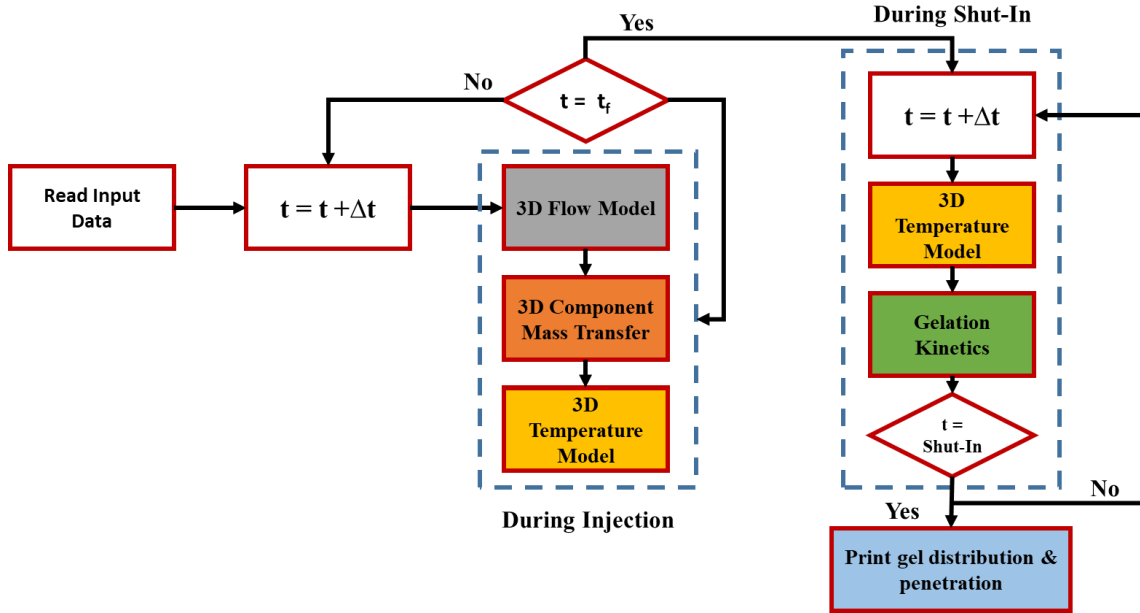


Figure 4.1: Algorithm of the numerical model.

4.3.2 Mathematical Formulation

The numerical model involves solving the flow model, mass transfer, and heat transfer equations, which are known as conservation laws. It also utilizes predefined equations and pore correlations.

4.3.2.a Flow Model

Under the fluid flow model, Equation 4.1 represents the mass conservation of the fluid phase, and Equation 4.2 depicts Darcy's law. By combining both equations, we get the simplified diffusivity equation having no sink nor source terms for incompressible fluid,

as presented in Equation 4.3. The superficial velocity in Equation 4.2 is obtained after solving the diffusivity equation by finding the pressure profile.

$$\frac{\partial(\rho\phi)}{\partial t} + \nabla \cdot (\rho\vec{u}) = \dot{m}_{ss} \quad (4.1)$$

$$\vec{u} = \frac{-1}{\mu} \bar{\mathbf{k}} \cdot \nabla p \quad (4.2)$$

$$\nabla \cdot (\bar{\mathbf{k}} \nabla p) = \mu\phi c_t \frac{\partial p}{\partial t} \quad (4.3)$$

Where the t represents the time, \dot{m}_{ss} is the generated or consumed mass rate per unit volume, ρ is the density of the fluid, μ is the fluid's viscosity, ϕ is the porosity, p is the pressure, $\bar{\mathbf{k}}$ is the permeability tensor, \vec{u} is the vector velocity, and c_t is the total compressibility of fluid, which is basically the combination of rock compressibility and fluid compressibility.

4.3.2.b Mass Transfer Model

Under the mass transfer model, the concentration distribution of the activator was obtained by solving the mass conservation equation for the chemical component, as depicted in Equation 4.4.

$$\frac{\partial(\phi C_A)}{\partial t} + \nabla \cdot (\vec{u} C_A) - \nabla \cdot (\phi D_e \nabla C_A) = a_v r_A \quad (4.4)$$

Where a_v represents the surface area of the rock, r_A is the rate of gelation reaction, D_e is the effective diffusion of activator, and C_A is the activator concentration. The reaction term on the right-hand side is negligible since the reaction is assumed to start during the shut-in period. On the left-hand side, we have the accumulation, convection, and diffusion terms.

4.3.2.c Heat Transfer Model

Under the heat transfer model, as the fluid flows along the porous media, the temperature varies due to heat convection, as presented in Equation 4.5.

$$\overline{\rho\hat{c}_p} \frac{\partial T}{\partial t} + \overline{\rho\hat{c}_p} \nabla \cdot (\vec{u}T) - \nabla \cdot (\bar{\kappa}\nabla T) = \Delta H_r a_v r_A \quad (4.5)$$

Where \hat{c}_p represents the specific heat of fluid, $\overline{\rho\hat{c}_p}$ refers to the multiplication of rock porosity, fluid density, and specific heat as a weighted average, $\bar{\kappa}$ is the thermal conductivity of fluid as weighted average by the porosity of the rock, and ΔH_r , is the heat of the reaction that is ignored during the fluid flow. To simplify solving the model, the thermal properties (ρ , \hat{c}_p , $\bar{\kappa}$) were made to hold constant values. During shut-in, the heat transfer mechanism is dominated by conduction, as the convection term is neglected.

4.3.2.d Gelation Model

After conducting extensive rheological experiments, the gelation reaction model was predicted and validated. The gelation model given in Equation 4.6 was derived based on the Arrhenius equation and Rate law.

$$GT = \frac{C_{A0}}{A \exp\left(-\frac{E_a}{RT}\right) C_N^{23.44} C_A^{16.18}} \quad (4.6)$$

Where GT is the gelation time, C_{A0} is the activator's initial concentration, C_A and C_N are the activator and nanosilica concentrations, respectively, A is the Arrhenius pre-exponential factor, E_a is the activation energy, R is the universal gas constant, T is the absolute temperature.

4.3.2.d Initial Distribution

A random field, namely r_{random} was generated as a standard normally distributed domain. The objective of r_{random} is to normally assign initial porosity and permeability values as illustrated in Equation 4.7 and 4.8, respectively.

Where ϕ_0 and k_0 are the initial porosity and permeability values, $\bar{\phi}$ and \bar{k} are the average porosity and permeability values, σ is the standard deviation, σ_{log} is the logarithmic standard deviation, M is a tuning factor ranging between two and one for scaling. Furthermore, the created average values are utilized to generate the initial specific surface area fields and initial pore radius.

$$\phi_0 = \bar{\phi} + \sigma \times r_{random} \quad (4.7)$$

$$k_0 = \bar{k} \exp (M \times \sigma_{log} r_{random}) \quad (4.8)$$

4.4 Results and Discussion

In this section, the simulation of water shutoff injection and shut-in are presented in several scenarios. The following **Table 4.1** captures the simulation data inputs as the baseline. The number of grids in 3D and 2D were 59,049 and 6,561, respectively.

Table 4.1: Input data for the base run.

	Input	Symbol	Value	Unit
Domain	Length	L_x	20	ft
	Width	L_y	20	ft
	Height	L_z	500	ft
	Wellbore diameter	ϕ_w	2.375	Inch
	Temperature	T_{res}	220	°F
	Pore pressure	P	3000	Psi
Rock Prope	Rock Porosity	ϕ	0.2 ± 0.05	m^3/m^3
	Rock Permeability	k	$1,500 \pm 5.0$	mD

	Compressibility	c_r	1.0×10^{-6}	1/psi
	Rock Pore radius	r_p	10	Mm
	Specific area of rock	a_v	500	m^2/m^3
Data for Injection	Concentration	C_{inj}	25.0	wt. %
	Injection temperature	T_{inj}	190	°F
	Injection rate	q	1.0	bbbl/min.
	Treatment Volume	V_t	300	bbbl
Properties	Viscosity	μ_A	1.0	cP
	Density	ρ_A	1330	kg/m^3
	Molecular weight	MW_A	252.51	g/mol
	Specific heat	\hat{c}_{p_a}	4.182	$kJ/kg \cdot ^\circ C$
	Thermal conductivity	κ_a	5.5×10^{-4}	$kJ/m \cdot s \cdot ^\circ C$
	Activation energy	E_a	126,430	J/mol
	Pre-exponential factor	A	6.3297	$1/M^{39} \cdot s$
	Gas constant	R	8.3145	J/mol · K

The random normal distribution field for the initial porosity and permeability values was created using a scaling factor of two. All simulation scenarios were performed assuming flowing through Calcite rock.

4.4.1 Impacts on Near Wellbore Gel Distribution in 2D

This section describes and discusses the temperature and gel distributions around the wellbore in 2D utilizing the data input in **Table 4.1** by generating multiple scenarios by varying one parameter at a time to examine the impacts of certain parameters on near wellbore temperature profile and gel penetration. In **Figures 4.5, 4.6, and 4.7**, the yellow color represents the original formation permeability. However, the blue color indicates zero permeability, confirming the gel's development.

4.4.1.a Effect of Injection Rate

The treatment injection of water shutoff fluid is crucial in designing such a system as it can affect the temperature around the wellbore and, consequently, the gelation time. In **Figure 4.2**, the near wellbore formation temperature was 220°F while the injection temperature of the fluid was 190°F but at three different rates (0.1, 0.25, 1 BPM) in A, B, and C, respectively. At 1 BPM (C), the temperature profile decreased to 200°F within almost 1.5 ft. However, at 0.1 BPM, the temperature dropped to 200°F only up to ~ 0.5 ft. Selecting the optimum pumping rate depends highly on the formation permeability and required gel penetration to isolate the desired section.

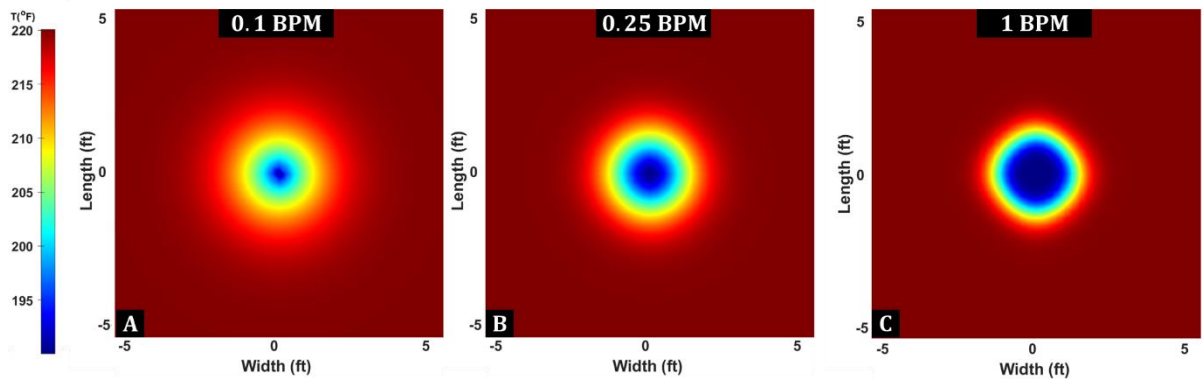


Figure 4.2: Temperature profile at different injection rates.

