Integrated Evaluation of The Clean-Up Performance of Unconventional Gas Plays: Investigating the Impact of Desiccation and Low Permeability Jail

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Student Declaration

Type of Award: *Master of Philosophy (MPhil)*

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I declare that no material contained in the thesis has been used in any other submission for an academic award and is solely my own work.

Abstract

Tight and ultra-tight gas formations refer to low permeability gas bearing formations that predominantly produce dry gas. Literature reviewed shows no study has been carried out to investigate the effects of desiccation and low permeability jail on fracture-fluid clean-up. In previous literatures (Tannich, 1975; Cheng, 2012), investigated the effects of inefficient fracture-fluid clean-up on gas production. It was discovered that liquid removal from damaged matrix, capillary pressure and relative permeability are governing characteristics of the flow of water in a fracture.

The aim of this research is to investigate the impact of weak permeability jail and desiccation in fracture-fluid clean-up of unconventional gas plays. Analyzing the effects of these factors will help to mitigate the impact of residual water and maximize the recovery of natural gas.

A numerical model was developed using CMG software, which was then validated by comparing the simulated model to the analytical model. Several geo-mechanical properties and their effects on the reservoir formation, gas and water production and fluid dynamics were also compared.

Some preliminary results gotten from this research are both critical gas saturation and irreducible water saturation have a negative relationship with porosity as well as permeability. Towards the end of production life of the well; there are gas bubbles, which means the gas is not completely dissolved in water due to the average water saturation in the later stages of the well production.

Preliminary conclusions drawn from investigations are presence of water changes the gas percolation. When there is high water saturation within the formation, then gas-water two-phase flow takes place. Gas-water ratio increases with the drawdown pressure, this agrees with the assumption in (Tannich, 1975). Both bottom-hole pressures from analytical and CMG simulation models are overlapping and almost on top of each other, where R^2 is 0.9993 which is satisfactory and confirms the accuracy of the developed model in the report.

Understanding desiccation's detrimental effects and implementing effective mitigation strategies are crucial for ensuring optimal well performance, minimizing environmental impact, and maximizing the economic viability of unconventional gas resources.

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Glossary of Terms, Abbreviations, List of symbols

Abbreviations

MFHW – Multiple Fractured Horizontal Well

HW – Horizontal well

NF – Number of Fractures.

TGP – Total Gas Production

IFT – Interfacial tension

LGR – Local grid refinement

HF – Hydraulic Fracturing

GPL – Gas production loss

FFV – Fracture fluid volume

FF – Fracture / Fracking fluid

NF – Number of fractures

Nomenclature

$S_{w\,irr}$ - Irreducible water saturation.

S_{wc} - Critical water saturation.

S_{gc} - Critical gas saturation.

k_{rg} – Relative permeability to gas.

k_{rw} - Relative permeability to water ratio of effective permeability of oil, gas, or water to absolute permeability.

P_i - Initial reservoir pressure

S_D - Damage skin

S_C - Convergence skin in a fractured horizontal well.

h - Formation thickness

k_m - Matrix permeability

k_f - Fracture permeability

W_f - Fracture width

C_t - Total compressibility

Q - Flowrate from each fracture

B - Formation volume factor

T – time

X_f – Fracture half-length

Greek Letters

ϕ - Porosity

μ - Viscosity

ρ - density

λ - Pore size distribution index

σ - Interfacial tension

Subscript

BHP- Bottom hole pressure

x: x-direction

y: y-direction

w: refers to well-bore.

MPhil Thesis Structure

Opening Statement

Literature reviewed shows no study has been carried out to investigate the effects of desiccation and low permeability jail on fracture-fluid clean-up. The aim of this research is to investigate the impact of weak permeability jail and desiccation in fracture-fluid clean-up of unconventional gas plays. Analysing the effects of these factors will help to mitigate the impact of residual water and maximize the recovery of natural gas.

Summary of work

A mathematical model was developed using CMG software, which was then validated by comparing the simulated model to the analytical model. Several geo-mechanical properties and their effects on the reservoir formation, gas and water production and fluid dynamics were also compared. The effect of desiccation in fracture fluid clean-up was thoroughly discussed and conclusions were drawn.

- Chapter 1 introduces the research concept and its objectives. It covers the background of the research, its context, purpose, significance, scope of research as well as providing definitions of terms.
- Chapter 2 outlines a synopsis of the previous research done in related areas and a critical evaluation of each research. Past literature which has investigated factors causing ineffective fracture fluid clean-up in unconventional formations. This chapter also covers earlier experimental and simulation studies in fracture fluid clean-up and its impacts on gas productivity and well deliverability. This is then followed up by a summary of recent studies as regards to simulation of the performance of unconventional reservoir.
- Chapter 3 outlines the methodology and research design, as well as the development of a numerical model using Computer Modelling Group (CMG) software and its validation using analytical correlations and analysing different scenarios.
- Chapter 4 outlines the results of the research using different modules in CMG like GEM and STARS geo-mechanical features including geo-mechanical

coupling to investigate the flow dynamics, as well as the geo-mechanics on the clean-up efficiency simultaneously.

- Chapter 5 discusses in detail the iterations carried out on Base case, Desiccation and Mobile Water scenarios and analyses in great details the effects on gas production, water production and avg. reservoir pressures.
- Chapter 6 outlines the conclusions and recommendations, knowledge gaps, as well as future work.
- Appendixes provide sample CMG / IMEX / GEM input files related to the models studied, as well as graphs.

Chapter 1: Introduction

Tight and ultra-tight gas formations usually refer to low permeability gas bearing formations that predominantly produce dry gas. The most important issue with the development of tight and ultra-tight gas formations is that their production rate is not at economic flow rates without stimulation, i.e., hydraulic fracture. In other words, commercial production of these unconventional resources involves the development of either hydraulically fractured vertical wells or multiple fractured horizontal wells (Nasriani, Jamiolahmady, Tarik Saif*,* 2018). Permeability of the reservoir refers to the ability of a rock to allow fluid flow through it. It is an intrinsic property that determines how easily a fluid can pass through the rock. The initiation and propagation of fractures in unconventional tight and ultra-tight reservoirs are achieved through the injection of high volumes of fracture-fluid (FF). Several field experiences have shown that ineffective fracture-fluid clean-up can significantly impair gas production. For example, (Gdanski and Walters, 2010) estimated a flowback range of 9% to 15% in the Marcellus shale, which is attributed to the volume loss to fracture-fluid being retained in nonconductive portions of the fractures, and in spaces that were previously occupied by salts, which were dissolved by the fracture-fluid. The (EPA, 2012) estimates that national flowback water volume ranges from 10% to 70% of the injected fluid.

1.1 Shale Gas and Shale Gas Play

Shale gas is usually found in shale ‘’plays’’. These are shale formations, which contain significant accumulations of natural gas, possessing similar geological and geographic properties. Some examples of Shale gas plays in the UK are Bowland Basin and Weald Basin. Information gathered from these gas plays have helped to improve the efficiency of the shale gas development in the UK. (Energy in Brief, 2010).

Surface-level observation techniques and computer-generated maps of the subsurface allow surveyors and geologists to identify suitable well locations, which possess areas with potential for economical gas production.

1.2 Gas Play

In geology, a petroleum play, or simply a play, is a group of oil fields or prospects in the same region that are controlled by the same set of geological circumstances. The term is widely used in the realm of exploitation of hydrocarbon-based resources.

The play cycle normally exhibits the following steps:

- initial observations of a possible oil reserve
- testing and adjustments to initial estimates of extraction
- high success in locating and extracting oil from a reserve
- lower success as the reserve is depleted
- continued decrease in further exploration of the region.

1.3 Bowland Basin

Up until June 2013, the Bowland shale was the only area in the UK, which was been drilled or explored for shale gas. Although, Cuadrilla resources and one by IGAS Energy, but none have previously drilled four wells produced natural gas.

Cuadrilla started drilling UK’s first gas exploration well in August 2010, and then proceeded to hydraulic fracture the well in early 2011, but this triggered two seismic events of magnitudes 2.3 and 1.5 respectively. Due to this, work was subsequently stopped by the government in May and then re-continued in September the same year after additional controls were put in place to control the seismic risk.

In July 2013, Cuadrilla announced discovery of 200 trillion cubic feet (Tcf) of gas in place under the Fylde Coast in Lancashire and went ahead to apply for a permit to hydraulically fracture its previously drilled Grange Hill site. Cuadrilla claimed if they could recover about 10 - 20% of this gas, it could satisfy the UK’s gas consumption for a further 56 years as well as providing a further 1,700 jobs in Lancashire.

In 2019, Lancashire Constabulary estimated that the cost of policing fracking in the Lancashire country is £11.745m (Cuadrilla resources, 2019). Subsequently, fracking was banned at the site following concerning tremors in 2019. A spokesperson for NSTA said that it had issued "a Plug and Abandonment notice on the two Preston New

Road wells operated by Cuadrilla" on 9 August. The company now has until 30 December 2024 to complete the work and plug wells (BBC News, 2023).

1.4 Weald Basin

In 2014, BGS/DECC carried out a shale gas assessment to investigate the potential for shale gas fracturing in the Weald Basin, South of London. It was concluded that there is little potential for shale gas as well as, possibility of extraction of light tight oil from the shales. Successive exploration showed discovered a potentially major oilfield near Gatwick Airport, extraction of oil is taking place through a conventional technique, although initial forecasts of a flowrate of 1000+ barrels per week were not achieved the production at Horse Hill mostly originated from the tight oil from Kimmeridge-micrites (Jurassic limestone bands), not of the oil from shale. Drilling carried out at Broadford Bridge in May 2018 found out it was not commercially viable to produce oil from the well drilled and hence, four more drill test holes were going to be explored to boost production.

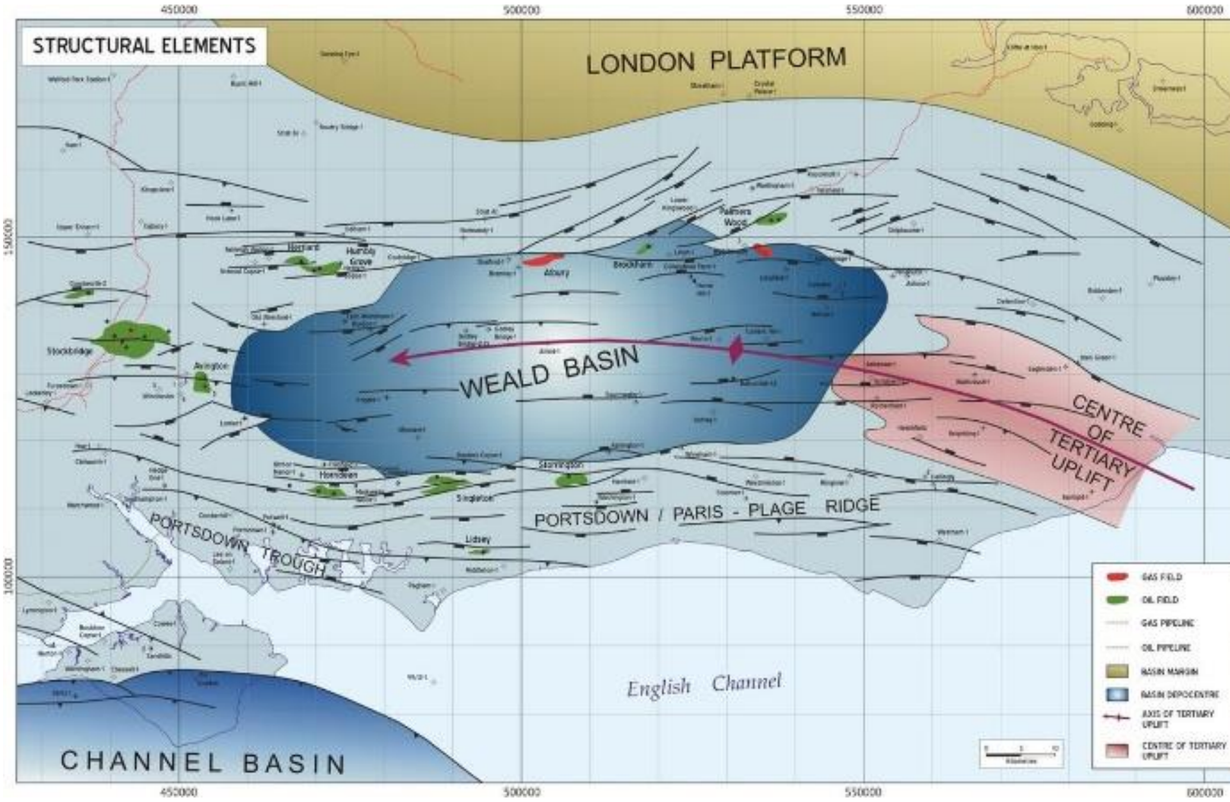

Fig. 1.1 Weald Basin location, with structural elements. Adapted from Magellan Petroleum (UK) Ltd (2012).

On 11th of April 2019, DECC published a regulatory news specifying that the initial flow rate being achieved was at the rate of 360 barrels per week prior to the 11th of April 2019. It dropped to 220 barrels per week and the well was going to shut for a further 60 hours to allow the oil pressure around the well to build back up (BGS, 2019).

1.5 Conventional Gas Plays:

Naturally occurring gases are trapped in different types of geological formations. They are categorised as either 'conventional' or 'unconventional' gas reserves.

Conventional gas is the type of gas that is trapped in a naturally porous reservoir formation which is found below an impermeable rock formation These formations act as barriers to hydrocarbon migration, resulting in natural gas been trapped below them.

Conventional gas comes from geological formations that are relatively straightforward to develop – they do not need specialized technologies to unlock their potential. Once intercepted by a vertical wellbore (using minimal stimulation), natural gas can move to the surface without the need of a pump.

1.6 Unconventional Gas Plays:

These are gas-bearing formations with very low permeability and porosities, hence resource cannot be economically extracted through a vertical well bore, instead requires a horizontal well bore which is followed subsequently by multistage hydraulic fracturing to achieve economic production.

There are different types of unconventional gases, which includes Shale gas and tight gas, these usually occur in reservoirs with very low permeability in comparison to conventional reservoirs. Horizontal drilling and hydraulic fracturing are important for natural gas extraction in these geological formations, to be economically viable.

Another form of unconventional gas is Coal seam gas, where methane gas is trapped within the coal seam, under pressure by overlying formations. During the extraction of the gas a steel-encased well drilled vertically into the coal seam, at this point, the well is hydraulically fractured or drilled horizontally along the coal seam to increase the access to the gas reserves. After de-watering the coal seam, the pressure is released which in turn allows the methane to escape the coal formation by flowing through the cleats and fractures in the coal seam back to the gas well.

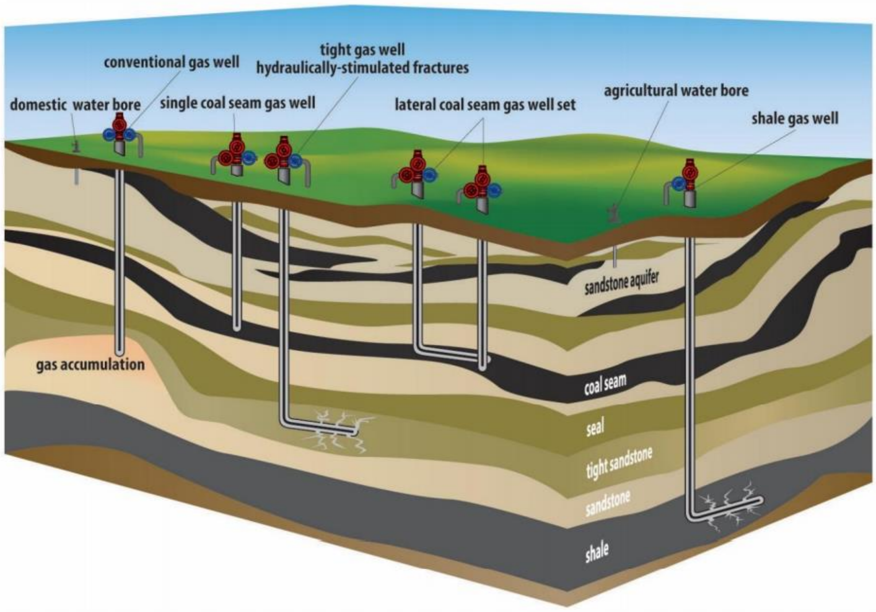

Figure 1.2: Illustration of typical geological conventional and unconventional gas formations (Environment Protection Authority, 2015).

This project is targeted at investigating the clean-up performance of Unconventional gas plays: hence, other types of Unconventional resources will be looked at like:

- Hydrates
- Tight gas
- Coal bed methane
- Shale gas will be discussed in more depth.

1.7 Gas Hydrates

Gas hydrates present a huge unexploited resource of natural gas, with estimates greater than the known reserves of all oil, natural gas, and coal in the world. Despites these huge volumes, future production volumes are speculative because there is still active research being done, to venture into large-scale commercial operations. Currently, only small-scale field experiments in methane production from gas hydrates have been explored.

Exploration of gas hydrates poses so many challenges. For example, during drilling operations intended to extract methane from the hydrates, it is very difficult to cope with the volatile nature of the gas and its expansion, when it rises to the surface from a high-pressure to a low-pressure environment. In addition, most of the world's deposits are found in the Artic, which is considered one of the world's most fragile biological environments. This is a major reason why exploration of natural resources in this region is met with concern and criticism.

1.7.1 Definition: Gas hydrates often regarded as methane hydrates are created when methane is frozen or trapped in the molecular structure of ice. They are categorised as clathrates; these compounds are formed by the inclusion of one molecule within the cavities in the crystal lattice of another. It I relatively easy to separate clathrates due to the absence of chemical bonding. When methane hydrates are warmed or depressurized, it will revert to water and natural gas.

Hydrates deposits typically occur in two types of settings: on submarine continental slopes and in deep ocean floor sediment where the temperature and pressure conditions are suitable for their formation.

Majority of the world's gas hydrates supply is found blow 1,600 ft below the surface of the sea. The methane which forms the hydrates can either be produced through a biogenic process (created by biological activity in sediments) and thermogenic process (created by geological processes deeper within the earth) (Jancovici, 2014).

1.7.2 Production and Recovery: Traditional production methods, e.g., depressurization, thermal stimulation, and chemical injection, are considered unsafe due to the perceived danger of hydrate dissociation causing geo-mechanical instability and natural disasters. Recently, a novel technique comprised of carbon-dioxide (CO2) or CO2 + nitrogen (N2) gas mixture injection into methane hydrate was proposed to produce methane gas and sequestration of CO2 at the same time without disturbing the geo-mechanical stability (Nicholas, 2017).

This technology is still immature and there are many unknowns, for example, the reaction rate (kinetics), the stability of the mixed hydrates structures, structural changes, the recovery rate of methane, and the storage percentage of CO2 are currently under investigation.

Gas hydrates can be recovered in the following ways:

- When the hydrates are heated up using hot water, steam, electromagnetic radiation (such as microwaves) or electricity. These methods help in raising the temperature, so that the hydrates will meet, which subsequently releases the natural gas.
- Lowering the pressure of the hydrates causes the hydrates to melt, which subsequently releases the natural gas.
- Injecting chemical inhibitors. Inhibitors prevent hydrates from forming or cause hydrates that have formed to melt.

1.8 Tight Gas

Tight gas is very similar to conventional gas, but in this case, it is the gas that has gone through secondary mitigation, the major difference is that the reservoir rock has very small pores and have usually lost its permeability because of a geological action that has cemented the pores. Therefore, even after the fracking process, there is still considerable friction inside the reservoir rock when the gas is produced, causing the flow rates to be limited. To produce this gas efficiently, the drilling of wells must be in very close proximity to each other.

It is relatively easy to drill and extract from the ground in a conventional gas formation without any form of stimulation required. But in the case of tight gas, more effort is needed to pull it from the ground, because of its extremely tight formation. The gas is usually trapped in this rock formation which have irregularly distributed / badly connected pores, lessening the formation's permeability. Without a secondary production method, gas from a tight formation would flow at a very slow rate, making its production uneconomical.

Tight gas formations are typically found in Palaeozoic formations, these have been formed and deposited over 248 million years ago and have undergone cementation and recrystallization, which reduce the level of permeability in the rock formation. Typical conventional natural gas deposits have a permeability level of .01 to .5 darcy

(Rigzone, 2019), but in the case of tight gas formations, permeability levels have merely a fraction of that, measuring in the millidarcy or micro-darcy range.

1.8.1 Production and Recovery:

To prevail over the challenges that tight rock formations present, there are various additional procedures that can be performed to help produce tight gas. Deviating drilling practices and more specific seismic data can help in tapping tight gas, as well as artificial stimulation, such as fracturing and acidizing.

Broad seismic data is gathered and analysed to determine the best point to drill and have an idea what is located below the earth's surface. Carrying out a seismic survey helps to pinpoint the best areas to tap tight gas reserves, as well as helping to show the areas in formation with improved porosity and permeability, where the gas is located. When drilled wells hit the best area, costs of development are usually minimised.

Most tight gas formations are found onshore, and land seismic techniques undergo transformations to better map out where drilling and development of these unconventional gas plays. Typical techniques include exploding dynamite and vibriosis and measuring the vibrations produced by purpose-built trucks. Not only providing operators with the best locations for drilling wells into tight gas formations, but extensive seismic surveys can also help drilling engineers determine where and to what extent drilling directions should be deviated.

A common technique for developing tight gas reserves includes drilling more wells. The more the formation is tapped, the more the gas will be able to escape the formation. This can be achieved through drilling myriad directional wells from one location, lessening the operator's footprint and lowering costs.

1.9 Coal Bed Methane

Coal Seam Gas (CSG) or Coal Bed Methane (CBM) is primary coal seam gas which is originated from unmined coal seams. These coal seams are drilled down into, which in turn releases the associated gas, which is then extracted and then used for electricity generation. CSG consists of over 90% methane and can be harvested independently of coal mining in some locations. The gas composition is normally stable, meaning that the gas can be fed directly into the natural gas network or a gas engine (USGS, 2018).

1.9.1 Production and Recovery:

Coal Bed Methane (CBM) is an unconventional form of natural gas found in coal deposits or coal seams. CMB is formed during the process of coalification, the transformation of plant material into coal. It is considered a valuable energy resource with reserves and production having grown nearly every year since 1989. Varied methods of recovery make CBM a stable source of energy.

CBM can be recovered from underground coal before, during, or after mining operations. It can also be extracted from “un-minable” coal seams that are relatively deep, thin or of poor or inconsistent quality. Vertical and horizontal wells are used to develop CBM resources. Extraction requires drilling wells into the coal seams and removing water contained in the seam to reduce hydrostatic pressure and release absorbed (and free) gas out of the coal (US Energy Information Administration (EIA), 2014).

CBM extraction continues to undergo research and development. Concerns include assessing the resource, identifying favourable geologic production areas, establishing efficient recovery schemes, demonstrating advanced drilling technologies, and supporting capture and use of diluted gas streams (US Department of Energy (DOE), 2012).

The environmental impacts of CBM also continue to be assessed. Methane is a greenhouse gas emitted through CBM extraction. Global methane emissions from coal mines are projected to account for approximately 8 percent of total global methane emissions. Disturbance of lands drilled and its effect on wildlife habitats results in ecosystem damage. CBM production behaviour is complex and difficult to predict in the early stages of recovery. Reservoir engineers and simulators must be employed to assess gas content, thickness, and reservoir pressure, among other factors. Though this is considered the optimum development strategy that could lead to economic recovery of CBM, any single factor can be affected by unpredictable nuances in a land’s profile (Thakur, 2014). An increasing concern is the effect water discharges from

CBM development could potentially have on downstream water sources. Disposal of the highly salinized water that must be removed to release the methane creates a challenge, as its introduction into freshwater ecosystems could have adverse effects (Environmental Literacy Council, 2008). Land disputes have emerged regarding claimed effects of waters as well as the water damage that might arise in the future (Environmental Protection Agency (EPA).

CBM development is a rapidly emerging industry and is considered an important source of energy. Communication links and information sharing between industry, government, non-governmental organizations, private developers and individual landowners will remain critical if this energy source is to be developed responsibly (National Park Service (NPS), 2003).

