EFFECT OF CONDENSATE DROPOUT ON WELL PRODUCTIVITY IN PROPPED FRACTURE STIMULATED "UNCONVENTIONAL" GAS/CONDENSATE RESERVOIRS

Master of Science Thesis

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Gas condensate reservoir; Hydraulic fracturing; Well productivity index; condensate dropout

نبذة مختصرة

يتم انتاج جزء كبير من النفوط حاليًا من مكامن مكثفات الغاز. يمثل هذا النوع من المكامن تحديًا كبيرًا في الإنتاج والتطوير. حيث ان السائل المكثف سيتراكم حول حفرة البئر والكسر الهيدروليكي بسبب الإنتاج دون مستوى نقطة الندى. إن انخفاض نسبة الغاز المكثف **(CGR)** أثناء الإنتاج هو مؤشر واضح على تجمع المكثفات، مما يقلل من جدوى البئر الاقتصادية. يعد تحديد مؤشر إنتاجية البئر **(PI)** وطرق تحسين الإنتاجية أمرًا بالغ الأهمية في الصناعة البترولية. الهدف من هذا البحث هو دراسة سلوك السوائل أثناء الإنتاج في بئر عمودي مكسور هيدروليكيًا في مكمن مكثفات غاز منخفض النفاذية للغاية. تشمل الدراسة تراكم المكثفات على حجم كبير من المكمن، وليس فقط بالقرب من البئر ووجه الكسر.

هناك حاجة لمحاكاة المكامن مع تحسين الشبكة المحلية **(LGR)** لفهم هذه الظاهرة وتأثيراتها على البئر **PI** ولتحديد انخفاض الضغط في الخزان نتيجة لتراكم المكثفات. تم دراسة العلاقة بين تراكم المكثفات، وانخفاض الضغط، ومعدل الغاز ونفاذية الخزان، مقارنة المكامن التقليدية الضيقة ومكامن مكثفات الغاز غير التقليدية الضيقة جدًا، وكلاهما يتم إنتاجهما بالكسر الهيدروليكي. تم استخدام برنامج محاكاة ثلاثي الأبعاد مع **LGR** حول الكسر الهيدروليكي لمحاكاة مثل هذا المكامن مع كل من البيانات التجريبية والميدانية من خلال مراقبة التغييرات التركيبية (أي ، **C1** ، **C2** ، **C3** ،..) في محتوى المكمن مع مرور الوقت. بالإضافة إلى ذلك، تم أيضًا تضمين مناقشة شاملة للافتراضات والقيود النموذجية في برنامج المحاكاة.

تظهر النتيجة تغيرًا كبيرًا في التركيب والنفاذية النسبية للغاز مع انخفاض الضغط أثناء الانتاج. تمت المحاكاة في جزأين: مطابقة البيانات التجريبية والميدانية. توضح النتائج المضاعفات في فهم تطور **PI** للآبار المكسورة هيدروليكيًا في خزانات مكثفات الغاز "غير التقليدية" وتبين كيفية تقييم أداء الكسر بشكل صحيح في مثل هذه الحالة. يتضمن هذا البحث مراجعة للعديد من التقنيات والأساليب لحساب حدوث تراكم المكثفات على مسافات مختلفة من البئر والكسر ويتضمن تحليل للمعايير المختلفة وكيفية تأثيرها بشكل جيد على **PI** بمرور الوقت.

تساعد نتائج هذه الدراسة ونهجها الجديد في التنبؤ بدقة أكبر بأداء ما بعد الكسر الهيدروليكي وتوفير فهم أفضل لتغير طور الهيدروكربونات ليس فقط بالقرب من حفرة البئر والكسر، ولكن أيضًا في عمق المكمن، وهو أمر بالغ الأهمية في خزانات مكثفات الغاز غير التقليدية. من خلال تحسين قدرة مهندسي الإنتاج على توليد تنبؤات أكثر واقعية لإنتاج الغاز والمكثفات بمرور الوقت، يمكن تحقيق الاستفادة المثلى من تباعد الكسر الهيدروليكي في الآبار الأفقية وتباعد الآبار لتطوير الحقل.

Abstract

A large fraction of hydrocarbons is recovered from gas condensate reservoirs. A major production challenge from gas condensate reservoirs is condensate dropout, as condensate liquid saturation will build up due to drawdown below dewpoint level. Condensate Gas Ratio (CGR) decrease during production is a clear indication of condensate dropout, which reduces well deliverability. Determining the well productivity index (PI) and methods to optimize productivity is paramount to the industry. The aim of this research is to investigate fluid phase change behavior during depletion in a hydraulically fractured well in an extremely low-permeability gas condensate reservoir. Here it is considered the case where condensate dropout occurs over a large volume of reservoir, rather than just near the fracture face (condensate banking).

Reservoir simulation with local grid refinement (LGR) was used to understand this phenomenon and its impact on well PI, and to quantify pressure drop in the reservoir as a result of condensate dropout. The relationship of condensate dropout, pressure drop, gas rate and reservoir permeability are investigated by comparing conventional tight reservoirs, and very tight unconventional gas condensate reservoirs, both of which are produced with propped fracture stimulation. A commercial 3-D compositional simulator with LGR around the fracture was utilized to simulate such a reservoir with both synthetic and field data by observing the compositional changes (i.e., C1, C2, C3,..) in hydrocarbon content over time and distance from the fracture face, and the results were used in turn to generate more realistic production profiles over time. Additionally, a comprehensive discussion of the model assumptions and limitations is also included.

The result shows a significant change in the composition and relative permeability to gas in the reservoir as the pressure declines during depletion. The simulation is done in two parts: synthetic and field data history matching. The results illustrate the complications in understanding the PI evolution of hydraulically fractured wells in "unconventional" gas condensate reservoirs and shows how to correctly evaluate fracture performance in such a situation.

This research includes a review of several techniques and methods to calculate the occurrence of condensate at various distances from the well and fracture and includes a sensitivity analysis of the different parameters and how they affect well PI over time and ultimate recovery of gas and condensate.

This finding of this study aims to more accurately predict post-fracture performance and provide a better understanding of the hydrocarbon phase change not only near the wellbore and fracture, but also deep in the reservoir, which is critical in unconventional gas condensate reservoirs.

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List of Abbreviations

K_{ro} = Relative permeability to oil
K_{rw} = Relative permeability to water
K_{rg} = Relative permeability to gas
m_{γ}^{wn} = Mass flow
WI^{wn} = Well index
ρ_{γ}^{wn} = Density (well)
ρ_{γ}^{fn} = Density (field)
P_{γ}^{wn} = Pressure (well)
P_{γ}^{fn} = Pressure (field)
g = Acceleration
ΔZ = Vertical distance
$\boldsymbol{k_f}$ = Fracture gird block permeability
$\emptyset_{\boldsymbol{f}}$ = Fracture gird block porosity
K_{row} = Oil relative permeability (oil + water)
k_{rog} = Oil relative permeability (oil + gas)
K_{rwo} = Water relative permeability (oil + gas)
K_{rgo} = Gas relative permeability (oil + gas)

Acknowledgements

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Chapter 1: Introduction

The primary purpose of this research is to understand how the performance of a fracture-stimulated well is affected by oil saturation buildup over a large portion of the drainage area in the reservoir, which occurs in tight gas\condensate reservoirs. Reservoir and well simulation with a finely gridded local grid refinement (LGR) around the fracture is required to understand this phenomenon, its impact on the well productivity index (PI) and to quantify pressure drop due to condensate dropout. Furthermore, the relationships between condensate dropout, pressure drops, gas rates, and reservoir quality will be investigated, by focusing on the differences between conventional tight reservoirs and very tight unconventional gas\condensate reservoirs, both of which are normally produced with propped fracture stimulation.

This thesis describes the development of various simulation runs to quantify the effect of condensate dropout on both initial deliverability and ultimate recovery (EUR) of such reservoirs. These simulation runs consider the changes in fluid properties with pressure and phase change. The simulators have been used to investigate the effects of different important geometrical and flow parameters on the performances of hydraulically fractured wells.

This research was conducted using commercially available ECLIPSE™ 100 and 300 simulators from Schlumberger. The results are aimed to help improve the understanding of unconventional gas condensate reservoirs through a comprehensive understanding of the mechanism of liquid buildup. It also provides a novel approach for quantifying the condensate damage that impairs the linear flow of gas into the hydraulic fracture (condensate banking). The applied techniques are general, and the outcomes of the study apply as guidelines to fractured gas\condensate wells in general.

Chapter 1 presents a critical review of reservoir fluid flow behavior in gas\condensate reservoirs. The discussion presented in this chapter demonstrates some of the research that had been previously done "along the way" by the author that paved the way for understanding gas condensate reservoirs and laid the foundation for developing steps necessary to deal with some rather difficult problems. It is intended that by including this background material will help convey the message that engineering of unconventional tight gas\condensate reservoirs is merely an extension of traditional gas\condensate reservoir engineering.

1.1 PROBLEM RECOGNITION

When the gas-oil ratio (GOR) is between 8,000 and 70,000 scf/bbl with API of up to 60, a reservoir is considered a gas condensate reservoir (Cronquist, 1973). The standard hydrocarbon mixture phase envelope is depicted in Figure 1-1. The two-phase region exists between the bubble point curve with the first gas bubble and the dew point curve with the first fluid drop.

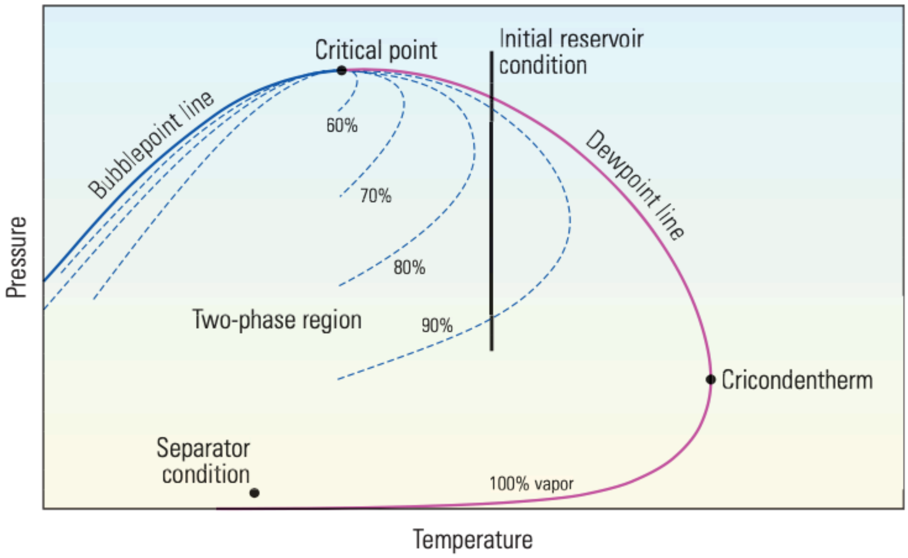

Figure 1-1:Classification of reservoir fluids based on the composition: P-T diagram –After (Fan, L.,2005)

A large fraction of hydrocarbons is currently recovered from gas condensate reservoirs (Fan, L.,2005). In moderate to high permeability gas condensate reservoirs, which can produce economically without fracture stimulation, the main issue is condensate banking in near wellbore region. Condensate liquid saturation can build up near a wellbore due to drawdown below dew point, eventually choking the flow of gas. Because of relative permeability effects, the effective permeability of gas is reduced, in turn decreasing well deliverability.

In a “conventional” gas\condensate reservoir, propped hydraulic fracturing restores most of the productivity lost due to liquid buildup (Carlson et al, 1995). There are a large number of low-permeability gas\condensate reservoirs around the world producing below the dew point and therefore experiencing variable amounts of condensate dropout.

The focus of this project is on condensate dropout in unconventional gas condensate reservoirs. The classification of tight and unconventional reservoir permeability is not fixed; however, a reasonable cutoff used here is a permeability of 0.1 to 1 mD for “conventional” tight gas condensate reservoirs and one of less than 0.1 mD for “unconventional” tight gas condensate reservoirs.

Condensate dropout in "conventional" tight gas condensate fields may cause considerable well impairment due to buildup if the extension of the condensate bank becomes large enough. The condensate bank can reduce well productivity by a factor of 3. Productivity declines of about 70% have been reported for wells in two fields (Smits et al., 2001). Figure 1-2 illustrates a schematic of PI reduction due to condensate blockage in vertical propped fractured wells. The degree of condensate blocking depends on several factors, including fluid properties, formation characteristics, flow rate and pressure.

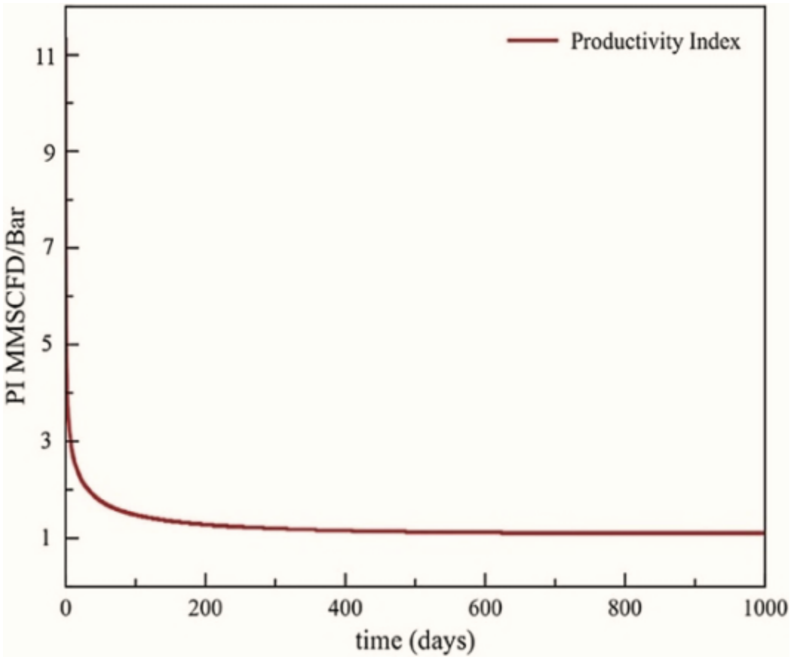

Figure 1-2: Representation of PI reduction. After (Smits et al., 2001).

1.2 BACKGROUND

Gas condensate un-fractured well performance declines quickly when the bottom-hole pressure goes below the dew point pressure. This decline is a result of increasing immobile condensate saturation around the wellbore causing a reduction in relative permeability to gas and decreasing the well PI. This leads to decreased gas production rate for a well in such state. Simulation runs in the literature clearly indicate that productivity losses were attributable to liquid dropout near the wellbore. Condensate buildup decreases the effective permeability to gas and leads to performance deterioration when the bottom-hole pressure drops below the dew point pressure. (Barnum et al, 1995) showed that such effect is more evident in low-permeability reservoirs, where the kh of the wells is less than 1,000 mD-ft.

(El-Banbi et al, 2000) conducted a reservoir simulation study which indicated that the PI of un-fractured vertical wells in a rich gas condensate reservoir initially declined sharply, but that gas productivity then increased as the reservoir was depleted. Productivity of wells was first reduced by high condensate buildup radially, which severely damaged the effective gas permeability. Nevertheless, after an initial decline and subsequent increase in gas production, the wells demonstrated relatively stable gas production. The gas that flowed into the radial condensate bank became leaner, which reduced condensate saturation in the ring; such phenomena were observed in field data.

Hydraulic fracturing has been applied to mitigate formation damage and to improve the well productivity in condensate reservoir. This is because fracturing will increase contact area, reduce drawdown pressure, and will establish a flow path that extends beyond damaged area around the wellbore. Furthermore, the induced hydraulic fracture is filled with proppant that has higher permeability than the formation. Figure 1-3 shows the main effects involved in the propagation of a hydraulic fracture. The state of stresses in the formation determine the fracture direction of fracture propagation. Fractures grow perpendicularly to the minimum stress direction. When the fracture conductivity is high, linear flow perpendicular to the fracture was seen in the early time performance of any fracture design.

(Al-Hashim et al, 2000) demonstrated the remarkable positive impact of hydraulic fracturing on the PI of a gas condensate reservoir (above and below the dew point pressures), improving it by approximately three times over non-fractured wells.

When the dew point is reached and pressure drops below the dew point level, condensate will start to build up, and productivity drops for both fractured and non-fractured wells. However, the productivity drop is less severe in the fractured case. Furthermore, for formations with low permeability, long fractures are necessary; for formations with high permeability, wide but short fractures are recommended (Romero et al, 2000).

This manuscript concerns the effect of condensate dropout on the PI of hydraulically fractured wells in tight gas condensate reservoirs. The focus of the project is on extremely low-permeability gas condensate reservoirs in the micro-Darcy range (0.1-0.001 mD). Such reservoirs exhibit a complex recovery mechanism due to the effect and extent of condensate dropout. The current work will focus on investigation of condensate damage extending far from the hydraulic fracture face in reservoirs. Tight gas condensate reservoirs have larger pressure drops, so condensates can form over larger zones in the reservoir, and more quickly.