After injecting the required treatment volume, the well is planned for shut-in for a certain time, allowing the water shutoff fluid to cure and transform into gel completely. During shut-in, the bottomhole temperature rises gradually until it reaches the initial temperature prior to injection. Predicting the near wellbore warmback temperature is essential to

selecting the optimum shut-in period for a successful water shutoff job. In **Figure 4.3(A)**, the temperature profile is illustrated after completing the water shutoff injectivity. **Figures 4.3(B)** and **4.3(C)** present the temperature warmback after 24 and 48 hours of shut-in, respectively. In general, the well with lower formation temperature will require more shut-in time to allow sufficient curing time.

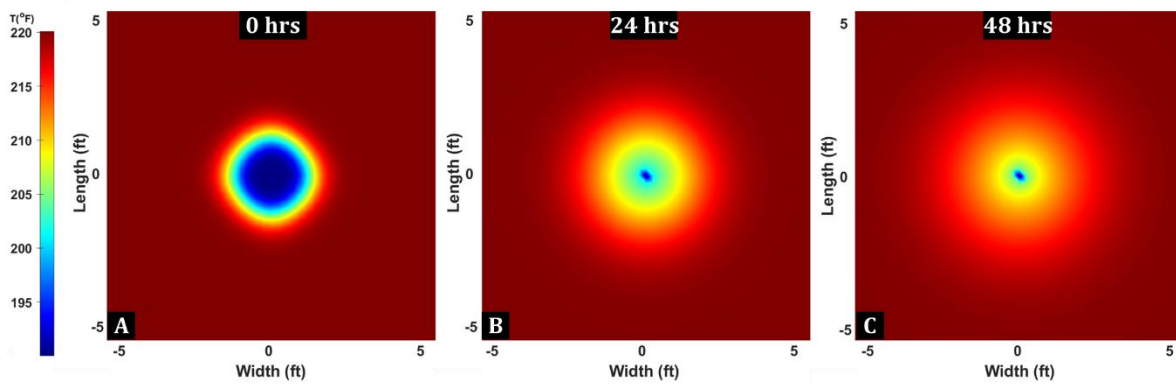


Figure 4.3: Temperature profile at different shut-in periods.

4.4.1.b Effect of Treatment Volume

The treatment volume of a water shutoff system determines the expected fluid penetration into the porous media based on certain parameters such as formation permeability, pumping rate, and gelation time. **Figure 4.4** depicts the effect of injected volume per length using altered treatment volume at fixed intervals on temperature distribution. As the volume increases, the temperature cooldown propagates more into the formation. At 0.5 bbl/ft, the cooldown effect was detected up to 2 ft of radial penetration, as shown in **Figure 4.4 (A)**. In **Figure 4.4 (C)**, the temperature cooled down to 3.5 ft of radial penetration.

Prior to job execution, the optimum treatment volume will be estimated based on the required radial penetration to isolate the targeted zone.

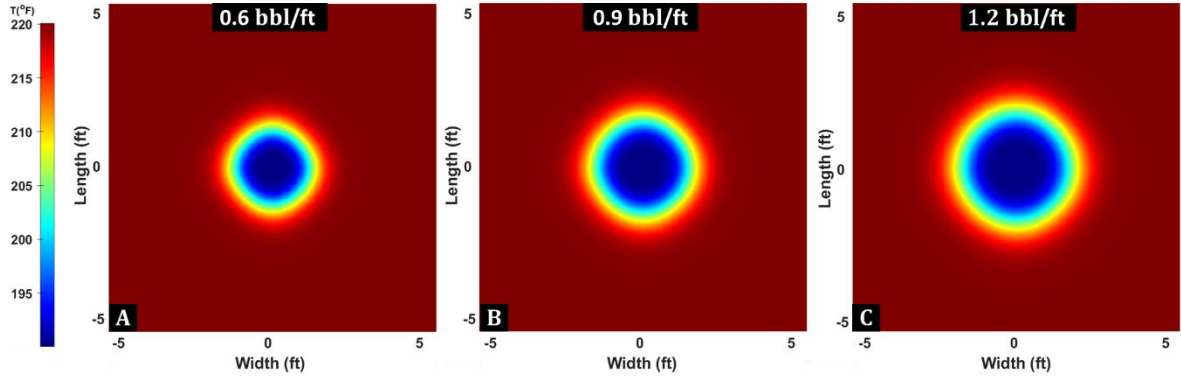


Figure 4.4: Temperature profile at different treatment volumes.

As shown in **Figure 4.5**, the gel penetration matches the temperature cooldown distribution as presented in **Figure 4.4**. The gel penetration could be hindered if the shut-in time was not sufficient to cure the entire fluid around the wellbore.

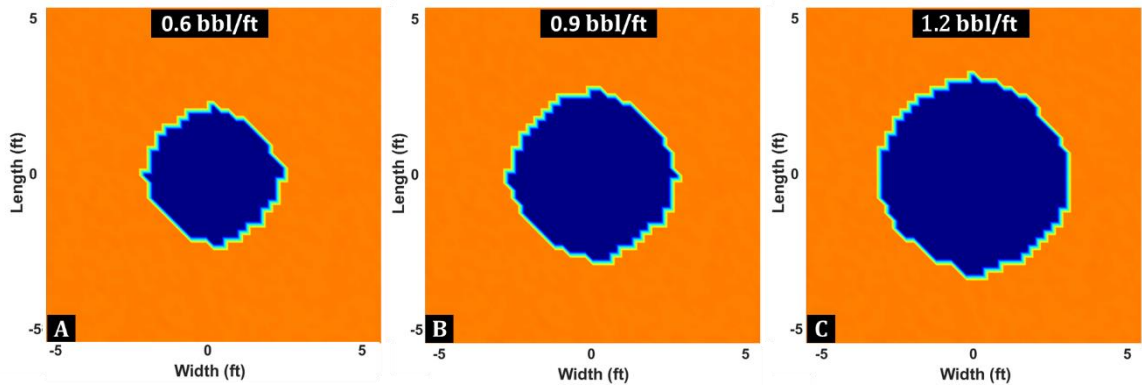


Figure 4.5: Distribution of gel penetration at different treatment volumes.

4.4.1.c Effect of Fluid Temperature

The temperature of the injected fluid may influence the formation temperature around the wellbore based on multiple factors such as treatment volume, injection rate, and targeted

interval. For instance, the cooldown effect during water shutoff injection should be estimated to predict the gelation time to have an excellent plugging with optimum shut-in time. **Figure 4.6 (A)** and **(B)** present typical examples of excellent gelation using different fluid temperatures, which are 190°F and 170°F, respectively. In contrast, **Figure 4.6 (C)** is an example of poor gelation and plugging due to insufficient curing time to gel the fluids surrounding the wellbore. This issue can be solved by increasing the shut-in time or lowering the injection rate to minimize the cooling effect.

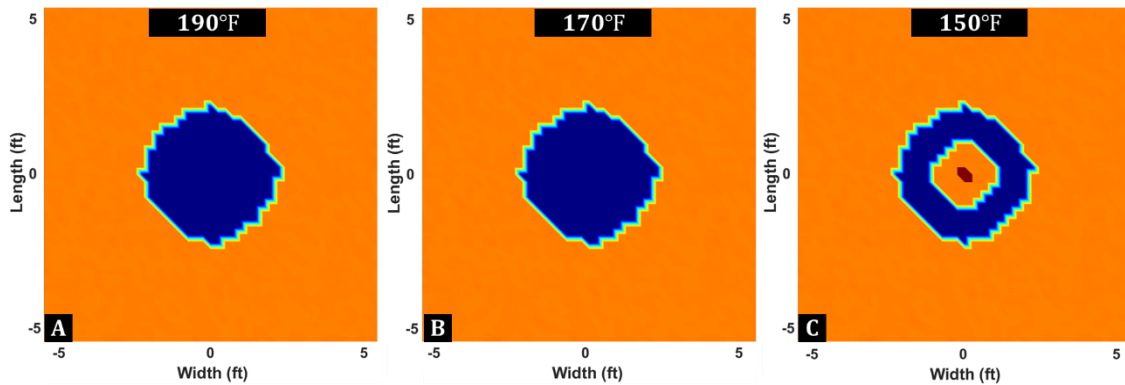


Figure 4.6: Radial gel penetration at altered injected fluid temperature.

4.4.1.d Effect of Activator Concentration

In general, deep gel penetration involves a long gelation time and, hence, an appropriate setting time. For this system, more activator loadings will yield a faster gelation reaction. For example, **Figure 4.7** depicts the gelation quality at varied activator concentrations. At 25 and 30 wt.% of activator loadings, the gel penetration was perfect, as shown in **Figure 4.7 (A)** and **(B)**, respectively. Nevertheless, in **Figure 4.7 (C)**, the gelation was poor due to the low activator loading (20 wt.%), which requires a longer shut-in duration.

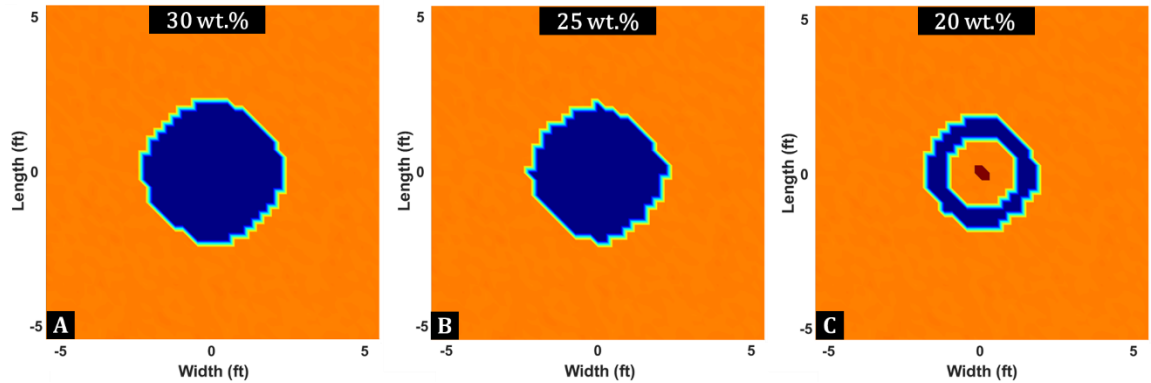


Figure 4.7: Radial gel penetration at altered activator loadings.

4.4.1.e Effect of Heterogeneity

The heterogeneity of formation rocks may drastically influence the penetration behavior of in-situ gels while injecting. It can impact the gel propagation to seal off high permeability channels or thief zones. For instance, within the heterogeneous reservoirs, the water shutoff fluid may preferentially penetrate through the thief zones and leave some low permeability zones untreated^{30,31}. The following figures investigate the performance of water shutoff treatment in heterogeneous formations having multiple layers. For example, **Figure 4.8** illustrates the pre-treatment and post-treatment permeability distribution in 3D, which has three layers with original permeabilities in mD (40 [top], 1,500 [middle], 40 [bottom]). The yellow layer in the middle represents the thief zone, and the other two layers in brown are tight zones. After injecting the treatment, the snapshot on the right of **Figure 4.8** confirms that most of the fluid penetrates the high permeability layer up to 3.5 ft of radial penetration.