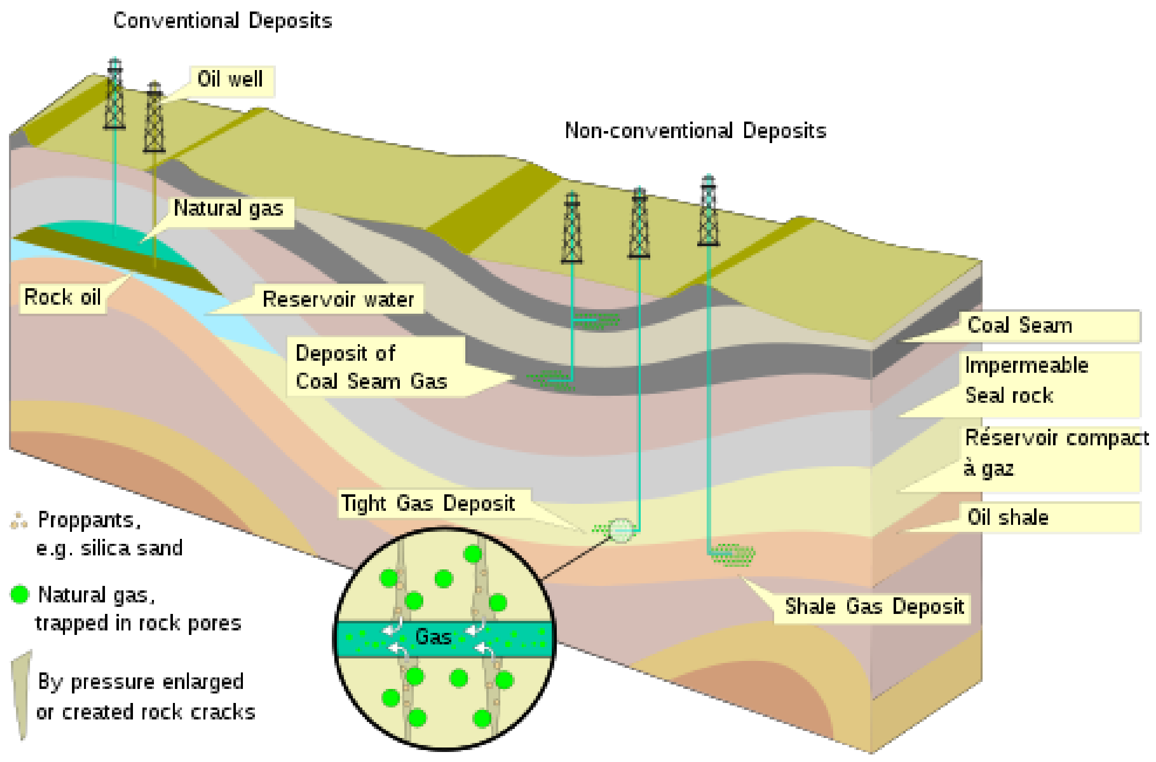

Figure 1.3: An illustration of different types of gas deposits (Modified from US Geological Survey, 2012).

1.10 Shale Gas

Shale gas is referred to as a natural gas that is trapped within shale formations. They are classed as fine-grained sedimentary rocks that can be rich sources of Petroleum and Natural gas. In the past, Shale gas formations have been uneconomical to produce from until the technology combination of horizontal drilling and hydraulic fracturing came into play, allowing access to large volumes of Shale gas.

1.10.1 Production and Recovery

Two major drilling techniques are used to produce shale gas. Horizontal drilling is used to provide greater access to the gas trapped deep in the producing formation. First, a vertical well is drilled to the targeted rock formation. At the desired depth, the drill bit is turned to bore a well that stretches through the reservoir horizontally, exposing the well to more of the producing shale.

Hydraulic fracturing, otherwise known as fracking, is a method in which water, chemicals and sand may be pumped into the well to penetrate the hydrocarbons trapped in the shale formation by opening cracks and allowing natural gas to flow from the shale into the well, and then up to the surface. When used in conjunction with horizontal drilling, hydraulic fracturing enables gas producers to extract shale gas at reasonable cost. Without these techniques, natural gas does not flow to the well rapidly, and commercial quantities cannot be produced from shale.

1.10.2 Environmental Concerns

Some potential environmental issues that are also linked with the production of shale gas include: Shale gas drilling has considerable water supply issues. The drilling and fracturing of wells require large amounts of water. In some areas of the country, significant use of water for shale gas production may affect the availability of water for other uses and can affect aquatic habitats.

Large amounts of wastewater are usually produced during drilling and fracturing, which may contain dissolved chemicals and other contaminants that require treatment before disposal or reuse. Due to the quantities of water used, and the complexities inherent in treating some of the chemicals used, wastewater treatment and disposal is an important and challenging issue.

If mismanaged, the hydraulic fracturing fluid can be released by spills, leaks, or various other exposure pathways. The use of potentially hazardous chemicals in the fracturing fluid means that any release of this fluid can result in the contamination of surrounding areas, including sources of drinking water, and can negatively impact natural habitats.

Shale is formed from muddy sediments rich in organic matter deposited in seas millions of years ago. As these sediments were buried, they were heated and turned into rock and the organic matter was converted into oil or gas.

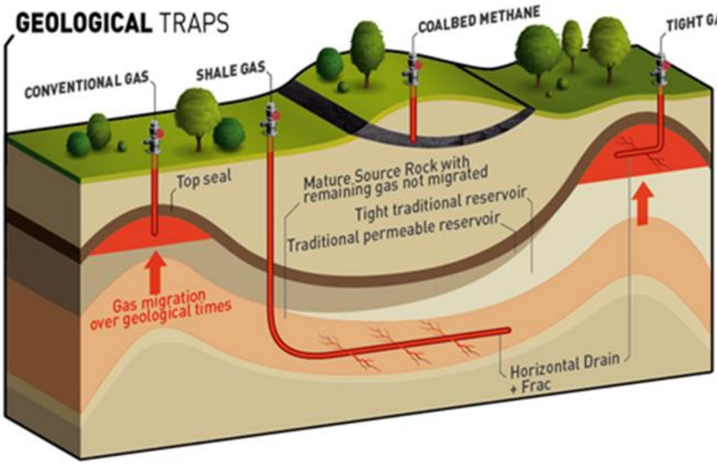

Figure 1.4: Schematic diagram showing geological traps ((Modified Brian. (2015). ***Implementing a Greener Hydraulic Fracturing in Scotland.)***

1.11 Gas Play

In geology, a petroleum play, or simply a play, is a group of oil fields or prospects in the same region that are controlled by the same set of geological circumstances.

These rocks are often the source rocks for conventional oil and gas fields but have low permeability, so it is difficult to extract oil or gas from them directly. Unconventional gas is gas trapped in rocks which are more difficult to produce from – e.g., Shale gas, but also: tight gas in sandstone and coal bed methane.

Shale gas is usually found in shale ‘’plays’’. These are shale formations, which contain significant accumulations of natural gas, possessing similar geological and geographic properties. Some examples of Shale gas plays in the UK are Bowland Basin and Weald Basin. Information gathered from these gas plays have helped to improve the efficiency of the shale gas development in the UK (Britt and Schoeffler, 2009).

Surface-level observation techniques and computer-generated maps of the subsurface allow surveyors and geologists to identify suitable well locations, which possess areas with potential for economical gas production.

1.12 Statement of Originality

Hydraulic fracturing sometimes does not respond as expected. Ineffective fracture clean-up is one of the main reasons put forward to explain this underperformance (Assiri and Miskimins, 2014; Jamiolahmady 2014; Nasriani, Jamiolahmady, T. Saif, 2018). There are several other factors that affect the clean-up process like fracture fluid viscosity, pressure drawdown, gel residue, etc.

In the literature which has been critically examined, experimental or numerical simulation studies have investigated the factors above. No systematic study has been published to investigate the effects of desiccation and low permeability jail on fracturing fluid clean-up, this research will help quantify its effects on fracture-fluid clean-up.

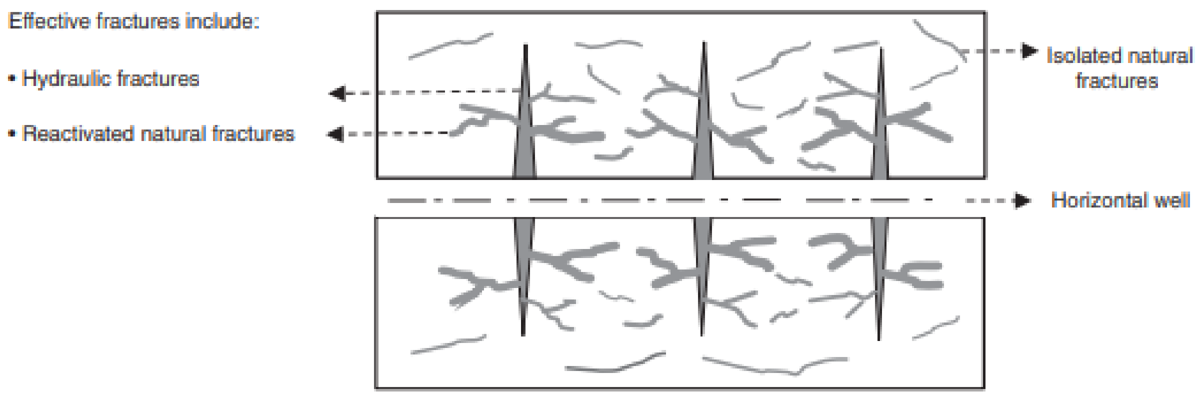

Figure 1.5 Schematic of a fractured horizontal well showing hydraulic fractures and reactivated natural fractures ((Hedong Sun, 2015) Advanced Production Decline Analysis and Application)

The fractures enhance communication within the wellbore and contributes to the fluid recovery during flowback.

1.12.1 Aim of Research

The primary aim of this research is to study the effect of desiccation and low permeability jail in unconventional gas-plays. This helps to provide solutions to the volume of flowback in tight and ultra-tight formations, thoroughly investigating the impact of these on flowback volume in these formations. A methodical study of the elements that impede fracture-fluid clean-up in unconventional formations can help enhance fracture treatments and calculate long term volumes of produced water and gas.

1.13 MPhil objectives

- Develop a numerical model using Computer Modelling Group (CMG) software.
- Validate the numerical model using analytical correlations.
- Conduct research and collecting results in CMG which will help to investigate the flow dynamics, as well as the geo-mechanics on the clean-up efficiency simultaneously.
- Conduct a sensitivity on water saturation in different scenarios, (Scenario 1, $S_{w\,i}$ = $S_{w\,irr}$), (Scenario 2, initial mobile water, $S_{w\,i}$ > $S_{w\,irr}$), (Scenario 3, Desiccation, $S_{w\,i}$ < $S_{w\,irr}$), this will help to study the effects of desiccation and low permeability jail on fracturing-fluid clean-up and quantify its effect on fracture-fluid clean-up
- Input different parameters into the validated CMG model to investigate the mobility of fluid flow into porous media.

1.14 Critical Gas Saturation vs. Trap Gas Saturation

In reservoir engineering, particularly in the context of gas reservoirs, there exists a negative correlation between porosity and critical gas saturation. This means that as porosity increases, critical gas saturation decreases.

Understanding the Terms:

- **Porosity:** This is the measure of void space in a rock, expressed as a percentage of the total rock volume. Higher porosity implies more space for fluids to reside.
- **Critical Gas Saturation:** This is the minimum gas saturation required to initiate gas flow in a reservoir. It's the point at which the gas phase becomes continuous and can move through the pore network.

Why the Negative Correlation?

The negative correlation arises from the interplay between capillary forces and pore geometry. In a porous rock:

Higher Porosity:

- Larger and more interconnected pores.
- Weaker capillary forces, as these forces are inversely proportional to pore throat radius.
- Gas can more easily displace water and become continuous at lower saturations.

Lower Porosity:

- Smaller and less interconnected pores.
- Stronger capillary forces.
- Gas needs to overcome stronger capillary forces to become continuous, requiring a higher saturation.

Critical Gas Saturation vs. Trap Gas Saturation

While both terms relate to gas saturation in reservoirs, they have distinct meanings:

- **Critical Gas Saturation:** As discussed, it's the minimum gas saturation needed for gas flow. It's a fundamental property of the reservoir rock and fluid system.

- **Trap Gas Saturation:** This refers to the gas saturation within a specific geological trap. It's influenced by factors like trap geometry, reservoir properties, and the overall hydrocarbon accumulation process.

Table 1: Differences between Critical Gas Saturation and Trap Gas Saturation

Feature	Critical Gas Saturation	Trap Gas Saturation
Definition	Minimum gas saturation for flow	Gas saturation within a trap
Dependence on Porosity	Negatively correlated	Indirectly influenced by porosity
Relevance	Reservoir characterization and production	Hydrocarbon resource assessment and recovery strategies

Ultra-Large Reservoirs

Ultra-large reservoirs are simply very large conventional or unconventional reservoirs. They are characterized by their immense size and significant hydrocarbon reserves.

Ultra-Low Permeability Reservoirs

Ultra-low permeability reservoirs are a subset of unconventional reservoirs. They are characterized by extremely low permeability, often requiring advanced drilling and production techniques such as hydraulic fracturing to extract hydrocarbons.

Table 2: Key differences between unconventional and ultra-large reservoirs

Feature	Unconventional Reservoirs	Ultra-Large Reservoirs
Size	Can vary widely, from small to very large	Extremely large
Permeability	Low	Can vary, but often higher than unconventional
Production Methods	Specialized techniques like hydraulic fracturing and horizontal drilling	Conventional or advanced techniques
Hydrocarbon Type	Conventional or unconventional	Typically, conventional

Chapter 2: Literature Review

Hydraulic fracturing, otherwise known as Fracking, can limit the productivity of a gas well after a treatment, due to the reduction in relative permeability to gas in the region invaded by fracking liquid.

All hydraulic fracturing treatments require a poststimulation flow period (cleanup) that returns the fracture-fluid to the surface and prepares the well for long-term production. However, the reservoir typically captures a percentage of the injected fluid, which may later hinder oil and gas flow.

The problem of fracture-fluid loss / invasion of liquid into the rock matrix after hydraulic fracturing has been widely studied in the past. The primary reason for attention in this area, is mainly because most stimulations do not perform as well as expected, due to the fact of inadequate models for fracture-fluid clean-up as well as liquid trapped in the matrix.

Formations that are water-wet or have low permeability are more inclined to trap the fracture-fluid in their pores because they possess high capillary pressures. Due to the liquid trapped, there is an increase in aqueous phase saturation near the fracture which subsequently reduces the gas relative permeability. In turn, slows down the flow of gas. Crushed proppant or gel damage in the fracture can lead to a slower fracture-fluid clean-up and reduction in gas productivity (Tannich, 1975).

Multiple numerical simulations as well as experimental studies have been performed over the years to study the mechanisms involved. Some papers which have addressed similar, or a part of this project title will now be critically reviewed below:

Tannich (1975) investigated and conducted a comprehensive simulation study of fracture fluid clean-up and its transient productivity variation by modelling four diverse zones of interest: 1) a virgin reservoir which is undamaged, 2) the invaded, damaged near fracture zone 3) the fracture itself and 4) the tubing. The study reveals that for efficient clean-up and enhancement of gas productivity, it is required to remove the liquid from the damaged matrix near the fracture, the fracture itself and the tubing. The author mentioned that presence of liquid in the tubing reduces gas productivity due to an increase in bottom hole flowing pressure, whereas turbulence in the fracture can also cause a further decrease in productivity.

However, this work’s distinct model never accounted for liquid build up within the fracture. In a case study mentioned in this work, the author draws attention to the fact that gas breakthrough from the simulation was slower than the actual breakthrough and attributed this to the redistribution of fracture-fluid due to gravity and capillary forces, during shut-in.

In further works carried out by Holditch (1975) he investigated the Tannich model and concluded it may not predict well behaviour during clean-up accurately, because of two main assumptions in the Tannich model: 1) The most critical limitation is that capillary forces in the reservoir are assumed to be zero 2) The effect of water mobility in the reservoir is not considered. By ignoring the effects of capillary pressure and water mobility, the Tannich paper's conclusion that "permanent productivity damage is not likely if the fracture conductivity is high relative to formation permeability" is not valid for all reservoirs. This conclusion is valid only in reservoirs where the pressure drawdown during clean-up is much greater than the capillary pressure in the invaded zone.

In conclusion, it was observed that short and highly conductive fractures assist clean-up and turbulent flow in the fracture causes a reduction in the gas productivity because of a reduction in apparent permeability to gas.

Holditch (1979) carried out a comprehensive study of formation damage caused by injection of fracture fluid in tight gas reservoirs. For this complex problem, he used a numerical simulation-based analysis to investigate the effect of increase in capillary pressures, decrease in gas relative permeability and formation permeability due to fracture fluid entering the water-wet matrix on gas production.

In conclusion, he said that in low permeability reservoirs, invasion of fracture fluid has a significant impact on peak gas productivity. It also specified that the production of gas can be severely influenced if drawdown is not greater than the matrix capillary pressures and if the mobility of water is not high enough to cause quick imbibition away from the matrix face. However, if the matrix permeability next to the fracture is not significantly damaged, the study showed that the cumulative gas production will not be significantly impacted, provided the drawdown is greater than the capillary entry pressure. The study also emphasized the significance of water mobility in clean-up.

Solimon (1985) presented a numerical simulation-based study of the clean-up of fracture fluid and its impact on production of natural gas. Their analysis found that the conductivity of a fracture has a significant effect on the clean-up of the fracturing fluid from the tight gas reservoirs. it highlighted that the ideal conductivity necessary for clean-up must be higher than that needed for production of gas. Nevertheless, they also highlighted that in very tight reservoir formations, the clean-up is principally dependent on the capillary pressure inside the matrix. The main conclusion deduced from this study is that the presence of mobile water in the fracture has an important effect on build-up pressure response after flow back.

Montgomery (1990) presented and discussed the fracturing fluid clean-up process and its influence on the post-fracture build-up analysis. Their investigation found out that increased high fracture conductivity, low matrix damage and high-water mobility subsequently increases the recovery of fracture water. On other hand, in low formation permeability, decreased fracture conductivity and damage in / around fracture, conventional pressure build-up analyses were found to be unreliable. They also highlighted that in situations where the fracture has severe damage, the pressure derivative in the build-up test will have an identifiable shape.

Berthelot (1990) studied the effects of fluid recovery upon well performance, conducting a comprehensive analysis on ultimate recovery of fractured gas wells. His study found out that when there is an accumulation of liquids at the well bottom, it causes a backpressure at the sand-face and triggers a higher loss of pressure in the well bore. Due to this problem, there is a significant loss in well deliverability, causing a significant decrease in the well head pressure which subsequently, causes the gas production to cease. Accordingly, the liquid-loading issue reduces the ultimate recovery of a gas well.

Bennion (1994) conducted a comprehensive analysis into the likely mechanisms of aqueous phase trapping in a reservoir post-drilling or stimulation. They discussed various forms of reservoirs which are most susceptible to water blocking: which is a condition where the water saturation is increased in the near-well bore area. According to the writers, the most susceptible reservoirs to water blocking highly include oil-wet oil/ gas reservoirs and this is because their initial water saturation are always lower than their residual water saturation. They also mentioned the most critical elements which determine the relative permeability curves are the pore distribution and surface characteristics of the reservoir. The paper discussed causes for initial water saturation below residual saturation and points it to the following possibilities: A) Vaporization caused by low pressures in geological formation B) Alterations in pore arrangements caused by compression or diagenesis in the past C) Adsorption and hydrate formation D) Hysteresis. The study suggested that to enhance clean-up, non-aqueous fluids and alcohol should be utilised.

May (1997) carried out a comprehensive study with the issue of polymer fluid clean-up and why the recovery rate was often lower than 50%. It was a numerical simulation-based study which investigated why post-fracture conductivity and fracture length are often estimated to be lower than projected, the study highlighted that the polymer yield stress and the relatively permeability were the main factors influencing the fracture clean-up. The study also highlighted the vital mechanisms relevant to efficient clean-up: 1) Time and temperature effects on proppants. 2) Gel residue which damages proppant pack. 3) Non-Darcy and multiphase flow. 4) Effects of capillary pressure. 5) Viscous fingering through proppant pack 6) Effects of unbroken fluid of proppant permeability

This study never accounted for gel damage and porosity blockage effects as separate factors, instead they were both considered as a single effect, which might not be entirely accurate for all reservoir types.

Settari (2002) carried out an investigative analysis on the factors like water blockage and fracture associated geo-mechanical issues found in water fractures in the Bossier play, which is found in the Upper Jurassic sandstone that is located between Houston, Texas and Dallas, Texas. The study used a coupled reservoir and geo-mechanics simulation technique, which will allow for dynamic fracture propagation during the fracturing job and static fracture during flow back. They concluded that the geo-mechanical issues play a vital role on productivity of fracture and that an extended shut-in time does not lead to increased gas productivity.

Mahadevan (2003) presented a very comprehensive study of removal of water blocks under various rock permeability, wettability, temperature and drawdowns. The reservoir clean-up was measured through the variations in gas relative permeability. The study found out that 1) Water displacement when drawdown is higher than capillary pressure 2) Evaporative clean-up of water were the two major mechanisms responsible for removing water blocks. The latter been more important especially after injecting gas to remove water blocks. The major conclusion drawn from this study was: clean-up could be enhanced by using solvents which not only modify the wettability of the reservoir but also its volatility. They also highlighted that for a faster and more efficient clean-up, an increase in temperature, change of wettability from oil wet to water wet and higher drawdown are all required. Capillary effects are also very important in clean-up of water blocks.

The study did not account for reservoirs where surfactants or solvent have been for well treatments to remove water blocks.

Kamath et al. (2003) carried out an analysis on the impact of water blocks on the productivity of gas by experimental observations. The main conclusions drawn were that clean-up or removal of water blocks happen in two stages: 1) Displacement of water immediately after the initiation of the flow-back. 2) Evaporative clean-up, which is highlighted to be accelerated by the utilisation of alcoholic solvents. The authors also highlighted that in extremely tight reservoirs, the clean-up process is very slow due to the low gas volume flowing in the formation.

Gdanski (2005) in this study, the authors re-evaluated Holditch (1979) and examined the effects of formation damage on low permeability gas formations which experience slow clean-up and lower gas production due to stimulation. This rea-evaluation was done because a lot of authors have been misquoting Holditch for his study on near fracture damage and its effect on gas production. A new type of numerical simulator was used to justify those formations with over 90% permeability damage generally have increased capillary pressures which in turn leads to a reduced gas production. The study also highlighted that due to gas production, water piles up close to the fracture face, but there will be no water production until the capillary forces are overcome.

Jamiolahmady (2007) investigates the gas condensate reservoirs and its process of fracture fluid clean-up and its influence on the production of gas. This study involved a series of sensitivity analysis, where various forms of hydraulic fracturing fluids were simulated (i.e., water-based, or oil-based), as well as different viscosities of the fracturing fluid. The main conclusions drawn from this study are: 1) the clean-up efficiency generally increases for a high viscosity fracturing fluid especially for a water-based fracking fluid, due to a reduced penetration length. They also highlighted that the drop-out of condensate accelerates the fracture water clean-up.

Some factors which affect well deliverability were not investigated in this study like choking of the near well region and over displacement, as well as polymer residue which occurs when proppant pack permeability reduces.

Bazin (2008) utilised a Special Core Analysis Laboratory (SCAL) method in the derivation of the absolute permeability damage on tight gas reservoirs to investigate formation damage problem. They highlighted that two primary factors in fracture fluid clean-up are matrix relative permeability and its hysteresis. The main conclusions drawn from this analysis are polymer molecules do not generate enough permeability reduction. On the other hand, water sensitivity causes huge reductions in permeability. Gas return permeability values are very low unless there is enough application of drawdown.

Wang (2009) investigated the challenge which involved modelling of fracture fluid clean-up from tight gas-condensate wells. The study had not investigated the clean-up inside the fracture, the focus was recovery from the matrix. Some factors such as gel strength, polymer filter cake and proppant crushing were all analysed. The study highlighted that clean-up is usually faster in the case of lower yield stress fluids. A major inhibitor is Gel damage. The authors concluded that in cases where the fracturing fluid breaks down because of low viscosity and acts as a Newtonian fluid, then a fracture conductivity value of greater than 10 will enhance the clean-up of the fracture fluid. Fluids with a yield stress retention value of ~100 exhibit very slow clean-up.

Friehauf (2009) produced a model which studied the productivity of hydraulically fractured gas and the effects of fracturing fluid escaping into the matrix. They concluded that provided the permeability damage in the invaded region is greater than 90%, then production of gas will not be significantly affected if drawdown is more than the capillary pressure. They also concluded that in cases of depleted reservoirs, where drawdown cannot be raised, fracture fluid should be energised with a gas component, so that fracture permeability of the damage zone can be increased.

In Gdanski (2010) the authors developed a numerical simulator which is called Fracture Clean-up and Chemistry Simulator (FCCS) to thoroughly imitate the fracture fluid flow back process. The study also investigated the impacts of several parameters on fracture fluid recovery like drawdowns, drawdown rate, shut-in time, etc. The numerical simulation found out that there was no dependence of productivity on shut-in times under several relative permeability regimes. A higher water relative permeability often leads to an increase in capillary imbibition for increased shut-in time and a decrease in load recovery, but it was highlighted that this low recovery did not affect the production of gas. During gas recovery, the fracture conductivity was found to be more important than the shut-in period.