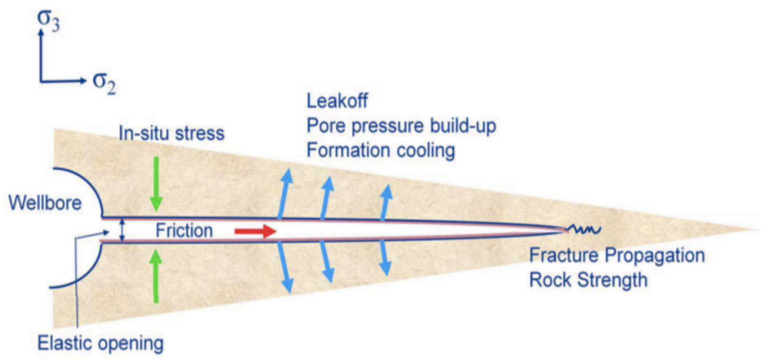

Figure 1-3: This shows cross-section through the fracture. As soon as the pressure in the fracture exceeds the minimum in-situ stress, it will open the fracture (elastic opening). The Fluid will leak-off in vast quantities from the fracture into the formation. (Lecture Note of Drilling & Production Engineering, Published by TU Delft, 2019)

1.3 THESIS OUTLINE

This thesis includes the chapters below:

Chapter 1 provides a brief introduction and motivation of the issue, problem recognition, and background information that support the project.

Chapter 2 of this study provides a full literature review and investigation of the theory and recent industrial publications regarding condensate buildup, hydraulic fracturing and flow regions.

Chapter 3 presents simulation results of Synthetic base case propped fractured well in single layer using ECL100. Sensitivity runs on various cases including different grid numbers and matrix permeability are explored in depth.

Chapter 4 addresses simulation results of Synthetic base case using ECL300. Condensate build up in such Synthetic reservoir is also investigated.

Finally, Chapter 5 contains the adaptation of a compositional reservoir simulation model and history matching exercise in ECLIPSE™ (ECL100 & ECL300) for Field Case to validate the conclusions drawn from this project. Followed by the main conclusions and recommendations for future investigations.

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Chapter 2: Background

This chapter presents a brief literature review on the methods for modeling well deliverability in gas condensate reservoirs. Well performance is simulated using several methods such as the classical (Evinger et al, 1942) pseudo-pressure approach or the modified approach (Favang, 1995-2000).

Condensate buildup plays a major role in managing well deliverability when pressure drops below dewpoint level. The key parameters that govern the pressure profile and thus the condensate saturation around wellbore and fracture face are as follows: (1) fluid composition, (2) reservoir temperature and pressure, (3) flowing bottom-hole pressure, and (4) rock flow resistance.

Moreover, for hydraulically fractured gas\condensate wells, the fluid flow around the wellbore becomes more complex. This is due to the difference between the matrix rock and propped fracture physical properties and flow behavior. (Mahdiyar, 2009) has indicated that pressure distribution around the hydraulically fractured well depends on the fracture conductivity.

High-permeability reservoirs (higher than 10-15 mD), owing to a low-pressure drawdown as a result of production, are cause for no significant concern about condensate buildup. However, for tight reservoirs with low or extra-low permeability, specific strategies must be implemented to avoid condensate buildup.

This chapter contains two specific gas condensate topics, section 2.1 covering gas condensate reservoir and section 2.2 covering gas condensate flow around hydraulically fractured wells. Additionally, this chapter will provide an overview of the reservoir for actual field case that is discussed in section 2.3.

2.1 GAS CONDENSATE RESERVOIR

One key difference between dry gas and gas\condensate reservoirs is well deliverability loss as a result of buildup in gas condensate reservoirs. Such reduction in well deliverability will not occur in dry gas reservoirs.

The flow behavior and deliverability of gas condensate reservoirs has been a subject of scientific research since the early twentieth century. Evinger (Evinger et al, 1942) presented a simple method for estimating the radius condensate block as a function of time, gas rate and rock and fluid reservoir properties. Fetkovich (Fetkovich, 1973) derived a rate- and time-dependent blockage skin for the standard gas rate equation based upon the method of Evinger. The first numerical models of radial gas condensate well deliverability were conducted by Kniazeff (Kniazeff et al, 1965) and Eilerts (Eilerts, et al, 1965). These authors could predict the condensate and saturation and pressure profiles as a function of time and other operational parameters, supporting that condensate buildup decreases well deliverability. Gondouin (Gondouin et al, 1967) extended the research of Kniazeff et al., and highlighted the significance of condensate blocking and non-Darcy flow effects on the well performance. They also included experimental methods and measurements that quantified the effects of relative permeability and multiphase non-Darcy flow. The authors showed that even small regions of condensate buildup can significantly reduce well deliverability.

(Metcalfe et al, 1988) utilized a field sample of gas condensate fluid and applied several simulation runs using laboratory PVT tests, such as constant composition expansion (CCE) and constant volume depletion (CVD), to demonstrate that the fraction of heavy components varies with sampling depth. They found that, for leaner condensate, the model of black oil could estimate dewpoint fairly correctly. However, for richer condensate, the predictions of the black oil model deviated considerably from the experimental data. This implies that fully compositional models should be used for the simulation of gas condensates.

(Creek et al, 1985) adjusted the equation of state of Peng-Robinson to predict variability of composition, solution gas-oil ratio and saturation pressure within a reservoir affected by a compositional gradient.

(Fussell, 1973) demonstrates the impacts of condensate accumulation on well productivity. In comparison with the compositional simulation results, Fussell indicates that the (O'Dell et al, 1967) equation significantly exaggerates the loss of deliverability due to condensate blockage. Furthermore, this study by Fussell evaluates the influence of phase behavior and relative permeabilities on production.

Calculations of fluid flow in condensate reservoirs involves the use of effective permeability for each phase, expressing the capability of a specific fluid to flow through a porous medium. The effective permeability is typically written as a ratio of the absolute permeability, which is usually selected as the base permeability; this ratio is known as the relative permeability. A careful assignment of the relative permeability assists in guaranteeing that fluid movement in a reservoir is rationally modeled.

$$k_{ro} = \frac{k_o}{k}, k_{rw} = \frac{k_w}{k}, k_{rg} = \frac{k_g}{k}$$

When the simulated and actual production histories match, we can conclude that a reliable representation of the flow throughout the reservoir has been reflected accurately. The gas condensate wells producing with the bottom-hole pressure below the dewpoint level have up to three main flow regions extending from the wellbore outward. A correct and simple model of a gas condensate well undergoing depletion contains three regions (Fevang et al, 1995). Figure 2-1 illustrates the gas condensate reservoir flow regions, and the boundaries of these regions are dynamic during the life of the reservoir. Region 1 is the innermost, close to the wellbore and saturated with oil and gas that are both flowing simultaneously. Region 2 is a region of condensate accumulation; however, the liquid is immobile (critical oil saturation is not achieved yet), and only gas is flowing. Region 3 is the outermost, where the reservoir pressure is higher than the dewpoint level and only a single-phase gas exists. One, two or all three regions might exist for a given production condition.

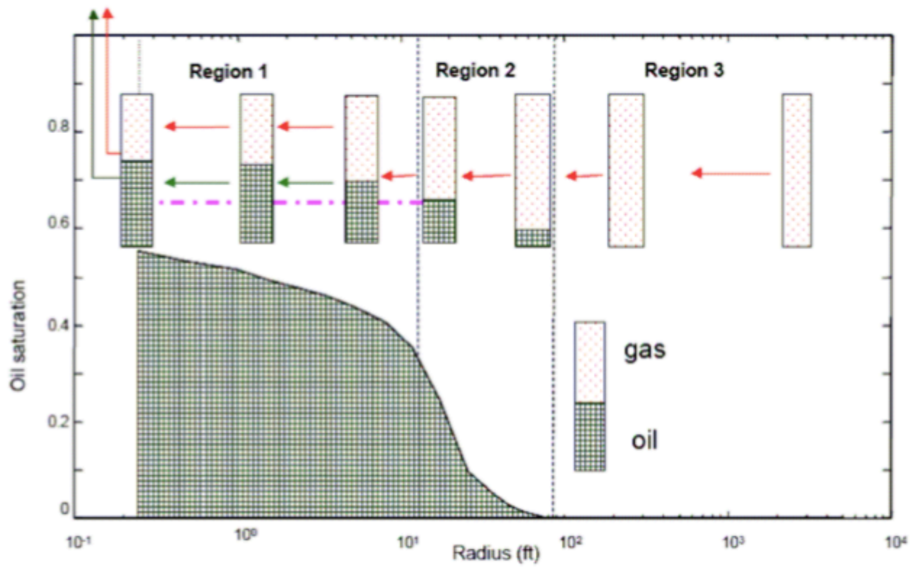

Figure 2-1: Schematic gas condensate flow regions (Roussennac, 2001).

According to (Favang, 1995) effective permeability is the main factor of the various sources for pressure loss on well performance.

In summary, condensate buildup effect depends on (1) relative permeability, (2) PVT properties, and (3) production strategy (constant rate vs. constant bottom-hole pressure). There are various advanced techniques to mitigate the pressure drop and its subsequent problems caused by gas condensate blockage; some of these techniques include well placement, production strategy, chemical treatment and hydraulic fracturing, which will be discussed fully in the next section. However, all of these mitigation approaches have limitations or are temporarily effective only.

2.2 GAS CONDENSATE FLOW AROUND HYDRAULICALLY FRACTURED WELLS

One of the most used and accepted approaches to improve well performance is the hydraulic fracturing technique, especially for tight and unconventional gas condensate reservoirs. Hydraulic fracturing consists of injecting viscous fluid and proppant at a sufficient pressure into a zone of interest to create propped fracture. After fracturing treatment is finished, it is generally assumed that two symmetrical wings will be developed along the maximum horizontal stress. To maintain the fracture with high conductivity, these wings are filled with proppant, which holds the fracture open. The proppant type will be selected based on formation properties, such as stress and permeability. Based on the used design technique and pumping schedule (treatment size), the propped fracture can have a typical width between 5 and 35 mm and a length of 100 m or more.

A hydraulic fracture decreases the flow resistance around a well, thus reducing the pressure drawdown and the undesirable effect of condensate banking. Gas condensate flow around hydraulically fractured wells is distinct from conventional gas oil systems. According to (Mahdiyar et al, 2007) this distinction is essentially because of phase change, condensate buildup and coupling (i.e., the increase of relative permeability as velocity increases and/or interfacial tension decreases) and inertial (i.e., the reduction of relative permeability as velocity increases) effects. Figure 2-2 schematically shows typical fracture containment by stress contrast in a hydraulically fractured well. Two types of possible damages in hydraulically fractured wells are fracture face and choked damage. Fracture face impairment occurs because the fracturing liquid is introduced into the matrix, thus reducing the matrix permeability near the fracture. Choked damage is the decrease of proppant permeability in the fracture, occurring close to the wellbore. These impairments decrease the well productivity of the matrix and the fracture respectively due to increased flow resistance. The inertial effects are some of the essential factors that can significantly decrease fracture conductivity. Multi-phase flow may also alter the well performance. When the bottom-hole pressure of a gas condensate well drops below the dewpoint pressure, condensate will build-up around the fracture (and potentially in the fracture), resulting in a significant decline in the well performance. The condensate buildup in and around the fracture and the adjacent matrix will significantly affect the performance of the hydraulically fractured well. On the other hand, an increase in relative permeability of gas condensate due to velocity increase or reduction in interfacial tension (IFT) might improve productivity as a result of coupling effects.

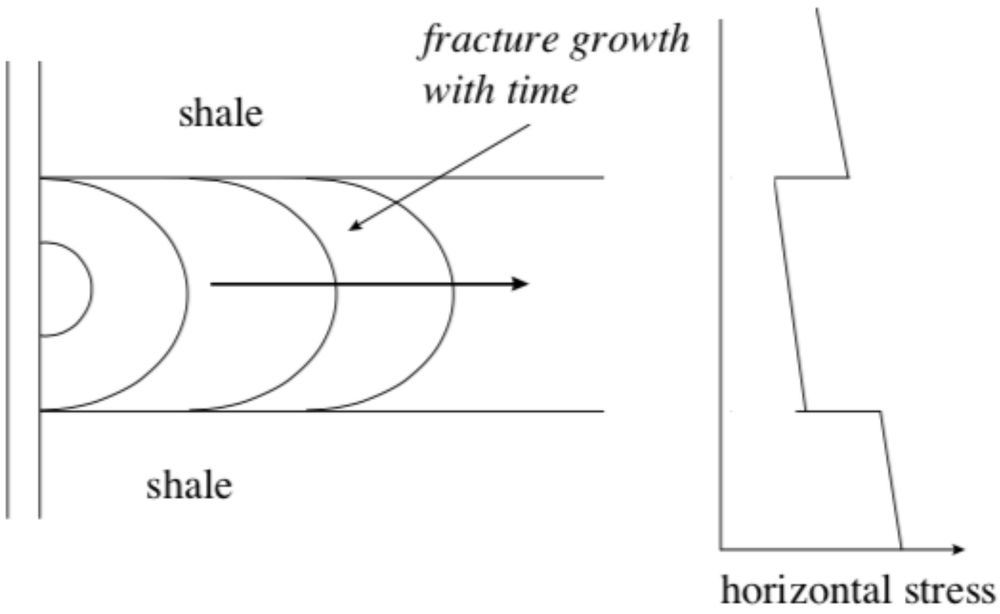

Figure 2-2: Fracture containment by horizontal stress contrasts

The significance and wide applications of hydraulic fracturing in condensate systems have caught the attention of numerous researchers, including (McGuire et al, 1960, Economides et al, 2002 and Meyer et al, 2005). The aim of these studies was to evaluate improved well productivity and optimal fracture design. Such studies examined the effects of flow behavior and pressure distribution around the fracture on well productivity, as well as the skin factor or effective wellbore radius under steady state and pseudo-state conditions. The majority of methods available in the literature to estimate the fracture skin or the effective radius of a hydraulically fractured well were developed for single-phase Darcy flow systems (McGuire et al, 1960; Prats, 1961; Mahdiyar et al., 2007).

By simulating a hydraulically fractured well under pseudo-state conditions, (Settari et al, 2002) attempted to develop a correlation for the calculation of a non-Darcy flow skin. The results of their simulations were compared with Guppy's buildup correlation, showing that this equation overestimates the non-Darcy effect. In addition to absolute fracture conductivity and the

Reynolds number, they proposed that the non-Darcy skin factor should be based on two extra factors, i.e., absolute fracture permeability (mD), fracture width (m) and absolute matrix permeability (mD). (Smith et al, 2004) reviewed their previous study and suggested that Guppy's method overestimates the inertial effect in a hydraulically fractured well. Neither of the researcher groups have compared their findings with the drawdown correlation that can describe their simulations more accurately.

Numerical simulation of a hydraulically fractured gas condensate vertical well was performed by (Carvajal et al, 2005) in a square, closed boundary using an ECLIPSE^{TM} simulator. The study indicated that, in comparison with Radial grid systems, a Cartesian grid system could capture flow in fractured well model more realistically. The study also demonstrated how important the width of the fracture is in minimizing the inertial impact that can be exacerbated by increasing the fracture length. Lastly, it supported the idea that coupling affects matrix flow while inertia affects the flow within the fracture.

As previously mentioned, non-Darcy flow within the fracture can drastically reduce the deliverability. A variety of formulas are available in the literature to predict the magnitude of this effect. Whereas all researchers agree that inertia has a negative effect on hydraulically fractured wells, there is no such agreement on the formula proposed that represent the effect.

Two-phase matrix flow in an unconventional gas condensate reservoir will decrease conductivity in both the matrix and the fracture, although to different degrees. Two-phase flow in the fracture has been neglected and condensate buildup around the fracture has been treated as fracture face damage in most well deliverability studies concerning unconventional gas condensate reservoirs, with the exception work of (Carvajal et al, 2005).

This thesis aims to examine the gas condensates flow around hydraulically fractured wells and matrix in very low permeability reservoirs, including the effects of liquid condensate buildup, and non-Darcy.

2.2 AN UNCONVENTIONAL GAS CONDENSATE RESERVOIRS FIELD CASE STUDY

As the oil and gas industry develops and evolves technologically and economically, it starts to target more challenging reservoirs, such as extra-low-permeability gas\condensate reservoirs. A substantial effort has been made in several basins in Oman to exploit condensate gas reservoirs with an average permeability of less than 0.1 mD. Thus, the models under examination in this study will focus on unconventional tight gas\condensate reservoirs.

Unconventional and tight condensate gas reservoirs are economically attractive but present unique developmental challenges. These include performance losses due to condensate buildup, saturation pressure changes caused by pore confinement and rock-fluid interactions. The development of such reservoirs has improved in recent years through optimal lateral well placement and completion designs. Initial production rates and ultimate liquid recoveries are significantly affected by fluid and rock properties, and completion designs. Therefore, it is critical to have a full understanding of the controlling factors related to fluid and rock parameters that affect long-term productivity.

While various methods for assessing the performance of condensate reservoirs have been proposed, there is still a lack of studies in phase behavior, condensate buildup and optimization techniques for improving condensate recovery from such reservoirs. This work therefore presents a new approach to investigating condensate buildup in this field as presented in Chapter 5, using hydraulic fracture and reservoir simulator to track the phase changes around the wellbore and hydraulic fracture.