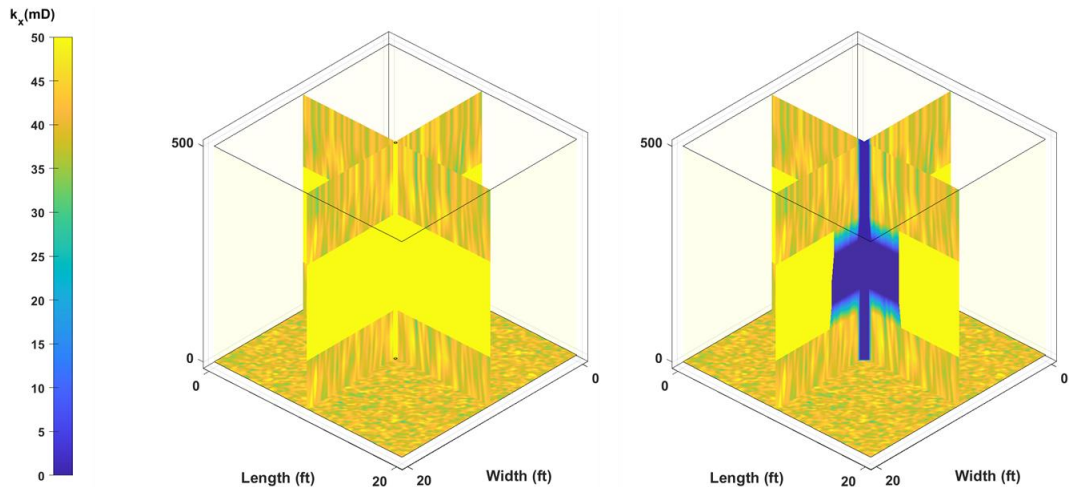


Figure 4.8: Pre-treatment vs post-treatment gel penetration in 3D.

In some cases, the well is having excessive water production coming from two thief zones instead of one. Treating such well requires a careful design to satisfy the required gel penetration for each targeted section. **Figure 4.9** depicts two scenarios of treated layers; the snapshot on the left represents five intervals, including two high permeability layers (500 mD [top], 1500 mD [bottom]), while the other snapshot represents three intervals including one thief zone (1,500 mD [middle]). It is clear from the figure that the one thief zone experienced deeper gel penetration (~ 5 ft [middle]) compared to the two thief zones (2.5 ft [top], 4 ft [bottom]). Additional volume might be required to be injected into the two thief zones to achieve the anticipated gel penetration.

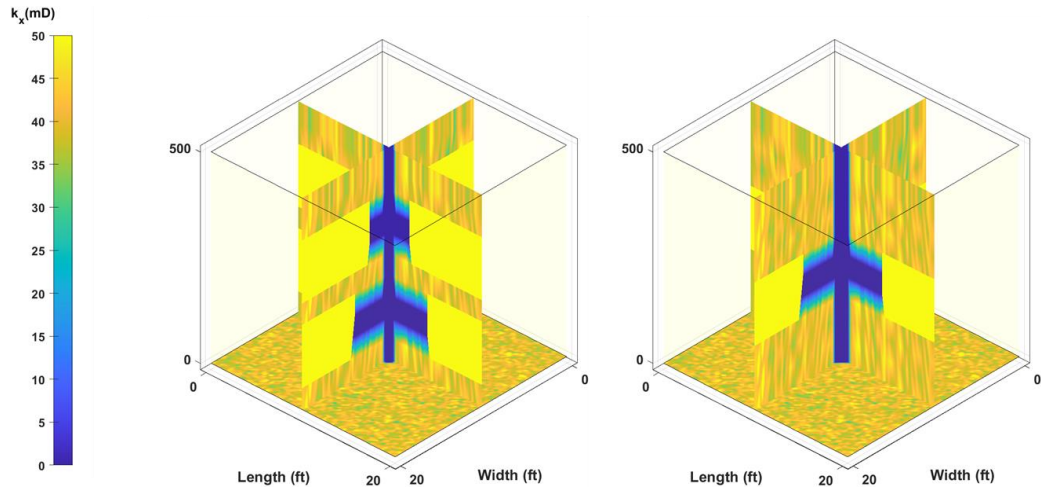


Figure 4.9: Two thief zones vs one thief zone of gel penetration in 3D.

Likewise, the effect of heterogeneity can be seen in the temperature cooldown for each layer. Logically, more cooldown will be anticipated in higher permeability sections. For example, **Figure 4.10** is like **Figure 4.9**, yet it shows the temperature profile in 3D in two thief zones vs. in the thief zone. According to the temperature cool-down profiles from each snapshot, more volume and radial penetration are clear on the right for the one thief zone.

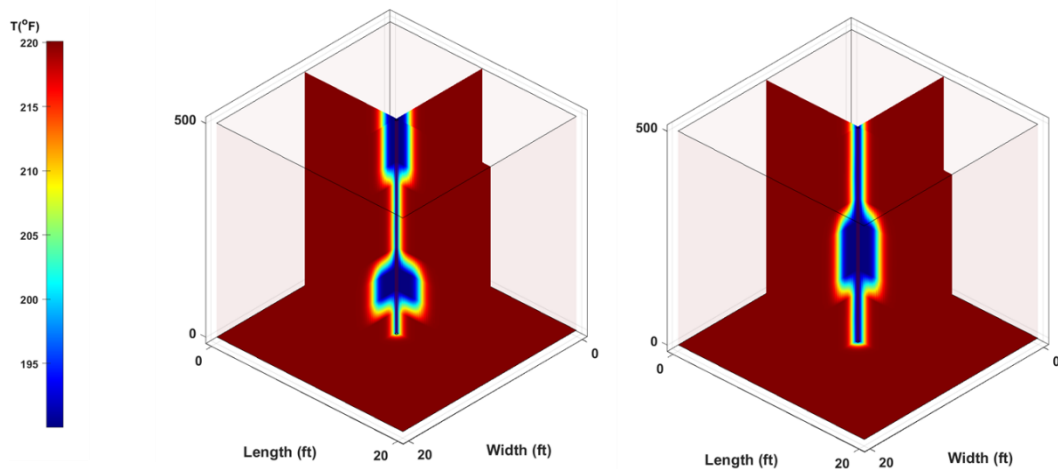


Figure 4.10: Two thief zones vs one thief zone of temperature distribution in 3D.

4.5 Conclusions

The state-of-the-art numerical simulation presented in this study demonstrates the significant influence of various parameters on near-wellbore temperature and gel distribution during the water shutoff injection of the Nanosilica system. The investigated parameters in 2D involve injection rate, temperature, treatment volume, and activator concentration, which were all critical factors affecting gel penetration. Additionally, formation heterogeneity was shown to have a substantial impact on gel distribution in 3D models. The results highlight the importance of careful parameter selection and optimization for successful water shutoff operations. For example, increasing injection rate and/or treatment volume proportionally enhances fluid propagation through the porous medium. However, this leads to greater temperature cooldown around the wellbore, delaying gelation time. Conversely, elevated fluid temperature and activator concentration accelerate gelation time, limiting gel penetration. Formation heterogeneities significantly impact gel distribution and performance:

In particular, high-permeability streaks enable rapid gel transport, increasing breakthrough risks, whereas low-permeability layers impede gel entry, requiring extended treatment periods. Incorporating localized permeability and porosity variations during design phases enhances gel placement precision and operational efficacy. Ultimately, optimizing the Nanosilica system for water shutoff demands balanced consideration of multiple influential factors: namely, injection rate, treatment volume, fluid temperature, activator loading, and reservoir heterogeneity to maximize treatment outcomes and reduce water management costs.

5 CHAPTER 5

CONCLUSION, FUTURE WORK, AND RECOMMENDATION

5.1 Conclusion

The study explores the generation of a numerical simulation model using MATLAB software in 2D and 3D spaces to predict temperature cooldown, warmback, and gel penetration of the Nanosilica system that has been successfully utilized in the field for water and gas shutoff applications. The following are the study's main findings:

- Exploring the effect of temperature cooldown during water shutoff injection. For instance, at high activator concentration (~40 wt.%), the gelation time can increase from 30 to 180 minutes once the temperature drops from 210°F to 160°F. The effect of temperature drop can be increased dramatically after decreasing the activator loading.
- Analyzing the impact of activator concentrations on gelation time at altered temperatures. A careful selection of the activator loading should be considered when designing the nanosilica treatment at high temperatures above 200°F to avoid premature gelation during the injection.

- Constructing and validating a reaction kinetics model from extensive rheological experiments.
- Building a schematic for the numerical algorithm to solve the model in two stages: while injecting the treatment and during the shut-in period.
- Incorporating flow, mass transfer, heat transfer, and gelation models in the algorithm.
- Solving the mathematical formulations and generating multiple scenarios to explore the influences on near-wellbore temperature distribution and gel penetration.
- All generated scenarios are crucial in optimizing Nanosilica treatment before field implementation.

5.2 Future Work and Recommendation

Several areas can be further explored and investigated to enhance the developed model as follows, based on the study's promising outcomes:

- Capturing two-phase flow to mimic downhole conditions.
- Introducing a non-Newtonian flow model since most of the in-situ gels are non-Newtonian.
- Considering variable fluid's thermal and flow characteristics.

- Capturing viscosity development during gelation reaction to accurately predict the gel penetration instead of relying on gelation time and temperature distribution.

References

- (1) Almohsin, A.; Huang, J.; Karadkar, P.; Bataweel, M. Nanosilica Based Fluid System for Water Shut-Off. In *World Petroleum Congress Proceedings*; 2017; Vol. 2017-July.
- (2) Salazar Aldana, S. F.; Sánchez, R. H.; Alviso Zertuche, X. O.; Rivera, M. M.; Camarillo Valtierra, J. L.; Andrade Sierra, E. A.; del Carmen Santini Perez, J.; Anleu, P. L.; Resendiz Torres, J. T. Water Shutoff in Naturally Fractured, Low-Pressure Reservoirs: Case Studies. In *Society of Petroleum Engineers - SPE Asia Pacific Oil and Gas Conference and Exhibition 2020, APOG 2020*; 2020.
- (3) Bai, B.; Wei, M.; Liu, Y. Field and Lab Experience with a Successful Preformed Particle Gel Conformance Control Technology. In *SPE Production and Operations Symposium, Proceedings*; 2013; pp 506–522. <https://doi.org/10.2118/164511-ms>.
- (4) Yusta-García, R.; Orta-Martínez, M.; Mayor, P.; González-Crespo, C.; Rosell-Melé, A. Water Contamination from Oil Extraction Activities in Northern Peruvian Amazonian Rivers. *Environ. Pollut.* **2017**, 225. <https://doi.org/10.1016/j.envpol.2017.02.063>.
- (5) Kazemi, S. Review of Polymer Gels for Conformance Control in Oil Reservoirs, University of Windsor, 2019. <https://scholar.uwindsor.ca/cgi/viewcontent.cgi?article=1109&context=major-papers>.
- (6) Sydansk, R. D.; Romero-Zerón, L. Reservoir Conformance Improvement. In *Reservoir Conformance Improvement*; Society of Petroleum Engineers (SPE), 2011. <https://doi.org/10.2118/9781555633028>.
- (7) Bailey, B.; Crabtree, M.; Tyrie, J.; Elphick, J.; Kuchuk, F.; Romano, C.; Roodhart, L. Water Control. *Oilf. Rev.* **2000**, 12 (1), 30–51.
- (8) Grand View Research Group. *Produced Water Treatment Market Size, Share & Trends Analysis Report By Production Source (Crude Oil, Natural Gas), By Technology, By Application (Onshore, Offshore), By Region, And Segment Forecasts, 2016 - 2024*; 2016. <https://www.grandviewresearch.com/industry-analysis/produced-water-treatment-market>.
- (9) Borling, D.; Chan, K.; Hughes, T.; Sydansk, R. Pushing out the Oil with Conformance Control. *Oilf. Rev.* **1994**, 6 (2).
- (10) Sydansk, R. D.; Southwell, G. P. More than 12 Years' Experience with a Successful Conformance-Control Polymer-Gel Technology. *SPE Prod. Facil.* **2000**, 15 (04), 270–278.
- (11) Bai, B.; Zhou, J.; Yin, M. A Comprehensive Review of Polyacrylamide Polymer Gels for Conformance Control. *Pet. Explor. Dev.* **2015**, 42 (4), 525–532.