Yu (2010) analysed the effects of fracture face matrix damage in multi-fractured horizontal wells, with the use of a mathematical model. This model was built on a rigorous coupling reservoir pseudo-radial flow, reservoir linear-flow, fracture linear-flow, and fracture radial-flow near the wellbore. Spurt-loss and possible leak-off coefficients were investigated, it was concluded that the fracture face skin has little to no impact on gas productivity in multi-fractured horizontal wells. Even in the worst-case scenario, there is never more than 5% reduction in well productivity due to fracture-face matrix damage.

Shaoul et al. (2011) studied the relevance of formation damage in unconventional reservoir formations. They noted that there are numerous opinions in the industry as regards to the most vital mechanisms and their effect on gas productivity. Two main ideas that were proposed are ‘permeability jail’ and stress-sensitive matrix permeability. The study found out that there is a strong relationship between fracture length and clean-up time. The authors concluded that other parameters apart from capillary pressured must be investigated, to properly understand the factors, affect reduced and delayed gas productivity. They also highlighted that it is necessary to use non-aqueous fracturing fluids in a weak permeability jail scenario, because this helps to improve early time clean-up and gas productivity. The effects of gel retention and damage of proppant pack was not modelled in this study.

Wang (2012) investigated several damage mechanisms found in unconventional gas formations and attempted to examine and calculate each of their impacts on the gas productivity, The elements examined included: 1) gel residue in proppant pack 2) gel filter cake 3) proppant embedment 4) trapping of fractur fluid. After running the gas, it estimated the reductions in gas productivity to 7%, 6%, 0.6% and 12.5% respectively.

Clarkson (2013) analysed the latest techniques for quantitative production data analysis (PDA) including type-curve analysis, straight-line (flow-regime) analysis, analytical and numerical simulation, and empirical methods, which specifically helped in addressing adaptation for Shale gas reservoirs. Understanding the flow regime sequence caused by hydraulic fracture geometry and reservoir properties is critically important when interpreting rate-transient/decline characteristics of unconventional gas wells. The long-term performance of ultra-low permeability reservoirs is therefore generally dominated by linear flow to fractures (early linear flow of Fig. 5), which can be represented by an equivalent fracture, whose length is "equal to the aggregate length of hydraulic fractures and the conductivity of the equivalent fracture is equal to the average conductivities of the individual fractures" (Ozkan 2011).

Chapman et. Al (2014) thoroughly reviewed the fracture conductivity principles. In conclusion, he envisaged that many methodologies could increase the fracture conductivity, such as the use of cleaner frac fluids, placing higher proppant concentrations, employing higher tier or quality proppants, and utilizing larger mesh proppants. In most cases, all options should be considered when attempting to optimize fracture designs. However, proppant selection is highlighted as the main underlying factor that can increase the fracture conductivity.

Assiri et. Al (2014) examined if water blockage is a potential damage issue in tight gas reservoirs using an analytical method (simulated generic model) by generating relative permeability curves and simulating different production cases with different water saturation settings. Investigating the well performance and water and gas recovery in these situations, a new understanding of tight gas performance was achieved. In conclusion, cases with different water saturation settings never recovered all the injected water, and in fact, the degree of recovery is proportional to the degree of desiccation.

Xu et. Al (2015) discussed the formation damage in shale gas reservoirs, including factors such as proppant embedment, residual fracturing fluid, shale fines and proppant fines migration, and long-term rock creep. It also explores the use of high-pressure nitrogen as a heat-transfer media in shale gas reservoirs and the effects of heat treatment on reservoir properties. The study emphasizes the importance of working fluid loss control and provides field cases illustrating the impact of formation damage on production in shale gas reservoirs. Additionally, the paper covers formation damage mechanisms, processes, and main properties of shale gas reservoirs, highlighting the need for systematic evaluation methods for formation damage, heat treatment, and working fluid loss control.

Gao et. Al (2016) investigated the effect of effective stress and water saturation on the gas relative permeability in tight sandstones; a conclusion was drawn that agreed on the pronounced reduction of gas relative permeability due to increasing water presence and higher effective stress, which explained the permeability jail concept, where there is little water or gas production.

(Fu 2017) constructed diagnostic plots to study the relationship between rate and pressure during early water flowback, which helped to examine the dynamics of flow in two different regions. Region 1 referred to the pressure reduction inside the fractures and Region 2 demonstrated the oil and gas breakthrough into the active fracture network. The governing parameters in region 1 were the original field pressure and type of hydrocarbon present in the formation. Some of the vital parameters to consider in enhancing the fracturing operation includes FF volume, number of clusters and perforation intervals: these parameters helped to examine and understand the flowback cleanup process in post-fracturing operation. Their study did not consider the influence of all applicable parameters instantaneously over a wide practical range on the post-fracturing cleanup.

(Nasriani and Jamiolahmady, 2018a) conducted a numerical simulation to parametrically investigate the FF clean-up effectiveness. This was done with 143360 simulations (35 different sets) and included the injection, shut-in and production stages. Twelve different parameters were considered in this study: fracture and matrix permeability, capillary pressure, end points and exponents of gas and FF in the Brooks-Corey relative permeability correlation in both the fractures and matrix were investigated. Results showed that the length of fracture reduced the impact of fracture pertinent parameters, i.e. as the length of fracture reduced, a faster clean-up was noticed in comparison to those for longer fractures. It was also noted that the factors that affected the mobility of FF inside the fracture, had the most significant effects on clean-up efficiency, as observed in (Nasriani 2014).

(Nasriani, Jamiolahmady, Tarik Saif, 2018) this work carried on from (Nasriani and Jamiolahmady, 2018a), but in this case linear surface methodology was used to map out the simulation output i.e. loss in gas production (GPL) in comparison to reference base case (Clean case – 100% clean-up) at production periods of 10, 30 and 365 days. It was concluded that injecting high volumes of fracturing fluid into tight formations significantly impaired gas production and caused a delay in clean-up. A slower clean-up was also noticed with sets with larger initial water saturation due to the damaging effects of mobile water on gas production. In some sets with higher initial water saturation, surface tension (IFT) reducing agents were employed to reduce capillary pressure which subsequently reduces GPL and enhances clean up efficiency.

(Nasriani and Jamiolahmady, 2019) investigated the post-fracturing clean-up operations in hydraulically fractured vertical wells (VW) in comparison to multiple fractured horizontal wells (MFHWs). Several parameters like soaking time, matrix permeability, applied drawdown pressure, fracture spacing, FF volume, etc. it was concluded that factors affecting capillary pressure in the matrix were more important in MFHWs than in VW. A larger matrix capillary pressure was more significant in clean-up of MFHWs because of more absorption of FF into the matrix which subsequently causes a lower conflict in between the FF in the fracture and flow of gas.

Tian et. al (2020) investigated the water removal behaviour in tight rocks and discussed the formation damage issues encountered during the water drainage process. The investigation mainly focused on rock physical properties, pore size distribution, displacement pressure, and invasion depth that influence the process of water removal in tight rocks. The issues of wettability, temperature, and capillary force on water removal in tight rocks are suggested for future consideration. The main conclusion drawn were water removal in tight rocks experiences two stages which are immiscible displacement stage and gas flow-through drying stage and that pore size distribution has a significant influence on water removal. When water invasion happens to tight rocks with small distribution ranges of pore size, water removal under a constant high displacement differential pressure can be more effective. When water invasion happens to tight rocks with wide distribution ranges of pore size, water removal can be greatly improved with the gradual increasing displacement differential pressure.

Liu et. al (2021) investigated the effects of fracturing fluids in gas formations and its aftermath post clean-up, by comparing the desorption isotherms, desorption efficiency, free gas content as well as cumulative gas production before and after treatment. It was concluded that cleanup additive treatment results in the decrease of adsorption capacity and the increase of adsorption intensity. There exists an intersection between two curves of desorption efficiency before and after treatment. Cleanup additive significantly translates adsorbed phase into free phase to improve free gas content and increases cumulative gas production.

Modebelu et. al (2022) studied the impact of desiccation in unconventional gas formations on pre and post fracturing. The post-fracturing flow back and subsequent gas production of the desiccated shale formation are compared to those of the un-desiccated shale formation. The effect of desiccation and shut-in duration on shut-in performance in removing water blockage was quantified using a mathematical model. While there are other factors besides desiccation that influence well response to shut-in treatment in the field, it was concluded that desiccation is a critical factor in determining whether shut-in is beneficial in removing water blockage.

Rozploch; et. al (2023) evaluated the effects of long-term shut-in periods in unconventional gas formations, and the study revealed a wide range of both positive and negative effects from both a reservoir and a production perspective, suggesting that factors such as well age, generation, spacing, and stimulation size were drivers. Near-term improvements were observed in previously damaged parent wells following the shut-in period. Several of the wells experienced a second, higher initial production rate than during flow back due to fluid cleanup effects. However, certain tightly spaced wells experienced negative effects on production in the longer term.

Shoukry et. al (2024) analysed the impact of the capillary desaturation curve (CDC) in subsurface porous media and whether it is vital for planning non-aqueous phase liquid (NAPL) cleanup and recovery projects. They concluded that the sweep efficiency is not significantly affected by the capillary number in a system with a “dead-end” fracture, but it does depend on the capillary number in connected fracture structures. Only two (Du 2020; Haghighi 1994) of the studies delineated CDC plots. The reported

CDCs, however, suffered from the following limitations: 1) insufficiency of elaboration on the pore-scale events responsible for the behaviour of the reported CDCs, and 2) lack of comprehensive reasoning for using matrix or fracture capillary number formulas when their experimental platforms contained both.

2.1 Significance of Research

This research will attempt to address a gap in knowledge and as it is still new and original, the simplest form of fracking fluids; water, will be used to test the computer model initially and act as a control simulation.

Thorough research will be conducted on the following topics of the post-fracturing performance of the unconventional formations, which have been undertaken by researchers previously: Tight and ultra-tight low permeability reservoirs typically have large initial water saturation (Swi); However, this is not always the case in many fields where they have "sub-irreducible" Swi. The irreducible water saturation (Swirr) in these tight gas reservoirs tends to be higher than the Swi. This is attributed to desiccation (Bennion 2004).

- Nasrani 2014a & b studied the impact of Swi on cleanup efficiency when it was equal to/larger than Swirr. However, the impact of Swi when it is smaller than Swirr, i.e., desiccation, was not studied. This work will investigate the impact of desiccation on the post-fracturing cleanup extensively.
- The literature put forward two possible answers regarding the volume of flow-back in tight and ultra-tight formations, i.e., weak permeability jail and desiccation, but there was no integrated study that thoroughly investigate the impact of these two factors on the flow-back.

Chapter 3: Methodology

The methodology that will be used to achieve the MPhil objectives are outlined below:

- Compare different geo-mechanical properties and their effects on the reservoir formation, gas and water production and fluid dynamics.
- Development of a numerical model using Computer Modelling Group (CMG) software.
- Validation of the numerical model using analytical correlations and analysing different scenarios.
- Conducting research and collecting results using different modules in CMG like GEM and STARS geo-mechanical features including geo-mechanical coupling to investigate the flow dynamics, as well as the geo-mechanics on the clean-up efficiency simultaneously.

3.1 Introduction to Imex

Computer Modelling Group (CMG) software was used in the development of a numerical model, utilising its builder and IMEX functions. IMEX is CMG's specific black oil reservoir simulator that offers capabilities such as detailed well management, refinement of local grid, single/dual porosity and permeability models. It can handle three phase black oil simulations along with capillary and gravity effects, as well as its ability to fully solve bottom-hole pressures and individual block properties, in which, the wells pass through.

IMEX models complex, heterogeneous, faulted oil, and gas reservoirs, to achieve fast and accurate predictions and forecasts. Reservoir engineers use IMEX to move from history-matched, primary production and waterfloods to enhanced recovery processes in GEM and STARS quickly and easily.

3.1.1 Why Computer Modelling Group (CMG)?

CMG's unconventional reservoir workflow streamlines incorporating heterogeneity, well complexity and the physics of fluid flow, heat flow, and geomechanics to understand and predict production. The version of CMG and STARS that has been used for the simulation is v4.0. The CMG software has also been chosen due to use in previous literature reviewed.

Some of the benefits of CMG over other reservoir modelling tools are.

- Achieve accurate & reliable forecasts for better planning and reduced risk.
- Only hydraulic fracturing workflow that models single and multiple wells in a reasonable run time.
- Evaluate secondary & tertiary recovery methods, such as waterflood and CO2 injection to enhance recovery.
- A user-friendly interface makes learning and set-up easy.
- A fast workflow that applies numerical simulation through to history matching & optimization.
- Set up reservoir model as a dual matrix with intrinsic porosity and absolute permeabilities.
- Model adsorbed component, in both gas and multi-component phases.
- Parameterize the rock physics data during history matching.
- Ability to model natural and hydraulic fractures.
- Model transient flow from the matrix rock into the natural fractures.

3.2 SIMULATION MODEL DESCRIPTION

In this study, a 3D, gas-water black oil reservoir model was used to simulate a multiple fracture (3 fractures) in a horizontal well formation. The reservoir properties used are provided in Table 2 and are based (Nasriani, Jamiolahmady, Tarik Saif, 2018). The model is based on a 21 X 29 X 10 Cartesian grid in the X, Y, and Z direction respectively with a total of 3384 reservoir blocks. The horizontal wellbore of radius 0.25 ft passes through Y= 8 and Z =10.

3.2.1 Justification / Assumptions for base case model methodology

- Water, which is the simplest fracturing fluid has been used, this is because the constituents of a complex fracking fluid may adversely affect simulation output. Gas and FF phases could produce under controlled bottom-hole flowing pressure of 5500 psi (37921.17kPa). (Local grid confinement was employed to areas near the fracture face to capture the FF flowback more accurately and monitor liquid build up in the matrix and fracture).

- The location of each perforation at each layer was chosen at random, this is because the well is horizontal and assumed to be homogeneous (formation with rock properties that do not change with location in the reservoir) and isotropic (formation whose rock properties are the same in all directions), box-shaped, and of uniform thickness with impermeable boundaries.

The modelling was carried out using some simulation parameters and boundary conditions as below.

Table 3: Base Case reservoir model properties

Parameter	**Imperial field units**	**Metric Units**
Matrix Permeability	0.1 md	0.1 md
Fracture Permeability	30,000md	30,000md
Reservoir Thickness	131.24ft	40m
Matrix Porosity	15%	15%
Fracture Porosity	35%	35%
Fracture Height	131.24ft	40m
Fracture Thickness	0.328084ft	0.1m
Fracture width	0.0131ft	0.004m
Fracture Half Length	590.58ft	180m
Gas-Water Surface tension	40 dyne/cm	0.4 dyne/m
Water Density	64.0 lb/ft^3	1000 kg/m^3
Flowing Wellbore pressure	5500 psi	37921.17kPa
Initial Reservoir Pressure	7500 psi	51710.68kPa
Initial Water Saturation	0.15	0.15
Residual Water Saturation	0.15	0.15

Base case reservoir properties adapted from (Nasriani, Jamiolahmady, Tarik Saif, 2018) which is in line with relevant past literature as a basis for modelling.

Base Case ***(Scenario 1)***, $\boldsymbol{S_{w\,i} = S_{w\,irr}}$, investigation into water production when initial water saturation is equivalent to irreducible water saturation

Table 4: Location of perforations and its properties

Layer	Perforation Block Address	Connect to	Form factor (FF)	Status	WI-Geom (md*ft)	Block top (ft) in Z direction	Block bottom (ft) in Z direction
1	11 9 1 / 7 13 1	Surface	1	Open	836.69	14000	14131.234
2	11 15 1 / 7 13 1 1	1	1	Open	836.69	14000	14131.234
3	11 21 1 / 7 13 1 2	2	1	Open	836.69	14000	14131.234

Where:

- Form Factor (FF) is a software design aspect that defines and prescribes the size, shape, and other physical specifications of components. A form factor may represent a broad class of similarly sized components, or it may prescribe a specific standard. It may also define an entire system, as in a computer form factor.

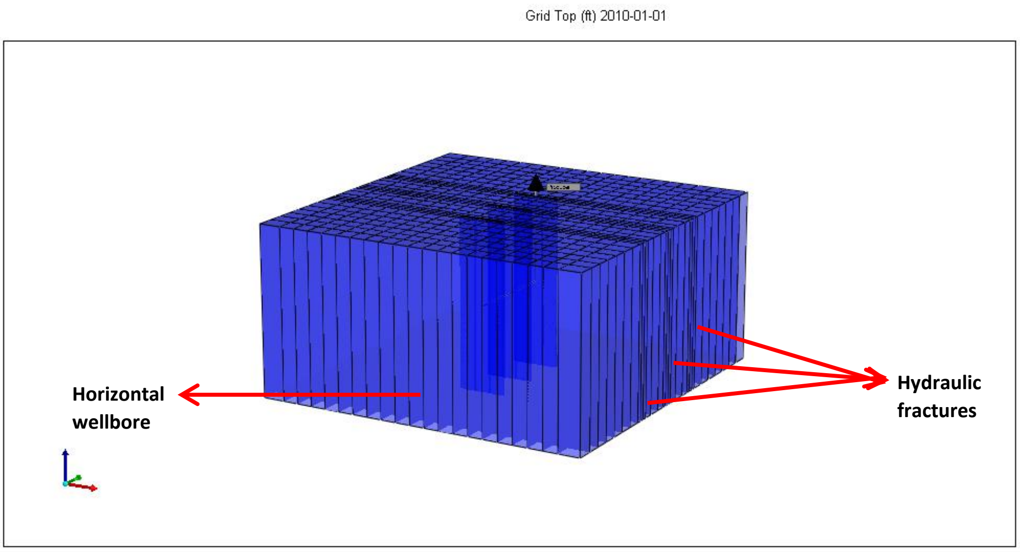

Figure 2.1: Reservoir model overview in 3D showing three fractures.

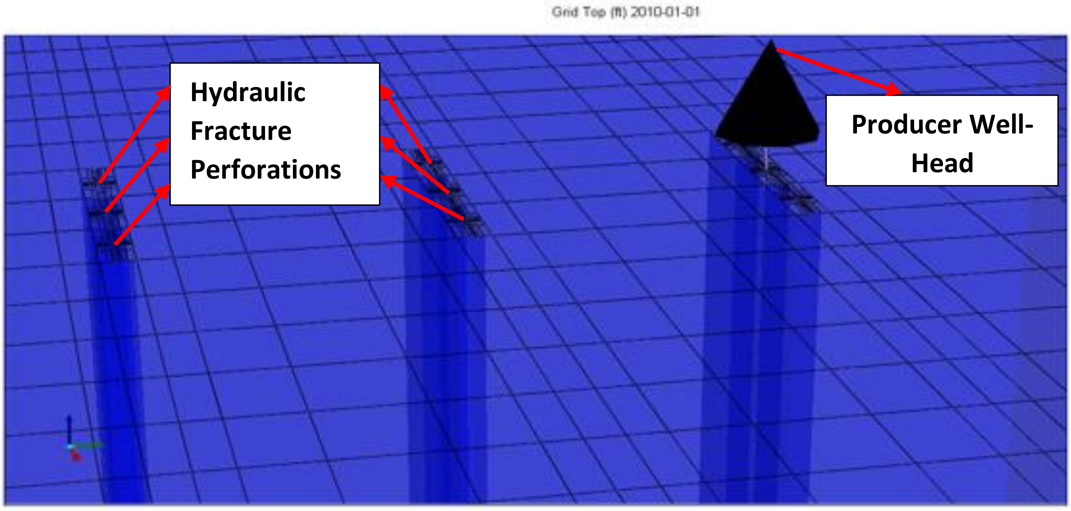

Figure 2.2: Aerial view of top of grid block showing the 3 induced fractures and producer Well-Head.

Figure 2.1 shows a horizontal wellbore with three fractures. Horizontal drilling is a commonly used technology because drilling at an angle other than vertically can stimulate reservoirs and obtain information that cannot be done by drilling vertically. Horizontal drilling can increase the contact between the reservoir and the wellbore, hence why a horizontal wellbore has been used as the base case reference set in this study. Horizontal drilling can help to intersect a maximum number of fractures (in this base case of 3 fractures as seen in (figure 2). It increases the pay-zone within the target rock unit which enhances productivity. According to EIA statistics from the USA, of all the wells drilled in 2020 that went on to produce more than 400 barrels of oil equivalent per day, 77% were drilled horizontally. It is clear to see that there is a correlation between drilling horizontal wells and increased production.

In the fracture and matrix, there are two main factors that play a vital role in the clean-up of the water which are the buoyancy effects (Bond number) and the ratio of viscous and capillary force (capillary number). (Pope 2000) showed that the relative permeability is a function of interfacial tension, as well as trapping number.

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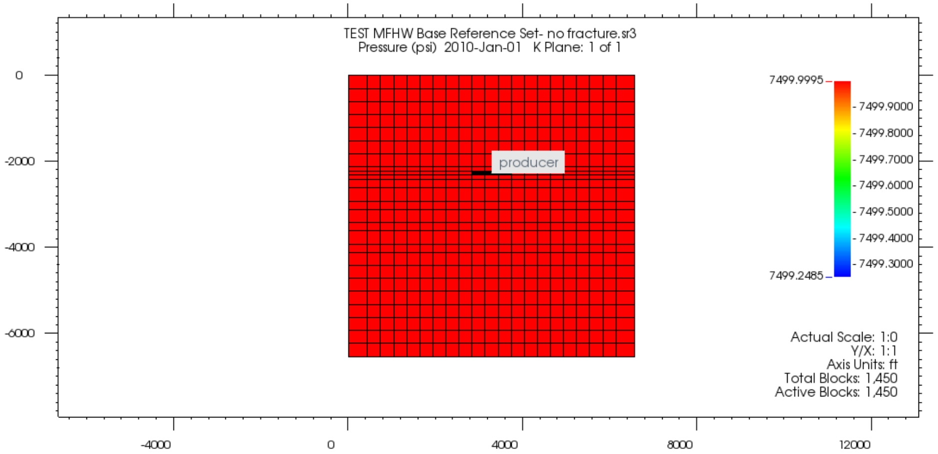
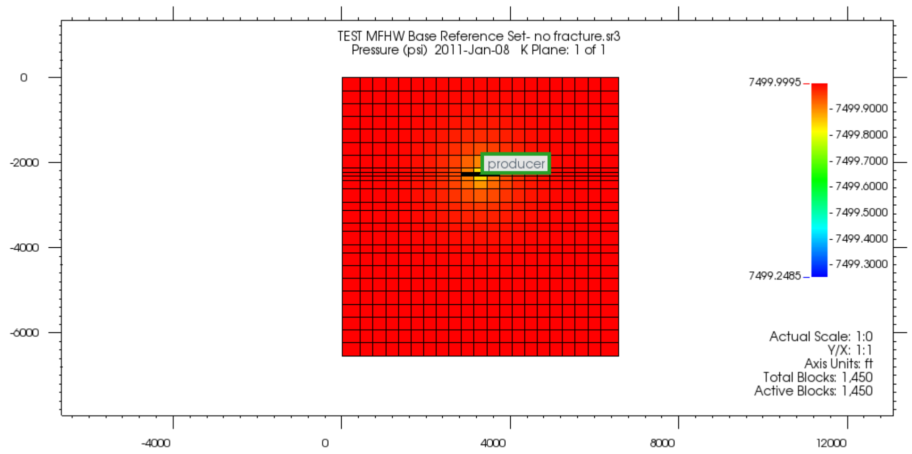
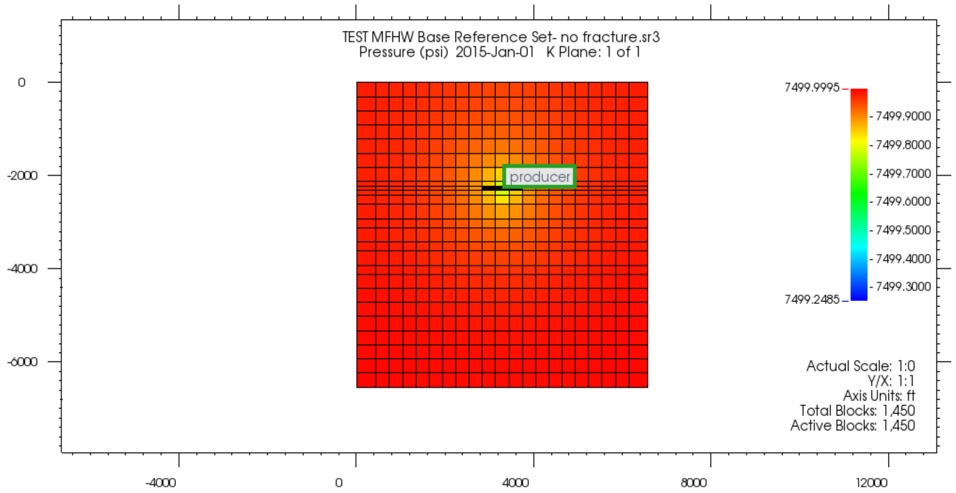