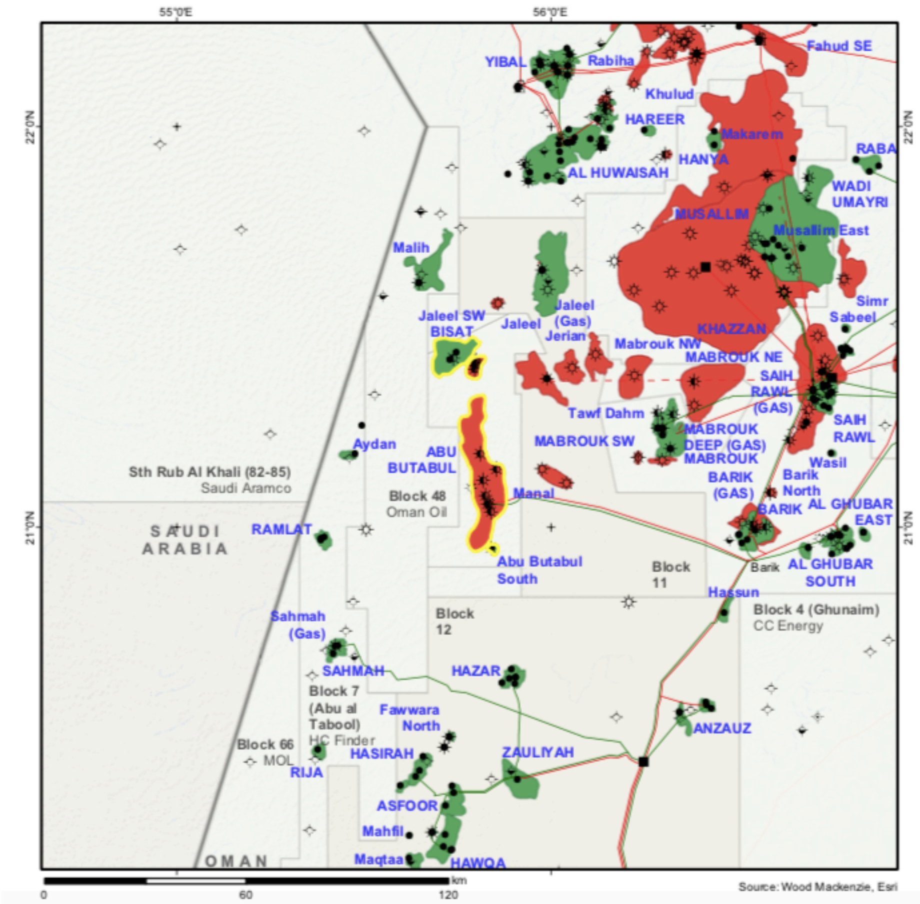

Figure 2-3: Oil & gas fields location map, Field Case Map (Wood Mackenzie, 2020)

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Chapter 3: Gas Flow of Fractured Well

This chapter describes the methodology to simulate condensate accumulation of hydraulically fractured wells: (1) flow from fracture grid to matrix grid, (2) flow from one grid block to the next, (3) flow from gird to well completion. This method includes a novel approach integrating hydraulic fracture and reservoir flows.

Hydraulically fractured wells can be modelled by modifying the skin or PI. These methods do not grasp the essential flow mechanics through and into fractures. Additionally, such techniques do not establish pressure distribution with elliptical shape around the fracture and could cause a negative well connection factor. Capturing the flow mechanics is significantly important in multi-phase flow and heterogeneous reservoirs. In tight gas/condensate reservoirs it can be very important to model the clean-up phase after fracture treatments and this demand a comprehensive fracture simulation. To achieve such capability, we need more than a rough description and estimation of the fractures.

A commercial lumped 3D fracture simulation model (FracPro^{TM}) is utilized to accurately predict fracture properties (Shaoul et al, 2005). Functions are internally defined in the software that relate established pressure gradients and rock properties to rate of fracture growth in three directions: (1) fracture tip, (2) fracture upper-height, and (3) fracture lower-height. The fracture input files to ECLIPSE^{TM} represent fracture geometry, damage zone, initial pressure, rock and fluid properties. To represent the reservoir, layers and fracture adequately; and capture the changes over time LGR is used in the region of well-bore, fracture tip and plane. Moreover, cartesian geometry grid with a symmetric approach is applied in the model because it is providing a better representation of hydraulically fractured wells flow geometry than radial grid. The issue with radial grid mesh is that the width of the cells increases away from the well-bore which is not representative for hydraulically fracture case.

This chapter contains two specific topics, section 3.1 covering methodology and modelling mathematic as shown in Figure 3-1 and section 3.2 covering Black Oil Model of a hydraulically fractured simplified synthetic case. Additionally, this chapter will provide a sensitivity and robustness analysis.

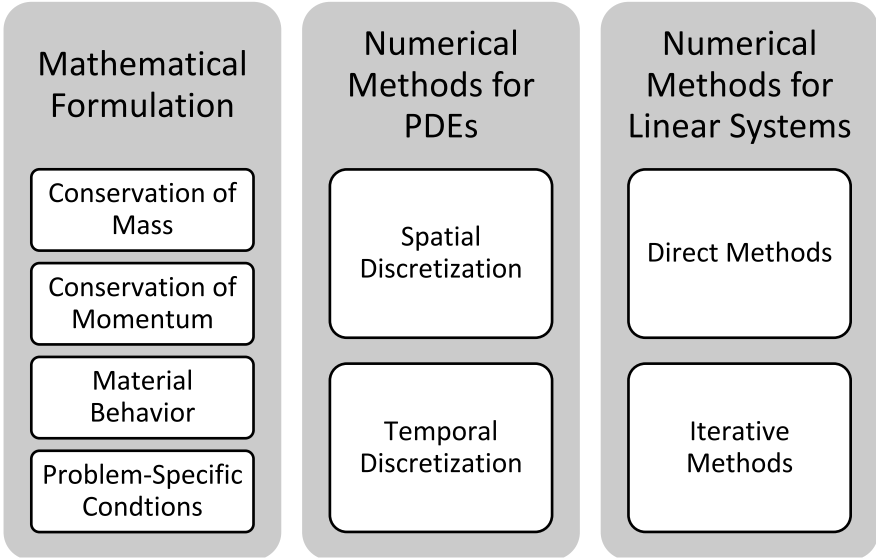

Figure 3-1: Typical numerical simulation methods and formulation.

3.1 METHODOLOGY AND MATHEMATICAL MODELING

In this study, finite difference method (FDM) is utilized to discretize the flow pressure equation. Because the flux entering a given volume is identical to that leaving the adjacent volume, this method is conservative. Another advantage of the FDM is that it suited for unstructured meshes. The method is used in many packages of computational fluid dynamics. Understanding the physics and limitations of simulators are significant and for this reason, the below sub-sections contains the basic mathematical background of the simulator. The ECLIPSE™ simulator suite consists of two separate simulators: ECL100 specializing in Black Oil Modeling, and ECL300 specializing in Compositional Modeling. In this study both ECL100 and ECL300 were used to study the performances of hydraulically fractured wells at pseudo-steady state conditions. (Guppy et al, 1982) in their paper indicated that "wellbore grid size must be extremely fine due to the boundary conditions at that point and grid size could increase gradually outward of the fracture." This argument is aligned with Cinco-L. et al.'s, thought on low fracture conductivities.

3.1.1 The Governing Equations

ECLIPSE™ includes enormous code bases with advanced reservoir models such as Black Oil and Compositional. The following formulas such as mass conservation, conservation of momentum and saturation equation are characterizing the fluid flow physics and dynamics through porous media. A detailed derivation of these equations can be found in (ECLIPSE: Technical Description reference, 2015).

3.1.2 FDM

Such partial differential equations (PDEs) have no analytical solution, therefore numerical approximation is essential. Although the problem is subject to the same fundamental physics, several mathematical methods are available.

The FDM directly incorporates the conservation laws—the integral formulation of the Navier-Stokes and Euler formulas. By applying this method, the volume is divided into spatially fixed cells (sub-domains) as this called Eulerian approach. There are several choices of defining the shape and position of the flux volume with respect to the grid. For example, volume (mid cell node flux) calculated between nodes that represent equations in discrete form for each node directions. Every node has a number of equations which represent the cell volume and fluid flow to neighboring cells and its nodes. The reasons of using grid algorithm are: (1) to capture the geometry of the reservoir, layers and fracture (fluid flow), (2) to have an ideal CPU run time with optimal simulation accuracy and grid size.

The partial derivative is replaced by a time and space approximation based on discrete values, thereby giving it a smooth function. As a result, numerical model can approximate the mathematical model accurately.

The approximation methods lead to a system of several equations: (1) Black Oil Model: with two saturation equations and one pressure equation (three equations per-node). (2) Compositional Model: n saturation and pressure equations for n components (n+1 equation per-node). These equations can be solved either fully implicit (FULLIMP -same time), sequentially (IMPES- pressure implicit and saturation explicit) or adaptive implicit (AIM) to bypasses the time-step limitations enforced by small cells, such as those including wells, without using the FULLIMP approach. Furthermore, the well inflow in the FDM is determined by Peaceman's Well Model equation, that implies that the reservoir gird is much larger than well radius (Peaceman,1977).

3.1.3 Advantages and disadvantages of FDM

1. FDM generally is industry accepted technology, quick, robust, stable and precise.
2. FULLIMP FDM is more stable (complex non-linear system), such stability will help to explore a relatively short time step.

3. The downside of FULLIMP FDM is the tendency to smear the solution (Numerical Dispersion).
4. On the other hand, IMPES approach is not always stable because of time step length limitation (Courant-Friedrichs-Lewy, CFL). As a result, as the number of cells increases the CPU time also will increase for short time step.
5. One drawback of FULLIMP over IMPES approach is the reduction of discretization error.
6. Usually, finite difference discontinuities require careful and adequate control. Such discontinuities might lead to solution with numerical smearing and low accuracy.

3.2 RESERVOIR SIMULATION OF HYDRAULICALLY FRACTURED WELL SIMPLIFIED SCENARIO (DRY GAS)

3.2.1 Approach

Three basic approaches have been historically used to estimate hydraulically fractured wells performance: (1) analytical solutions based on an infinite conductivity, (2) solutions based on finite conductivity fracture with indicated half-length, (3) later, finite conductivity approach has been applied with multiple fractures (Basquet et al, 1999). The analytical solution will not capture certain sides of the problem (such as, fracture height growth to adjacent layer) that might impact the results considerably. In the last few years, for complex geology and multi-phase flow two other methods were established by modifying negative skin or wellbore radius. Then to have more adequate model, specialists manually built LGR to account for hydraulic fracture in reservoir models (Ehrl et al, 2000).

To solve the problem of achieving and modelling required fracture half length, we need to take to account the dominant physical processes that control the fracturing process. Generally, these processes can be subdivided into the four main categories: (1) fracture geometry, (2) fluid leak-off, (3) fluid rheology, and (4) proppant transport

Recently, with the advancement of reservoir simulators, a new effective approach with automatic fracture grid refinement and compatible with reservoir simulator was developed for unconventional reservoirs. This method lumps 3D fracture flow model and considers fracture properties (such as: porosity, permeability, phase saturation and rock compaction), and proppant characteristics (such as: pressure dependent permeability or the non-Darcy flow). The fracture in a lumped model consists of two half ellipses. At each time step, the fracture length (top & bottom half-ellipse) is calculated as shown in Figure 3-2. The advantages of this method are the effectiveness on capturing the physical behavior (such as fluid distribution, fracture dimensions and conductivity) and the availability to transfer the outputs to the reservoir simulator see Figure 3-4.

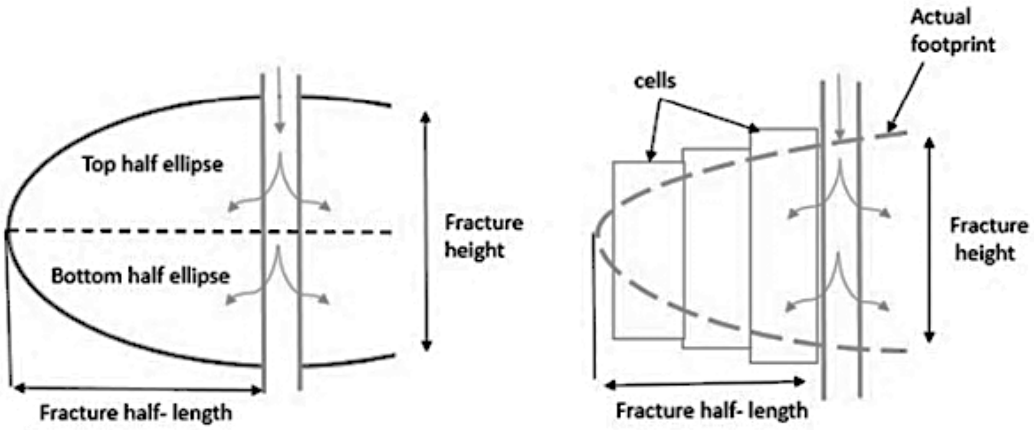

Figure 3-2: To the left diagram displaying the geometry of the fractures on a 3D lumped elliptical model and to the right a cell-based geometry (After Weng, 2015)

Fracture conductivity is a critical input to model hydraulic fracture. High permeability grid cells define the fracture, these cells capture fracture conductivity spatial variation within the reservoir simulator. Then, to achieve a representative prediction the fracture permeability grid cells are added to the reservoir simulator model to account for varying width and conductivity. A standard Cartesian grid is superimposed on elliptical fracture to. The Cartesian grid size can be modified based on the required resolution and fracture half-length for each case study. As a rule of thumb, fracture grid block size of 10×10 ft or 20×20 ft is adequate to reflect sufficient resolution and results (Shaoul et al, 2005).

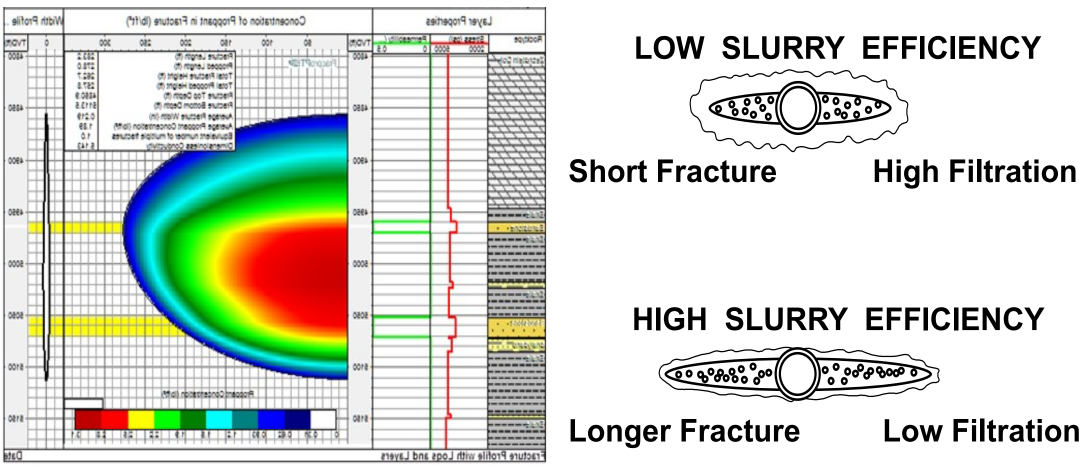

Figure 3-3: To the left is the output of fracture model that used for simulation model. To the right an illustration fluid efficiency. Picture is mirror image

Fluid efficiency is the portion of fluid remaining in the fracture. During hydraulic fracturing, a percentage of the fracturing fluid leaks-off to the matrix. As fluid loss increases, the remaining fluid in the fracture (fluid efficiency) decreases see Figure 3-3. According to (Holditch, 1979), fluid leak-off during fracturing tight gas reservoir might considerably reduce gas production as a result of two-phase flow and capillary effect. To have a beneficial design model a fracture simulator must accurately reflect the critical physical processes that govern hydraulic fracturing such as fluid leak off. For this reason, with LGR gridding the fracture simulator monitors fluid leak-off from the fracture face into the matrix. The leak-off amount is not equal along the fracture, there is less fluid leaking off at the tip than wellbore area. This style of fine gridding allows for a precise representation of the fracture filtrate fluid distribution. According to (Shaoul et al, 2005), that the standard filtrate leak off depth ranges from centimeters to tens of centimeters in tight gas reservoirs. Full derivation and estimation method of fluid distribution after hydraulic fracturing treatment and considering leak off processes can be found in (Behr et al, 2003).

In certain cases, non-Darcy and multi-phase flow effects in the hydraulic fracture effective permeability of the proppant pack can be significantly important. Also, this information is considered either in the fracture or reservoir simulator.

Reservoir data, such as layering is considered in the fracture simulator, where such data is important on fracture geometry and propagation. The drainage boundary from the well is identified based on quarter symmetry for the vertical well case and assuming ideal fracture geometries. As a result, the simulated production will be 1⁄4 of the actual anticipated production see Figure 3-4. This ¼ simulation approach will accelerate simulator time performance.