- (12) Alshehri, A. J.; Wang, J.; Kwak, H. T.; AlSofi, A. M.; Gao, J. A Study of Gel-Based Conformance Control within Fractured Carbonate Cores Using Low-Field Nuclear-Magnetic-Resonance Techniques. *SPE Reserv. Eval. Eng.* **2019**, *22* (03), 1063–1074.
- (13) Zhang, N.; Abushaikha, A. S. Fully Implicit Reservoir Simulation Using Mimetic Finite Difference Method in Fractured Carbonate Reservoirs. In *SPE reservoir characterisation and simulation conference and exhibition*; OnePetro, 2019.
- (14) Seright, R. S.; Lane, R. H.; Sydansk, R. D. A Strategy for Attacking Excess Water Production. In *SPE Permian Basin Oil and Gas Recovery Conference*; OnePetro, 2001.
- (15) Azari, M.; Soliman, M. Review of Reservoir Engineering Aspects of Conformance Control Technology. In *Permian Basin Oil and Gas Recovery Conference*; OnePetro, 1996.
- (16) Liu, Y.; Bai, B.; Wang, Y. Applied Technologies and Prospects of Conformance Control Treatments in China. *Oil Gas Sci. Technol. d'IFP Energies Nouv.* **2010**, *65* (6), 859–878.
- (17) Thomas, F. B.; Bennion, D. B.; Anderson, G. E.; Meldrum, B. T.; Heaven, W. J. Water Shut-off Treatments-Reduce Water and Accelerate Oil Production. *J. Can. Pet. Technol.* **2000**, *39* (04).
- (18) Seright, R.; Brattekas, B. Water Shutoff and Conformance Improvement: An Introduction. *Pet. Sci.* **2021**, *18* (2), 450–478.
- (19) Torrealba, V. A.; Hoteit, H. Conformance Improvement in Oil Reservoirs by Use of Microemulsions. *SPE Reserv. Eval. Eng.* **2019**, *22* (03), 952–970.
- (20) Joseph, A.; Ajenka, J. A. A Review of Water Shutoff Treatment Strategies in Oil Fields. In *Nigeria Annual International Conference and Exhibition*; OnePetro, 2010.
- (21) Rabiei, M. Excess Water Production Diagnosis in Oil Fields Using Ensemble Classifiers. Curtin University 2011.
- (22) Veil, J. Produced Water Volumes and Management in 2017—an Update. In *GWPC Annual Forum. Oklahoma city, OK*; 2019.
- (23) Kabir, A. H. Chemical Water & Gas Shutoff Technology-An Overview. In *SPE Asia Pacific Improved Oil Recovery Conference*; OnePetro, 2001.
- (24) Elphick, J.; Seright, R. A Classification of Water Problem Types. In *PNC 3rd International Conference on Reservoir Conformance, Profile Control, Water and Gas Shut Off, Houston Houston*; 1997.
- (25) Pappas, J.; Creel, P.; Crook, R. Problem Identification and Solution Method for Water Flow Problems. In *Permian Basin Oil and Gas Recovery Conference*;

- OnePetro, 1996.
- (26) Fulleylove, R. J.; Morgan, J. C.; Stevens, D. G.; Thrasher, D. R. Water Shut-off in Oil Production Wells-Lessons from 12 Treatments. In *Abu Dhabi International Petroleum Exhibition and Conference*; OnePetro, 1996.
 - (27) Mennella, A.; Chiappa, L.; Lockhart, T. P.; Burrafato, G. Candidate and Chemical Selection Rules for Water Shutoff Polymer Treatments. In *SPE European formation damage conference*; Society of petroleum engineers, 1999; pp 1–10.
 - (28) Hild, G. P.; Wackowski, R. K. Reservoir Polymer Gel Treatments to Improve Miscible CO₂ Flood. *SPE Reserv. Eval. Eng.* **1999**, 2 (02), 196–204.
 - (29) Love, T.; McCarty, A.; Miller, M. J.; Semmelbeck, M. Problem Diagnosis, Treatment Design, and Implementation Process Improves Waterflood Conformance. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 1998.
 - (30) Smith, D. D.; Giraud, M. J.; Kemp, C.; McBee, M. S.; Taitano, J.; Winfield, M.; Portwood, J. T.; Everett, D. M. The Successful Evolution of Anton Irish Conformance Efforts. In *SPE annual technical conference and exhibition*; OnePetro, 2006.
 - (31) Liang, J.-T.; Seright, R. S. Further Investigations of Why Gels Reduce Water Permeability More than Oil Permeability. *SPE Prod. Facil.* **1997**, 12 (04), 225–230.
 - (32) Yortsos, Y. C.; Choi, Y.; Yang, Z.; Shah, P. C. Analysis and Interpretation of Water/Oil Ratio in Waterfloods. *Spe J.* **1999**, 4 (04), 413–424.
 - (33) Chan, K. S. Water Control Diagnostic Plots. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 1995.
 - (34) Hwan, R. N. Numerical Simulation Study of Water Shut-off Treatment Using Polymers. In *Low Permeability Reservoirs Symposium*; OnePetro, 1993.
 - (35) Economides, M. J.; Hill, A. D.; Ehlig-Economides, C. *Petroleum Production Systems*; 1994.
 - (36) Novotny, R. J. Matrix Flow Evaluation Technique for Water Control Applications. In *SPE European Formation Damage Conference*; OnePetro, 1995.
 - (37) Lenn, C.; Kuchuk, F. J.; Rounce, J.; Hook, P. Horizontal Well Performance Evaluation and Fluid Entry Mechanisms. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 1998.
 - (38) Bai, B.; Li, Y.; Liu, X. New Development of Water Shutoff and Profile Control in Oilfields in China. *Oil Drill. Prod. Technol.* **1999**, 20 (3), 64–68.
 - (39) Wang, H.; Guo, W.; Jiang, H. Study and Application of Weak Gel System

Prepared by Complex Polymer Used for Depth Profile Modification. In *SPE International Symposium on Oilfield Chemistry*; OnePetro, 2001.

- (40) Chen, X.; Feng, Q.; Sepehrnoori, K.; Goudarzi, A.; Bai, B. Mechanistic Modeling of Gel Microsphere Surfactant Displacement for Enhanced Oil Recovery after Polymer Flooding. In *SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition*; OnePetro, 2015.
- (41) Yu, L.; Sang, Q.; Dong, M. Enhanced Oil Recovery Ability of Branched Preformed Particle Gel in Heterogeneous Reservoirs. *Oil Gas Sci. Technol. d'IFP Energies Nouv.* **2018**, 73, 65.
- (42) Boul, P. J.; Ajayan, P. M. Nanotechnology Research and Development in Upstream Oil and Gas. *Energy Technol.* **2020**, 8 (1), 1901216.
- (43) Kong, X.; Ohadi, M. M. Applications of Micro and Nano Technologies in the Oil and Gas Industry-an Overview of the Recent Progress. In *Abu Dhabi international petroleum exhibition and conference*; OnePetro, 2010.
- (44) Hendraningrat, L.; Li, S.; Torsaeter, O. Enhancing Oil Recovery of Low-Permeability Berea Sandstone through Optimized Nanofluids Concentration. In *SPE enhanced oil recovery conference*; OnePetro, 2013.
- (45) Ogolo, N. A.; Olafuyi, O. A.; Onyekonwu, M. O. Enhanced Oil Recovery Using Nanoparticles. In *SPE Saudi Arabia section technical symposium and exhibition*; OnePetro, 2012.
- (46) Al-Muntasheri, G. A.; Sierra, L.; Garzon, F.; Lynn, J. D.; Izquierdo, G. Water Shut-off with Polymer Gels in a High Temperature Horizontal Gas Well: A Success Story. In *SPE Improved Oil Recovery Symposium*; OnePetro, 2010.
- (47) Al-Mutairi, T. Z.; Shahid, M. A.; Reinhold, M. R.; Gazi, N. H. Remarkable Results from Water Shutoff Treatments Using a New Deep Penetrating Polymer System-Case Histories from South Umm Gudair Field, DZ-Kuwait/Saudi Arabia. In *SPE/IADC Middle East Drilling Technology Conference and Exhibition*; OnePetro, 2003.
- (48) Liao, J. *Gel Treatment Field Application Survey for Water Shut off in Production Wells*; Missouri University of Science and Technology, 2014.
- (49) Smith, D.; Ott, B. A Comprehensive Review of Conformance Engineering Part 1: Understanding the Problem. *World Oil* **2006**, 227 (5), 63–68.
- (50) Freyer, R.; Huse, A. Swelling Packer for Zonal Isolation in Open Hole Screen Completions. In *European Petroleum Conference*; OnePetro, 2002.
- (51) Hecker, M. T.; Barry, M. D.; Ryan, J. T.; Ruiz, V. F.; Stevens, P.; Pedro, N.; Yeh, C. S.; Inglesfield, J. First Installation of Alternate Path Openhole Packer Providing True Zonal Isolation in Openhole Gravel Packs. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 2011.