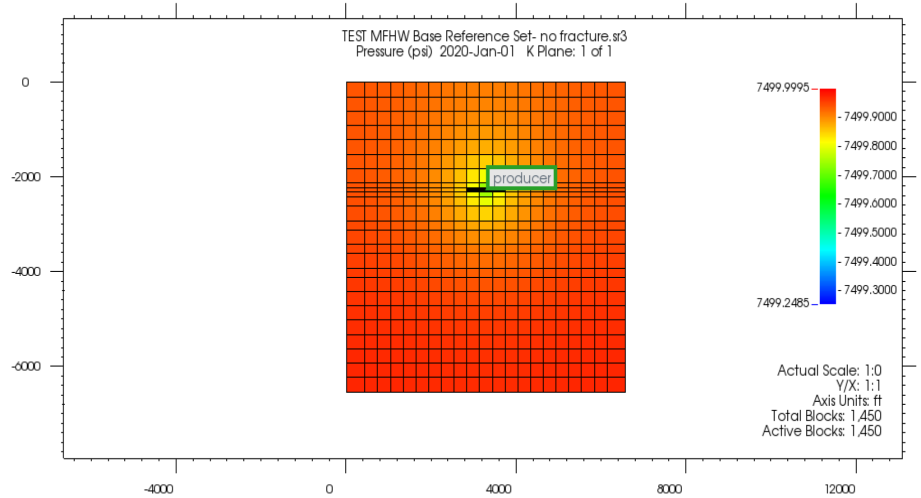
(a) Pressure inside formation with no fracture at start of production (Day 1)



(b) Pressure inside formation with no fracture after 1 year of production

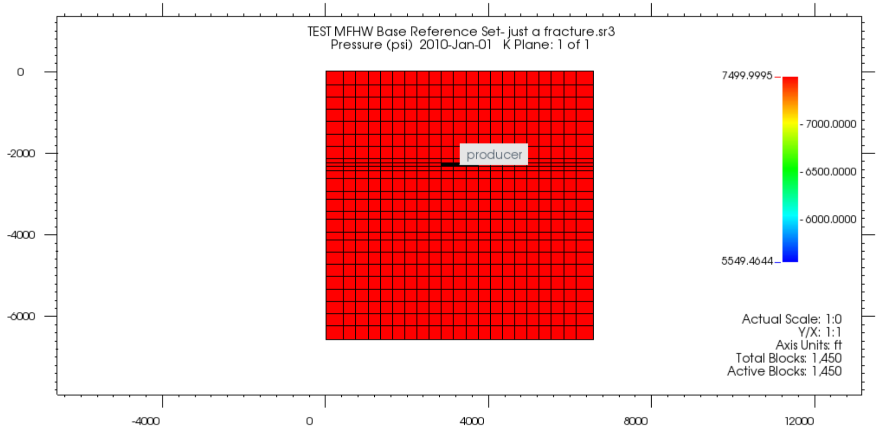


(c) Pressure inside formation with no fracture after 5 years of production

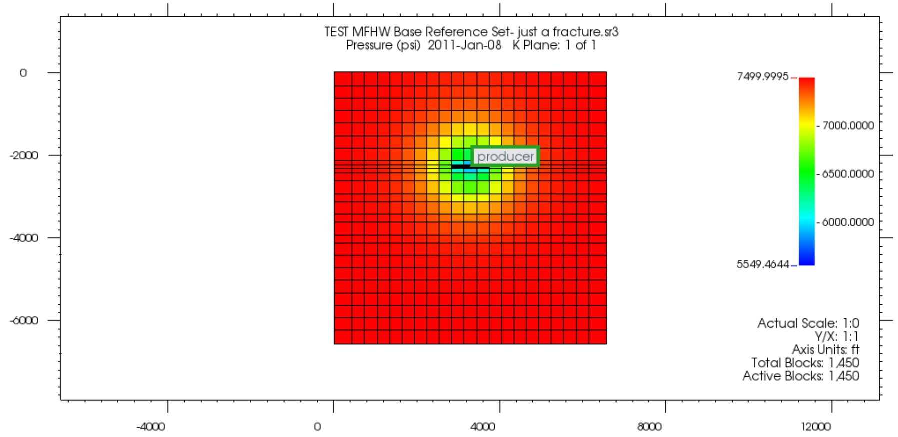


(d) Pressure inside formation with no fracture after 10 years of

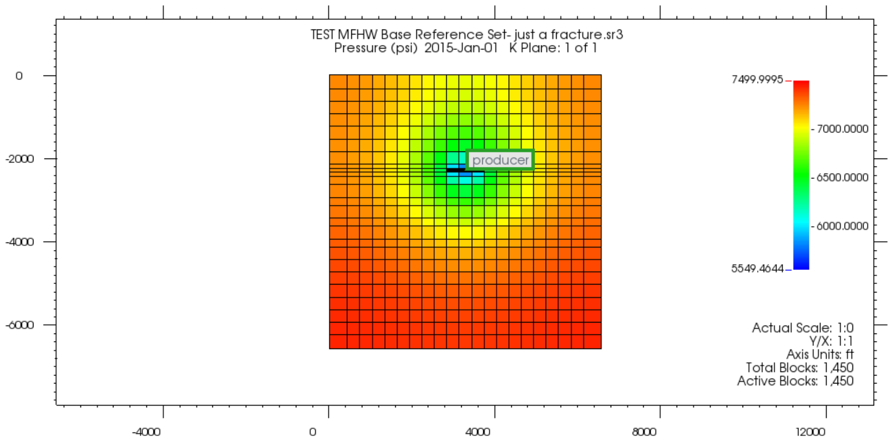
Figure 3.1 Pressure maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (No fracture)



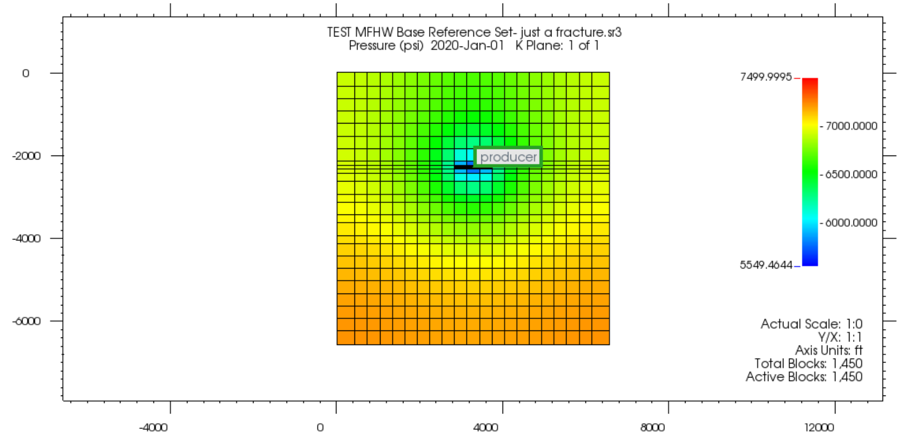
(a) Pressure inside formation with 1 fracture at start of production (Day 1)



(b) Pressure inside formation with 1 fracture after 1 year of production

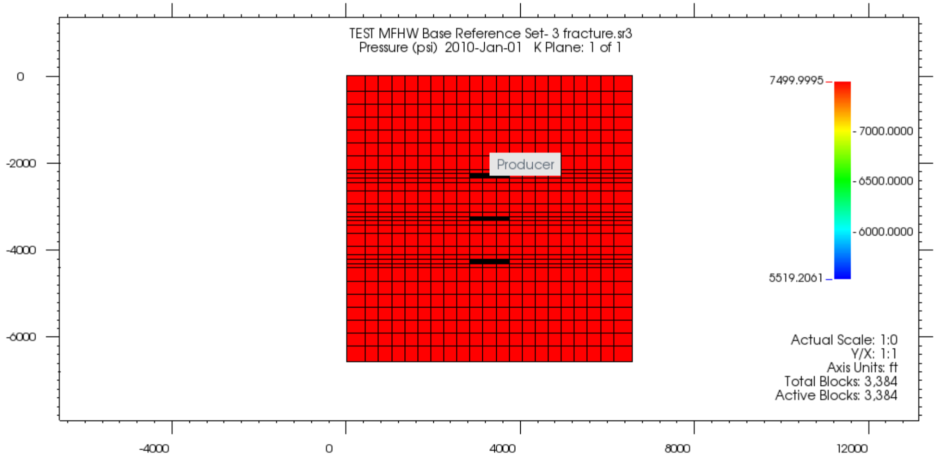


(c) Pressure inside formation with 1 fracture after 5 years of production

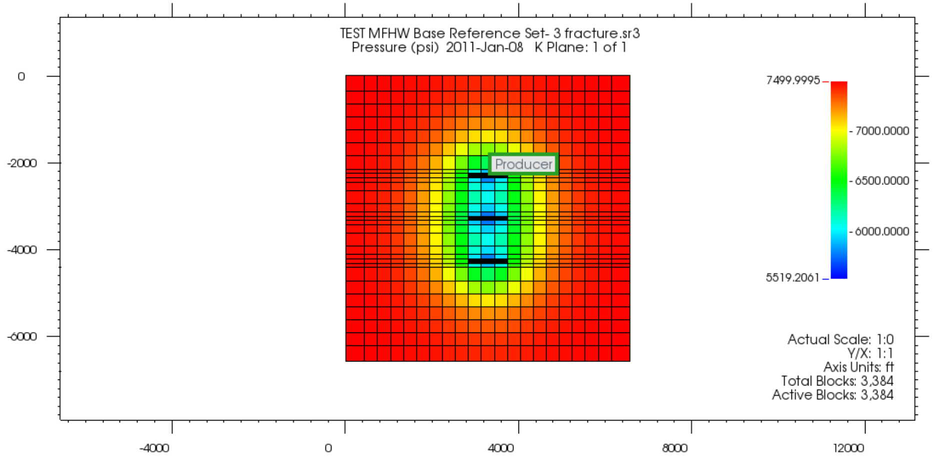


(d) Pressure inside formation with 1 fracture after 10 years of production

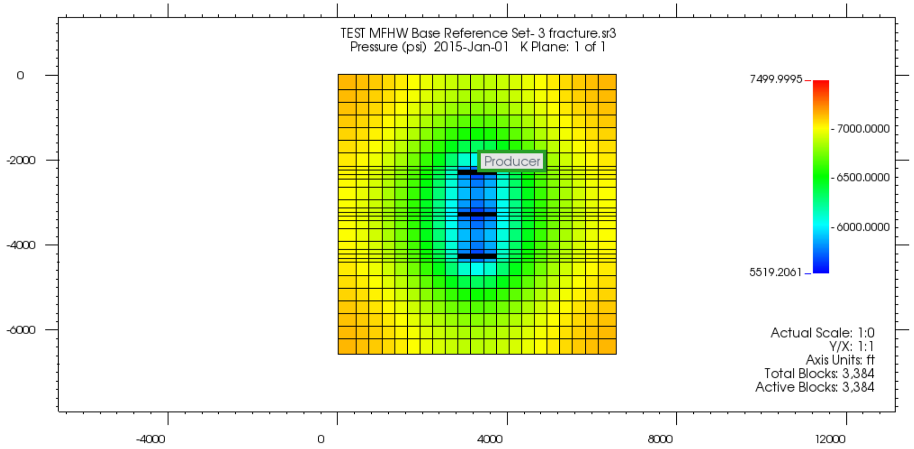
Figure 3.2: Pressure maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (1 fracture)



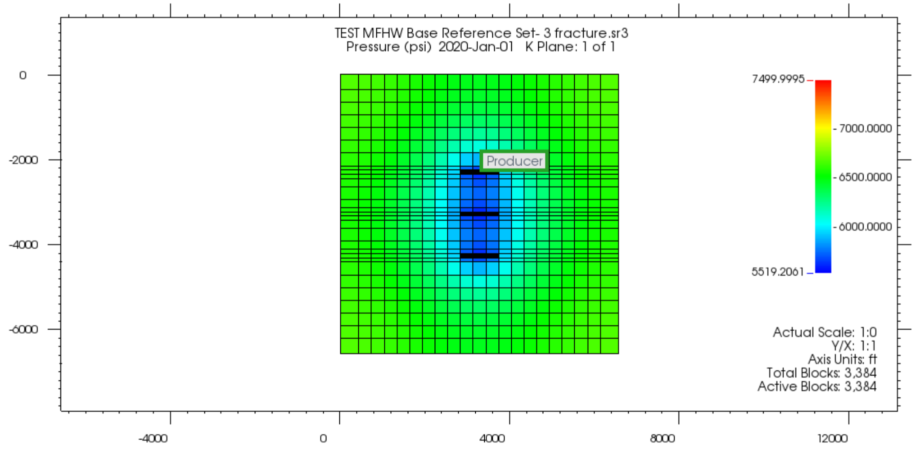
(a) Pressure inside formation with 3 fractures at start of production (Day 1)



(b) Pressure inside formation with 3 fractures after 1 year of production

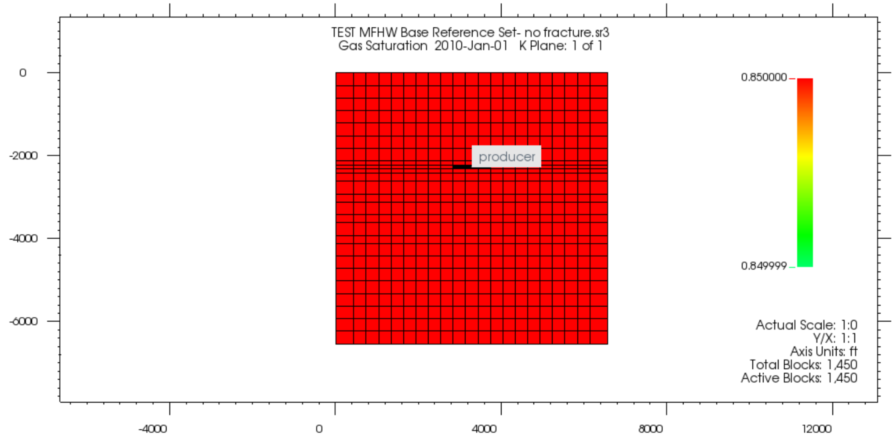


(c) Pressure inside formation with 3 fractures after 5 years of production

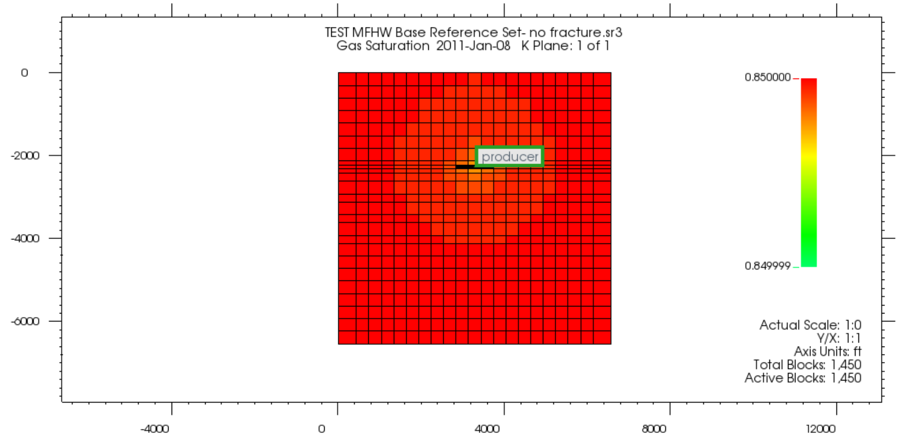


(d) Pressure inside formation with 3 fractures after 10 years of production

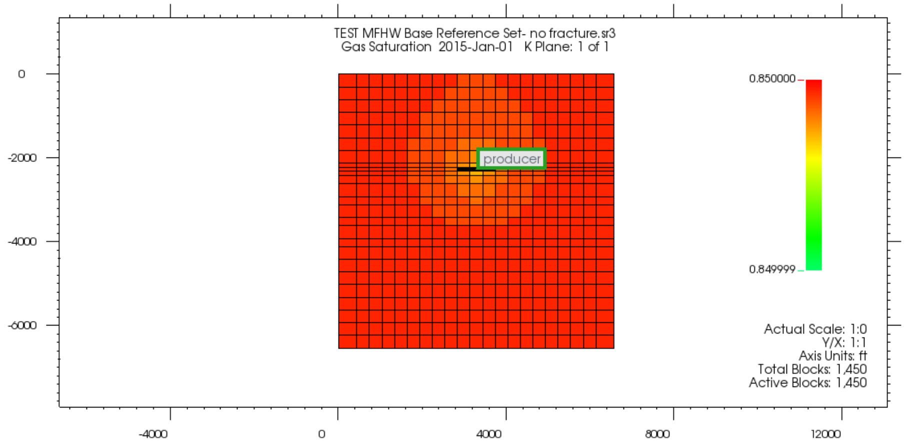
Figure 3.3: Pressure maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (3 fractures)



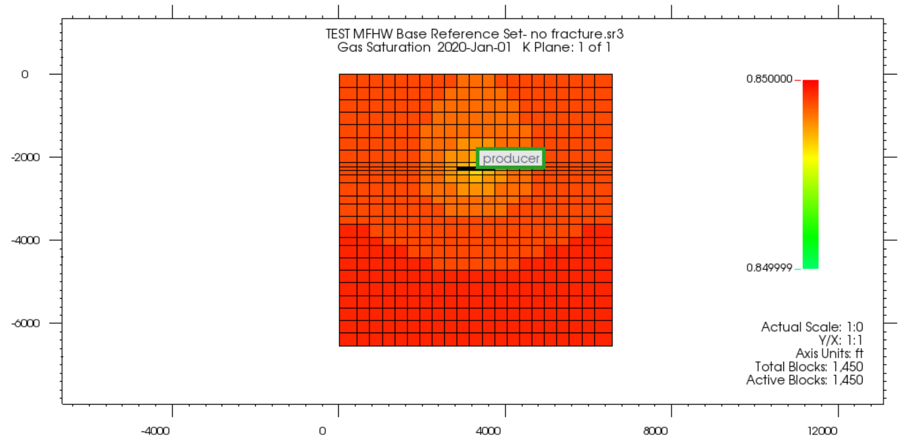
(b) Gas saturation inside formation with no fracture at start of production



(b) Gas saturation inside formation with no fracture after 1 year of production

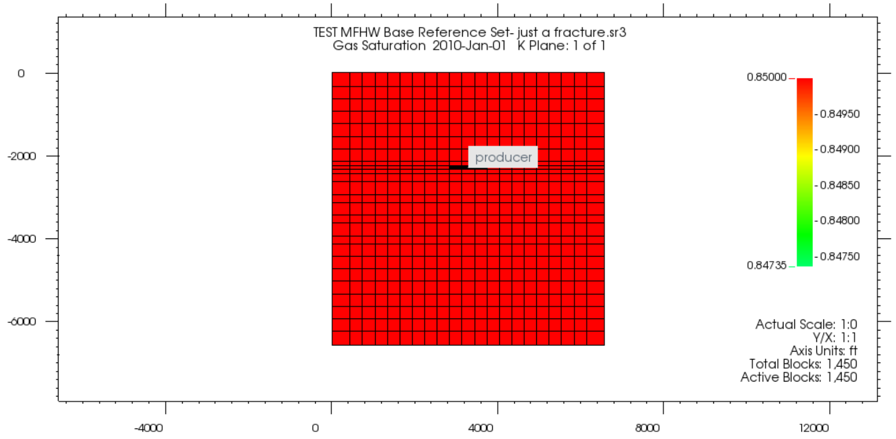


(c) Gas saturation inside formation with no fracture after 5 years of production

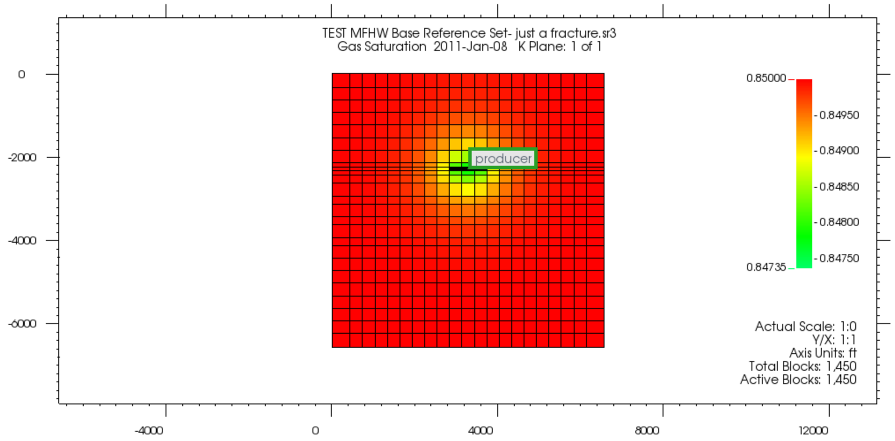


(d) Gas saturation inside formation with no fracture after 10 years of production

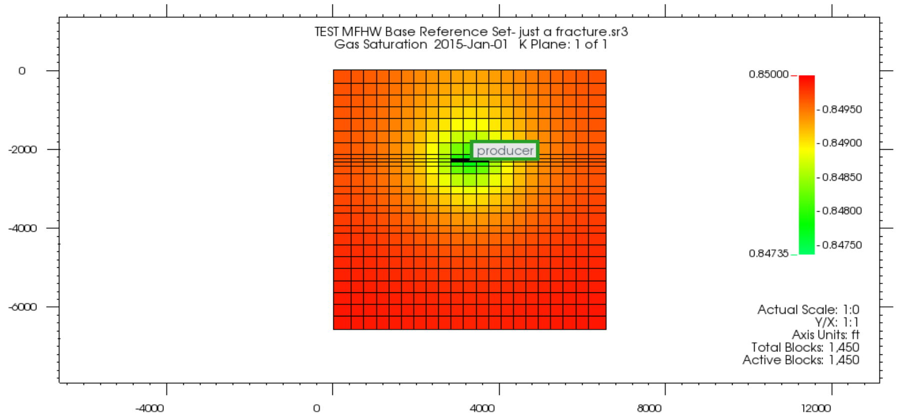
Figure 3.4: Gas saturation maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (No fracture)



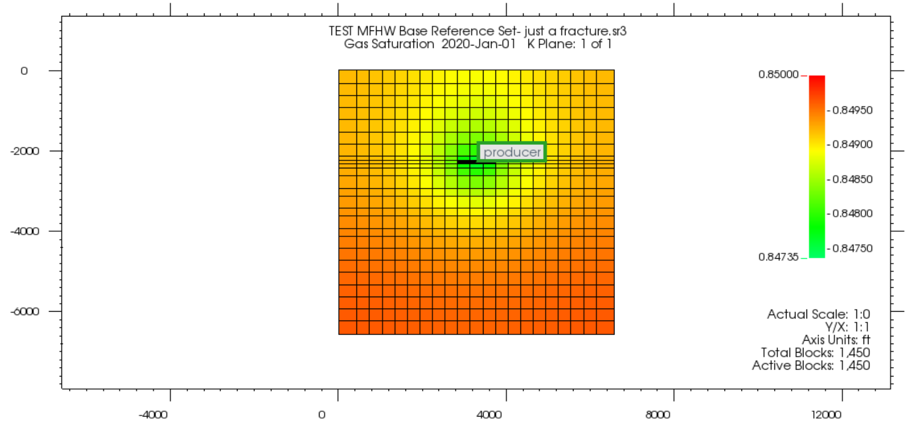
(b) Gas saturation inside formation with 1 fracture at start of production