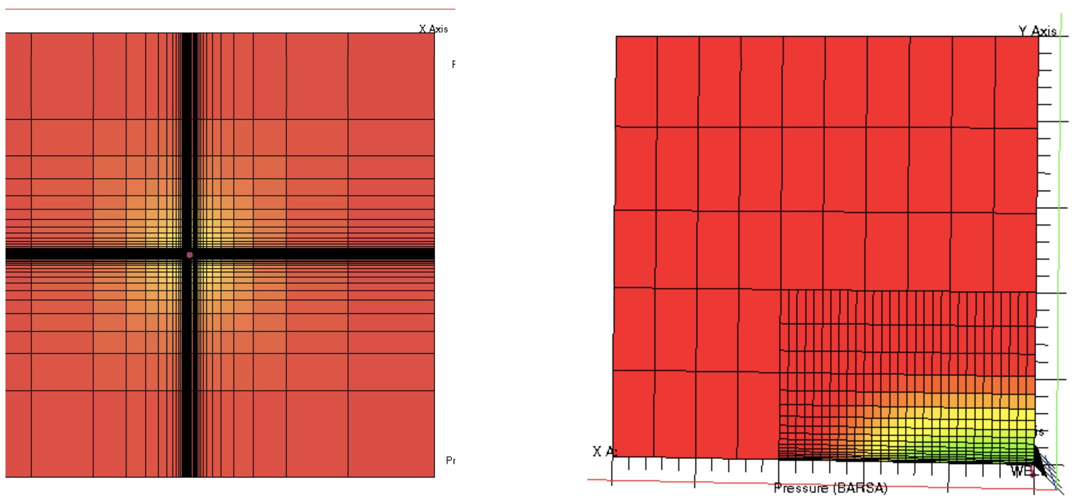

Figure 3-4: Left an example of hydraulically fractured vertical well with full symmetry model and to the right is using the quarter symmetry method.

The host grid XY plane contains typically low number of gird blocks, where the gird size gradually increases away from the fracture in both X and Y directions (length-height aspect ratios of 2 and larger). The changes in grid size is controlled by the fracture half-length. On the other hand, grid size in the Z directions is controlled by fracture and reservoir layers. The standard XYZ dimensions of the LGR are related to fracture geometry. To capture the flow behavior and to ensure a precise estimation of the high-rate transient flow around the wellbore and fracture tips finer gird is established in these areas as shown in Figure 3-5 for both find and coarse gird cases.

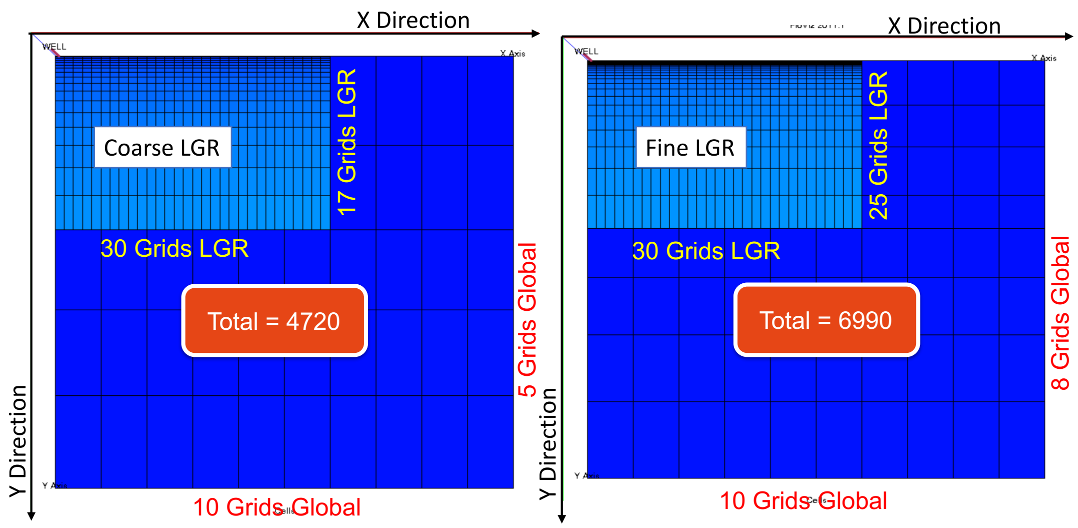

Figure 3-5: Simulation grid for both coarse and fine grid cases

3.2.2 Assumptions

The following sub-section discusses the important fracture simulator assumptions. Lumped 3D fracture model is a category of pseudo-3D (P3D) models. Pseudo-3D models are based on homogeneous elastic properties assumption and averaged over all grids enclosing the fracture height. Since this model assumes no mixing and perfect displacement as a result the injected fluid and proppant follow an elliptical trajectory model. According to (Adachi et al, 2006), this assumption is rational in many situations because confining stress dominates elastic properties when estimating fracture width. Additionally, fracture simulator assumes that fracture propagation is proportional in all directions (follow an elliptical trajectory assuming no mixing and perfect displacement efficiency) and the invading fluid characteristics is same as reservoir fluid (Behr et al, 2003). Due to time step limitation and Peaceman's Well Model grids configuration, the fracture is not essentially modelled with its actual width *b*. Typically, fictive width is adjusted to a value larger than the actual width, to enables larger time step. As a result, the permeability and porosity of the fracture blocks are recalculated to maintain the transmissibility and porous volume of the fracture.

$$\boldsymbol{k_f = K\,\frac{b}{b_f}} \qquad \boldsymbol{\emptyset_f = \emptyset\,\frac{b}{b_f}}$$

Furthermore, to model complex reservoirs with complex fracture network it is inadequate to use simplified cartesian grid techniques. To improve such method quality the local grid refinements patterns is implemented for the rectangular shaped fracture geometry. When the reservoir and fracture grids are formed, some further information is required to run the model. Such as fluid characteristics, relative permeability tables, initial conditions, well-bore and lift tables and production limitations.

3.2.3 Case Studies & Results (Sensitivities & Robustness)

The results presented in this sub-section are reservoir simulation model outcome of a simplified scenario of vertical single propped fracture well utilizing fracture model outputs directly. This section will examine how to handle single fractured vertical well with different LGR configuration, and study the impact of different reservoir permeabilities, on well performance simulation. LGR grid size is increasing logarithmically with distance from the well-bore and fracture. Such grid pattern ensures simulation efficiency; however, it significantly increases processing time for computation.

Water and gas PVT tables are included in the simulation model. These parameters assumed to be same for the entire reservoir, including the fracture. The saturation function tables for the host and fracture plane are depicted in Figure 3-6. The saturation tables for the relative permeability and capillary pressure are different for the region signifying the fracture.

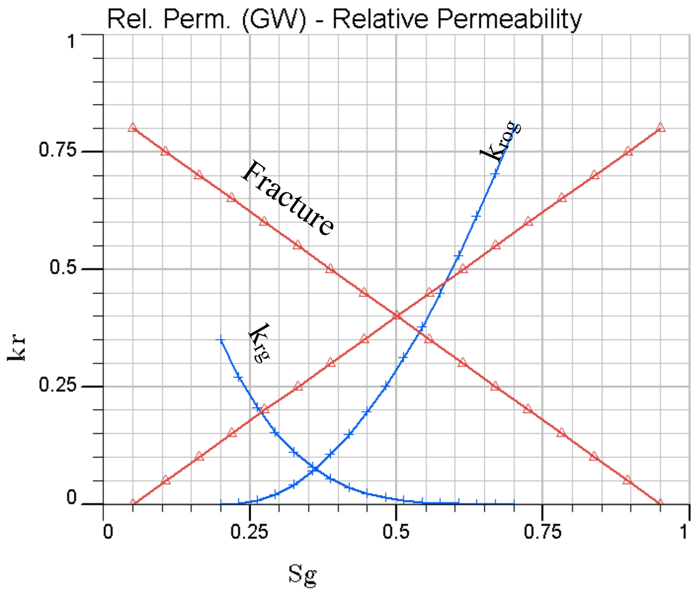

Figure 3-6: Relative permeability curves, fracture (Red) and matrix (Blue)

Also, a simulation run was conducted indicates adding fracture will improve productivity and cumulative volume with less pressure drawdowns and that fracture half-length and geometry will significantly influence the benefits obtained (stimulated reservoir volume SRV). Hydraulic fracturing increases well productivity by reducing flow resistance or pressure decline around the wellbore.

3.2.3.1 Case 1 (Hydraulically Fractured Vertical Well – Gas & Water) Coarse Grid LGR Black Oil Model (CGLGR)

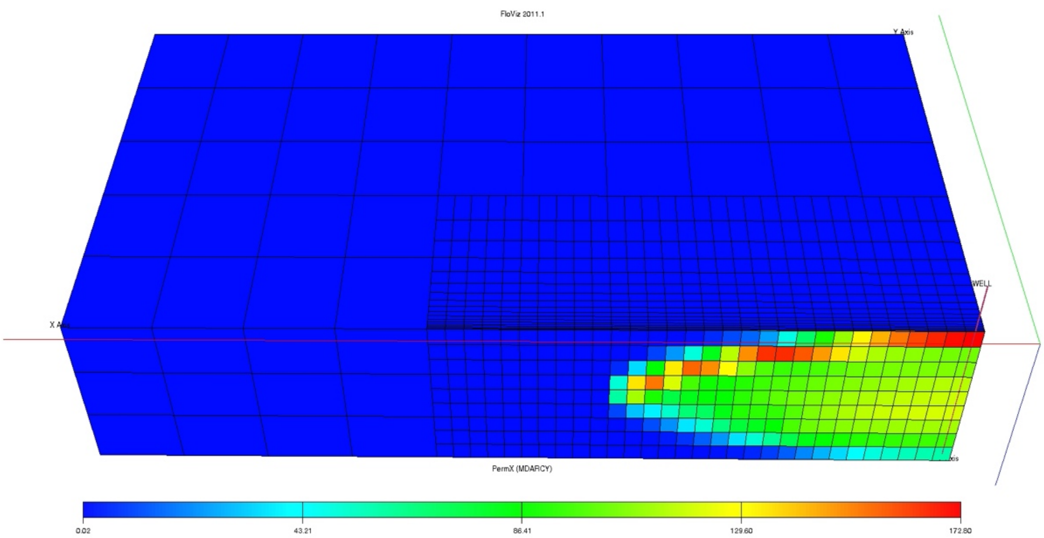

Figure 3-7:Simulation grid and permeability profile for coarse grid case

The first case is a simplified (synthetic) representation of unconventional and tight gas reservoirs with a hydraulic fracture (Figure 3-7). This model has 4720 grid cells in total as shown in Figure 3-5. The fracture half-length and height are 300 and 100 meters respectively and the reservoir depth is 4000 meters. Initial reservoir pressure and temperature assumed to be 520 bar and 134 °C respectively. In this scenario the objective was to evaluate performance after fracturing with different permeability values ranging from 0.1 to 0.001 mD using coarse and fine grid configuration. Figure 3-7 depicts the reservoir simulation gird of fracture model and output results in Figure 3-8 to 3-10. The reservoir and fracture properties for each scenario are summarized in Table 3-1. This is a shale reservoir with initial pressure of 520 bar at 4000 m depth and 100 m net pay thickness with 10 % porosity.

Table 3-1: Reservoir parameters of case 1

Case 1	Scenario A	Scenario B	Scenario C
Permeability (mD)	0.01	0.001	0.1
DIMENS-HOST (X,Y,Z)	10, 5, 3	10, 5, 3	10, 5, 3
DIMENS-LGR (X,Y,Z)	1-6, 1-2, 1-3	1-6, 1-2, 1-3	1-6, 1-2, 1-3

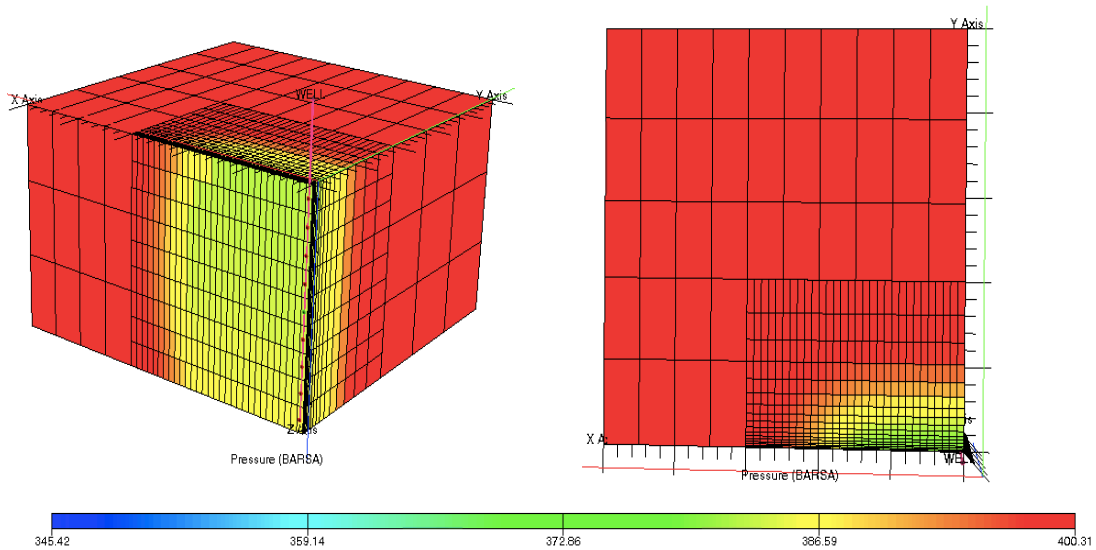

Figure 3-8: Discretization of a single fractured vertical well. Pressure distribution for Case 1 with quarter symmetry. (9 perforations are used in the vertical well)

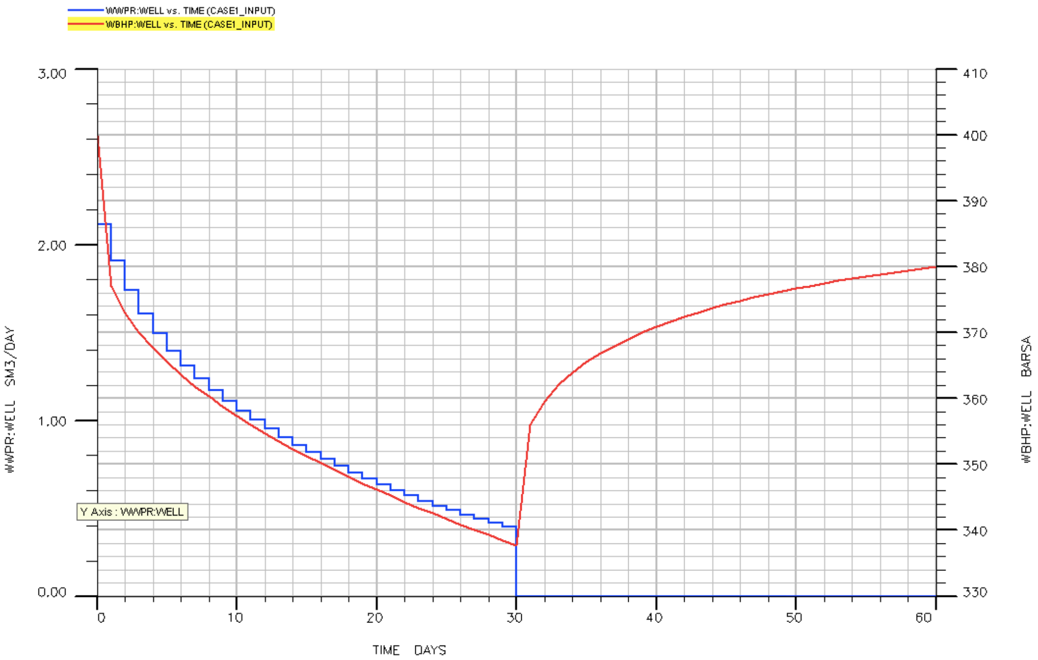

Figure 3-9: Water production rate (Blue) and bottom hole pressure (Red) versus time for case 1A. Gas production in all cases is constrained at 2500 sm3/day. Build-up started after 30 days of production.