- (52) Offenbacher, M.; Gadiyar, B.; Messler, D.; Krishnamoorthy, S.-R.; Abasher, D. Swellable Packer Fluids Designed for Zonal Isolation in Openhole Completions. In *SPE European Formation Damage Conference and Exhibition*; OnePetro, 2015.
- (53) Wilson, P.; Hoffman, C. E. Zonal Isolation in Stimulation Treatments and Gas/Water Shutoff Using Thermally Compensated Inflatable Packers and Plugs. In *IADC/SPE Drilling Conference*; OnePetro, 2000.
- (54) Bybee, K. Unique Rigless Casing Leak Repair. *J. Pet. Technol.* **2001**, *53* (06), 28–29.
- (55) Harrison, T. W.; Blount, C. G. Coiled Tubing Cement Squeeze Technique at Prudhoe Bay, Alaska. In *SPE California Regional Meeting*; OnePetro, 1986.
- (56) Lai, Q. J.; Bond, A. J.; Cahalane, T. W.; Carpenter, R. B.; Newhouse, D. P.; Singh, T.; Styler, J. W. Gel-Cement Combination Squeezes for Gas Shutoff. In *SPE Western Regional Meeting*; OnePetro, 1999.
- (57) Loveland, K. R.; Bond, A. J. Recent Applications of Coiled Tubing in Remedial Wellwork at Prudhoe Bay. In *SPE Gas Technology Symposium*; OnePetro, 1996.
- (58) Hornbrook, P. R.; Mason, C. M. Improved Coiled-Tubing Squeeze-Cementing Techniques at Prudhoe Bay. *J. Pet. Technol.* **1991**, *43* (04), 455–459.
- (59) Permana, D.; Ferdian, G.; Aji, M.; Siswati, E. Extracting Lessons Learned of 35 Water Shut-off Jobs in Mature Fields to Improve Success Ratio of Water Shut-off Job. In *SPE/IATMI Asia Pacific Oil & Gas Conference and Exhibition*; OnePetro, 2015.
- (60) Ahmad, N.; Al-Shabibi, H.; Zeybek, M.; Malik, S. Comprehensive Diagnostic and Water Shut-off in Open and Cased Hole Carbonate Horizontal Wells. In *Abu Dhabi International Petroleum Conference and Exhibition*; OnePetro, 2012.
- (61) Taha, A.; Amani, M. Overview of Water Shutoff Operations in Oil and Gas Wells; Chemical and Mechanical Solutions. *ChemEngineering* **2019**, *3* (2), 51.
- (62) Surguchev, L. M. Water Shut-off: Simulation and Laboratory Evaluation. In *European Petroleum Conference*; OnePetro, 1998.
- (63) Sun, Y.; Fang, Y.; Chen, A.; You, Q.; Dai, C.; Cheng, R.; Liu, Y. Gelation Behavior Study of a Resorcinol–Hexamethyleneteramine Crosslinked Polymer Gel for Water Shut-off Treatment in Low Temperature and High Salinity Reservoirs. *Energies* **2017**, *10* (7), 913.
- (64) Sydansk, R. D. A New Conformance-Improvement-Treatment Chromium (III) Gel Technology. In *SPE enhanced oil recovery symposium*; OnePetro, 1988.
- (65) Chan, K. S. Injection Profile Modification with a New Non-Polymer Gelling System. In *PETSOC Annual Technical Meeting*; PETSOC, 1989; p PETSOC-89.

- (66) He, H.; Wang, Y.; Qi, Z.; Sun, X. Gelation Performance and Feasibility Study of an Environmental Friendly Improved Inorganic Aluminum Gel for Conformance Control under Harsh Reservoir Conditions. *J. Energy Resour. Technol.* **2017**, *139* (1), 12911.
- (67) He, H.; Wang, Y.; Qi, Z.; Lv, P.; Guo, M. The Study of an Inorganic Gel for Profile Modification in High-Temperature and Low-Permeability Sandstone Reservoirs. *Pet. Sci. Technol.* **2013**, *31* (19), 1940–1947.
- (68) Seright, R. S. Gel Placement in Fractured Systems. *SPE Prod. Facil.* **1995**, *10* (04), 241–248.
- (69) El-Hadidi, S. M.; Falade, G. K.; Dabbouk, C.; Al-Ansari, F. Water Injection Profile Modification in a Layered Reservoir Using Polymer Treatment. In *Middle East Oil Show and Conference*; OnePetro, 1997.
- (70) Gallino, G.; Guarneri, A.; Poli, G.; Xiao, L. Scleroglucan Biopolymer Enhances WBM Performances. In *SPE annual technical conference and exhibition*; OnePetro, 1996.
- (71) A., Z.; N., K. Two-Phase Flow Through Porous Media: Effect of an Adsorbed Polymer Layer.
- (72) Zaitoun, A.; Bertin, H.; Lasseux, D. Two-Phase Flow Property Modifications by Polymer Adsorption. In *SPE/DOE improved oil recovery symposium*; OnePetro, 1998.
- (73) Sparlin, D. D.; Hagen, R. W. Controlling Water in Producing Operations. *World Oil;(United States)* **1984**, *198* (5).
- (74) Sydansk, R. D. Polymer-Enhanced Foams Part 1: Laboratory Development and Evaluation. *SPE Adv. Technol. Ser.* **1994**, *2* (02), 150–159.
- (75) Seright, R. S.; Liang, J. A Survey of Field Applications of Gel Treatments for Water Shutoff. In *SPE Latin America/Caribbean Petroleum Engineering Conference*; OnePetro, 1994.
- (76) Bedaiwi, E.; Al-Anazi, B. D.; Al-Anazi, A. F.; Paiaman, A. M. Polymer Injection for Water Production Control through Permeability Alteration in Fractured Reservoir. *Nafta* **2009**, *60* (4), 221–231.
- (77) Bai, B.; Wei, M.; Liu, Y. Field and Lab Experience with a Successful Preformed Particle Gel Conformance Control Technology. In *SPE production and operations symposium*; OnePetro, 2013.
- (78) Sydansk, R. D.; Moore, P. E. Gel Conformance Treatments Increase Oil Production in Wyoming. *Oil Gas Journal;(United States)* **1992**, *90* (3).
- (79) Delshad, M.; Varavei, A.; Goudarzi, A.; Zhang, H.; Sepehrnoori, K.; Bai, B.; Hu, Y. Water Management in Mature Oil Fields Using Preformed Particle Gels. In *SPE*

Western Regional & AAPG Pacific Section Meeting 2013 Joint Technical Conference; Society of Petroleum Engineers, 2013.

- (80) Chauveteau, G.; Tabary, R.; Le Bon, C.; Renard, M.; Feng, Y.; Omari, A. In-Depth Permeability Control by Adsorption of Soft Size-Controlled Microgels. In *SPE European Formation Damage Conference*; OnePetro, 2003.
- (81) Bai, B.; Li, L.; Liu, Y.; Liu, H.; Wang, Z.; You, C. Preformed Particle Gel for Conformance Control: Factors Affecting Its Properties and Applications. *SPE Reserv. Eval. Eng.* **2007**, *10* (04), 415–422.
- (82) Bai, B.; Liu, Y.; Coste, J.-P.; Li, L. Preformed Particle Gel for Conformance Control: Transport Mechanism through Porous Media. *SPE Reserv. Eval. Eng.* **2007**, *10* (02), 176–184.
- (83) Imqam, A.; Goudarzi, A.; Delshad, M.; Bai, B. Development of a Mechanistic Numerical Simulator for Preformed Particle Gel Applications in Non-Crossflow Heterogeneous Reservoirs. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 2015.
- (84) Kumar, A.; Mahto, V.; Sharma, V. P. Reinforced Preformed Particle Gel: Synthesis, Characterization and Performance Evaluation for Water Shut-off Jobs in Heterogeneous Reservoir. *J. Pet. Sci. Eng.* **2020**, *193*.
<https://doi.org/10.1016/j.petrol.2020.107408>.
- (85) Goudarzi, A. M.; Zhang, H.; Varavei, A.; Taksaudom, P.; Hu, Y.; Delshad, M.; Bai, B.; Sepehrnoori, K. A Laboratory and Simulation Study of Preformed Particle Gels for Water Conformance Control. **2015**.
- (86) Tongwa, P.; Bai, B. Degradable Nanocomposite Preformed Particle Gel for Chemical Enhanced Oil Recovery Applications. *J. Pet. Sci. Eng.* **2014**, *124*, 35–45.
- (87) Esfahlan, M. S.; Khodapanah, E.; Tabatabaei-Nezhad, S. A. Comprehensive Review on the Research and Field Application of Preformed Particle Gel Conformance Control Technology. *J. Pet. Sci. Eng.* **2021**, *202*, 108440.
- (88) Imqam, A.; Bai, B.; Ramadan, M. Al; Wei, M.; Delshad, M.; Sepehrnoori, K. Preformed-Particle-Gel Extrusion through Open Conduits during Conformance-Control Treatments. *SPE J.* **2015**, *20* (05), 1083–1093.
- (89) Sydansk, R. D.; Al-Dhafeeri, A. M.; Xiong, Y.; Seright, R. S. Polymer Gels Formulated with a Combination of High-and Low-Molecular-Weight Polymers Provide Improved Performance for Water-Shutoff Treatments of Fractured Production Wells. *SPE Prod. Facil.* **2004**, *19* (04), 229–236.
- (90) Sydansk, R. D.; Xiong, Y.; Al-Dhafeeri, A. M.; Schrader, R. J.; Seright, R. S. Characterization of Partially Formed Polymer Gels for Application to Fractured Production Wells for Water-Shutoff Purposes. *SPE Prod. Facil.* **2005**, *20* (03),

240–249.

- (91) Elaf, R.; Ben Ali, A.; Saad, M.; Hussein, I. A.; Nimir, H.; Bai, B. Biodegradable Preformed Particle Gel (PPG) Made of Natural Chitosan Material for Water Shut-Off Application. *Polymers (Basel)*. **2023**, *15* (8), 1961.
- (92) Coste, J.-P.; Liu, Y.; Bai, B.; Li, Y.; Shen, P.; Wang, Z.; Zhu, G. In-Depth Fluid Diversion by Pre-Gelled Particles. Laboratory Study and Pilot Testing. *SPE/DOE Improv. Oil Recover. Symp.* **2000**.
- (93) Rozhkova, Y. A.; Burin, D. A.; Galkin, S. V.; Yang, H. Review of Microgels for Enhanced Oil Recovery: Properties and Cases of Application. *Gels* **2022**, *8* (2), 112.
- (94) Rousseau, D.; Chauveteau, G.; Renard, M.; Tabary, R.; Zaitoun, A.; Mallo, P.; Braun, O.; Omari, A. Rheology and Transport in Porous Media of New Water Shutoff/Conformance Control Microgels. In *SPE international symposium on oilfield chemistry*; OnePetro, 2005.
- (95) Zaitoun, A.; Tabary, R.; Rousseau, D.; Pichery, T. R.; Nouyoux, S.; Mallo, P.; Braun, O. Using Microgels to Shut off Water in a Gas Storage Well. In *International Symposium on Oilfield Chemistry*; OnePetro, 2007.
- (96) Suk Kyoon, C.; Ermel, Y. M.; Bryant, S. L.; Huh, C.; Sharma, M. M. Transport of a PH-Sensitive Polymer in Porous Media for Novel Mobility-Control Applications. In *SPE/DOE Symposium on Improved Oil Recovery*; OnePetro, 2006.
- (97) Huh, C.; Choi, S. K.; Sharma, M. M. A Rheological Model for PH-Sensitive Ionic Polymer Solutions for Optimal Mobility Control Applications. In *SPE annual technical conference and exhibition*; OnePetro, 2005.
- (98) Al-Anazi, H. A.; Sharma, M. M. Use of a PH Sensitive Polymer for Conformance Control. In *International Symposium and Exhibition on Formation Damage Control*; OnePetro, 2002.
- (99) Benson, I. P.; Nghiem, L. X.; Bryant, S. L.; Huh, C. Development and Use of a Simulation Model for Mobility/Conformance Control Using a PH-Sensitive Polymer. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 2007.
- (100) Pritchett, J.; Frampton, H.; Brinkman, J.; Cheung, S.; Morgan, J.; Chang, K. T.; Williams, D.; Goodgame, J. Field Application of a New In-Depth Waterflood Conformance Improvement Tool. In *SPE international improved oil recovery conference in Asia Pacific*; OnePetro, 2003.
- (101) Frampton, H.; Morgan, J. C.; Cheung, S. K.; Munson, L.; Chang, K. T.; Williams, D. Development of a Novel Waterflood Conformance Control System. In *Proceedings - SPE Symposium on Improved Oil Recovery*; 2004; Vol. 2004-April. <https://doi.org/10.2118/89391-ms>.
- (102) Feng, Y.; Tabary, R.; Renard, M.; Le Bon, C.; Omari, A.; Chauveteau, G.