(b) Gas saturation inside formation with 1 fracture after 1 year of production

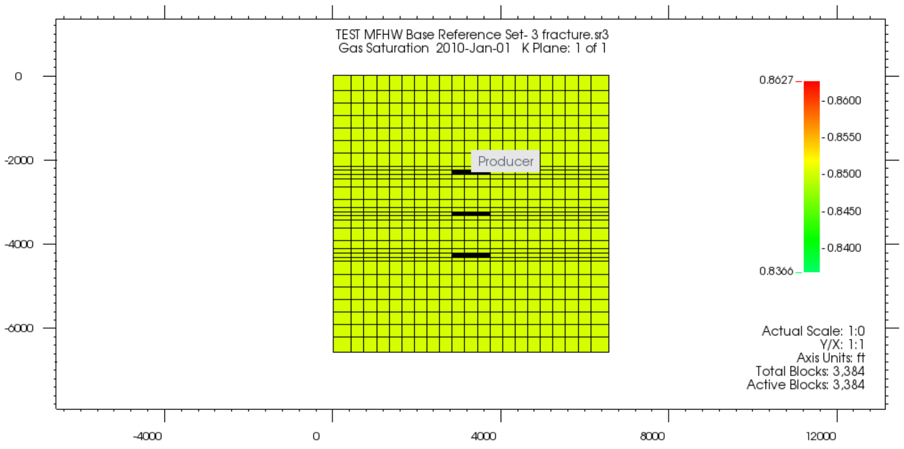


(c) Gas saturation inside formation with 1 fracture after 5 years of production

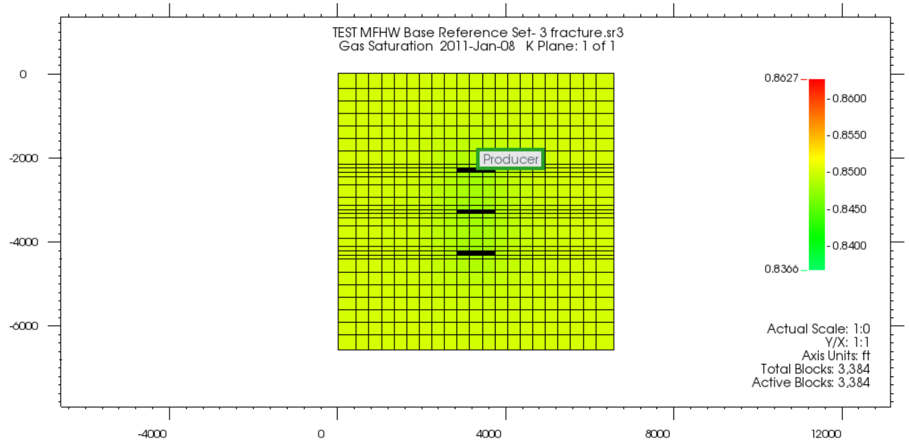


(d) Gas saturation inside formation with 1 fracture after 10 years of production

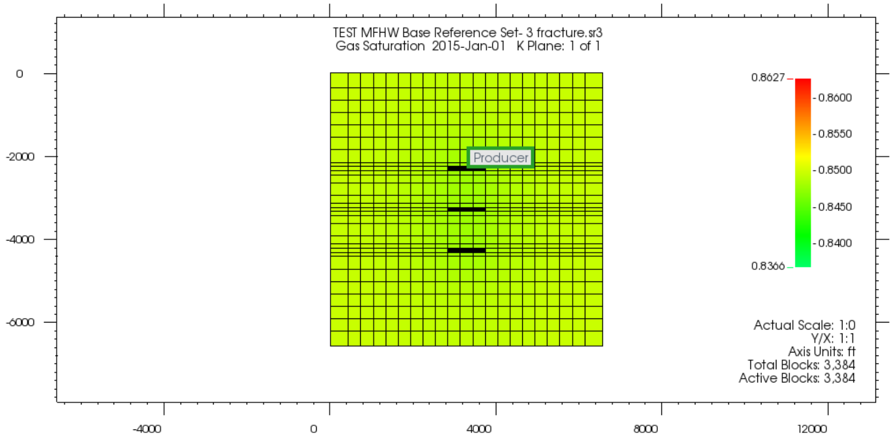
Figure 3.5: Gas saturation maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (1 fracture)



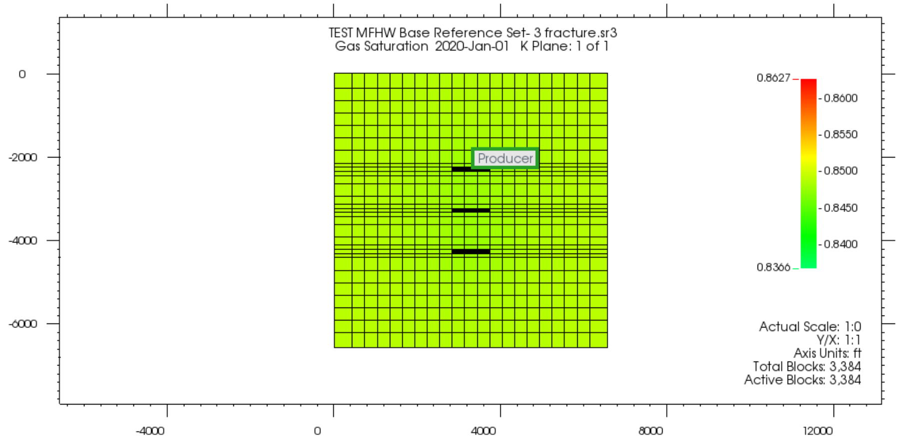
(a) Gas saturation inside formation with 3 fractures at start of production



(b) Gas saturation inside formation with 3 fractures after 1 year of production

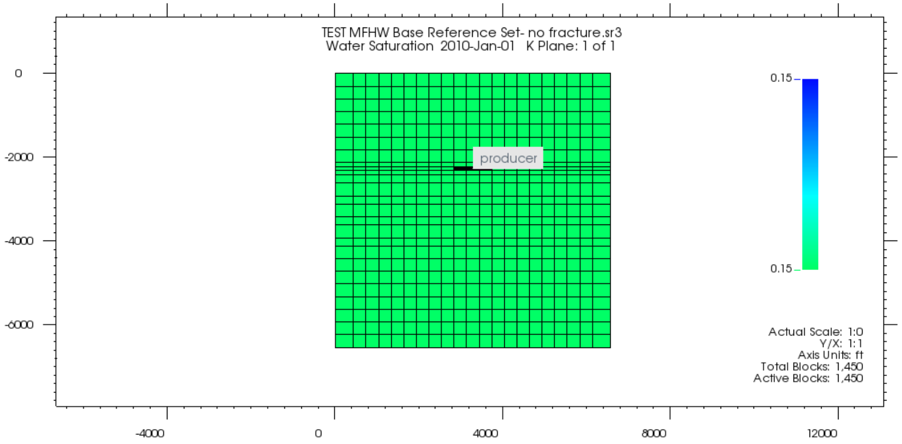


(c) Gas saturation inside formation with 3 fractures after 5 years of production

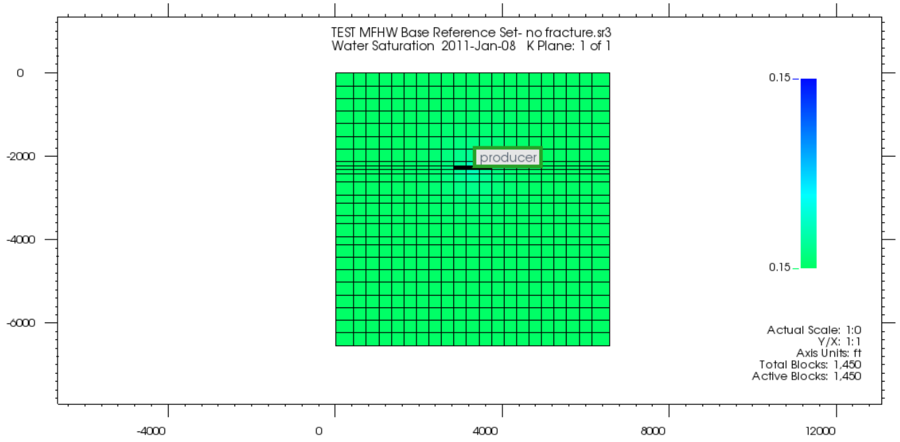


(d) Gas saturation inside formation with 3 fractures after 10 years of production

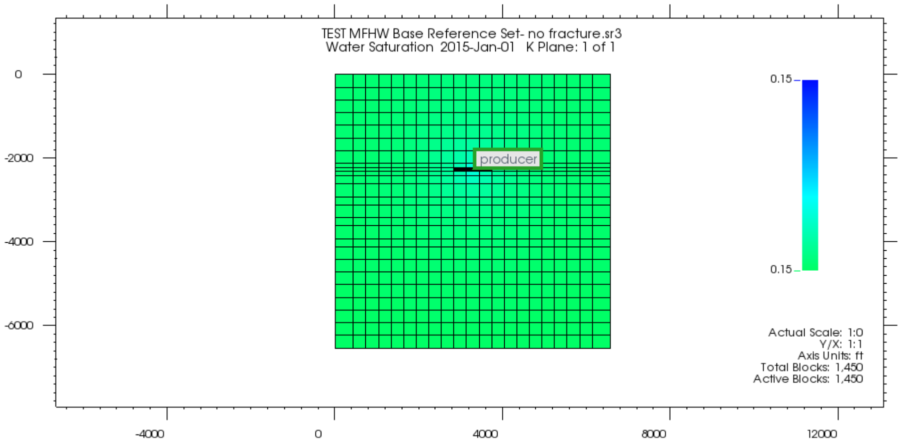
Figure 3.6: Gas saturation maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (3 fractures)



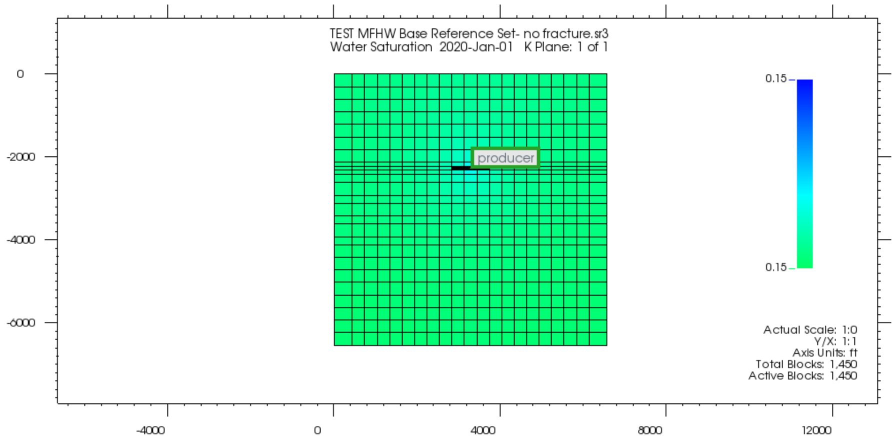
(b) Water saturation inside formation with no fracture at start of production



(b) Water saturation inside formation with no fracture after 1 year of production

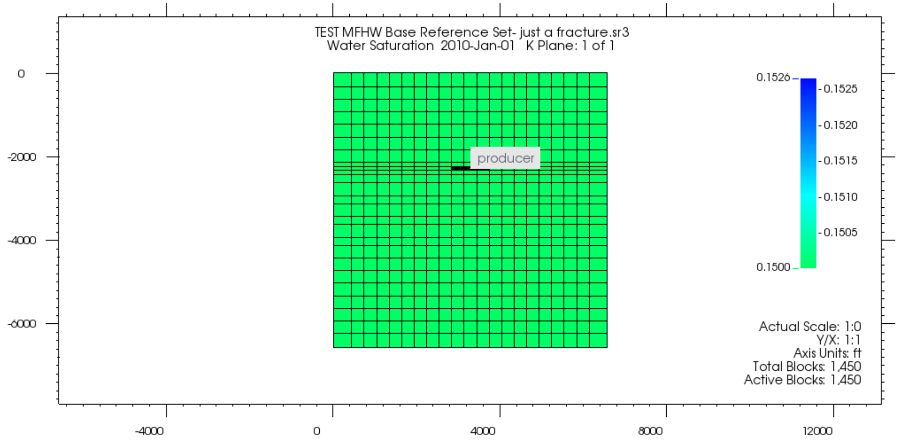


(a) Water saturation inside formation with no fracture after 5 years of production

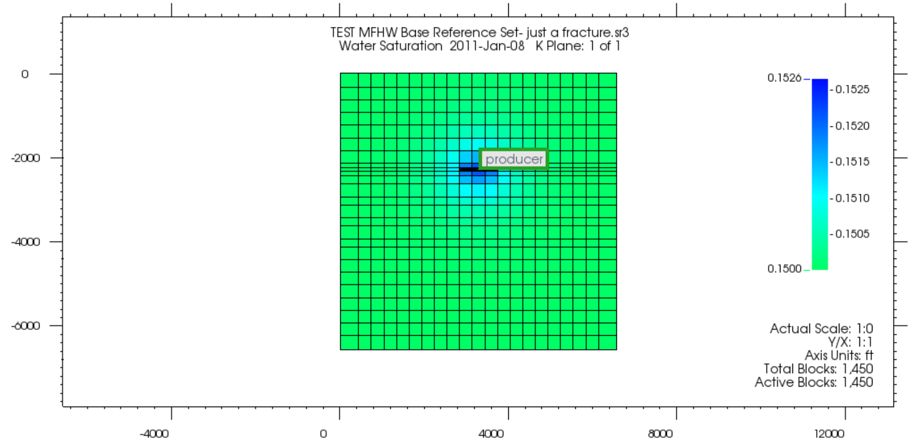


(d) Water saturation inside formation with no fracture after 10 years of production

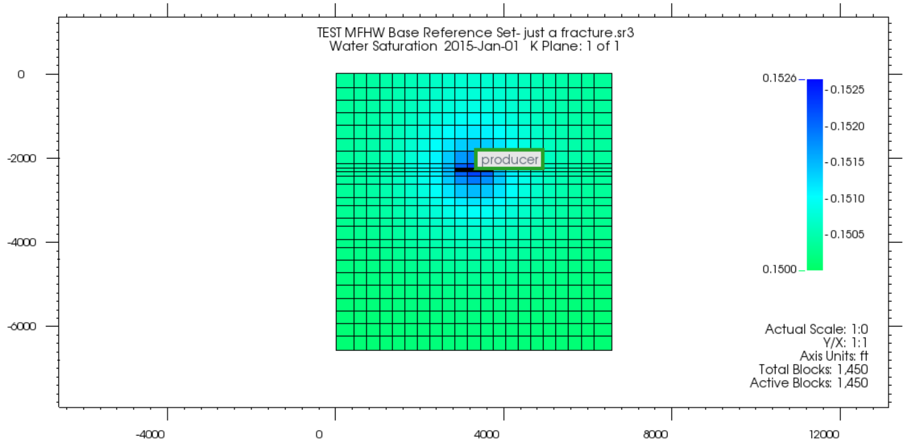
Figure 3.7: Water saturation maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (No fracture)



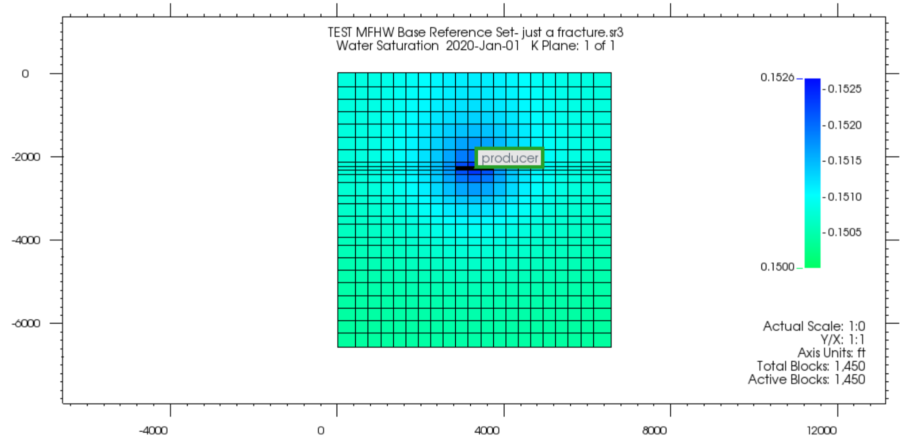
(a) Water saturation inside formation with 1 fracture at start of production



(b) Water saturation inside formation with 1 fracture after 1 year of

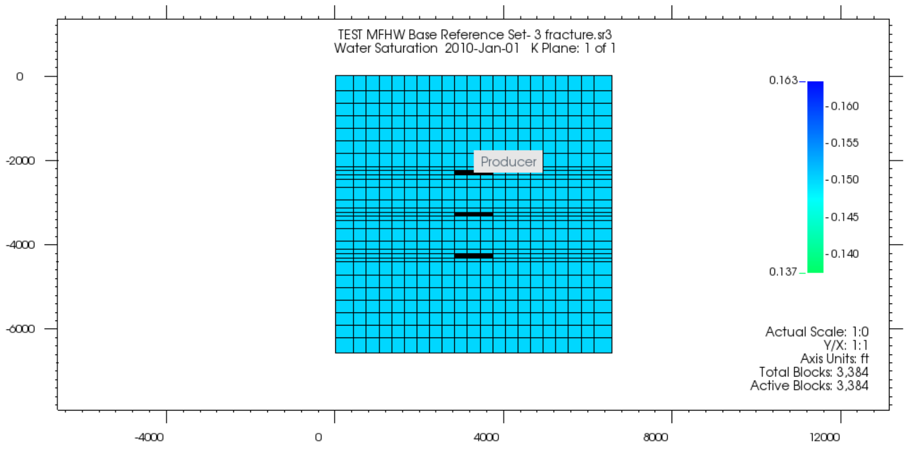


(c) Water saturation inside formation with 1 fracture after 5 years of production

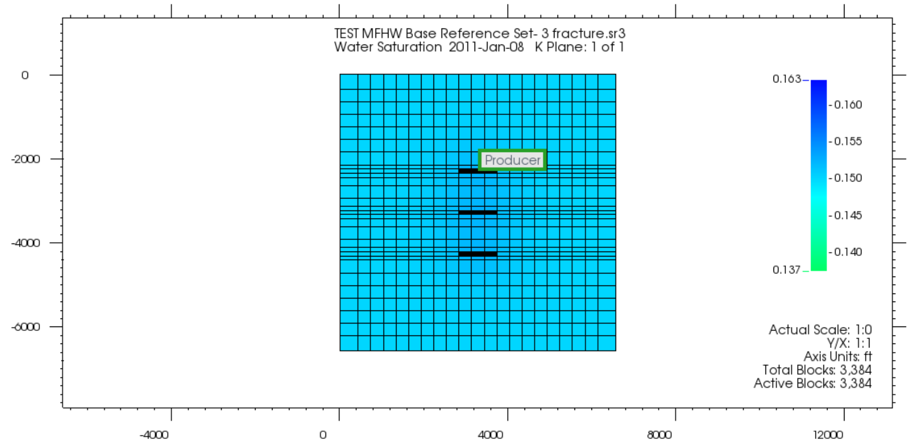


(d) Water saturation inside formation with 1 fracture after 10 years of

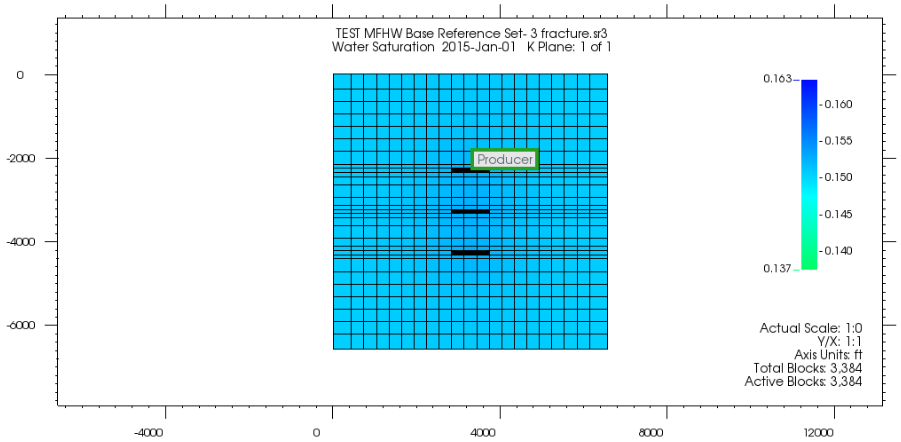
Figure 3.8: Water saturation maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (1 fracture)



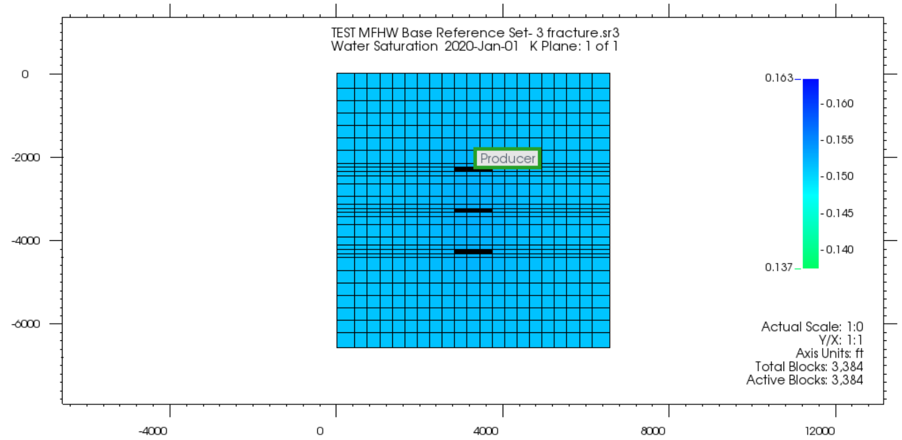
(a) Water saturation inside formation with 3 fractures at start of production



(b) Water saturation inside formation with 3 fractures after 1 year of production



(c) Water saturation inside formation with 3 fractures after 5 years of production



(d) Water saturation inside formation with 3 fractures after 10 years of production

Figure 3.9: Water saturation maps at different time intervals of 0, 1, 5 and 10 years after production for MFHW (3 fractures)

Table 5: Reservoir parameters showing relationship between number of fractures and production time.

Parameter	Number of Fractures	Production time		
		0 years	**5 years**	**10 years**
Reservoir Pressure	NF0	7500 psi	7499.7psi	7499.5psi
	NF1	7500psi	6157.9psi	6032.1psi
	NF3 (Base Case)	7500psi	5947.6psi	5763.2psi
Gas Saturation	NF0	0.85	0.849	0.847
	NF1	0.85	0.848	0.847
	NF3 (Base Case)	0.85	0.847	0.846
Water Saturation	NF0	0.15	0.15	0.15
	NF1	0.15	0.151	0.152
	NF3 (Base Case)	0.15	0.152	0.153

This section shows the variation of saturation in the matrix near the fracture face and in the fracture itself. It gives an indication of how much and where the water loading is taking place. Saturation is monitored and represented both by using saturation maps (figures 3.1, 3.2, 3.3, 3.4, 3.5, 3.6,3.7, 3.8, 3.9) of fracture and matrix as well as plotted vs. time. The base case performance of a water-gas system is first analysed.

Volumetric gas reservoirs are essentially depleted by expansion and, therefore, the ultimate gas recovery is independent of the field production rate. The gas saturation in this type of reservoir is never reduced; only the number of pounds of gas occupying the pore spaces is reduced. Therefore, it is important to reduce the abandonment pressure to the lowest possible level. In closed-gas reservoirs, it is not uncommon to recover as much as 90% of the initial gas in place.

Pressure maps have also been collected to investigate the pressure differential across the formation for 0, 1 and 3 fractures. Primary recovery uses naturally occurring energy, such as buoyancy (Archimedes principle) and reservoir pressure, to drive natural gas flow to the surface. Natural gas is simply allowed to flow under its own pressure unless fracking fluids are injected into the reservoir.

Conclusions drawn from table are:

- In figures 3.0, 3.1 and 3.2, the reservoir pressure depletion happens at a faster rate for an increasing number of fractures and natural gas extraction. The pressure gradient drops as natural gas is extracted, which leads to a limited rate of production according to Darcy's law. This results in a depletion-driven decline in the rate of production as depletion of the reservoir reduces pressure and hence gas flow.
- It is seen from figures 3.3, 3.4 and 3.5 gas saturation were relatively the same and only decreased slightly with a greater number of fractured wells and this decrease was seen at later stages of production. This is due to more wells being fractured, fracturing-fluid entering the formation will reduce the flow channel. Both critical gas saturation and irreducible water saturation have a negative relationship with porosity as well as permeability.
- It is seen from figures 3.6, 3.7 and 3.8 water saturation were relatively the same and only increased very slightly with a greater number of fractured wells and the increase was seen towards the later stages of production. Fractures improve the permeability of rocks greatly, hence with a greater number of fractures, a higher permeability in the formation is observed.
- From figures 4.0 to 4.3, Water and gas flow properties will increase with an increasing number of fractures.

Water saturation is determined by fluid flow. At early times, the water saturation front is almost identical to the fracture tip, suggesting that the fracture is mostly filled with injected water. However, at late times, advance of the waterfront is retarded compared to fracture propagation, yielding a significant gap between the waterfront and the fracture top, which is filled with reservoir gas.