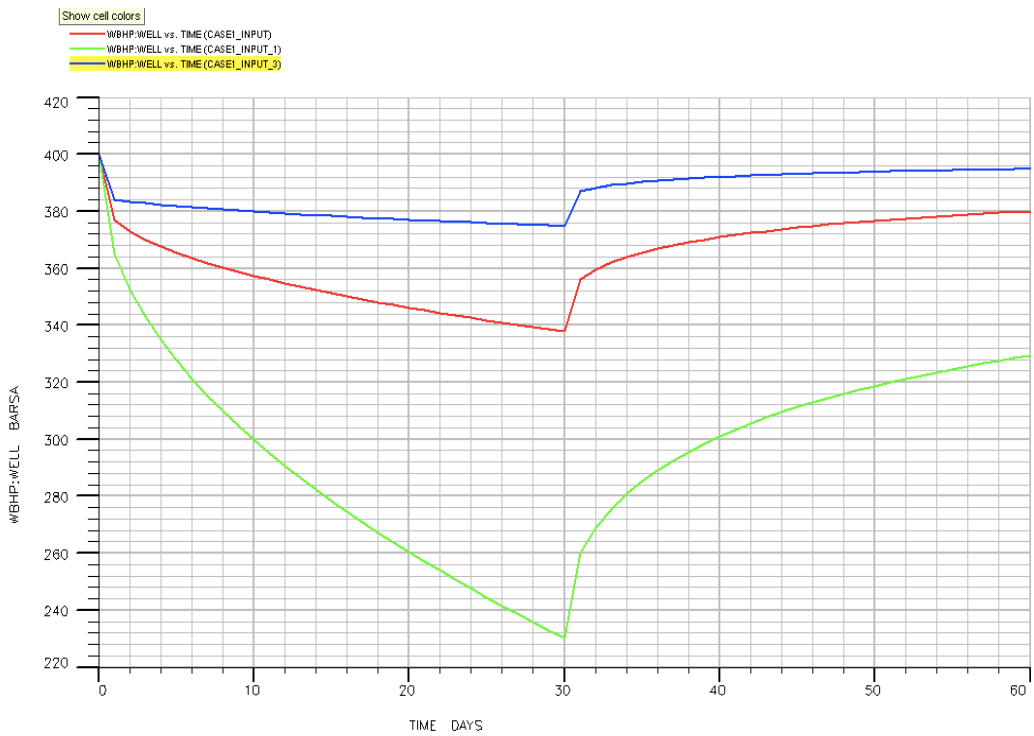

Figure 3-10: Permeability Sensitivity Analysis: This figure shows the bottom-hole flowing pressure of the three scenarios of case 1. 0.1mD (Green) 0.01mD (Red) and 0.001mD (Blue).

3.2.3.2 Case 2 (Hydraulically Fractured Vertical Well – Gas & Water) Fine Grid LGR Black Oil Model (FGLGR)

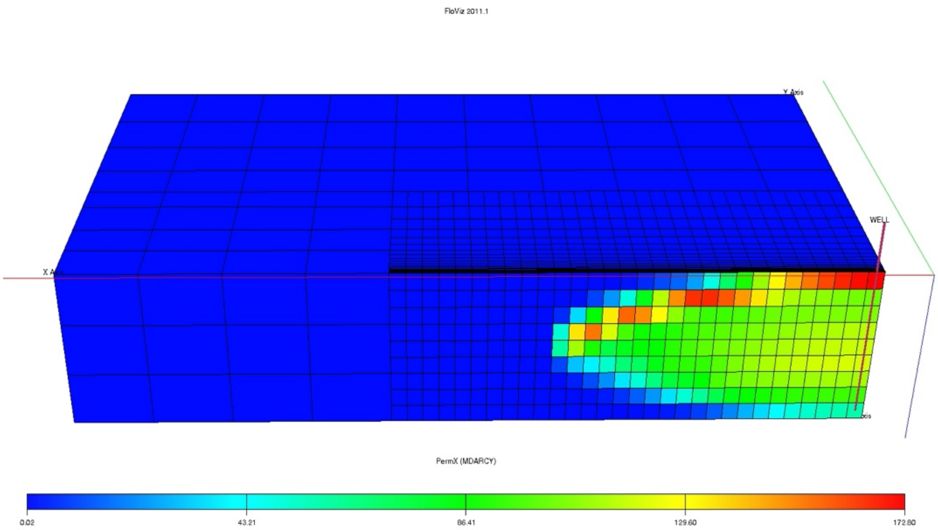

Figure 3-11: Simulation grid and permeability profile for fine grid case

The second synthetic case has same properties as in Case 1, except this time with finer grid refrainment approach see Figure 3-11 and Table 3-2 for LGR dimensions . This is because near fracture and well-bore regions typically require fine space grids to capture several physical processes. This model has 6990 grid cells in total as shown in Figure 3-5.

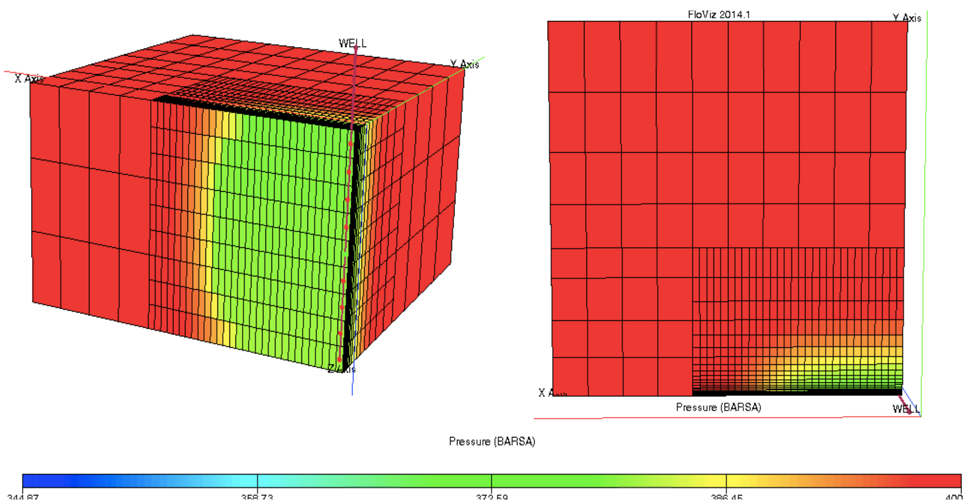

Figure 3-12: Discretization of a single fractured vertical well. Pressure distribution for Case 2 with quarter symmetry.

The reservoir and fracture properties for each case are summarized in Table 3-2. Figure 3-13 shows water production rate and bottom hole pressure versus time for Case 2 with 0.01 mD matrix permeability. Gas production in all cases is fixed at 2500 sm3/day.

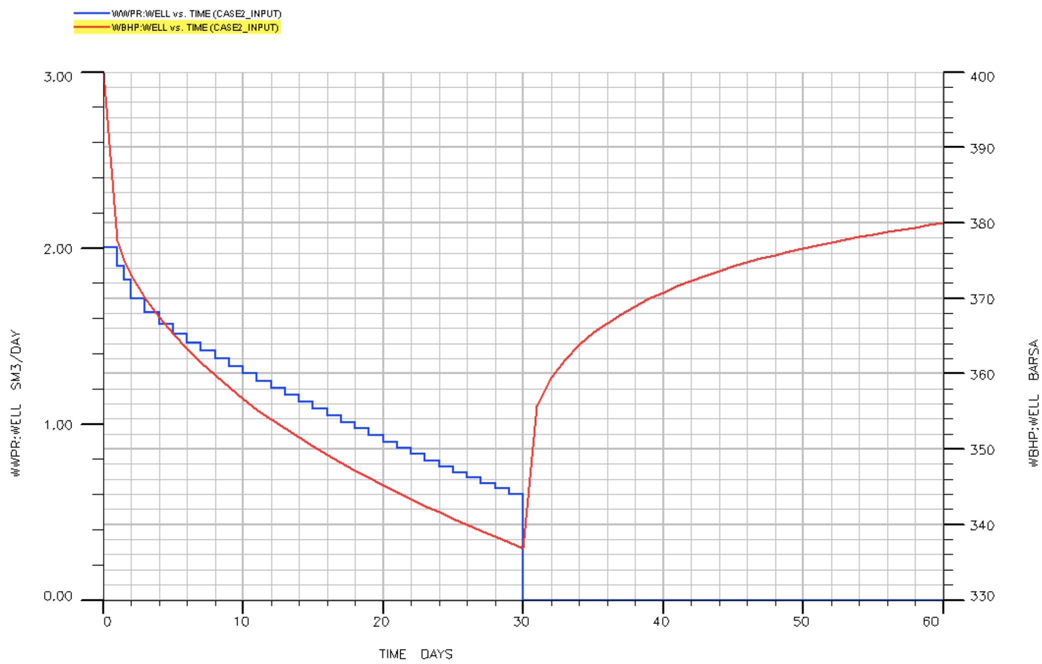

Figure 3-13: Water production rate and bottom-hole pressure versus time for case 1A.

Table 3-2: Reservoir parameters of case 2

Case 2	Scenario A	Scenario B	Scenario C
Permeability (mD)	0.01	0.001	0.1
DIMENS-HOST (X,Y,Z)	10, 8, 3	10, 8, 3	10, 8, 3
DIMENS-LGR (X,Y,Z)	1-6, 1-4, 1-3	1-6, 1-4, 1-3	1-6, 1-4, 1-3

This Figure 3-14 illustrates the bottom-hole pressure variation for Case 2 using different permeability values.

Figure 3-15 shows the difference in bottom-hole pressure using Case 1 and Case 2 outputs and scenarios. The bottom-hole pressure and water production rates clearly indicate that the fine refinement play a major rule on solution accuracy. The main results show that the fine LGR will improve the dynamic representation of fracture and well regions. As a result of this conclusion, LGR methods have become significant for tight gas reservoir to simulate near well hydraulic fracturing (Ding et al, 2014). This section results suggest further improvements and implantation on real data to examine that effect. Additionally, the transient consequence appears to be limited in the above cases, this is due to single-phase consideration.

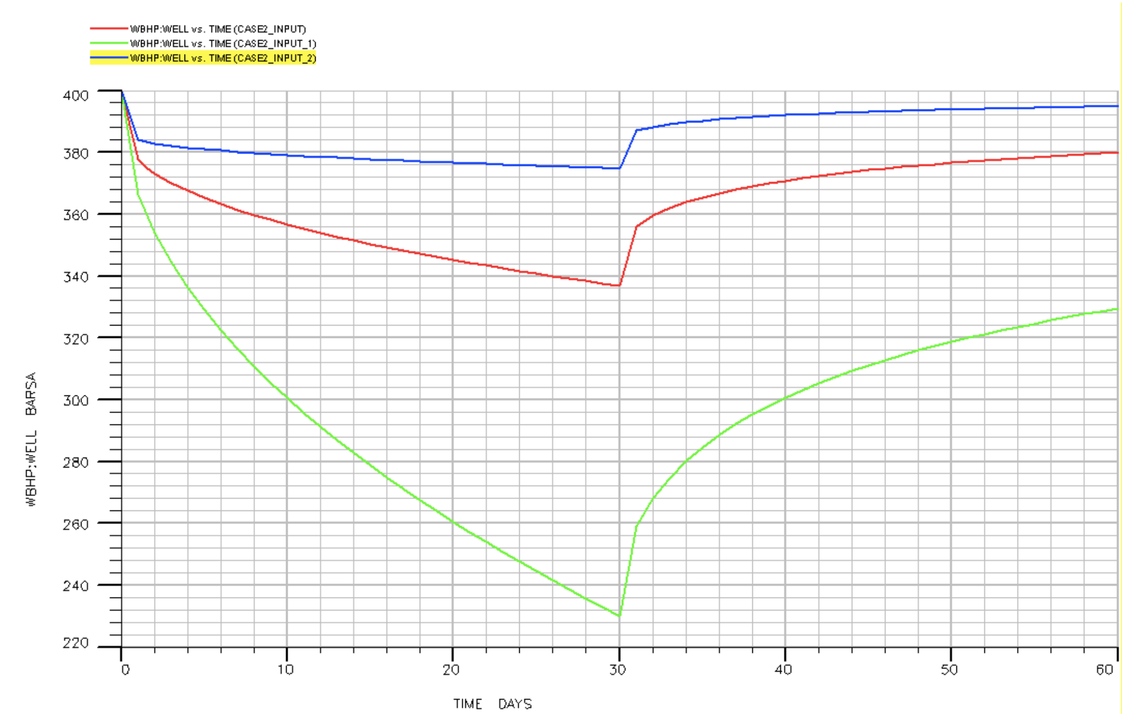

Figure 3-14 Permeability Sensitivity Analysis: this figure shows the bottom-hole flowing pressure of the three scenarios of Case 2. 0.1mD (Green), 0.01mD (Red) and 0.001mD (Blue).

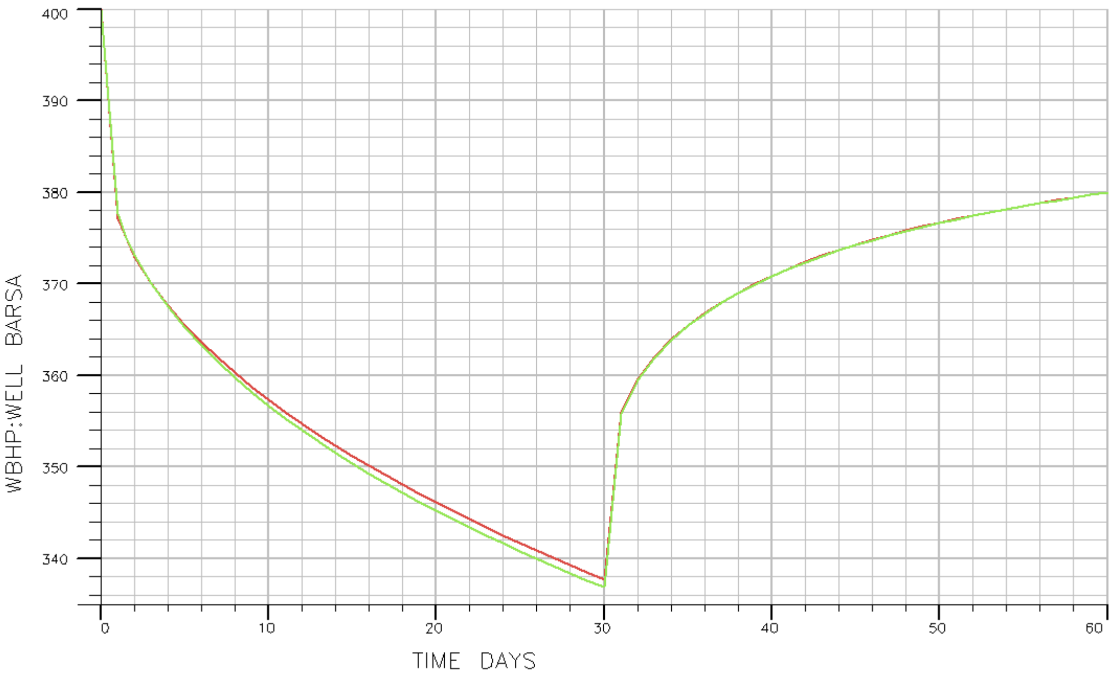

Figure 3-15: LGR Sensitivity Analysis (grid refinement effects): Bottom-hole pressure versus time for Case 1 (Red line) and Case 2 (Green line). (0.01 mD scenario).

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Chapter 4: Condensate Flow of Fractured Well (Multi-phase Flow)

In Chapter 3, a reservoir simulation model was developed in a single-phase dry gas reservoir. Similar analysis is established in this chapter however, with a rich condensate gas solution under different scenarios. Additional challenges will emerge when operating with gas condensate reservoirs. This and the next chapter detail the simulation results for gas-condensate reservoirs. Such reservoirs exhibit complex rock properties and PVT systems. The simulation of such reservoir is complex, because of liquid accumulation below dewpoint. The reservoir simulation of tight gas-condensate reservoirs is fundamental for field development design and planning to increase and maintain reservoir productivity.

This chapter investigates the elements that have a significant influence on the development of gas condensate reservoirs. The study results improve the understanding of fluid flow and performance of tight gas condensate reservoirs and will help to improve field planning and management. This section concludes with the description of how initial field production history data of a gas condensate field is matched in a single well simulation model.

Chapter 4 contains several topics, section 4.1 covering reservoir model description and section 4.2 covering simplified simulation results. Additionally, this chapter will provide simulation results with sensitivities and robustness analysis.

4.1 RESERVOIR SIMULATION OF HYDRULICALLY FRACTURED WELL SIMPLIFED SCENARIO (CONDENSATE GAS)

4.1.1 Reservoir model description

A 3D Cartesian compositional model ($10 \times 5 \times 3$) with single and homogenous layer is used to define the reservoir to investigate the condensate banking in hydraulically fractured well. AIM method and modified Peng Robinson cubic equation of state (PR EOS) are applied to generate pressure data. Since the main objective of this study is to understand the liquid build-up in a tight condensate gas reservoir, a single well with a single fracture and 9 perforations located at the corner of the model is used to model the fluid flow behavior. Table 4-1 summaries the reservoir characteristics, and pressure distribution is illustrated in Figure 4-7. The model is divided into 150 grid blocks, 10, 5 and 3 in the x, y, and z direction respectively and with LGR system covering the fracture side to increase properties computation accuracy (near fracture face, tip and within the fracture).

The gas condensate fluid used in the simulation model has an API gravity of 50˚and a CGR of 100 stb/MMscf. The initial reservoir pressure and temperature are 520 bar and 134˚C. The fluid composition is referred from (Kenyon et al, 1987)

Table 4-1: Table of reservoir, fluid, fracture and completion parameters.