- Characteristics of Microgels Designed for Water Shutoff and Profile Control. In *International Symposium on Oilfield Chemistry*; OnePetro, 2003.
- (103) Chauveteau, G.; Tabary, R.; Blin, N.; Renard, M.; Rousseau, D.; Faber, R. Disproportionate Permeability Reduction by Soft Preformed Microgels. In *SPE/DOE Symposium on Improved Oil Recovery*; OnePetro, 2004.
- (104) Kennedy, H. T. Chemical Methods for Shutting off Water in Oil and Gas Wells. *Trans. AIME* **1936**, *118* (01), 177–186.
- (105) Gussenov, I.; Nuraje, N.; Kudaibergenov, S. Bulk Gels for Permeability Reduction in Fractured and Matrix Reservoirs. *Energy Reports* **2019**, *5*, 733–746.
- (106) Pham, L. T.; Hatzignatiou, D. G. Rheological Evaluation of a Sodium Silicate Gel System for Water Management in Mature, Naturally-Fractured Oilfields. *J. Pet. Sci. Eng.* **2016**, *138*, 218–233.
- (107) H.A., N.-E.-D.; K.C., T. Evaluation of Sodium Silicate/Urea Gels Used for Water Shut-off Treatments. *J. Pet. Sci. Eng.* *48* (3–4), 141–160.
- (108) Iler, K. R. The Chemistry of Silica. *Solubility, Polym. colloid Surf. Prop. Biochem. silica* **1979**.
- (109) Amiri, H. A. A. Evaluation of Alkaline Sodium Silicate Gel for Reservoir In-Depth Profile Modifications to Enhance Water Sweep Efficiency in Sandstone Reservoirs. **2014**.
- (110) Bauer, S.; Gronewald, P.; Hamilton, J.; LaPlant, D.; Mansure, A. High-Temperature Plug Formation with Silicates. In *SPE international Symposium on Oilfield chemistry*; OnePetro, 2005.
- (111) Dai, C.; You, Q.; He, L.; Zhao, F. Study and Field Application of a Profile Control Agent in a High Temperature and High Salinity Reservoir. *Energy Sources, Part A Recover. Util. Environ. Eff.* **2011**, *34* (1), 53–63.
- (112) Lakatos, I.; Lakatos-Szabó, J. Reservoir Conformance Control in Oilfields Using Silicates: State-of-the-Arts and Perspectives. In *SPE Annual Technical Conference and Exhibition*; OnePetro, 2012.
- (113) Vinot, B.; Schechter, R. S.; Lake, L. W. Formation of Water-Soluble Silicate Gels by the Hydrolysis of a Diester of Dicarboxylic Acid Solubilized as Microemulsions. *SPE Reserv. Eng.* **1989**, *4* (03), 391–397.
- (114) Herring, G. D.; Milloway, J. T.; Wilson, W. N. Selective Gas Shut-Off Using Sodium Silicate in the Prudhoe Bay Field, AK. In *SPE Formation Damage Control Symposium*; OnePetro, 1984.
- (115) Mebratu, A.; Nerland, B.; Kleppan, T. Annular Barrier Re-Establishment Using a Long-Life, High-Strength Polymer Gel System. In *SPE International Conference and Exhibition on Formation Damage Control*; SPE, 2004; p SPE-86547.

- (116) Lantz, M.; Muniz, G. Conformance Improvement Using Polymer Gels: A Case Study Approach. In *SPE Improved Oil Recovery Conference?*; SPE, 2014; p SPE-169072.
- (117) Deolarte, C.; Vasquez, J.; Soriano, E.; Santillan, A. Successful Combination of an Organically Crosslinked Polymer System and a Rigid-Setting Material for Conformance Control in Mexico. *SPE Prod. Oper.* **2009**, *24* (04), 522–529.
- (118) Dai, L. C.; You, Q.; Yuhong, X.; Long, H.; Ya, C.; Fulin, Z. Case Study on Polymer Gel to Control Water Coning for Horizontal Well in Offshore Oilfield. In *Offshore Technology Conference*; OTC, 2011; p OTC-21125.
- (119) Ortiz Polo, R. P.; Monroy, R. R.; Toledo, N.; Dalrymple, E. D.; Eoff, L.; Everett, D. Field Applications of Low Molecular-Weight Polymer Activated with an Organic Crosslinker for Water Conformance in South Mexico. In *SPE Annual Technical Conference and Exhibition?*; SPE, 2004; p SPE-90449.
- (120) Wu, Q.; Ge, J.; Ding, L.; Wei, K.; Liu, Y.; Deng, X. A Successful Field Application of Polymer Gel for Water Shutoff in a Fractured Tight Sandstone Reservoir. In *SPE Middle East Oil and Gas Show and Conference*; SPE, 2021; p D031S028R008.
- (121) Li, C. Pilot Tests of PPG Combined with In-Situ Gel to Control Conformance for Wenliu Oilfield. *Neimenggu PetroChemical* **2005**, *31* (4), 95–96.
- (122) Wang, J.; Yuan, Y. Using Combined Technology to Control In-Depth Conformance for Low Permeable Fractured Reservoirs. *Adv. Fine PetroChemicals* **2006**, *7* (6), 39–41.
- (123) Jurinak, J. J.; Summers, L. E. Oilfield Applications of Colloidal Silica Gel. *SPE Prod. Eng.* **1991**, *6* (04), 406–412.
- (124) Rolfsvag, T. A.; Jakobsen, S. R.; Lund, T. A. T.; Stromsvik, G. Thin Gel Treatment of an Oil Producer at the Gullfaks Field: Results and Evaluation. In *European Production Operations Conference and Exhibition*; OnePetro, 1996.
- (125) Lakatos, I.; Lakatos-Szabó, J.; Kosztin, B.; Al-Sharji, H. H.; Ali, E.; Al-Mujaini, A. A.; Al-Alawi, N. Application of Silicate/Polymer Water Shut-off Treatment in Faulted Reservoirs with Extreme High Permeability. In *SPE European Formation Damage Conference and Exhibition*; SPE, 2011; p SPE-144112.
- (126) Lakatos, I.; Szentes, G.; Lakatos-Szabo, J.; Vago, A.; Karaffa, Z. Development and Application of a Composite Silicate Gel for Water Shutoff Treatment in Hungary. In *IOR 2019–20th European Symposium on Improved Oil Recovery*; European Association of Geoscientists & Engineers, 2019; Vol. 2019, pp 1–15.
- (127) Long, Y.; Wang, Z.; Ding, H.; Geng, J.; Bai, B. Investigation and Characterization of a Robust Nanocomposite Preformed Particle Gel for Enhanced Oil Recovery. *Energy and Fuels* **2019**, *33* (6), 5055–5066.

<https://doi.org/10.1021/acs.energyfuels.9b00778>.

- (128) Schattling, P.; Jochum, F. D.; Theato, P. Multi-Stimuli Responsive Polymers—the All-in-One Talents. *Polym. Chem.* **2014**, *5* (1), 25–36.
- (129) Zhang, J.; Lei, W.; Liu, D.; Wang, X. Synergistic Influence from the Hybridization of Boron Nitride and Graphene Oxide Nanosheets on the Thermal Conductivity and Mechanical Properties of Polymer Nanocomposites. *Compos. Sci. Technol.* **2017**, *151*, 252–257.
- (130) Hu, Y.; Zhou, S.; Wu, L. Surface Mechanical Properties of Transparent Poly (Methyl Methacrylate)/Zirconia Nanocomposites Prepared by in Situ Bulk Polymerization. *Polymer (Guildf)*. **2009**, *50* (15), 3609–3616.
- (131) Michael, F. M.; Fathima, A.; AlYemni, E.; Jin, H.; Almohsin, A.; Alsharaeh, E. H. Enhanced Polyacrylamide Polymer Gels Using Zirconium Hydroxide Nanoparticles for Water Shutoff at High Temperatures: Thermal and Rheological Investigations. *Ind. Eng. Chem. Res.* **2018**, *57* (48), 16347–16357.
- (132) Liu, Y.; Dai, C.; Wang, K.; Zou, C.; Gao, M.; Fang, Y.; Zhao, M.; Wu, Y.; You, Q. Study on a Novel Cross-Linked Polymer Gel Strengthened with Silica Nanoparticles. *Energy & Fuels* **2017**, *31* (9), 9152–9161.
- (133) Asadizadeh, S.; Ayatollahi, S.; ZareNezhad, B. Performance Evaluation of a New Nanocomposite Polymer Gel for Water Shutoff in Petroleum Reservoirs. *J. Dispers. Sci. Technol.* **2019**, *40* (10), 1479–1487.
- (134) Cheraghian, G. Thermal Resistance and Application of Nanoclay on Polymer Flooding in Heavy Oil Recovery. *Pet. Sci. Technol.* **2015**, *33* (17–18), 1580–1586.
- (135) Shen, J.; Yan, B.; Li, T.; Long, Y.; Li, N.; Ye, M. Study on Graphene-Oxide-Based Polyacrylamide Composite Hydrogels. *Compos. Part A Appl. Sci. Manuf.* **2012**, *43* (9), 1476–1481.
- (136) Singh, R.; Mahto, V.; Vuthaluru, H. Development of a Novel Fly Ash-Polyacrylamide Nanocomposite Gel System for Improved Recovery of Oil from Heterogeneous Reservoir. *J. Pet. Sci. Eng.* **2018**, *165*, 325–331.
- (137) Chen, L.; Wang, J.; Yu, L.; Zhang, Q.; Fu, M.; Zhao, Z.; Zuo, J. Experimental Investigation on the Nanosilica-Reinforcing Polyacrylamide/Polyethylenimine Hydrogel for Water Shutoff Treatment. *Energy & Fuels* **2018**, *32* (6), 6650–6656.
- (138) Liu, R.; Liang, S.; Tang, X.-Z.; Yan, D.; Li, X.; Yu, Z.-Z. Tough and Highly Stretchable Graphene Oxide/Polyacrylamide Nanocomposite Hydrogels. *J. Mater. Chem.* **2012**, *22* (28), 14160–14167.
- (139) Almohsin, A. M.; Alsharaeh, E.; Fathima, A.; Bataweel, M. A Novel Polymer Nanocomposite Graphene Based Gel for High Temperature Water Shutoff Applications. In *SPE Kingdom of Saudi Arabia annual technical symposium and exhibition*; OnePetro, 2018.