Chapter 4: Results

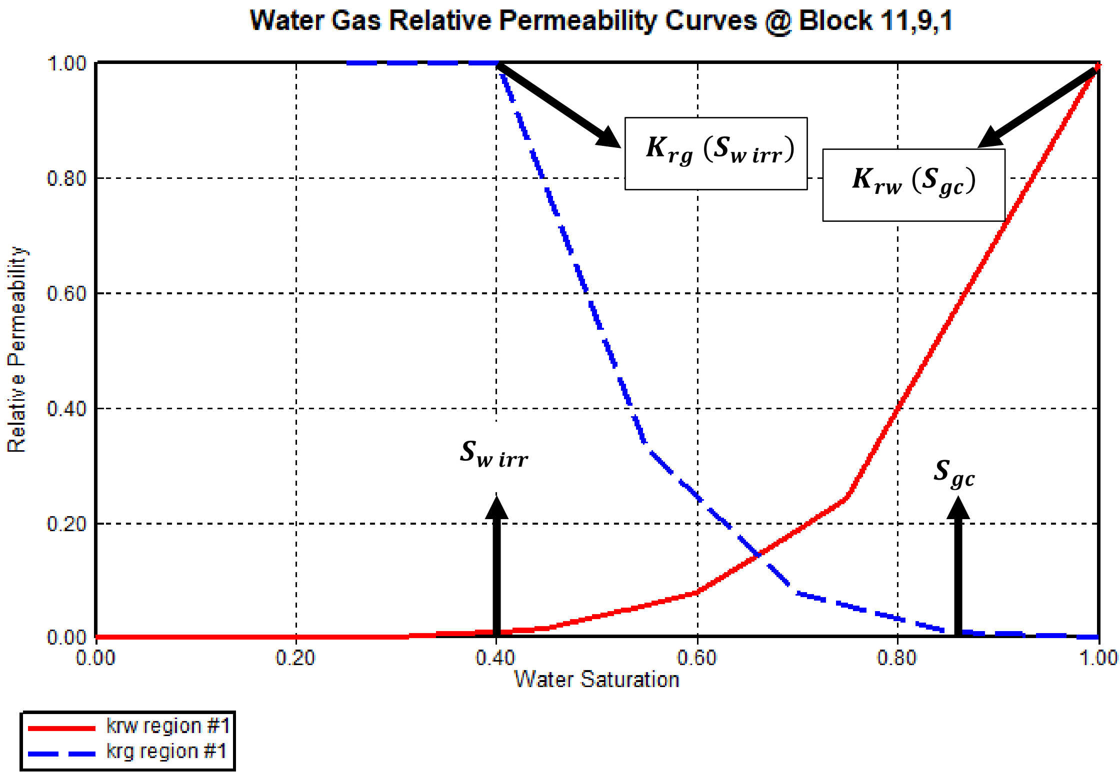


Figure 4.1 Matrix Relative Permeability curves (Base case – NF3)

From figure 4.1, irreducible water saturation is at 0.4, which means the MFHW formation is only capable of retaining 40% of the water in the formation without producing water, at the given permeability of 0.1mD and porosity of 0.1. This water is immobile as it is held in place by capillary forces. 0.85 is the critical gas saturation where gas first becomes mobile during a gas-flood in a porous material that is initially saturated with water. For example, the critical gas saturation is 85%, then gas does not flow until its saturation exceeds 85%.

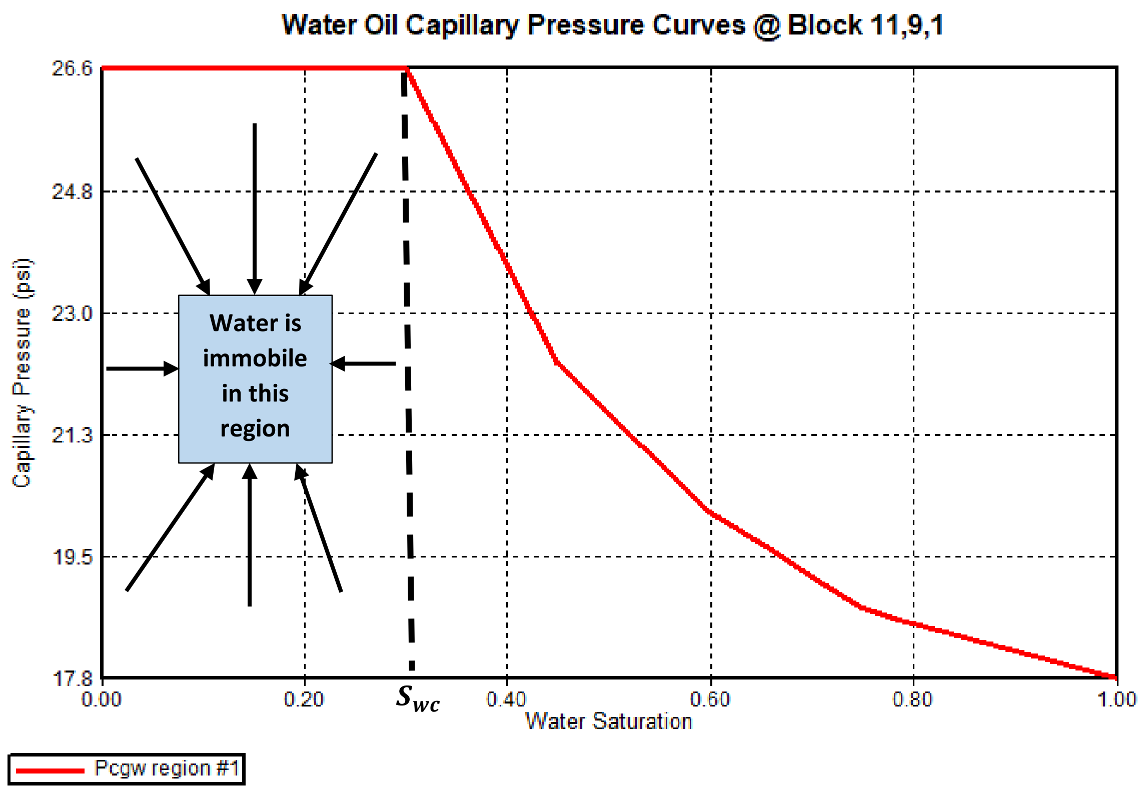


Figure 4.2 Water-Gas Capillary pressure curve (Base case – NF3)

In figure 4.2, at capillary pressure of 26.6 and water saturations between 0 and 0.30, water is immobile in this region and held in place by capillary forces. 0.30 is the critical water saturation where water first becomes mobile in a porous material. For example, the critical water saturation is 30%, then water does not flow until its water saturation exceeds 30%.

After the water becomes mobile at S_{wc} = 0.3, it is observed that capillary pressure decreases for increasing water saturation during imbibition, enhancing the mobility of water. Similarly, for increasing capillary pressure just above zero, a decrease in water saturation is observed during the secondary-drainage cycle.

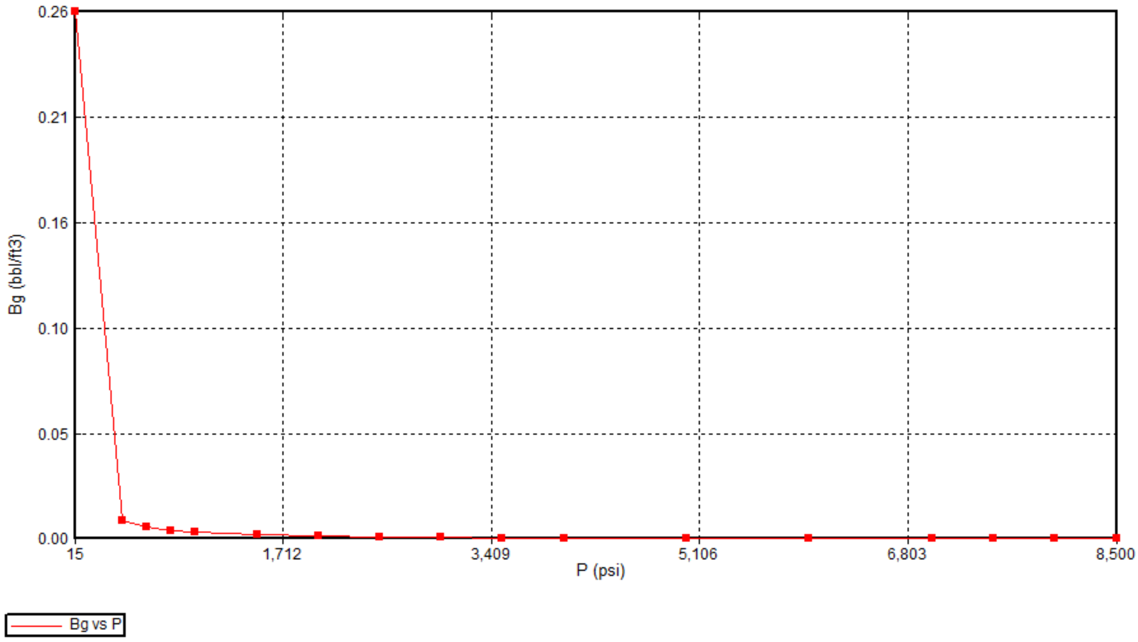


Figure 4.3 Gas formation volume factor (B_g) against Pressure

From figure 4.3, it is seen that gas formation volume factor is inversely proportional to pressure raised to a power, suggesting a non-linear relationship. This is because the volume factor (B_g) falls rapidly, and linearly as reservoir pressure increases, the gas will expand to occupy more volume in the reservoir.

Gas formation volume factor is influenced by two main factors. The dominant factor is solution gas. As pressure increases, the amount of solution gas that the water can dissolve increases. Once there is no remaining free gas available to dissolve in the water, further increases in pressure result in decline in formation volume factor due to the second influencing factor – the compressibility of water.

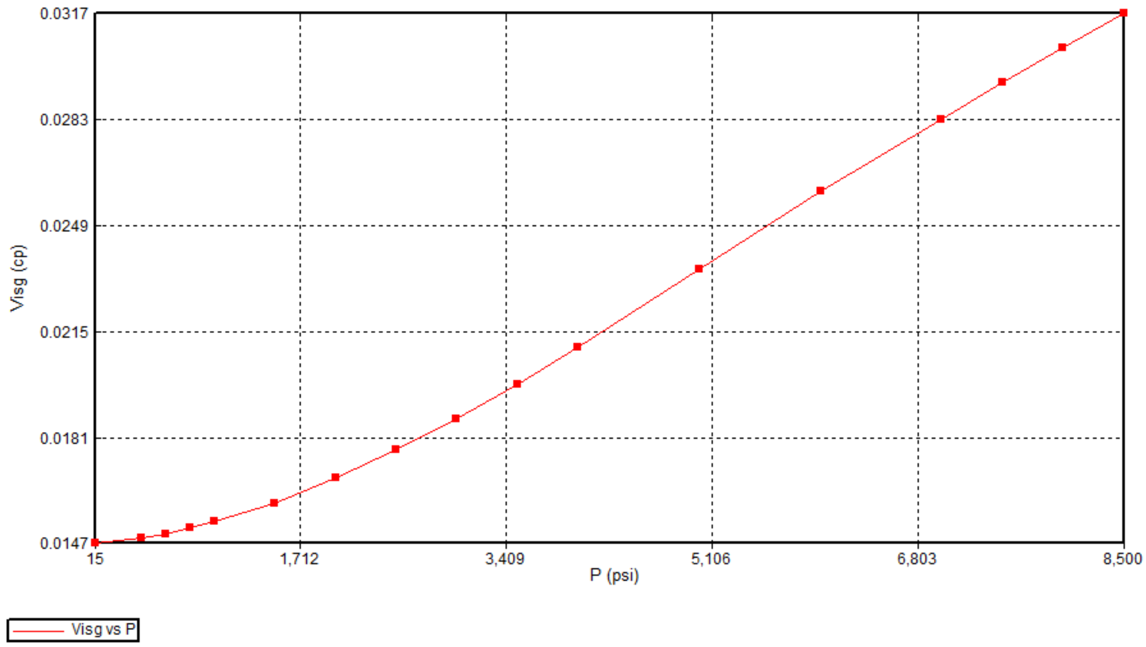


Figure 4.4 Gas Viscosity against Pressure

From figure 4.4, it is seen that gas viscosity is directly proportional to pressure. Gas viscosity is a measure of the resistance to flow exerted by the gas and is given in units of centipoises (cp). Higher values indicate more resistance to flow. For gas, the viscosity increases with increasing temperature and pressure. As pressure decreases, gas viscosity decreases. The molecules are simply further apart at lower pressure, and move past each other more easily (Schmelzer, Zanotto and Fokin, 2005).

The wettability is the tendency of a reservoir rock surface to preferentially contact a particular fluid. The fluids in the pore space are typically an immiscible combination of water, oil and gas. Wettability plays an important role in enhanced oil recovery as it determines the interactions between the solid (rock) and the liquids in the reservoirs (crude oil, brine). The wettability used in the simulations is 0.5, leaning towards a more water-wet core, according to the Amott-Harvey wettability index.

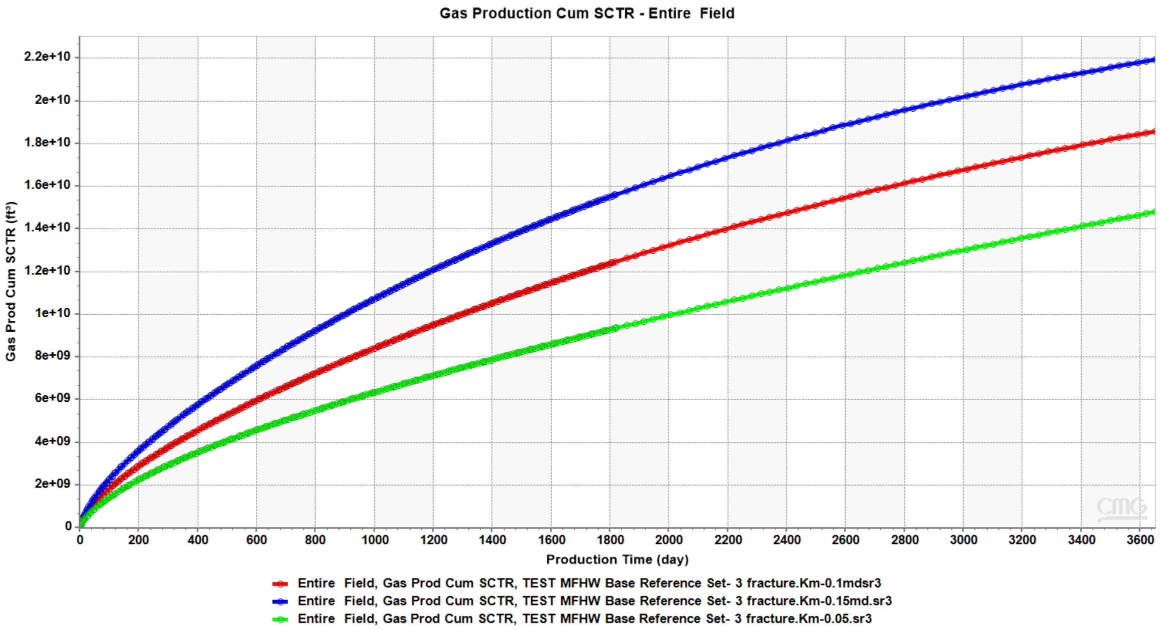


Figure 4.5: Gas Production vs Production time (day) for K_m 0.1md, 0.15md, 0.05md

In figure 4.5, it is clearly seen that there is a higher gas production with higher rates of matrix permeability because more pore spaces now exist for a larger number of gases to flow through the formation easily.

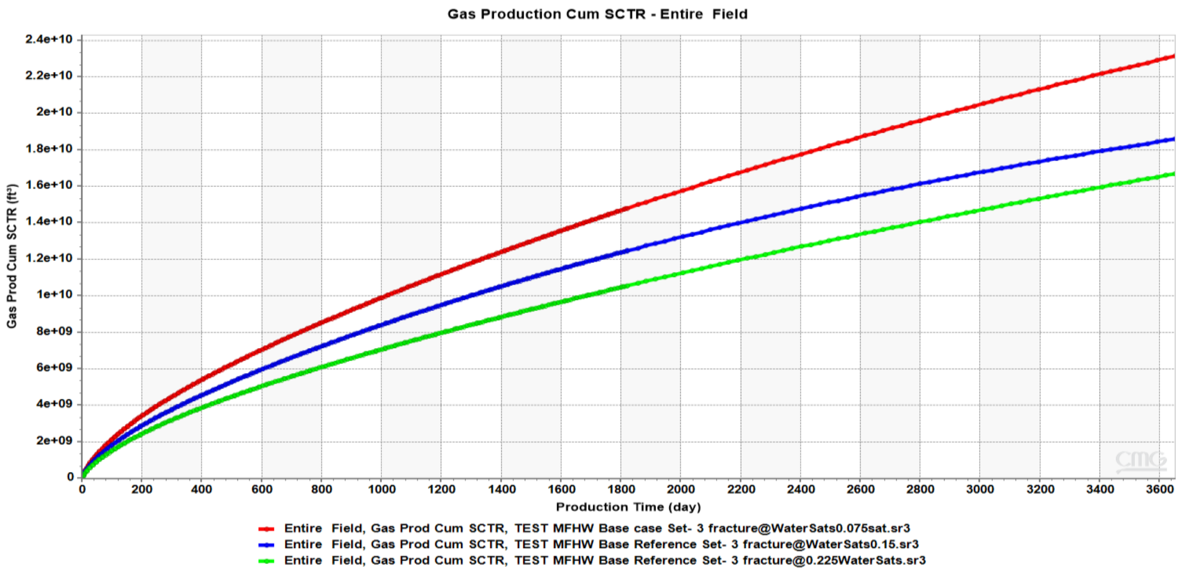
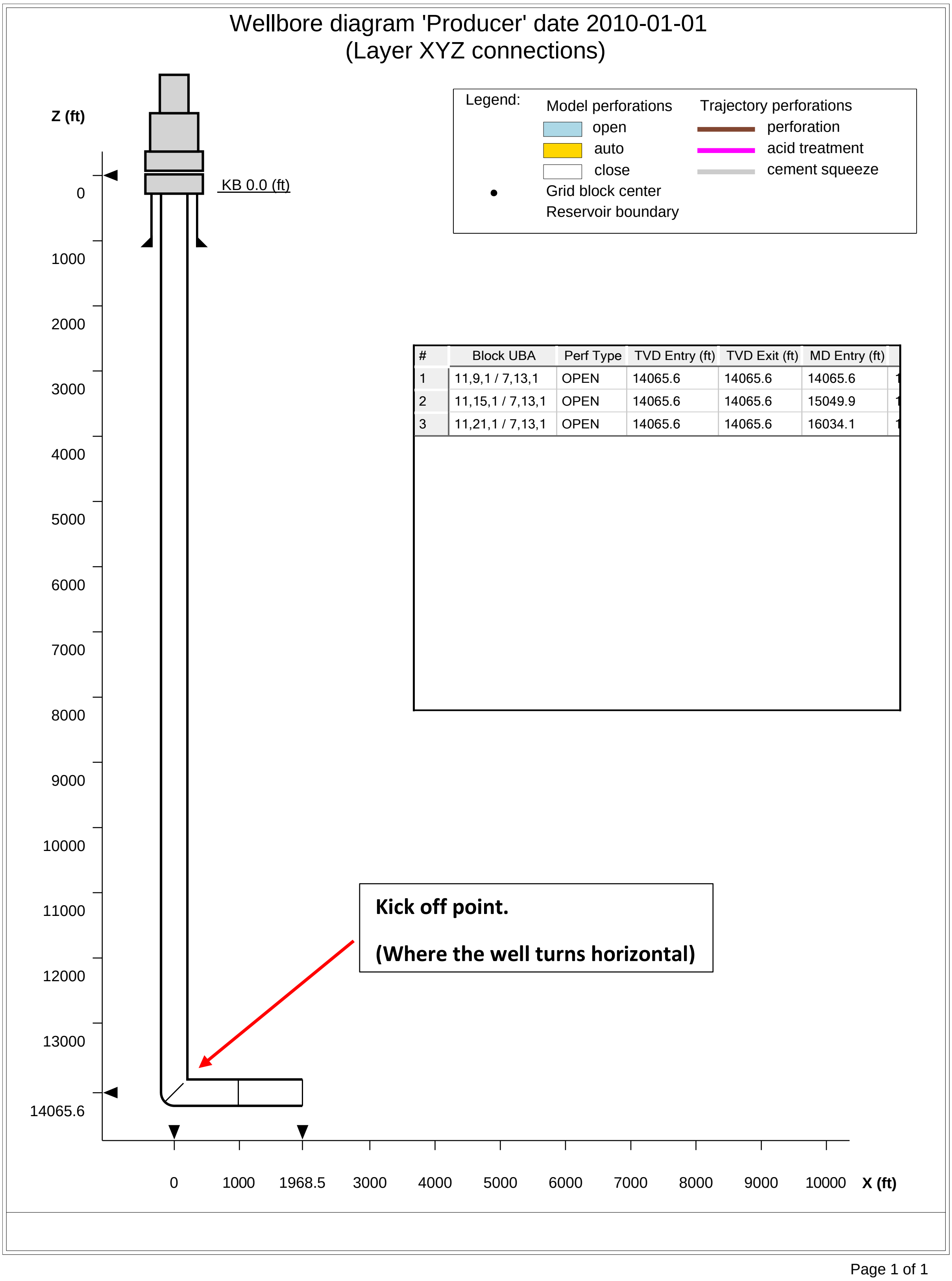


Figure 4.6: Gas Production SCTR vs water saturations 0.075, 0.15 and 0.225

From figure 4.6, gas production increases at a lower water saturation, this is because dry-gas reservoirs have a strong trapping effect, hence when water saturation levels in the formation increases, it impedes the flow of gas towards the well surface.

START OF VALIDATION: BASE CASE



#	Block UBA	Perf Type	TVD Entry (ft)	TVD Exit (ft)	MD Entry (ft)
1	11,9,1 / 7,13,1	OPEN	14065.6	14065.6	14065.6
2	11,15,1 / 7,13,1	OPEN	14065.6	14065.6	15049.9
3	11,21,1 / 7,13,1	OPEN	14065.6	14065.6	16034.1

Figure 4.7: Producer Wellbore diagram

A Multiple Fractured Horizontal Wells (MFHW) have been simulated rather than a vertical well because horizontal drilling can stimulate reservoirs and obtain information that cannot be done by drilling vertically. Horizontal drilling increases the contact between the reservoir and the wellbore.

In this study, for each set, the full factorial experimental design sampling technique was employed to generate the input to the simulation models, and then at the point, the numerical simulation is carried out by CMG.

For the case of MFHW, a new simulation model was set-up with three fractures placed on the 600m horizontal well length. Fracture half-length was 180m rather than 400 m corresponding to the Vertical-Well reference set (Nasriani and Jamiolahmady, 2018b). The local grid refinement, LGR, (rather than global refinement) was used around fractures to capture the variation of flow parameters in this area whilst not increasing the CPU time significantly.

Table 6: Fracture properties and reservoir dimensions for the reference model used for MFHW.

Horizontal well length(m)	Number of hydraulic fractures	X_f(m)	W_f (m)	X_{res} (m)	Y_{res} (m)	Z_{res} (m)
600	3	180	0.004	2000	2000	40

The fluid properties and the reservoir and fracture parameters and the variation range of all 12 parameters were similar to those of the SFVW-Sets as shown in (Nasriani and Jamiolahmady, 2018b).

4.1 Validation of the developed Model of Multiple Fractured Horizontal Well

To validate the model developed for MFHW clean-up operation, the same approach, as that of SFVW which was explained in (Nasriani and Jamiolahmady, 2018b) was conducted. The predicted bottom hole pressures from the reservoir simulation outputs were compared with analytical model.

At the early time flow period, the early linear flow is the main flow regime in most of SFVWs and MFHWs in tight reservoirs. For this flow regime, as the area perpendicular to the flow is the cross section of a fracture (2Xfh), the corresponding equation is as follows:

$$\boldsymbol{P_{wf} = P_i - \left(\sqrt{\frac{16.52q^2B^2\mu}{h^2\emptyset C_t}} \frac{\sqrt{t}}{\sqrt{K_m {X_f}^2}} + \frac{141.2q\mu B}{K_m h} \left(S_D + S_C\right) \right)} \text{......... Equation 1}$$

4.2 Justification for Choice of Analytical Model

(Schlumberger, 2013) used this early flow linear equation to validate results from the six different models of Vertical and Horizontal wells simulated using Eclipse 100 software. Since then, it has been used as a base model to work from and has been validated against real time results.

(Nasriani, Jamiolahmady, T. Saif, 2018) also used this analytical formular in the case of vertical wells and it was found to be a complete match to the simulation result with an R^2 of 0.9978, which is why in the case of this study, this model has been modified to meet the requirements of the research question. At the early time flow period, the early linear flow is the main flow regime in multiple fractured horizontal wells (MFHWs) in tight reservoirs. For this flow regime, as the area perpendicular to the flow is the cross section of a fracture (2Xfh), the corresponding equation 1 was used.

4.3 Sample Calculation with Analytical Equation 1

Sample analytical calculations will be shown for start of 1st day of production, 180th day of production (after 6 months) and 365th day of production (after 12 months). A more detailed analysis has been carried out in excel spreadsheet for every hour of production time from day 1 to day 3652 (end of production time of 10 years).