Properties	Values
Reservoir Characteristic	
Grid Dimensions	10 × 5 × 3
Datum Depth, m	4000
Thickness, m	100
Matrix permeability, mD	0.1 / 0.01 / 0.001
Matrix Porosity (), fraction	0.1
Water Saturation, fraction	0.20
Initial Pressure, bar	520
Dewpoint Pressure, bar	500
Temperature, F	273
Fluid Characteristic	
Total Compressibility, bar-1	6e-005
Water FVF, rm3/sm3	1.02
Viscosity, (cp)	0.50
Fracture Characteristic	
Fracture half-length, (meter)	300
Fracture permeability, (mD)	172
Completion Characteristic	
Perforations number	9

4.1.2 Relative permeability model & Velocity dependent flow coefficient

Stone's method II is used to construct a typical three phase relative permeability of fluids in tight gas condensate reservoir. Hydraulic fracture relative permeability is calculated using straight line approach assuming end point saturations of zero values. Stone's model II is formulated on the assumption of segregated phase flow and expressed as (Stone, 1973):

To research the impact of reservoir heterogeneity, two sets of relative permeability curves are simulated corresponding to optimistic (Set 1) and pessimistic cases (Set 2). For the fracture a straight-line curve is applied. Figure 4-1 displays the characteristics of the two relative permeability sets that derived from Stone's model.

To have an accurate reservoir simulation model, the complex phenomena occurring near fracture and well-bore area such as relative permeability variation and non-Darcy flow effect were considered. A velocity dependent flow coefficient for grid block flow (VDFLOW) keyword was used to capture the effect on reservoir performance. Based on Mott (1999), non-Darcy flow effect increase near well-bore permeability due to convergent flow, leading to productivity reduction. This is commonly known as β-factor (the non-Darcy flow coefficient) and has unit of $atma.s^2.g^{-1}$ (the Forchheimer unit). In a low permeability reservoir, it is not expected non-Darcy to be so important as shown in Figure 4-2. Figure 4-2 shows the effect of different Values of β = 100 (green line), 10 (blue line), 1 (yellow line), and 0.1 (pinkish line) on Pressure and oil rate profiles. As the results show in Figure 4-2 the non-Darcy has a minor impact in flow behavior in tight reservoir (matrix) and important impact in the fracture flow. Several Beta factor correlations were tested and applied based on Takhanov, D. (2011), and the final values used are 72 and 10 for matrix and hydraulic fracture respectively.

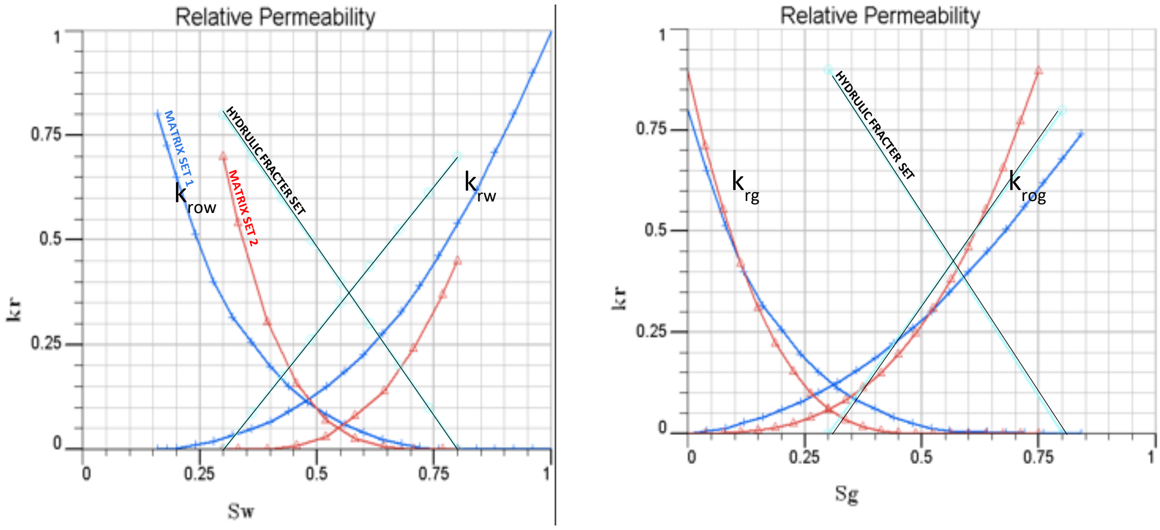
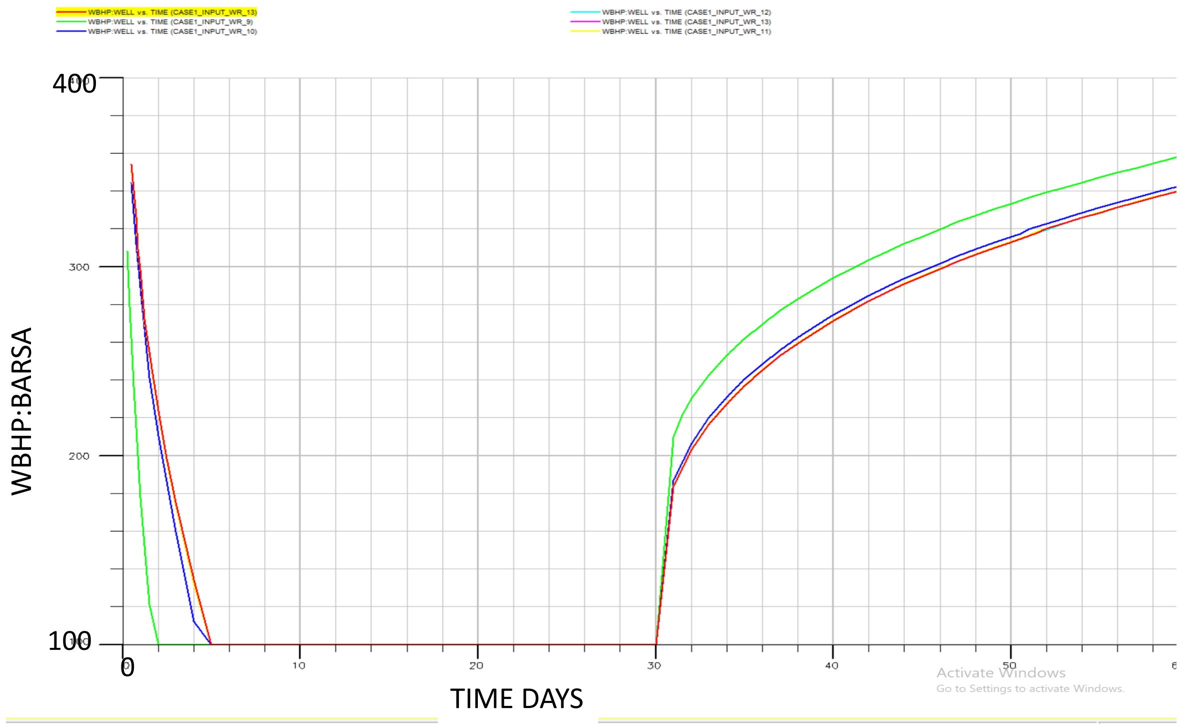


Figure 4-1: Matrix/Fracture relative permeability curves, for synthetic case: Fracture Set (Black) , Matrix Set 1 (Blue) and Matrix Set 2 (Red).



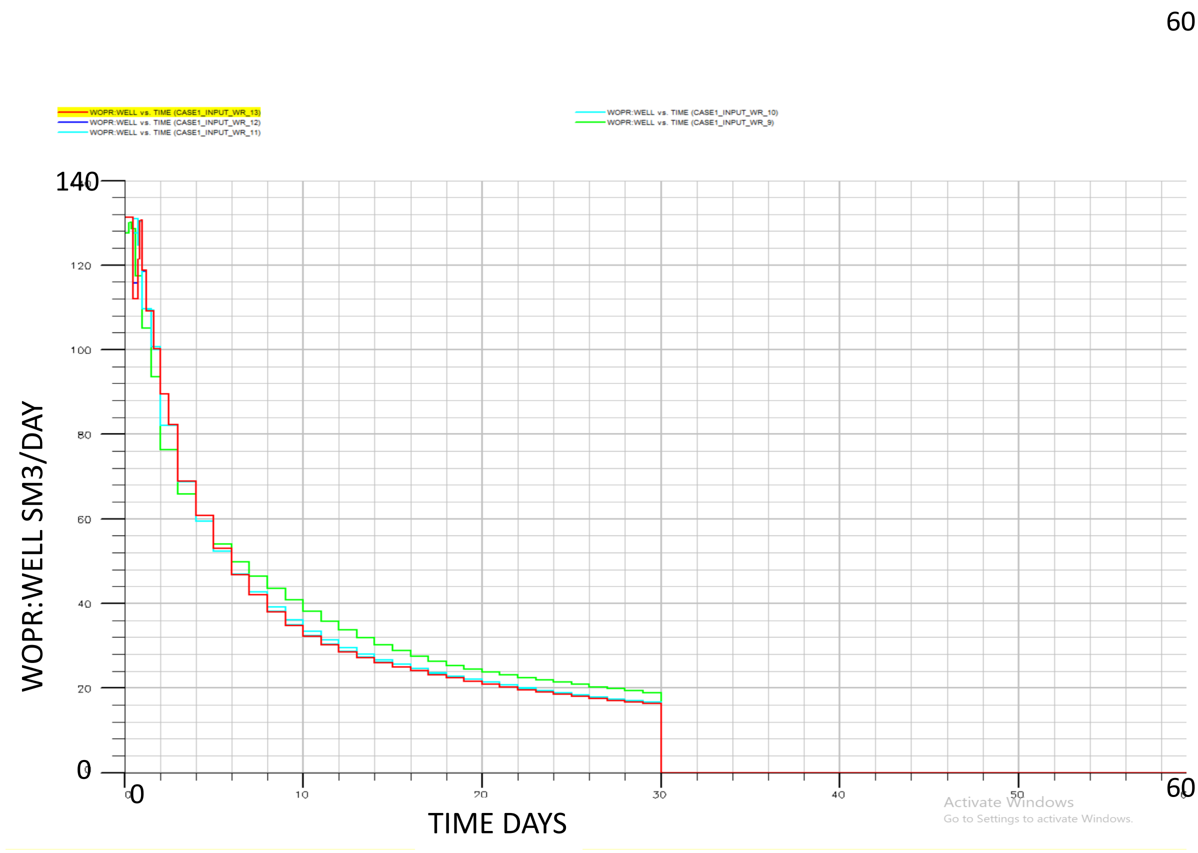


Figure 4-2:Pressure and oil rate profiles with different Values of β = 100 (green line), 10 (blue line), 1 (yellow line), and 0.1 (pinkish line).

4.1.3 Stress sensitive permeability

Permeability reduction during reservoir drainage impacts matrix and fracture fluid flow. This is due to the reduction of pore and throat size as a result of changes in net confining stress. Based on Jones and Owens (1980) observations this reduction is more significant in tighter rocks. According to (Chu et al., 2012) the compaction effect on permeability is 3-10 times higher than on porosity. According to (Shaoul et al., 2015) in reservoir with 0.001 mD permeability, gas production overestimate was anticipated of 35% for 5 year and 56% for 20 year. The simulation developed for this study considers this effect via using transmissibility multipliers for matrix and fracture. Figure 4-3 depicts pressure dependent fracture/matrix conductivity (transmissibility multiplier verses the pressure). This multiplier is based on various tight gas reservoirs correlation.

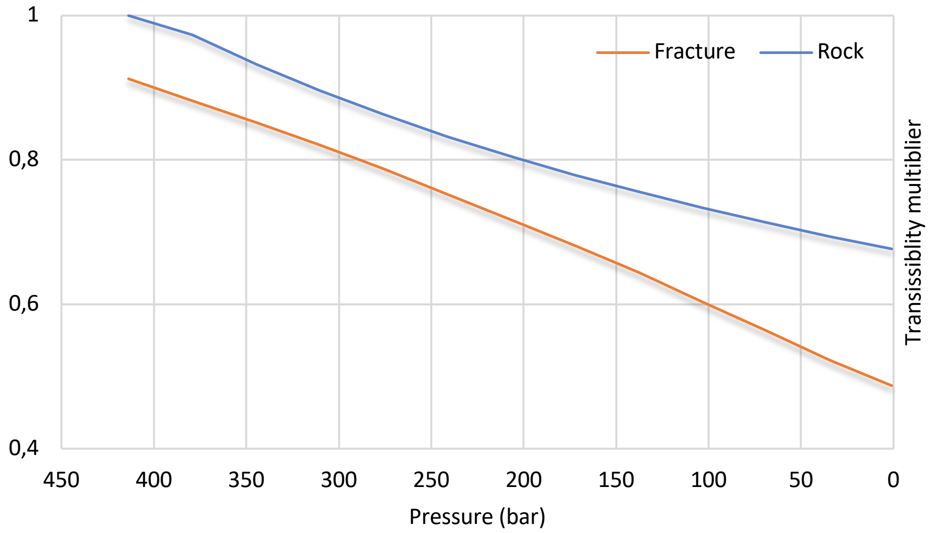


Figure 4-3: Change in transmissibility multipliers of fracture and rock with reservoir pressure

4.1.4 Fluid model (PVT)

This study applies two gas condensate compositions: the first one is based on (Kenyon, 1987) study and the second one in Chapter 5 is extracted from field report of a tight reservoir in the Middle East. This study incorporates a nine-components model according the PVT lab-report as shown in Table 4-2 for synthetic case. The reservoir fluid phase diagram is depicted in Figure 4-4. Lab measured dewpoint pressure is 500 bar with 134 °C reservoir temperature.

Table 4-2: Table of reservoir composition synthetic case.

Component	Mol %
N2	2,18
CO2	1,64
H2S	0,00
C1	42,31
C2	6,63
C3	4,36
IC4	1,43
NC4	2,19
IC5	1,16
NC5	1,37
C6	2,88
C7	33,88
TOTAL	100,00

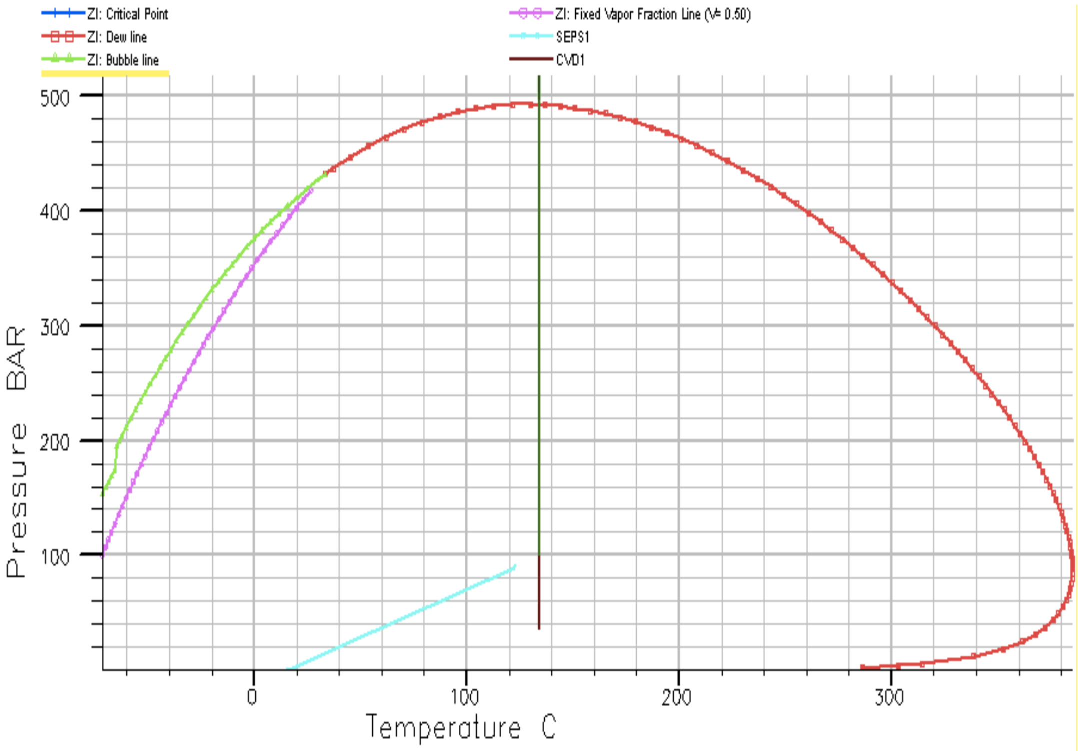


Figure 4-4:Phase diagram of the reservoir fluid for the synthetic case

4.2 SIMULATION RESULTS

The results presented in this sub-section are outcomes of a simplified synthetic scenario of a vertical single propped fracture well using compositional reservoir simulation. Schlumberger's E300 has been used. This section examines how to handle a single fractured vertical well with different LGR configurations (Coarse vs Fine grid) and study the impact of different reservoir permeabilities (Low vs High Perm). In this analysis, multiple simulation runs were performed for rock compaction, matrix and relative permeability, reservoir pressure and production rate to characterize the effect of each on the reservoir performance efficiency. The section below will also demonstrate the sensitivity of the liquid gas ratio under varying conditions.

4.2.1.1 Case 1: Hydraulically Fractured Vertical Well with Coarse Grid LGR (CGLGR)

The first case is a conceptual representation of tight homogenous gas reservoirs, that drained by a finite conductivity vertical fractured well see Figure 4-5. In the figure both coarse and fine LGR cases are shown. In the coarse LGR model (30 X 17 X7), there are 4720 grid cells in total. The fracture half-length and height are 300 and 100 meters respectively and the reservoir depth is 4000 meters. Initial reservoir pressure and temperature assumed to be 520 bar and 134 ^{o}C respectively.