- (140) Pereira, K. A. B.; Aguiar, K. L. N. P.; Oliveira, P. F.; Vicente, B. M.; Pedroni, L. G.; Mansur, C. R. E. Synthesis of Hydrogel Nanocomposites Based on Partially Hydrolyzed Polyacrylamide, Polyethyleneimine, and Modified Clay. *ACS omega* **2020**, *5* (10), 4759–4769.
- (141) Sheidaie, A.; Fahimpour, J.; Sharifi, M. Experimental Investigation of Low-Concentrated Nanocomposite Polymer Gels for Water Shutoff Treatment Under Reservoir Conditions. *SPE J.* **2022**, *27* (04), 2390–2407.
- (142) Khoshkar, P. A.; Fatemi, M.; Ghazanfari, M. H. Static and Dynamic Evaluation of the Effect of Nanomaterials on the Performance of a Novel Synthesized PPG for Water Shut-off and Improved Oil Recovery in Fractured Reservoirs. *J. Pet. Sci. Eng.* **2020**, *189*, 107019.
- (143) Paprouschi, A.; Fatemi, S. M.; Ghazanfari, M. H. Rheology and Morphology Analysis of an Enhanced Preformed Particle Gel Using Silicate Sodium and Graphene Nanoplatelets. In *81st EAGE Conference and Exhibition 2019*; European Association of Geoscientists & Engineers, 2019; Vol. 2019, pp 1–5.
- (144) Pandit, Y. K.; Mahto, V.; Udayabhanu, G.; Ravishankar, B.; Dhandi, M. Preparation, Characterization, and Evaluation of a Nanomaterial Reinforced Particle Gel System for the Control of Excessive Water Production in the Mature Oil Fields. *Geoenergy Sci. Eng.* **2024**, 212707.
- (145) Boul, P. J.; Ye, A.; Pang, X.; Goel, V.; Eoff, L.; Reddy, B. R. Nanosilica-Based Conformance Gels. In *SPE European Formation Damage Conference and Exhibition*; OnePetro, 2015.
- (146) Almohsin, A.; Hung, J.; Alabdrabalnabi, M.; Sherief, M. A Nano Method for a Big Challenge: Nanosilica-Based Sealing System for Water Shutoff. In *SPE Middle East Oil & Gas Show and Conference*; OnePetro, 2021.
- (147) Karadkar, P.; Almohsin, A.; Bataweel, M.; Huang, J. In-Situ Pore Plugging Using Nanosilica Based Fluid System for Gas Shutoff. *Soc. Pet. Eng. - Abu Dhabi Int. Pet. Exhib. Conf. 2019, ADIP 2019* **2019**, No. November, 11–14. <https://doi.org/10.2118/197578-ms>.
- (148) Mittal, A.; Gupta, D. K. *Review of Gelation Time Models of Polymer Systems Used for Profile Modification and Water-Shut off Jobs*; 2018. <http://iaetsdjaras.org/>.
- (149) Alabdrabalnabi, M. I.; Almohsin, A. M.; Busaleh, A. S.; Alharbi, B. G. An Experimental Approach of a Robust Polymer Gels for Water Shutoff Applications in Carbonate Formations; 2023. <https://doi.org/10.2118/214168-ms>.
- (150) Al-Muntasheri, G. A.; Nasr-El-Din, H. A.; Zitha, P. L. J. Gelation Kinetics and Performance Evaluation of an Organically Crosslinked Gel at High Temperature and Pressure. *SPE J.* **2008**, *13* (03), 337–345. <https://doi.org/10.2118/104071-PA>.
- (151) Almohsin, A.; Nakhli, A.; Badairy, H.; Alabdrabalnabi, M.; Hung, J.; Bataweel,

- M. A New Polymer System for Water Shutoff Application in Carbonate Formations. In *Society of Petroleum Engineers - SPE Kingdom of Saudi Arabia Annual Technical Symposium and Exhibition*; 2016. <https://doi.org/10.2118/182843-ms>.
- (152) Alabdrabalnabi, M.; Almohsin, A.; Huang, J.; Sherief, M. Experimental Investigation of a Novel Nanosilica for Blocking Unwanted Water Production. In *Society of Petroleum Engineers - SPE/IATMI Asia Pacific Oil and Gas Conference and Exhibition 2021, APOG 2021*; 2021. <https://doi.org/10.2118/205820-MS>.
- (153) Arrhenius, S. Über Die Dissociationswärme Und Den Einfluss Der Temperatur Auf Den Dissociationsgrad Der Elektrolyte. *Zeitschrift für Phys. Chemie* **1889**, 4U (1). <https://doi.org/10.1515/zpch-1889-0408>.
- (154) Hurd, C. B.; Letteron, H. A. Studies on Silicic Acid Gels - I. Measurements on Surface Tension during Setting and the Effect of Temperature on the Time of Set. *J. Phys. Chem.* **1932**, 36 (2).
- (155) Jordan, D. S.; Green, D. W.; Terry, R. E.; Willhite, G. P. EFFECT OF TEMPERATURE ON GELATION TIME FOR POLYACRYLAMIDE/CHROMIUM (III) SYSTEMS. In *Society of Petroleum Engineers journal*; 1982; Vol. 22. <https://doi.org/10.2118/10059-PA>.
- (156) D., B.; O., M.; N., B.; A., Z. Rheological Screening of Low-Molecular-Weight Polyacrylamide/Chromium (III) Acetate Water Shutoff Gels.
- (157) Appah D, M. S.; OF, J. Modelling Gelation Time of Organically Cross-Linked Water-Shutoff Systems for Oil Wells. *J. Pet. Environ. Biotechnol.* **2016**, 07 (02). <https://doi.org/10.4172/2157-7463.1000267>.
- (158) Xianchao, C.; Qihong, F.; Qiang, W. Performance Prediction of Gel Water Shutoff in Horizontal Wells Using a Newly Coupled Reservoir-Wellbore Model. *J. Energy Resour. Technol. Trans. ASME* **2014**, 136 (2). <https://doi.org/10.1115/1.4026919>.
- (159) Alghazal, M.; Ertekin, T. Modeling of Deep Polymer Gel Conformance Treatments Using Machine Learning. In *Society of Petroleum Engineers - Abu Dhabi International Petroleum Exhibition and Conference 2020, ADIP 2020*; 2020. <https://doi.org/10.2118/203450-ms>.
- (160) Meshalkin, V. P.; Yakubov, R. N.; Lenchenkova, L. E.; Chelnokov, V. V. Computer Modeling of the Integrated Chemical Engineering Process of Water Shutoff of High-Water-Cut Oil-Bearing Porous Rock Formations. *Dokl. Chem.* **2021**, 501 (1). <https://doi.org/10.1134/S0012500821110045>.
- (161) Ferreira, I.; Gammiero, A.; Llamedo, M. *SPE 153908 Design of a Neural Network Model for Predicting Well Performance After Water Shutoff Treatments Using Polymer Gels*; 2012. <http://onepetro.org/SPELACP/proceedings-pdf/12LACP/All-12LACP/SPE-153908-MS/1636820/spe-153908-ms.pdf>.

- (162) Feng, Q.; Chen, X.; Zhang, G. Experimental and Numerical Study of Gel Particles Movement and Deposition in Porous Media After Polymer Flooding. *Transp. Porous Media* **2013**, *97* (1). <https://doi.org/10.1007/s11242-012-0110-1>.
- (163) Bekbauov, B. E.; Kaltayev, A.; Wojtanowicz, A. K.; Panfilov, M. Numerical Modeling of the Effects of Disproportionate Permeability Reduction Water-Shutoff Treatments on Water Coning. *J. Energy Resour. Technol. Trans. ASME* **2013**, *135* (1). <https://doi.org/10.1115/1.4007913>.
- (164) Han, J.; Sun, J.; Lv, K.; Yang, J.; Li, Y. Polymer Gels Used in Oil–Gas Drilling and Production Engineering. *Gels*. 2022. <https://doi.org/10.3390/gels8100637>.
- (165) Sabaa, A.; Ragab, A.; Attia, I.; Seleim, A.; Saber, A. Effective Zonal Isolation Using Organic Crosslinked Polymer Maximized Production of Mature Fields. In *Offshore Mediterranean Conference and Exhibition 2017, OMC 2017*; 2017.
- (166) Liu, Y.; Bai, B.; Shuler, P. J. Application and Development of Chemical-Based Conformance Control Treatments in China Oil Fields. In *Proceedings - SPE Symposium on Improved Oil Recovery*; 2006; Vol. 1. <https://doi.org/10.2118/99641-ms>.
- (167) Bai, B.; Li, L.; Liu, Y.; Liu, H.; Wang, Z.; You, C. Preformed Particle Gel for Conformance Control: Factors Affecting Its Properties and Applications. *SPE Reserv. Eval. Eng.* **2007**, *10* (4), 415–422. <https://doi.org/10.2118/89389-pa>.
- (168) Bai, B.; Huang, F.; Liu, Y.; Seright, R. S.; Wang, Y. Case Study on Preformed Particle Gel for In-Depth Fluid Diversion. In *Proceedings - SPE Symposium on Improved Oil Recovery*; 2008; Vol. 3, pp 1438–1455.
- (169) Zhao, G.; Dai, C.; Zhang, Y.; Chen, A.; Yan, Z.; Zhao, M. Enhanced Foam Stability by Adding Comb Polymer Gel for In-Depth Profile Control in High Temperature Reservoirs. *Colloids Surfaces A Physicochem. Eng. Asp.* **2015**, *482*. <https://doi.org/10.1016/j.colsurfa.2015.04.041>.
- (170) Sagbana, P. I.; Abushaikha, A. S. A Comprehensive Review of the Chemical-Based Conformance Control Methods in Oil Reservoirs. *Journal of Petroleum Exploration and Production*. 2021. <https://doi.org/10.1007/s13202-021-01158-6>.
- (171) Qing, Y.; Yefei, W.; Wei, Z.; Ziyuan, Q.; Fulin, Z. Study and Application of Gelled Foam for In-Depth Water Shutoff in a Fractured Oil Reservoir. *J. Can. Pet. Technol.* **2009**, *48* (12). <https://doi.org/10.2118/132162-PA>.
- (172) Hakiki, F.; Salam, D. D.; Akbari, A.; Nuraeni, N.; Aditya, W.; Siregar, S. Is Epoxy-Based Polymer Suitable for Water Shut-off Application? In *Society of Petroleum Engineers - SPE/IATMI Asia Pacific Oil and Gas Conference and Exhibition, APOGCE 2015*; 2015. <https://doi.org/10.2118/176457-ms>.
- (173) Yu, H.; Yu, J.; Ji, W.; Zheng, J.; Wang, Y. Dynamic Gelation of the HPAM/Phenol–Formaldehyde Resin Gel under Oscillatory Shear: Critical