Table 7: Parameters used in the analytical equation for the early linear flow regime.

Symbol	Parameter	Imperial Field Unit	Metric Unit
P_i	Initial reservoir pressure	7500 psi	51710.68kPa
S_D	Damage skin (Calculated by CMG)	0.701	0.701
S_C	Convergence skin in a fractured horizontal well.	0	0
h	Formation thickness	131.234ft	40m
k_m	Matrix permeability	0.1md	0.1md
k_f	Fracture permeability	30,000md	30,000md
W_f	Fracture width	0.013124ft	0.004m
C_t	Total compressibility	1.37E-04 psi^{-1}	1.37E-04
q	Flowrate from each fracture (MScf/D) Q = $\frac{total\ flowrate\ of\ well}{Number\ of\ fractures}$ = $\frac{q_t}{N_f}$ = $\frac{\frac{150\text{MScf}}{\text{D}}}{3}$	50	50
B	Formation volume factor (reservoir volume)	0.6124	0.6124
μ	Viscosity (cp)	0.02945	0.02945
t	Time at start of production (hrs)	0	0
Ø	Porosity of formation	0.15	0.15
X_f	Fracture half-length	590.58ft	180m

<u>NB:</u> Imperial field units' values have been used in the equation instead of the metric unit values because CMG simulation has been done using imperial units. Base case reservoir properties adapted from (Nasriani, Jamiolahmady, Tarik Saif, 2018) which is in line with relevant past literature as a basis for modelling.

$$\therefore \mathbf{7500} - \left(\sqrt{\frac{16.52\times 50^2\times 0.6124^2\times 0.029}{131.234^2\times 0.15\times 1.37E{-04}}}\frac{\sqrt{0}}{\sqrt{0.1\times 590.58^2}} + \frac{141.2\times 50\times 0.029\times 0.6124}{0.1\times 131.234}\ (\mathbf{0.701+0})\right)$$

$\therefore P_{wf\ @\ start\ of\ production\ when\ t=0}$ **= 7493.3 psi**

$\therefore P_{wf\ @\ start\ of\ production\ when\ t=4380}$ **= 7478.36 psi**

$\therefore P_{wf\ @\ start\ of\ production\ when\ t=8760}$ **= 7472.09 psi**

The early linear flow equation 1 has been used in the analytical equation since the early time flow period is significantly longer than the maximum clean-up period. The inertia, coupling, turbulence around the wellbore need to be in the linear area too to match the flowrate, as analytical models cannot capture turbulence when the flowrate (Q) is too high.

Due to the very low flow rate of applied in the CMG model of 50MScf/D per fracture, the change in the pressure differential from the start of production life to its end is significantly low.

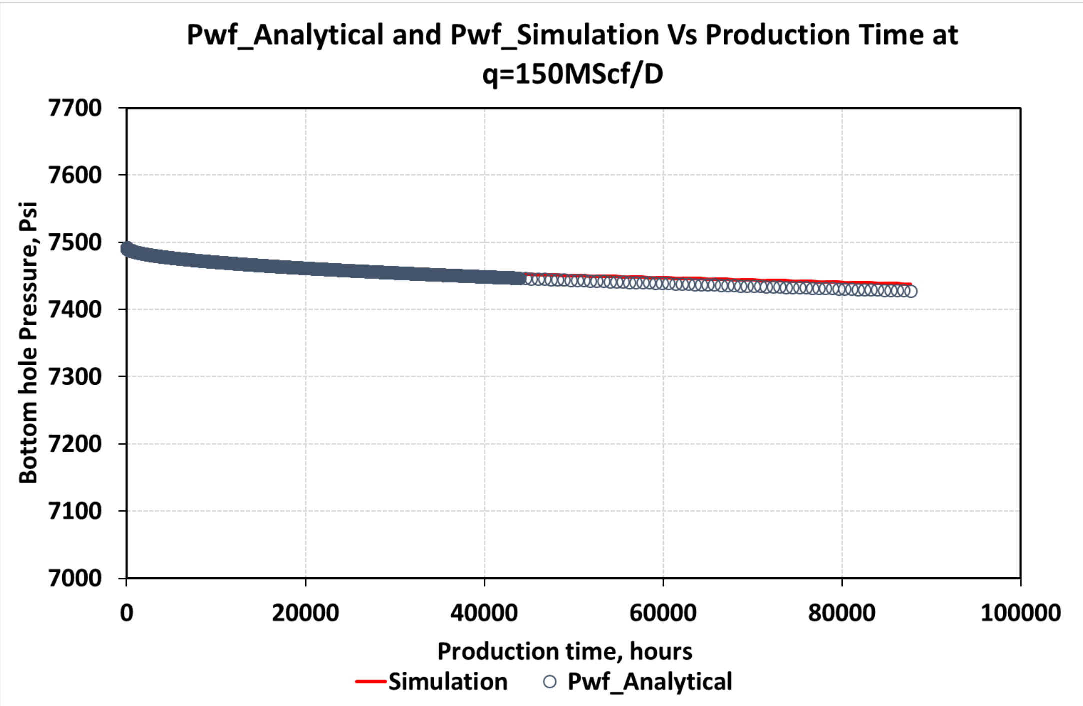


Figure 4.8: Pwf_Analytical and Pwf_Simulation Vs Production Time at q=150MScf/D

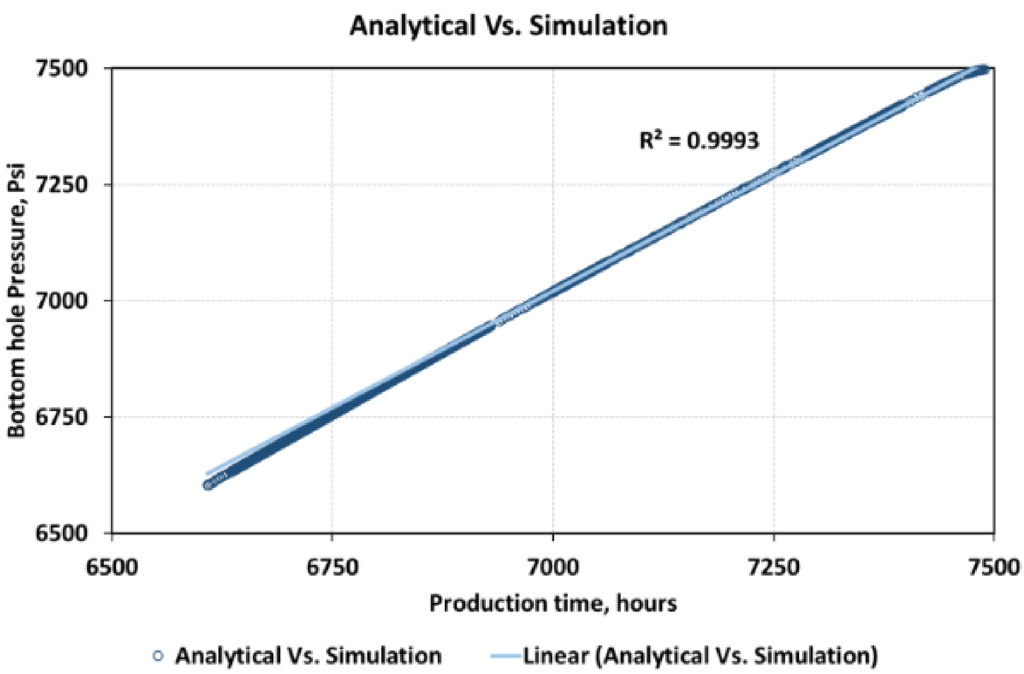


Figure 4.9: Predicted bottom hole pressure by analytical model vs the CMG simulation model.

4.4 Validation of the model

To validate the model developed for MFHW clean-up operation and to give confidence that the model is consistent, the predicted bottom hole pressures from the reservoir CMG simulation outputs were compared with analytical models (early linear flow).

Figure 4.8 shows the predicated bottom hole pressure by simulation model and the predicated bottom hole pressure by analytical model (Equation 1) versus production time (hours), it should be noted that both graphs are overlapping and almost on top of one another which confirms the accuracy of the developed model. Figure 4.9 shows the predicated bottom hole pressure by analytical model (Equation 1) versus the one of simulation model where satisfactory R^2 of 0.9993 is noted.

4.5 Why is R^2 not equal to 1.

- Some of the data have been mined, which means several independent variables have been used, this introduces a variety of problems, including misleading coefficients and an inflated R-squared value.
- Sometimes simulation findings do not give accurate evaluation due to the variation in the simulation environments.

- An analytical model may represent parameter values that are a function of time or parameter values that do not change with time. On the other hand, other solutions require numerical analysis methods to determine the change in state of the system as a function of time, space, and other parameters. In addition, the parameter values may be deterministic or probabilistic. In the latter case, the parameters in the model are defined with an associated probability distribution.

Chapter 5: Desiccation

Understanding the impact of desiccation and low permeability jail on unconventional gas play cleanup performance is crucial for optimizing production and minimizing environmental impact. Here's a breakdown of their individual and combined effect. Desiccation is referred to as the process of drying out, which plays a complex and multifaceted role in gas formations, particularly unconventional reservoirs like shale gas. Whilst it can offer some potential benefits, its negative consequences often outweigh them, demanding careful consideration and management.

5.1 Potential Benefits:

Enhanced gas flow: In some cases, desiccation can lead to slight shrinkage of clay minerals, which can potentially open pore spaces and facilitate gas flow. However, this benefit is often temporary and outweighed by negative impacts.

Water management: Controlled desiccation during well shut-in periods can aid in removing excess water from fractures, potentially improving gas production in certain formations.

5.2 Negative Consequences:

Permeability reduction: Desiccation can trigger swelling of clay minerals within the formation, significantly reducing pore size and permeability. This severely restricts gas flow, hindering production and potentially requiring costly remedial measures. Brine precipitation; Dissolved salts in formation water can precipitate upon drying, forming solid deposits that further plug pores and exacerbate permeability reduction.

Formation damage: Desiccation can weaken the rock matrix, making it more susceptible to fracturing and instability, which can compromise well integrity and long-term production potential. Environmental concerns: Uncontrolled desiccation can lead to increased fugitive methane emissions, posing environmental and economic risks.

In this chapter, a sensitive analysis has been carried out on water saturation in different scenarios, this is to investigate the mobility of fluid flow into the porous media, as well as study the effects of desiccation and low permeability jail on fracturing-fluid clean-up and quantify its effect on fracture-fluid clean-up.

- Base Case ***(Scenario 1)***, $\boldsymbol{S_{w\,i}}$ **=** $\boldsymbol{S_{w\,irr}}$**,** investigation into water production when initial water saturation is equivalent to irreducible water saturation
- Desiccation ***(Scenario 2)***, $\boldsymbol{S_{w\,i}} < \boldsymbol{S_{w\,irr}}$, investigation into water production when initial water saturation is less than the irreducible water saturation.
- Mobile Water ***(Scenario 3)***, $\boldsymbol{S_{w\,i}}$ **>** $\boldsymbol{S_{w\,irr}}$, investigation into water production when initial water saturation is more than the irreducible water saturation.

Where:

- Base case is $\mathbf{0.15}(\boldsymbol{S_{w\,i}}) = \mathbf{0.15}\ (\boldsymbol{S_{w\,irr}})$
- Desiccation is $\mathbf{0.01}(\boldsymbol{S_{w\,i}}) < \ \mathbf{0.15}\ (\boldsymbol{S_{w\,irr}})$
- Mobile Water is $\mathbf{0.35}(\boldsymbol{S_{w\,i}}) > \ \mathbf{0.15}\ (\boldsymbol{S_{w\,irr}})$

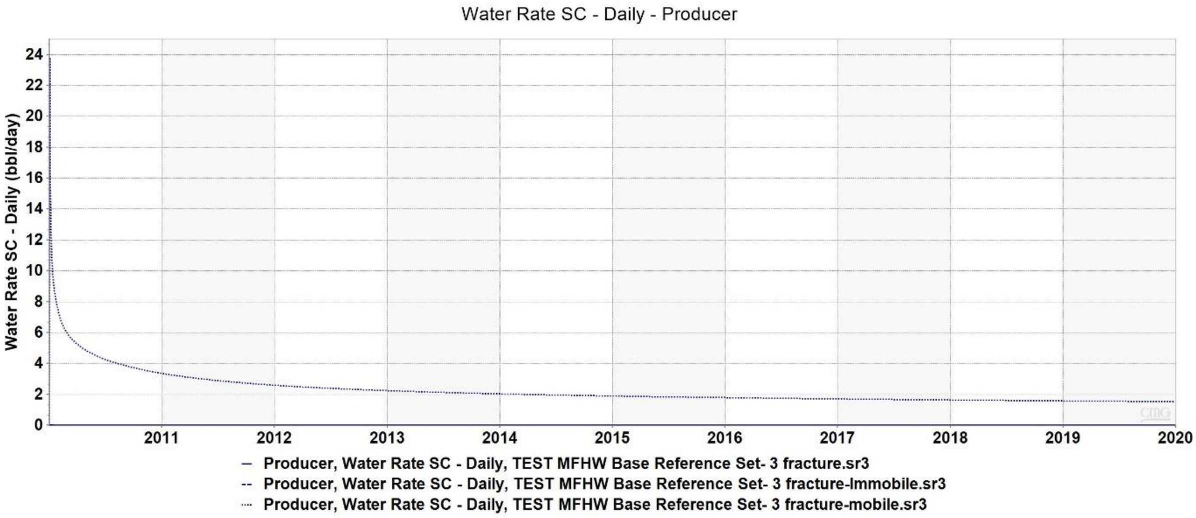


Figure 5.1: Daily water day rates (Base case, Desiccation & Mobile Water)

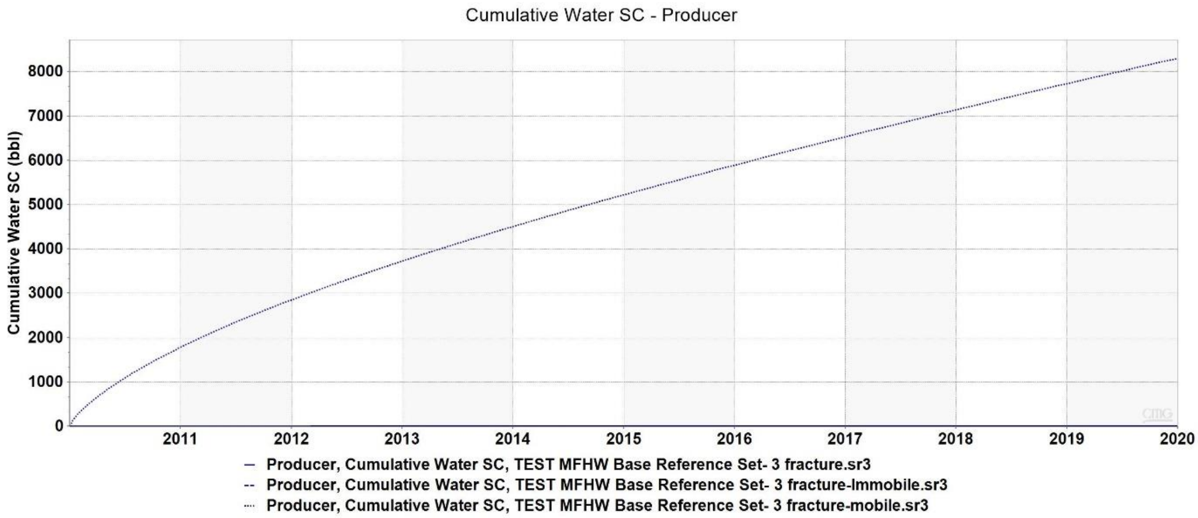


Figure 5.2: Cumulative Water production (Base case, Desiccation & Mobile Water)

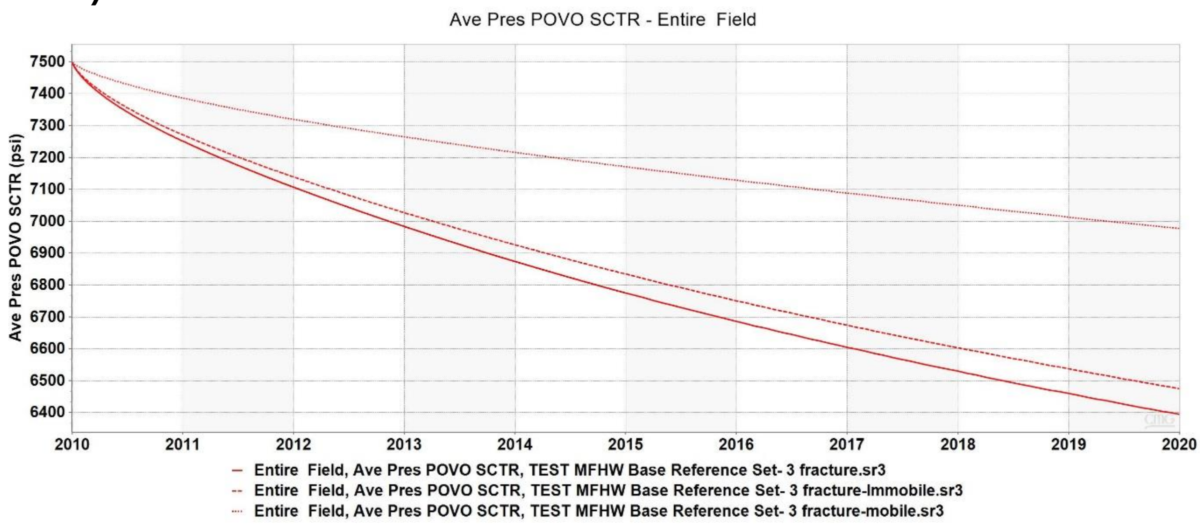


Figure 5.3: Average Reservoir pressure (Base case, Desiccation & Mobile Water)

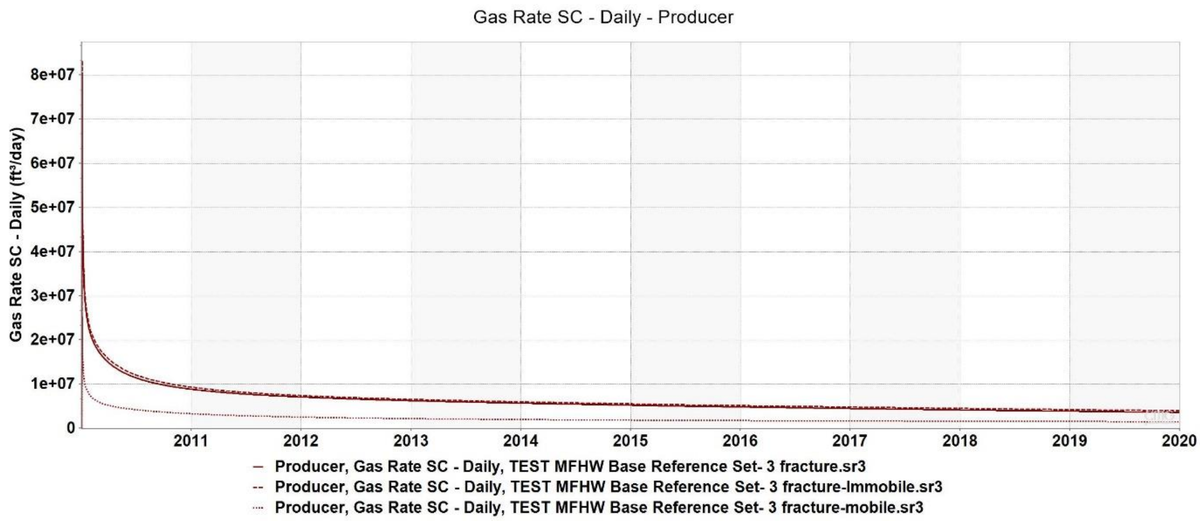


Figure 5.4: Daily Gas Rate (Base Case, Desiccation & Mobile Water)

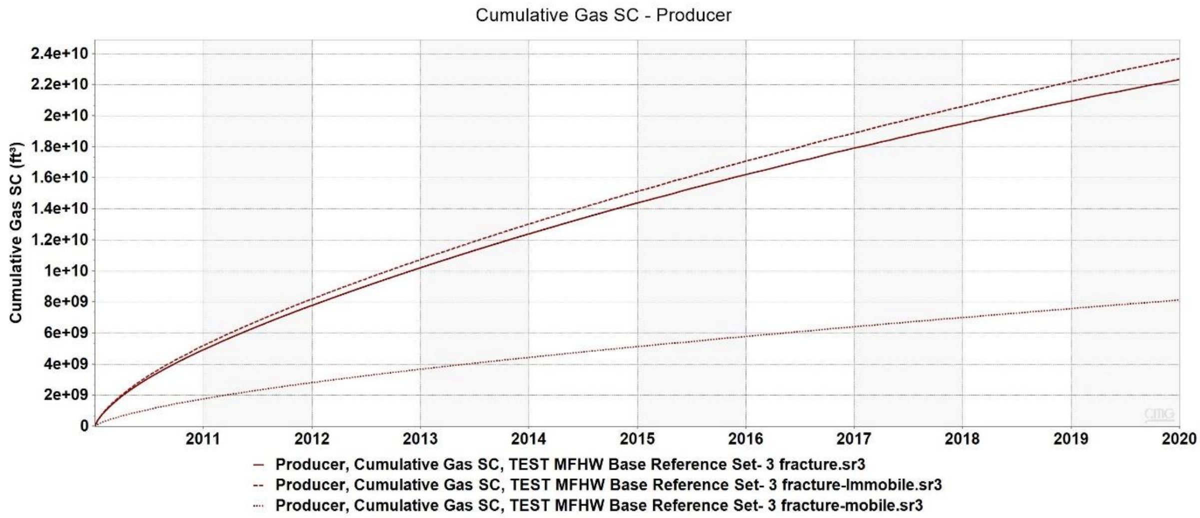


Figure 5.5: Cumulative Gas production (Base Case, Desiccation & Mobile Water)

From figure 5.1, in the case of mobile water scenario, where $S_{w\,i} > S_{w\,irr}$ there is a higher rate of daily water produced, as compared to the other two scenarios where there is little to no water production at all (Desiccation and Base case). The occurrence of large volumes of mobile water, if not well confined can pose significant technical and operational challenges.

From figure 5.2, in the case of mobile water scenario, where $S_{w\,i} > S_{w\,irr}$ there is significantly higher cumulative water production (bbl.), as compared to the other two scenarios where there is little to no water production at all (Desiccation and Base case). Capillary pressure decreases for increasing water saturation during imbibition, enhancing the mobility of water. Mobile water poses significant implication for production mechanisms.

From figure 5.3, the average reservoir pressure all start off at 7500 psi and then start declining for all 3 cases, the one with mobile water has declined less than the other two scenarios (Base case and Desiccation) because in the span of 10 years production, more water production which leads to a bigger intervention on gas production, and due to less gas production, the reservoir is depleted at a slower rate, which slows down the decline in the average reservoir pressure.

From figures 5.4 and 5.5, in the cases of Base case and Desiccation scenarios, there is more production of gas due to less intervention of mobile water. Especially in the case of desiccation where the cumulative gas production is at its highest after 10 years of production.