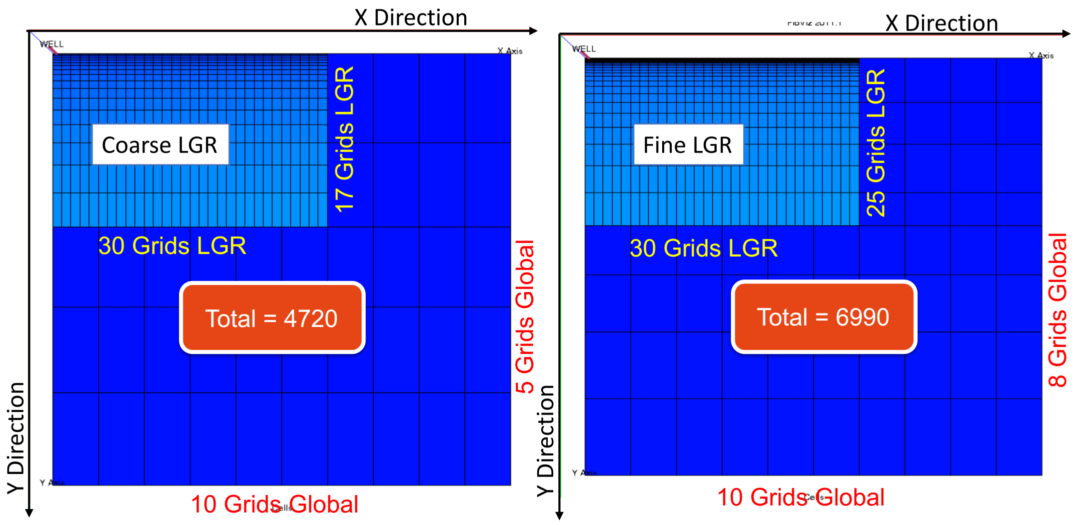
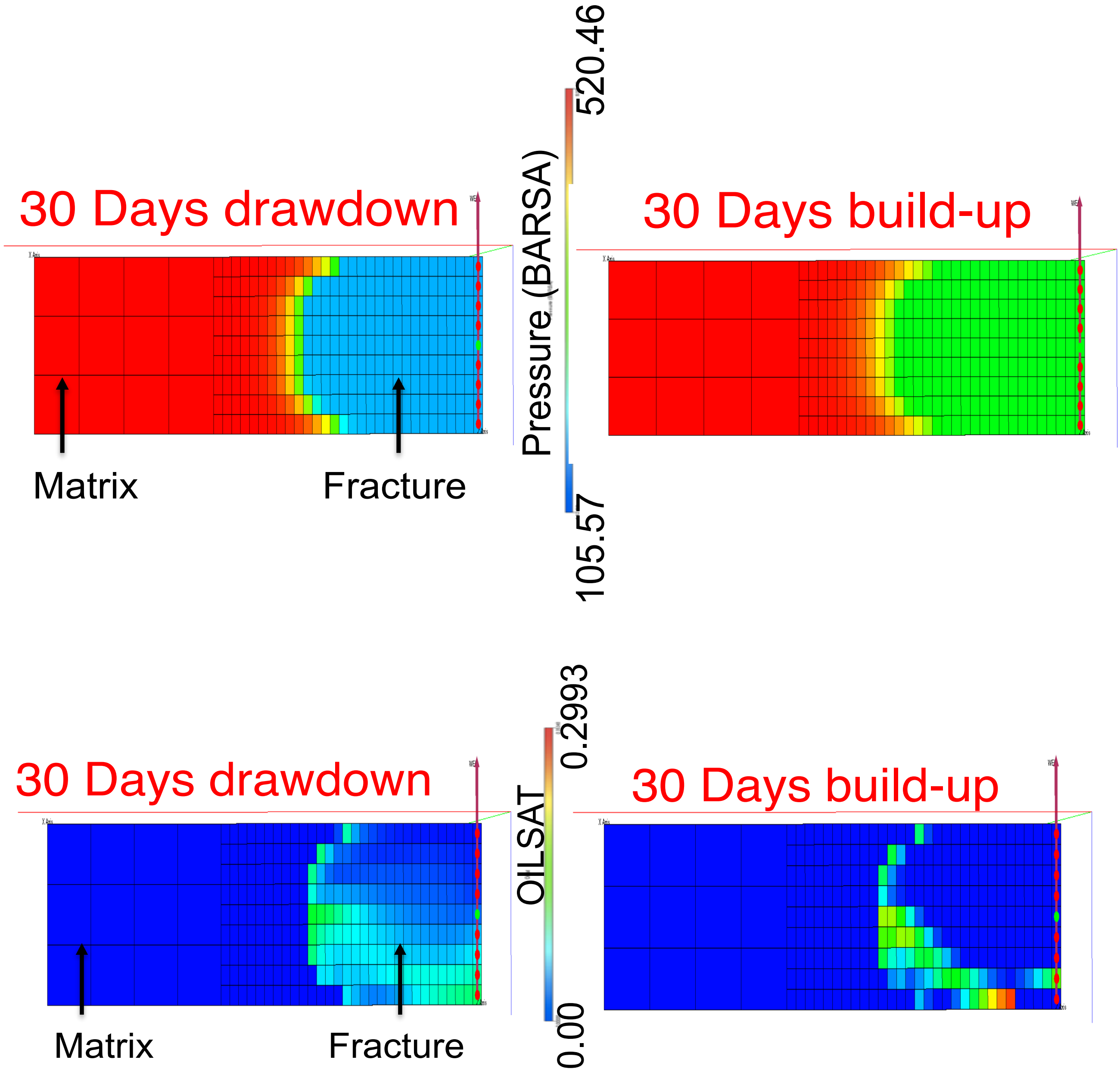


Figure 4-5: Top view of fine and coarse grid geometry in all models.

In this scenario, the objective was to evaluate performance after fracturing with different matrix permeability values ranging from 0.1 to 0.001 mD using coarse grid configuration. Simulation results are shown in Figure 4-6 and 4-7. As illustrated in the results different reservoir permeability will affect pressure drawdown, gas rate and this eventually will affect the production CGR


520.46
30 Days drawdown
Pressure (BARSA)
30 Days build-up
Matrix
Fracture
105.57
0.2993
30 Days drawdown
OILSAT
30 Days build-up
Matrix
Fracture
0.00

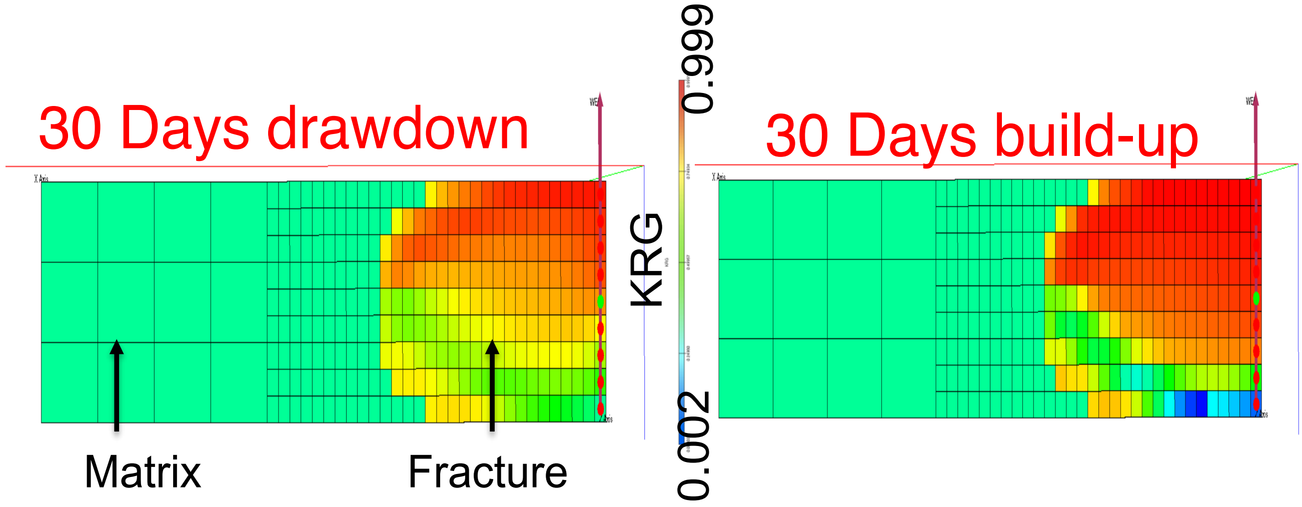
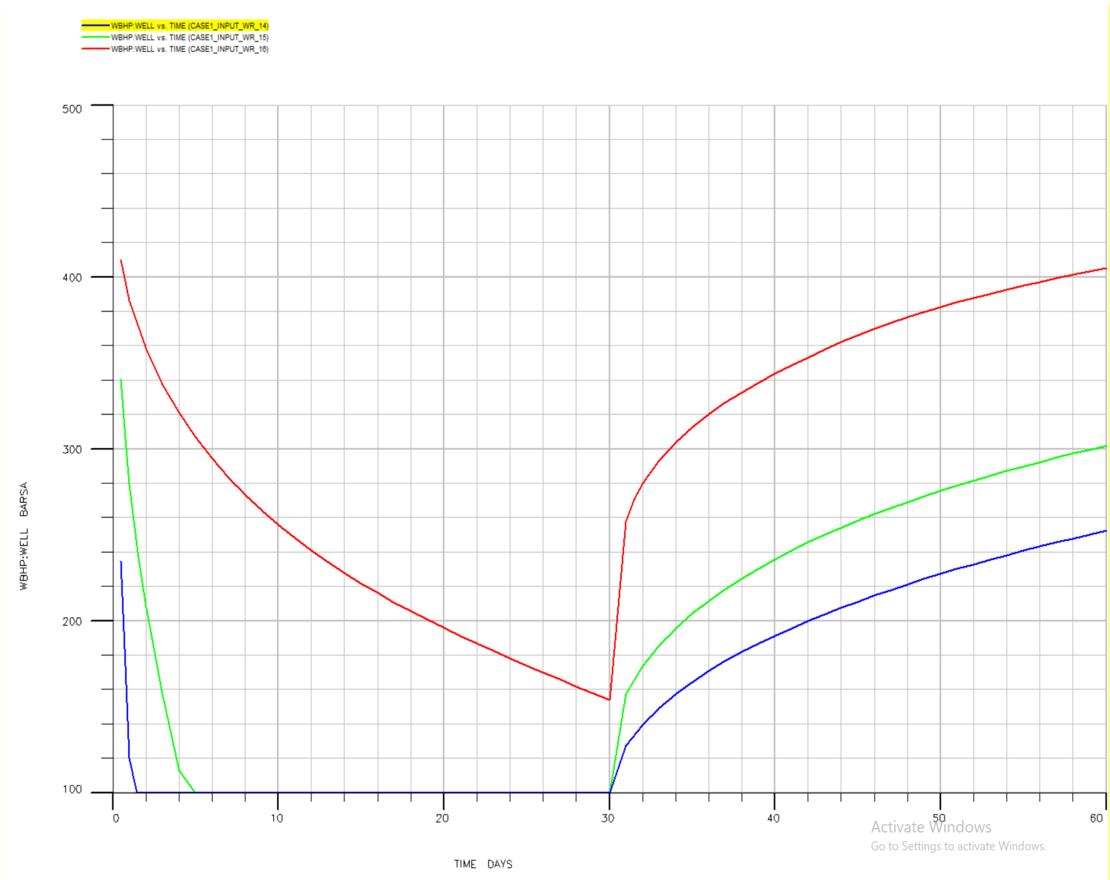


Figure 4-6: Simulation result of 0.01 mD case shows production time effect on condensate bank development after 30 day of drawdown (left side) and 30 days of build-up (right-side). plot A, B, C representing Pressure, Oil saturation and Gas relative permeability respectively.



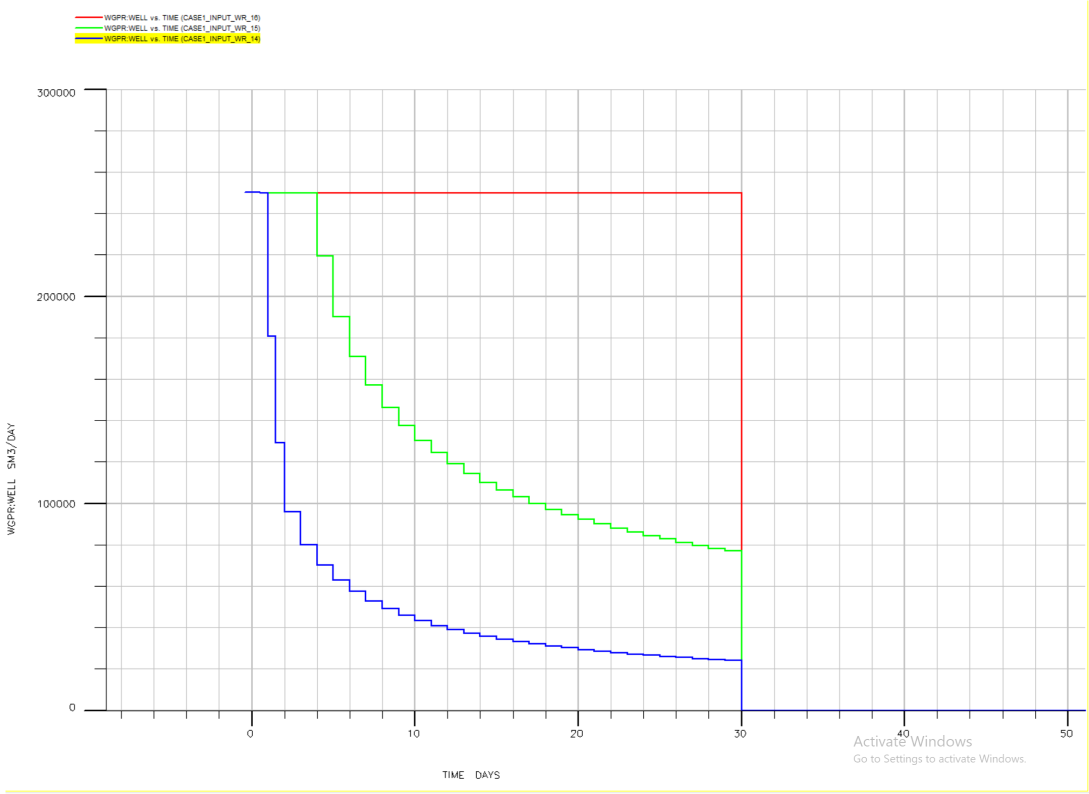


Figure 4-7: Comparison of BHP (Top) and gas production rate (Bottom) profiles for case 1 with 0.1 mD (Red), 0.01 (Green) and 0.001 (Blue).