- Gelation Shear Rate and Reformation. *Chem. Pap.* **2021**, 75 (4), 1313–1322.
<https://doi.org/10.1007/s11696-020-01416-7>.
- (174) Amir, Z.; Said, I. M.; Jan, B. M. In Situ Organically Cross-Linked Polymer Gel for High-Temperature Reservoir Conformance Control: A Review. *Polymers for Advanced Technologies*. 2019. <https://doi.org/10.1002/pat.4455>.
- (175) Banerjee, R.; Ghosh, B.; Khilar, K.; Boukadi, F.; Bemani, A. Field Application of Phenol Formaldehyde Gel in Oil Reservoir Matrix for Water Shut-off Purposes. *Energy Sources, Part A Recover. Util. Environ. Eff.* **2008**, 30 (19).
<https://doi.org/10.1080/15567030701268476>.
- (176) Almohsin, A.; Hashem, H.; Sadah, A.; Mahtani, M. Research and Successful Field Application of Nanosilica System for Gas Shutoff in Horizontal Well. In *Society of Petroleum Engineers - ADIPEC 2022*; 2022. <https://doi.org/10.2118/211471-MS>.
- (177) Karadkar, P.; Almohsin, A.; Bataweel, M.; Huang, J. In-Situ Pore Plugging Using Nanosilica-Based Fluid System for Gas Shutoff to Maximize Oil Production. In *SPE Production and Operations*; 2023; Vol. 38. <https://doi.org/10.2118/197578-PA>.
- (178) Shamlooh, M.; Hamza, A.; Hussein, I. A.; Nasser, M. S.; Salehi, S. Reinforcement of Polyacrylamide-Co-Tert-Butyl Acrylate Base Gel Using Nanosilica for Conformance Control at Low and High Reservoir Temperatures. In *Proceedings - SPE International Symposium on Formation Damage Control*; 2020; Vol. 2020-February.
- (179) Boul, P. J.; Ye, A.; Pang, X.; Goel, V.; Eoff, L.; Reddy, B. R. Nanosilica-Based Conformance Gels. In *SPE - European Formation Damage Conference, Proceedings, EFDC*; 2015; Vol. 2015-January, pp 858–870.
<https://doi.org/10.2118/174265-ms>.
- (180) Almohsin, A. M.; Sherief, M.; Alabdrabalnabi, M. I.; Muhammad, A. Colloidal NaSil Squeeze Operation to Successfully Isolate Water Zone in Horizontal Well. *Aramco J. Technol.* **2022**, 2–13.
- (181) Obino, V.; Yadav, U. Application of Polymer Based Nanocomposites for Water Shutoff—A Review. *Fuels* **2021**, 2 (3), 304–322.
<https://doi.org/10.3390/fuels2030018>.
- (182) Al-Ebrahim, A. E.; Al-Houti, N.; Al-Othman, M.; Hamad, A. M.; Al-Mehanna, M.; Mubarak, A.; Al-Adwani, Y.; Mahmoud, W.; Hai, L.; Panga, M.; Lafitte, V.; Lee, J. A New Cost Effective and Reliable Water Shutoff System: Case Study in Kuwait. In *Society of Petroleum Engineers - SPE Abu Dhabi International Petroleum Exhibition and Conference 2017*; 2017; Vol. 2017-January.
<https://doi.org/10.2118/188293-ms>.
- (183) Bøye, B.; Rygg, A.; Jodal, C.; Klungland, I. Development and Evaluation of a New Environmentally Acceptable Conformance Sealant. In *Society of Petroleum*

Engineers - 9th European Formation Damage Conference 2011; 2011; Vol. 1, pp 58–67. <https://doi.org/10.2118/142417-ms>.

- (184) El-Karsani, K. S. M.; Al-Muntasheri, G. A.; Hussein, I. A. Polymer Systems for Water Shutoff and Profile Modification: A Review over the Last Decade. *SPE J.* **2014**, *19* (1), 135–149. <https://doi.org/10.2118/163100-PA>.
- (185) Sydansk, R. D. Newly Developed Chromium(III) Gel Technology. *SPE Reserv. Eng. (Society Pet. Eng.)* **1990**, *5* (3), 346–352. <https://doi.org/10.2118/19308-pa>.
- (186) Sydansk, R. D. Acrylamide-Polymer/Chromium(III)-Carboxylate Gels for near Wellbore Matrix Treatments. *SPE Adv. Technol. Ser.* **1993**, *1* (1), 146–152. <https://doi.org/10.2118/20214-pa>.
- (187) Stavland, A.; Jonsbraten, H. C. New Insight into Aluminum Citrate/Polyacrylamide Gels for Fluid Control. In *Proceedings - SPE Symposium on Improved Oil Recovery*; 1996; Vol. 1, pp 347–356.
- (188) Chauveteau, G.; Tabary, R.; Renard, M.; Omari, A. Controlling In-Situ Gelation of Polyacrylamides by Zirconium for Water Shutoff. In *Proceedings - SPE International Symposium on Oilfield Chemistry*; 1999; pp 507–515. <https://doi.org/10.2118/50752-ms>.
- (189) Eoff, L.; Dalrymple, D.; Everett, D.; Vasquez, J. Worldwide Field Applications of a Polymeric Gel System for Conformance Applications. *SPE Prod. Oper.* **2007**, *22* (2), 231–235. <https://doi.org/10.2118/98119-pa>.
- (190) Hatzignatiou, D. G.; Askarinezhad, R.; Giske, N. H.; Stavland, A. Laboratory Testing of Environmentally Friendly Chemicals for Water Management. In *Society of Petroleum Engineers - SPE Bergen One Day Seminar 2015*; 2015; pp 220–242. <https://doi.org/10.2118/173853-ms>.
- (191) Al-Muntasheri, G. A.; Nasr-El-Din, H. A.; Peters, J. A.; Zitha, P. L. J. Investigation of a High-Temperature Organic Water-Shutoff Gel: Reaction Mechanisms. *SPE J.* **2006**, *11* (4), 497–504. <https://doi.org/10.2118/97530-PA>.
- (192) Al-Muntasheri, G. A.; Nasr-El-Din, H. A.; Al-Noaimi, K. R.; Zitha, P. L. J. A Study of Polyacrylamide-Based Gels Crosslinked with Polyethyleneimine. *SPE J.* **2009**, *14* (2), 245–251. <https://doi.org/10.2118/105925-PA>.
- (193) Ganguly, S.; Willhite, G. P.; Green, D. W.; McCool, C. S. The Effect of Fluid Leakoff on Gel Placement and Gel Stability in Fractures. *SPE J.* **2002**, *7* (3). <https://doi.org/10.2118/79402-PA>.
- (194) Chauveteau, G.; Tabary, R.; le Bon, C.; Renard, M.; Feng, Y.; Omari, A. In-Depth Permeability Control by Adsorption of Soft Size-Controlled Microgels. *SPE - Eur. Form. Damage Conf. Proceedings, EFDC* **2003**.
- (195) Pritchett, J.; Frampton, H.; Brinkman, J.; Cheung, S.; Morgan, J.; Chang, K. T.; Williams, D.; Goodgame, J. Field Application of a New In-Depth Waterflood

- Conformance Improvement Tool. In *Proceedings - SPE International Improved Oil Recovery Conference in Asia Pacific*; 2003; pp 365–372.
<https://doi.org/10.2118/84897-ms>.
- (196) Bai, B.; Liu, Y.; Coste, J.-P.; Li, L. Preformed Particle Gel for Conformance Control: Transport Mechanism through Porous Media. In *SPE - DOE Improved Oil Recovery Symposium Proceedings*; 2004.
- (197) Bai, B.; Li, L.; Liu, Y.; Liu, H.; Wang, Z.; You, C. Preformed Particle Gel for Conformance Control: Factors Affecting Its Properties and Applications. In *SPE Reservoir Evaluation and Engineering*; 2007; Vol. 10.
<https://doi.org/10.2118/89389-pa>.
- (198) Zaitoun, A.; Tabary, R.; Rousseau, D.; Pichery, T.; Nouyoux, S.; Mallo, P.; Braun, O. Using Microgels to Shut off Water in a Gas Storage Well. In *Proceedings - SPE International Symposium on Oilfield Chemistry*; 2007; pp 221–228.
<https://doi.org/10.2118/106042-ms>.
- (199) Hardy, M.; Botermans, W.; Smith, P. New Organically Crosslinked Polymer System Provides Competent Propagation at High Temperature in Conformance Treatments. *1998 SPE/DOE Improv. Oil Recover. Symp.* **1998**.
- (200) Alhashim, H. W.; Wang, J.; AlSofi, A. M.; Kaidar, Z. F. Gelation Time Optimization of an Organically Crosslinked Polyacrylamide Gel System for In-Depth Fluid Diversion Applications. In *Society of Petroleum Engineers - SPE EOR Conference at Oil and Gas West Asia 2018*; 2018; Vol. 2018-March.
<https://doi.org/10.2118/190372-ms>.
- (201) Huang, J.; Al-Mohsin, A.; Bataweel, M.; Karadkar, P.; Li, W.; Shaikh, A. Systematic Approach to Develop a Colloidal Silica Based Gel System for Water Shut-Off. In *SPE Middle East Oil and Gas Show and Conference, MEOS, Proceedings*; 2017; Vol. 2017-March, pp 2742–2756.
<https://doi.org/10.2118/183942-ms>.
- (202) Hakiki, F.; Arifurrahman, F. Cross-Linked and Responsive Polymer: Gelation Model and Review. *J. Ind. Eng. Chem.* **2023**, *119*, 532–549.
<https://doi.org/10.1016/J.JIEC.2022.11.076>.
- (203) Ali, A.; Alabdrabalnabi, M.; Ramadan, M. Al; Aljawad, M. S.; Almohsin, A.; Azad, M. A Review of Recent Developments in Nanomaterial Agents for Water Shutoff in Hydrocarbon Wells. *ACS Omega* **2024**, *9* (13), 14728–14746.
https://doi.org/10.1021/ACSOMEGA.3C09219/ASSET/IMAGES/LARGE/AO3C09219_0013.JPEG.
- (204) Imqam, A.; Bai, B. Optimizing the Strength and Size of Preformed Particle Gels for Better Conformance Control Treatment. *Fuel* **2015**, *148*.
<https://doi.org/10.1016/j.fuel.2015.01.022>.
- (205) Seright, R. S.; Zhang, G.; Akanni, O. O.; Wang, D. A Comparison of Polymer

Flooding with In-Depth Profile Modification. In *Society of Petroleum Engineers - Canadian Unconventional Resources Conference 2011, CURC 2011*; 2011; Vol. 1, pp 128–140. <https://doi.org/10.2118/146087-ms>.

Vitae

Name :Mohammed Ibrahim Alabdrabalnabi |
Nationality :Saudi |
Date of Birth :10/25/1992|
Email :mohammed.ibrahim1413@gmail.com|
Address :Riyadh street, 4818-Ash Shati District, Qatif, Saudi Arabia|
Academic Background :Chemical Engineering BSc., KFUPM, 2015
Petroleum Engineering MSc., KFUPM, 2024

Publications

Ali, A.; Alabdrabalnabi, M.; Ramadan, M. Al; Aljawad, M. S.; Almohsin, A.; Azad, M.
A Review of Recent Developments in Nanomaterial Agents for Water Shutoff in
Hydrocarbon Wells. ACS Omega 2024, 9 (13), 14728–14746.
<https://doi.org/10.1021/acsomega.3c09219> |