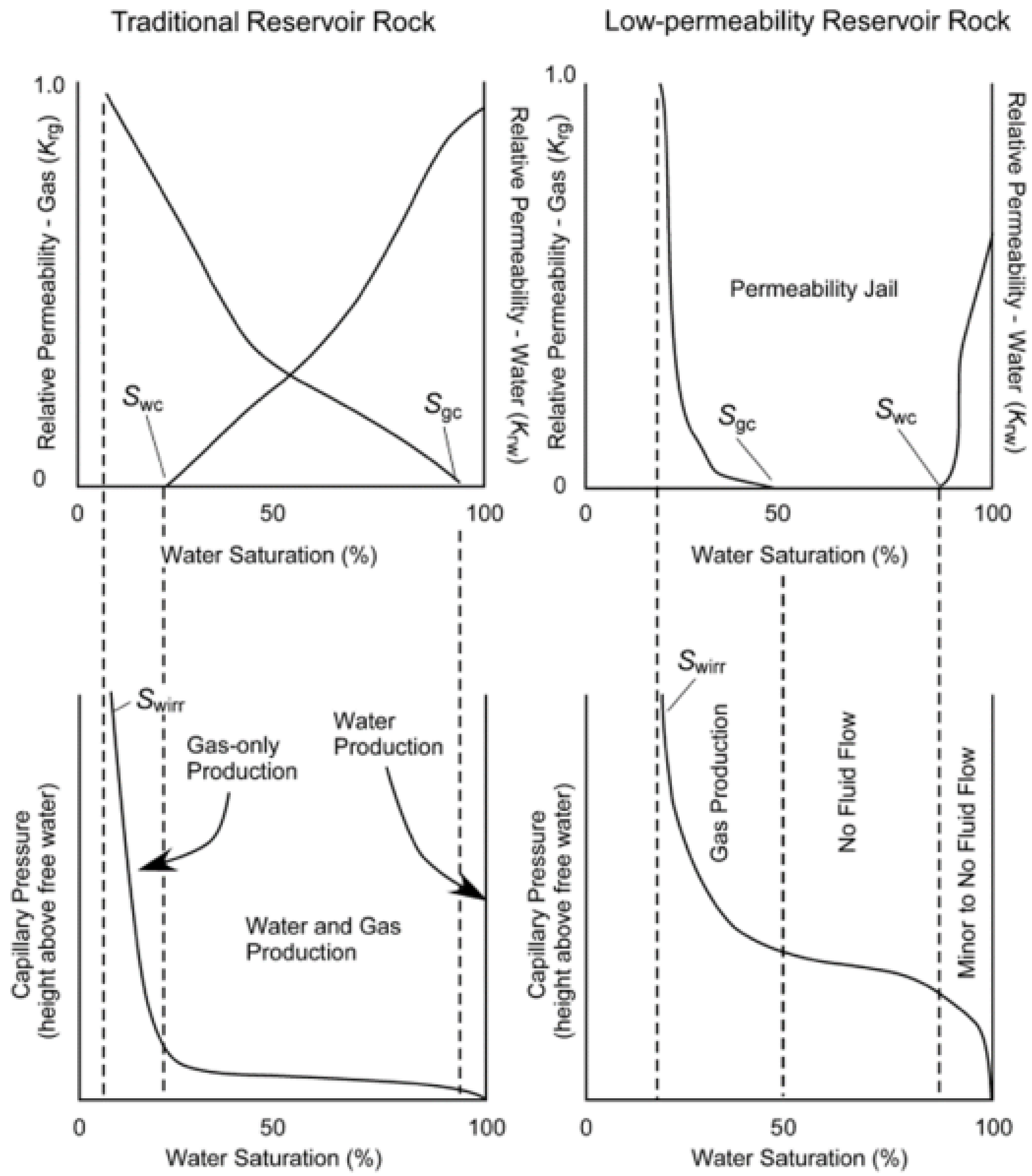


Figure 5.6 Illustration of capillary pressure and relative permeability curves in conventional and tight/ultra tight reservoir rocks. (Abdelaziz, 2018, *International Journal of Petrochemistry and Research)*

Critical water saturation (Sw_c), critical gas saturation (Sg_c), and irreducible water saturation (Sw_{irr}) are shown. (Shanley 2004)

- In conventional rocks, Sw_{irr} and Sw_c are similar. However, in tight/ultra tight reservoir rocks, Sw_{irr} and Sw_c can be extensively different.
- Although in conventional reservoirs, there is a wide range of water saturations at which both water and gas can flow, in tight/ultra tight reservoir rocks, there is a broad range of water saturations in which neither gas nor water can flow.

5.3 Impact on Cleanup Performance

A thorough understanding of the the individual and combined impact of desiccation and low permeability jail, operators can develop targeted strategies to optimize cleanup performance, which in turn enhances well productivity and minimizes environmental impact in unconventional gas plays.

The combined effects of desiccation and low permeability in unconventional gas formations significantly obscure cleanup operations:

Reduced water mobility: Dry formations impede the flow of fracturing fluids and proppants during flowback, hindering their removal and potentially impacting gas recovery. Incomplete fracture cleanup: Inadequate flowback due to desiccation can leave behind damaging residues, reducing well productivity, and necessitating costly interventions. Increased treatment complexity: Overcoming the combined flow resistance of desiccation and low permeability often requires specialized techniques and higher treatment pressures, further raising operational costs and environmental risks. Enhanced clay swelling: Desiccation can activate swelling clays in the formation, further restricting pore throats and permeability, impacting injectivity and flowback efficiency. Brine precipitation: Dissolved salts in formation water can precipitate upon desiccation, plugging pores and reducing permeability, hindering cleanup, and potentially impacting long-term productivity.

5.3.1 Mitigating Strategies

Given the detrimental effects of desiccation, proactive measures are very important: Pre-emptive hydration: This is the process of maintaining moisture in formation through controlled water influx, which can help to tackle desiccation and its associated issues. Permeability-enhancing treatments: Utilizing appropriate stimulation techniques tailored to the specific formation characteristics can improve flow paths and facilitate cleanup. Brine management: Optimizing brine composition and salinity during fracturing and flowback can minimize the risk of salt precipitation and its permeability-reducing effects. Data-driven monitoring: Closely monitoring formation pressure, water content, and other key parameters allows for early detection of desiccation and timely intervention.

5.3.2 Low Permeability Jail

Limited fluid flow: Tight formations inherently restrict fluid flow, making it challenging to remove formation damage, residual fluids, and proppant effectively during flowback. Incomplete fracture cleanup: Inadequate flowback due to low permeability can leave behind formation damage, hindering hydrocarbon flow and impacting well productivity. Increased treatment complexity: Stimulating and cleaning up low permeability formations often require specialized techniques and higher treatment pressures, increasing operational costs and potential environmental footprint.

5.3.3. Combined Impact

The combined effects of desiccation and low permeability jail can significantly exacerbate cleanup challenges:

Synergistic permeability reduction: Desiccation-induced clay swelling, and brine precipitation can further tighten the already low permeability jail, creating a vicious cycle that impedes cleanup and reduces well productivity. Ineffective stimulation: Desiccation-damaged formations might not respond well to conventional stimulation techniques, leading to suboptimal well performance and potential economic losses. Elevated treatment pressures: Overcoming the combined flow resistance of desiccation and low permeability jail often requires high treatment pressures, increasing the risk of formation damage and compromising well integrity.

5.3.4 Mitigating Strategies

Pre-emptive hydration: Maintaining formation moisture content through controlled water influx or wellbore hydration techniques can prevent desiccation and its associated issues. Permeability-enhancing treatments: Utilizing appropriate stimulation techniques tailored to the low permeability jail can improve flow paths and facilitate cleanup. Brine management: Optimizing brine composition and salinity during fracturing and flowback can minimize the risk of salt precipitation and its permeability-reducing effects.

5.4 Conclusion

While desiccation in gas formations might offer some theoretical benefits, the potential downsides far outweigh them in most cases. Understanding its detrimental effects and implementing effective mitigation strategies are crucial for ensuring optimal well performance, minimizing environmental impact, and maximizing the economic viability of unconventional gas resources.

Chapter 6: Conclusions

Quantitative production data analysis for unconventional gas reservoirs is a rapidly evolving field, and new techniques are continuously being introduced. There are no-agreed upon standardized procedures for deriving reservoir/hydraulic-fracture properties from production data, or for forecasting wells producing from unconventional reservoirs.

Critical advancements, however, have been made for analytical methods, such as straight-line (flow-regime) analysis, type-curve analysis, and analytical simulation, particularly the incorporation of reservoir properties unique to unconventional gas reservoirs, such as adsorption, non-Darcy flow (gas slippage, diffusion), non-static absolute permeability, and multi-phase flow.

Adaptations have also been made to analyse wells exhibiting complex hydraulic fracture geometries such as multi-fractured horizontal wells completed in shale reservoirs. Empirical methods have been altered to account for long transient and transitional flow periods encountered in some unconventional gas reservoirs—historical methods were applicable to boundary-dominated flow only. A new class of techniques, referred to as “hybrid” techniques that combine analytical methods for analysing/forecasting transient flow, with empirical methods for analysing/forecasting boundary-dominated flow have also been modified recently to account for common transient and transitional flow-regimes such as long-term transient linear flow and mixed linear-boundary flow (heterogeneous completions).

Continuous developments are being made in this field, which remains one of the most active areas of research in the field of unconventional gas reservoir engineering. Those practicing reservoir engineers and geoscientists working in this field are advised to consult the literature for further advances and best practices—the value and future of many oil & gas companies will depend directly on how well these techniques are used for forecasting production and optimizing field development.

The academic literature has helped to contextualise the research question, literature will be continuously reviewed throughout the duration of the research. Several results were collected using different modules in CMG like GEM and STARS geo-mechanical features including geo-mechanical coupling to investigate the flow dynamics.

Preliminary conclusions are presence of water changes the gas percolation which agrees with (Lin 2020). When there is high water saturation within the formation and gas-water two-phase flow takes place. Gas-water ratio increases with the drawdown pressure, this agrees with the assumption in (Tannich, 1975).

6.1 Limitations to Current Research / Literature

As drilling technology advances and more wells are drilled in shale formations, reservoir engineering and modelling are gaining their right places in the asset management of these important energy resources. The presence of highly complex multi- cluster, multi-stage hydraulic fractures has significantly complicated the simulation and modelling of production from shale.

As stated by the results of the literature demonstrate that minimum ingredients required to model shale gas reservoirs are: (1) Considering desorption phenomena; and (2) Considering pressure-dependent permeability for hydraulic and induced-fractures into the flow governing equations. Consequently, it is unnecessary to add more mechanisms and nonlinearity into the model.

The limitations of the understanding of this complex phenomenon have resulted in limitations in our ability to perform accurate modelling of the production from shale formations which consequently have resulted in making significant assumptions to make the models work.

- Use of predictive models such as CRM, newly developed Arps equation, AI & DM, Data-driven modelling will help validate the results of numerical simulation for evaluating shale gas reservoir performance and forecasting production. However, a careful attention should be given while using these methods.
- Historically with shale gas and CBM plays, the Extended Langmuir model has been the most frequently applied for multi-component adsorption modelling, but the limitations of this model are well-known (see Clarkson and Bustin, 2000). Hartman (2011) suggested that more rigorous adsorption models should be utilized and compared predictions of binary gas adsorption using the Ideal Adsorbed Solution (IAS) model and the Extended Langmuir (EL) Model. The details of the models are discussed elsewhere (ex. Clarkson and Bustin, 2000).

- Relative permeability is similarly difficult to measure in Unconventional Gas Reservoirs (UGRs). Steady-state and non-steady-state techniques have been applied, with associated limitations. Usually, large differential pressures are required to initiate 2-phase flow in tight gas reservoirs, creating large saturation and pressure gradients. As with absolute permeability, non-Darcy flow effects must be accounted for, and the correction is known to vary with saturation and temperature (Rushing 2003). Failure to correct for slippage may cause effective permeability to gas to be overestimated.
- Another limitation of the mathematical model is the difficulty to fit experimental data at high pressures. A linear relationship between the volume of gas adsorbed and the associated pressure. At some point the adsorption will reach a maximum and no increase in pressure will allow for additional molecules to be adsorbed.
- The suitability of individual techniques depends on permeability, porosity and adsorption capacity of the porous rock, and the limitations of the underlying assumptions of the solution.
- Empirical methods, such as decline curve analysis, rely on empirical curve fits to historical production data, and projections to the future. These methods do not rigorously account for dynamic changes in well operating conditions (i.e. flowing pressures), or reservoir or fluid property changes.
- As with numerical simulation, a research focus in the future will be inclusion of more complex reservoir behaviour into analytical models. i.e. Ozkan (2010) recently incorporated gas-slippage effects and non-static fracture permeability effects into the trilinear flow solutions. Apaydin (2012) recently discussed the inclusion of discontinuous matrix microfractures in analytical modelling of shale gas reservoirs.

6.2 Future Work and Recommendations

Recommendations the research that has been undertaken for this thesis has highlighted several topics on which further research would be beneficial.

- Tight and ultra-tight low permeability reservoirs usually possess large initial water saturation $(S_{w\,i})$; However, this is not typically the case in many fields where they have “sub-irreducible” $S_{w\,i}$. the irreducible water saturation ($S_{w\,irr}$) in these tight gas reservoirs tends to be higher than the Swi. This is attributed to desiccation (Bennion, 2004).

- Proposal of a more advanced technology which will play an increasing role in Unconventional Gas Reservoir’s fluid saturation and pore size analysis in the future.
- Ideas for future research are recommended to improve the understanding of the complex mechanisms of Enhanced gas recovery in Unconventional reservoirs.
- Challenges and prospects associated with multi-disciplines for future research and applications of induced seismicity monitoring are identified, and it contributes to achieve safe and efficient unconventional (tight) oil and gas resource exploitation.
- In this thesis, a pre-fractured well was considered to model hydraulically fracturing process. To model the hydraulically fracturing process more realistically it is recommended that geomechanics of hydraulic fracturing will be considered in addition to the flow dynamics to capture the impact of fluid flow and geomechanics on the cleanup efficiency simultaneously.
- Advanced research should be carried out in monitoring induced seismicity activity, there are still several vital challenges and limitations which hinder improvements in its applicability in tight oil and gas reservoirs.

Although great progress has been made in the development of production data analysis techniques for unconventional reservoirs, there is still much room for improvement.

6.2.1 Analytical (type-curves, straight-line, analytical simulation)

- Further modifications to include complex reservoir behaviour, such as non-Darcy flow (slip-flow and diffusion) and non-static permeability (i.e. Ozkan 2010).
- Further modifications to account for complex fracture geometries (i.e. Apaydin 2012).
- Incorporation of fluid properties contained within nano-porosity, such as the alteration of critical properties (i.e. Michel 2012), and incorporation of

complex adsorption behaviour of heavier hydrocarbon components of wet gas and gas condensate.

- Continued development of techniques to account for multi-phase flow (CBM, gas condensate), such as alteration of pseudo variables or inclusion of dynamic skin (Clarkson in press).
- Integration of rate-transient techniques with surveillance data, such as micro seismic data, chemical and radioactive tracers, distributed temperature surveys etc. to improve the extraction of stage-specific (in multi-fractured wells) or layer-specific properties (for wells completed in multiple zones).
- Adaptation of methods to analyse multi-phase, post-stimulation flow-back data (i.e. Clarkson, 2012), to enable early forecasts.
- Improved flow-regime identification for wells with noisy data.

6.2.2 Empirical

- Investigation of further constraints to matching parameters by relating them to actual reservoir and hydraulic fracture properties.
- Continued development of diagnostic methods using empirical approaches to diagnose reservoir behaviour and operational problems.

6.2.3 Hybrid

- Advancement of these techniques will rely on advancements in both analytical and empirical techniques, but an immediate development need includes adaptation of these techniques for complex fracturing—current techniques currently applicable mainly to planar fracture case.

6.3 Desiccation: Knowledge Gaps and Research Needs:

Despite growing research, several key areas require further investigation:

- Quantifying the trade-off: While the negative consequences of desiccation are well-documented, quantifying the potential benefits in specific formations and scenarios remains challenging. More research is needed to assess its true impact on well performance and economic viability.

- Predictive models: Developing predictive models to accurately forecast the extent of clay swelling, brine precipitation, and permeability reduction under various desiccation scenarios is crucial for proactive management and optimal well development strategies.
- Mitigation strategies: Exploring and optimizing strategies to mitigate the negative impacts of desiccation, such as tailored well completion fluids, controlled water influx techniques, and advanced stimulation methods, is vital for minimizing damage and maximizing long-term well productivity.

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APPENDIX

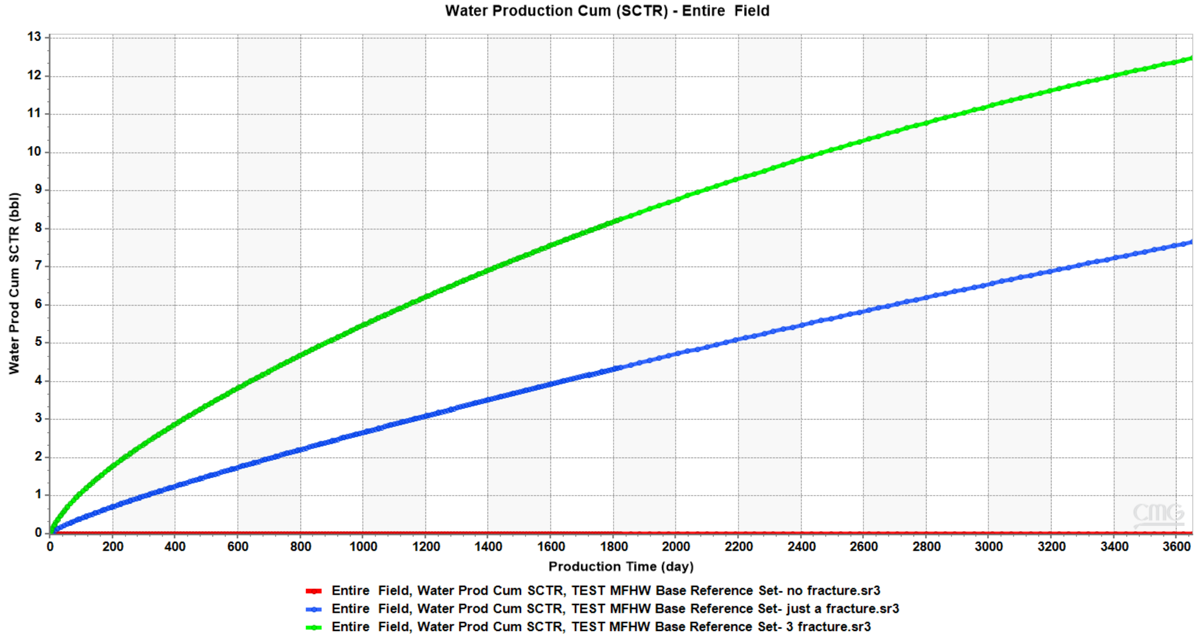

Figure 4.10: Water Production Cumulative (SCTR) vs Well Production Time (day)

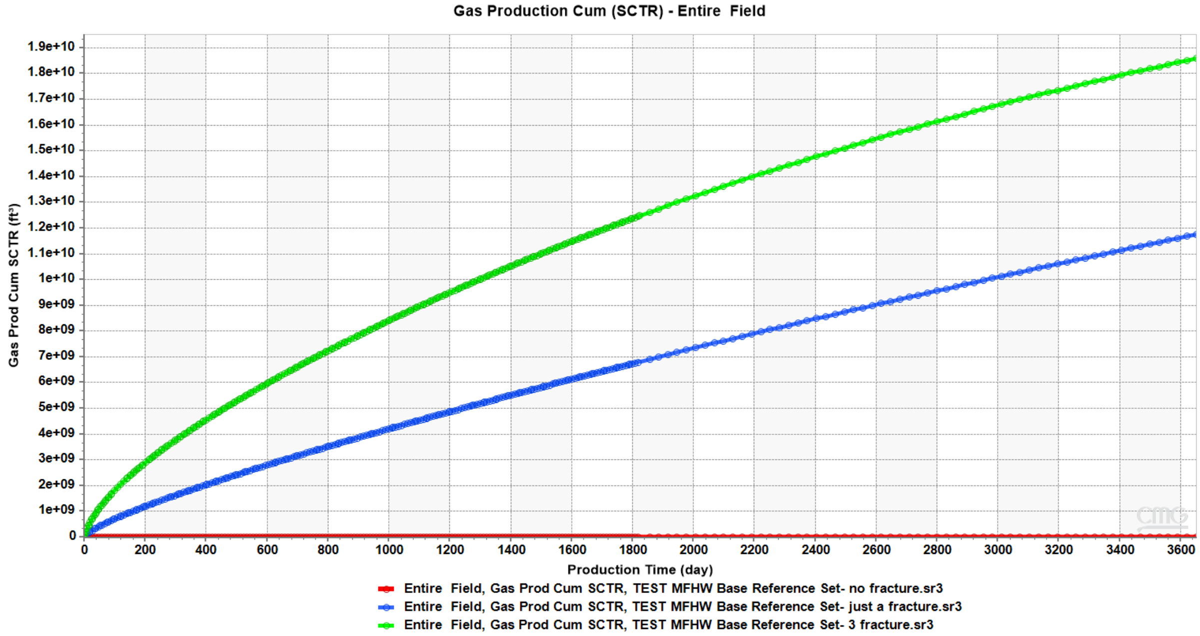

Figure 4.11: Gas Production Cumulative (SCTR) vs Well Production Time (day)

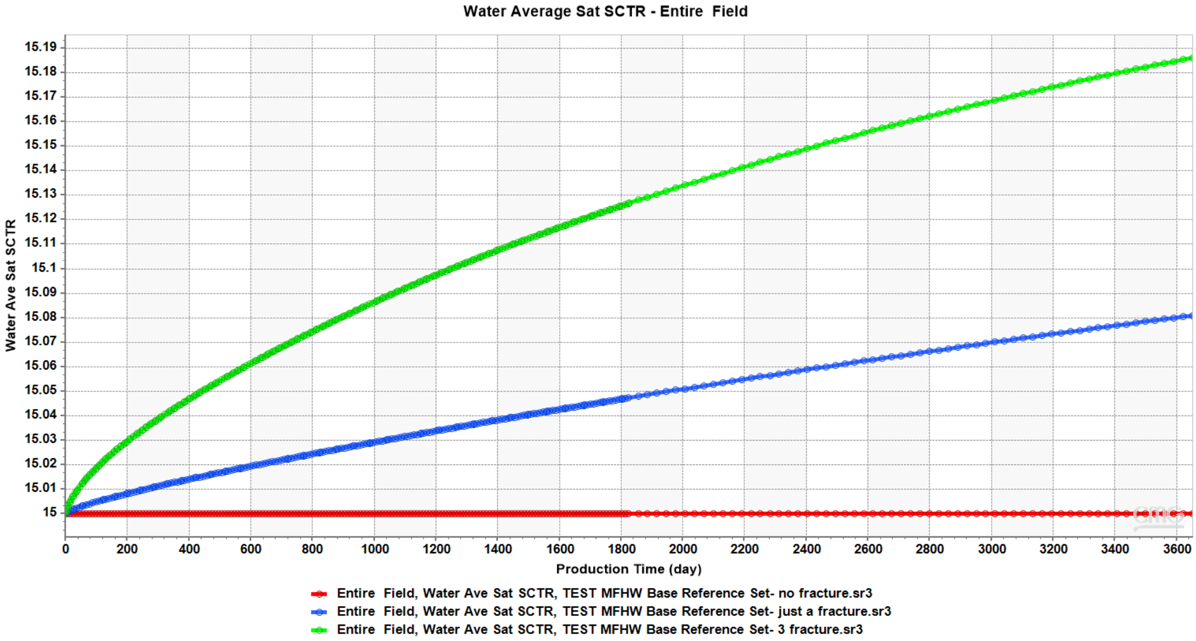

Figure 4.12: Water Average SAT SCTR vs Well Production Time (day)

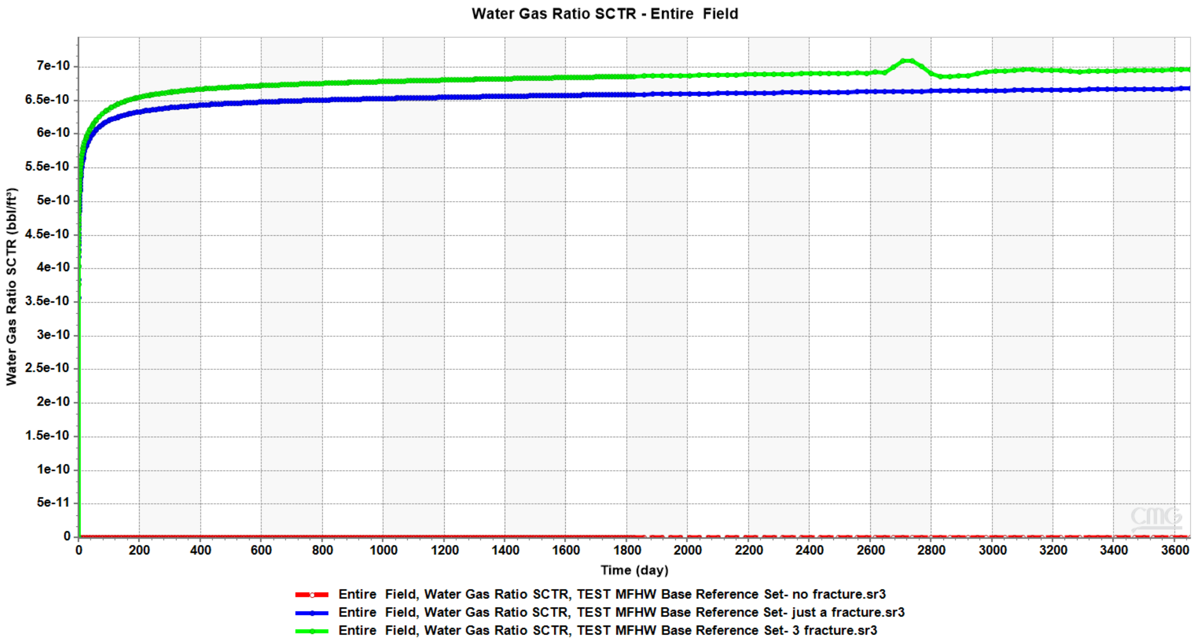

Figure 4.13: Water Gas Ratio SCTR vs Well Production Time (day)