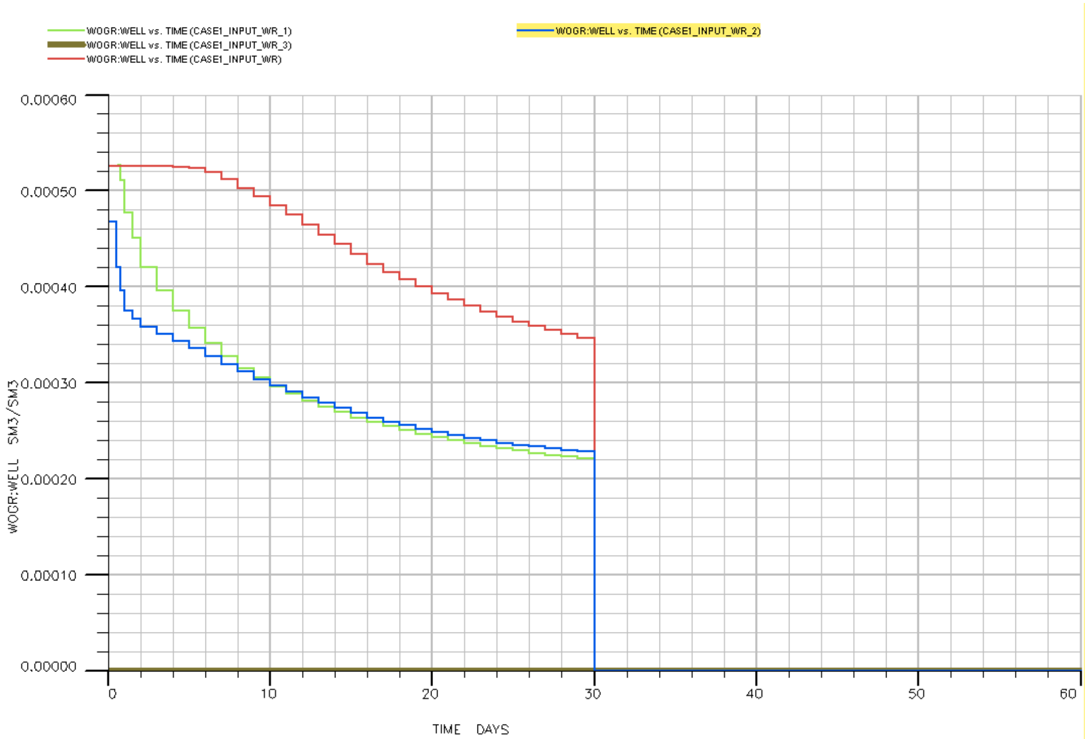
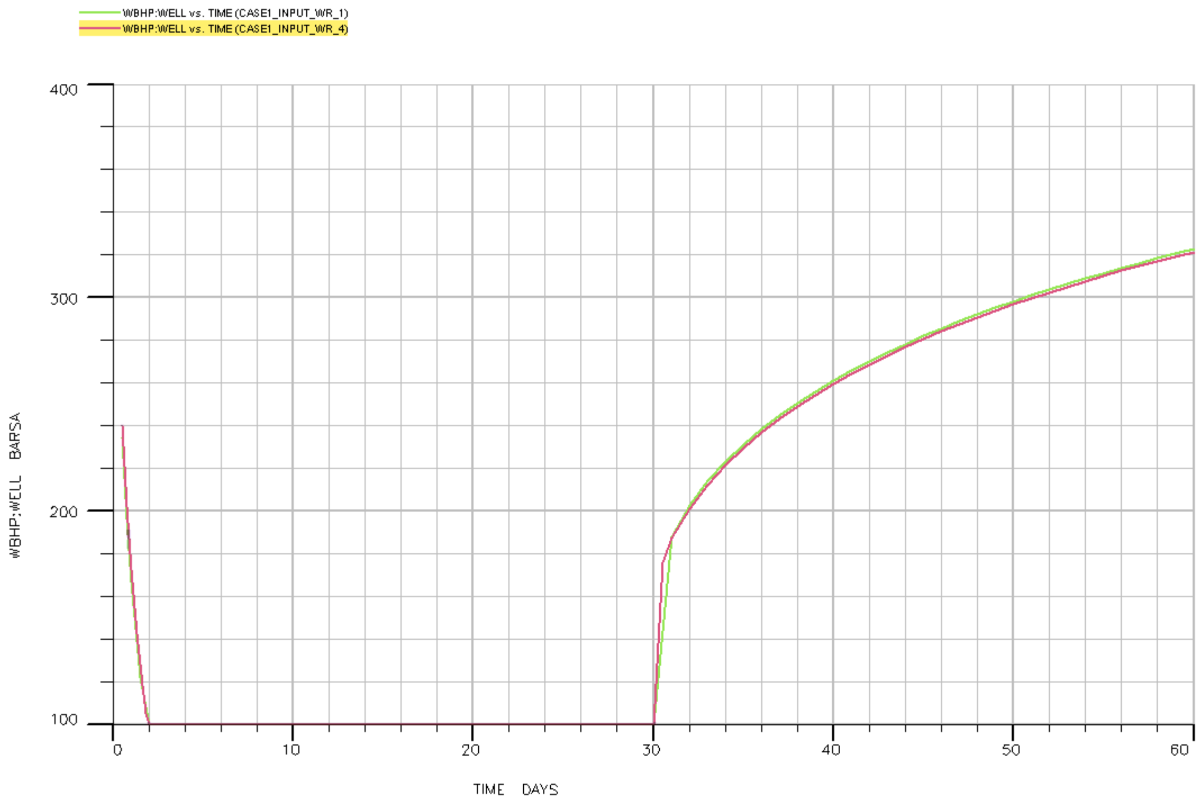
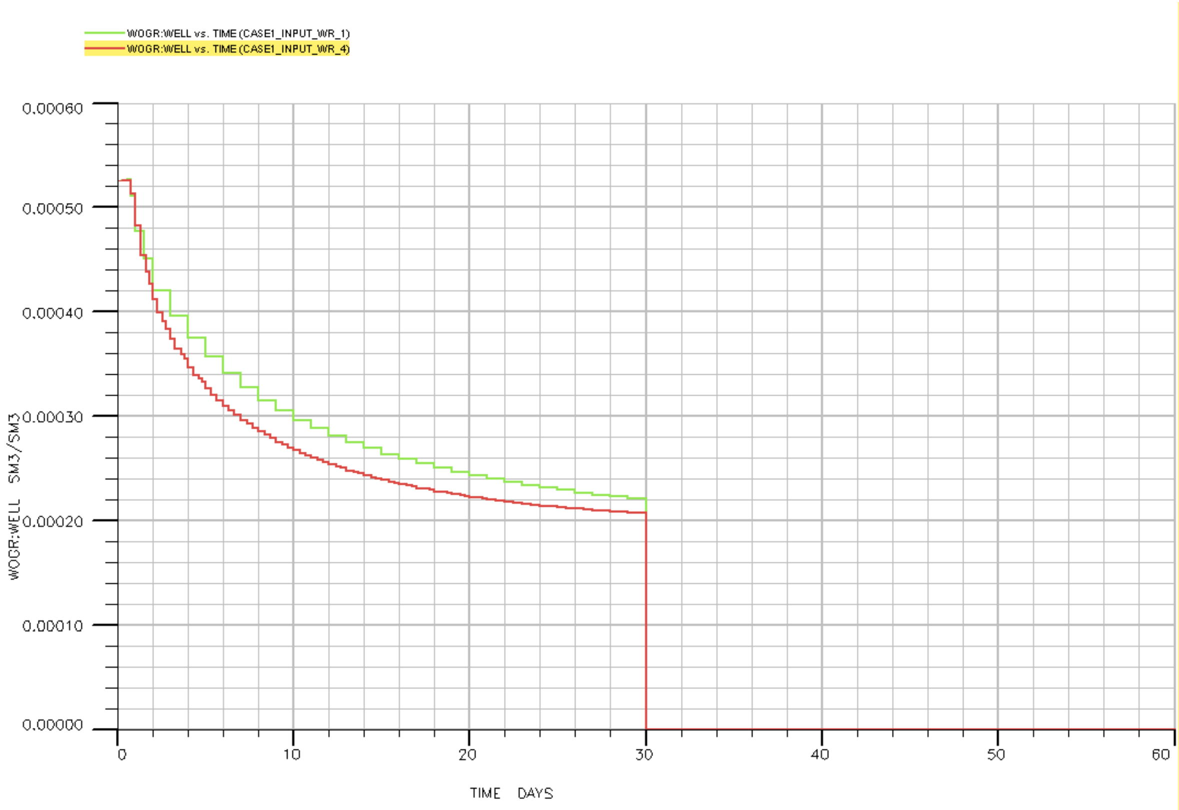


Figure 4-8: Comparison of CGR profile for case 1 with 0.1 mD (Red), 0.01 (Green) and 0.001 (Blue).

4.2.1.2 Case 2: Hydraulically Fractured Vertical Well with Fine Grid LGR (FGLGR)

The second condensate case has the same properties as Case 1, except the finer grid refrainment approach see Figure 4-5. This is because near fracture and well-bore regions typically require fine space grids to capture several physical processes. The purpose of this case is to compare results from coarse LGR approach (Case 1) and fine LGR approach (Case 2). This model has 6990 grid cells in total (LGR= 30 X 25 X 9). Figure 4-9 shows oil production rate and bottomhole pressure versus time for Case 2 with 0.01 mD matrix permeability. It’s clearly indicated that the pressure profile in coarse grid case is not the same with the fine grid. This is because of the underestimation of the block pressure drop in the coarse grid case. So, as the BHP drops below the dewpoint the heavy components start to drop-out and CGR of well stream will reduce as shown in Figure 4-9. Also, overall composition in the Region 1 and 2 will be higher than the initial reservoir fluid as shown in Figure 2-1.





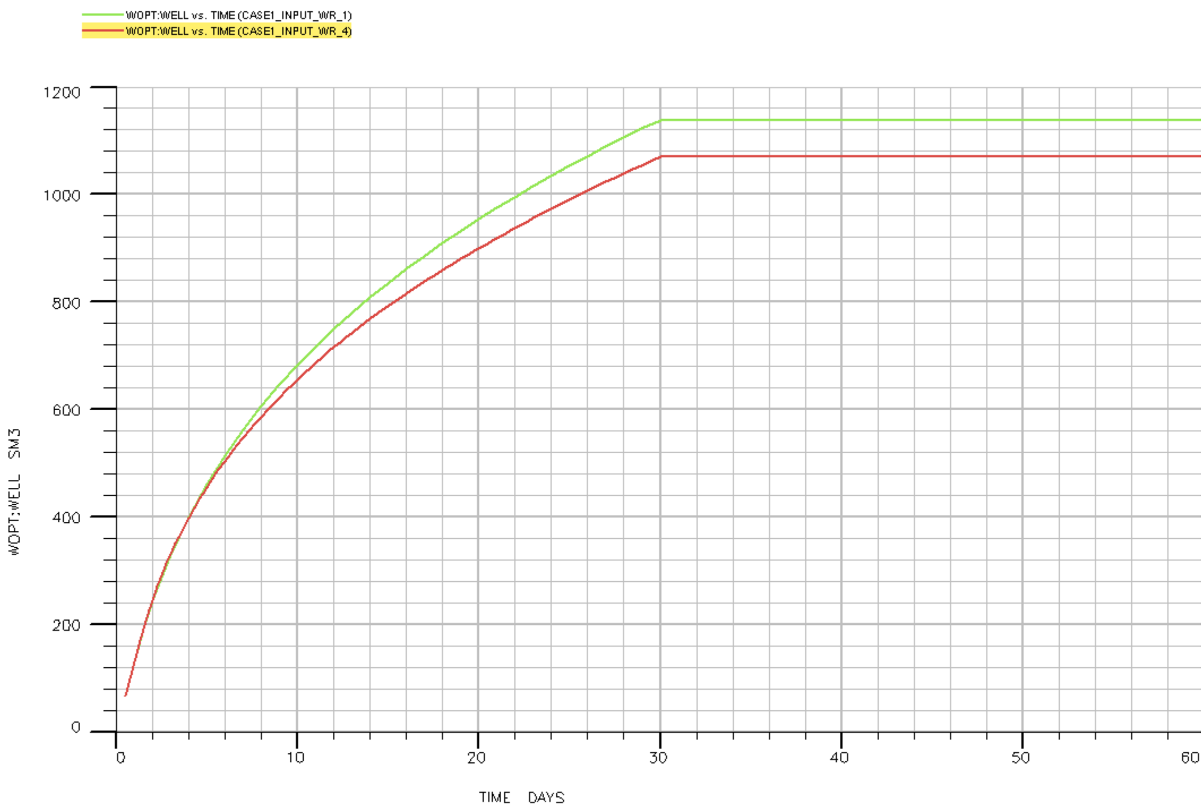
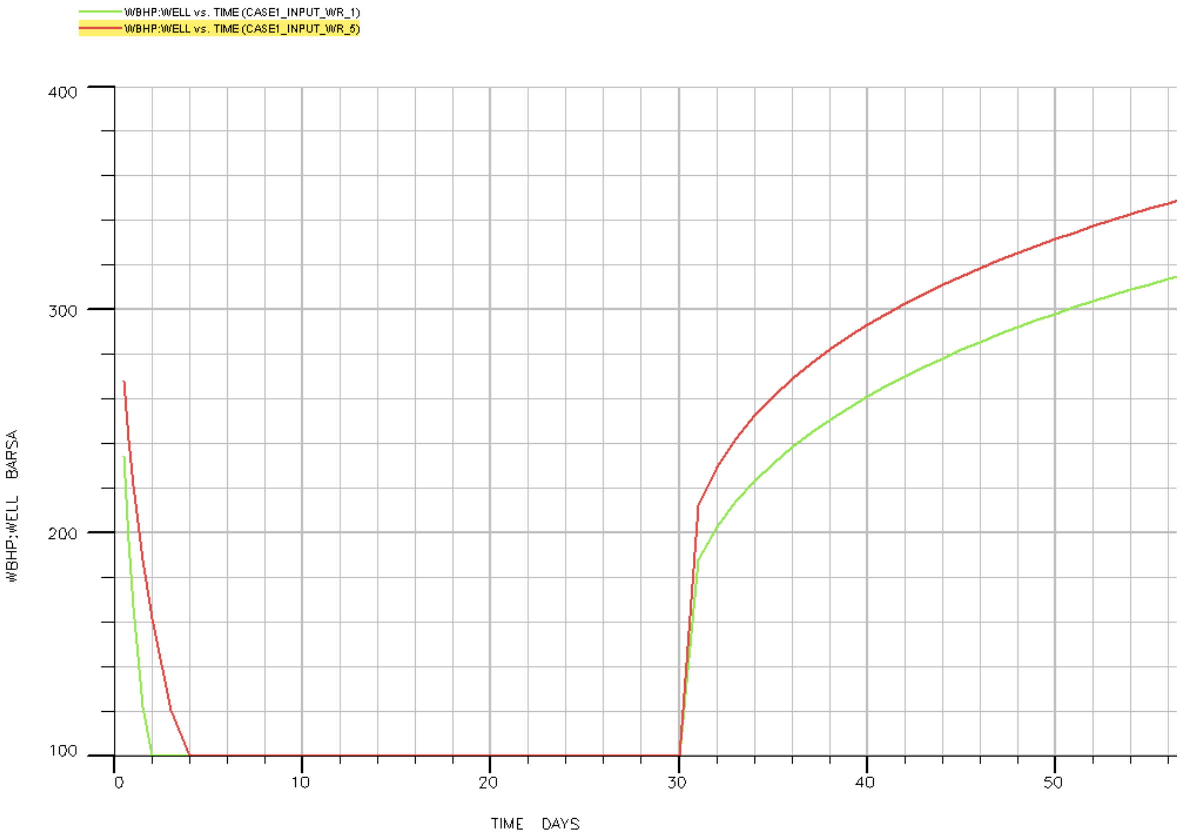
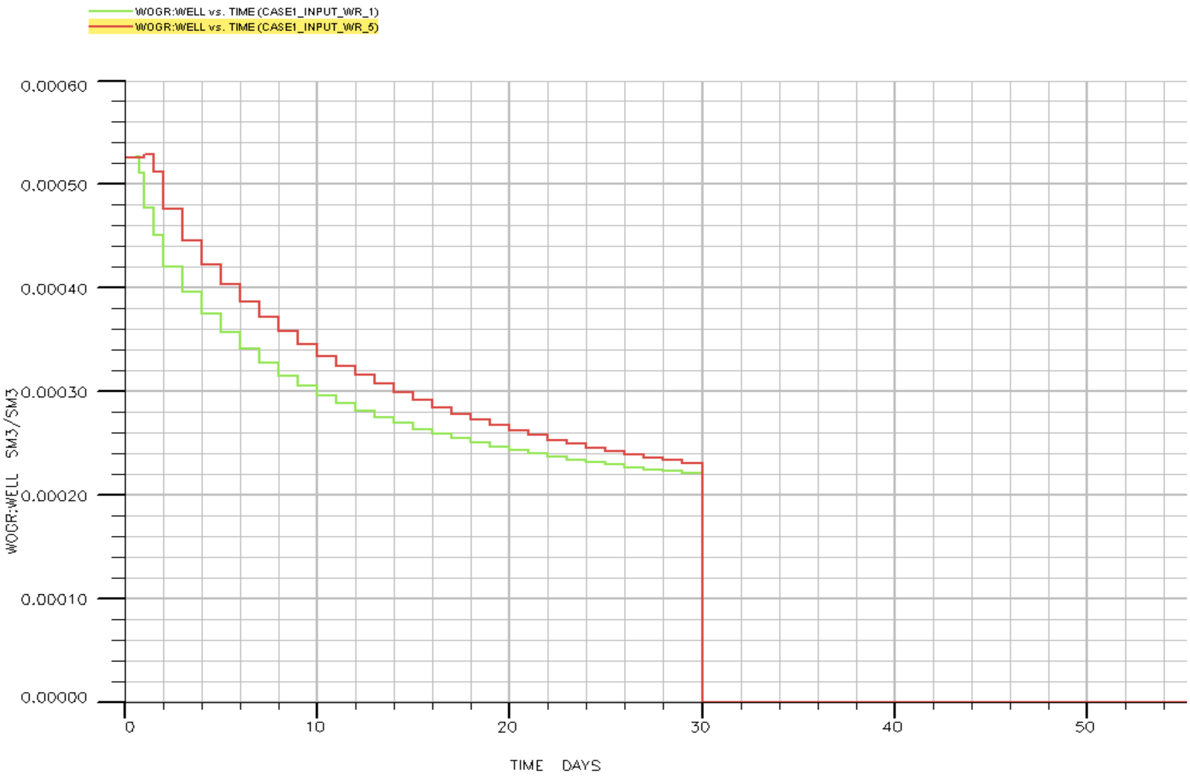


Figure 4-9: Comparison of BHP, Oil production rate and Oil cumulative profiles for coarse LGR case 1 (Green) and fine LGR case 2 (Red).

Figure 4-10 displays oil production rate, cumulative and bottom hole pressure versus time for Case 2 with different sets of relative permeabilities sets as shown in Figure 4-1. Figure 4-10 illustrates the important factor that relative permeability plays on history matching for the field case.





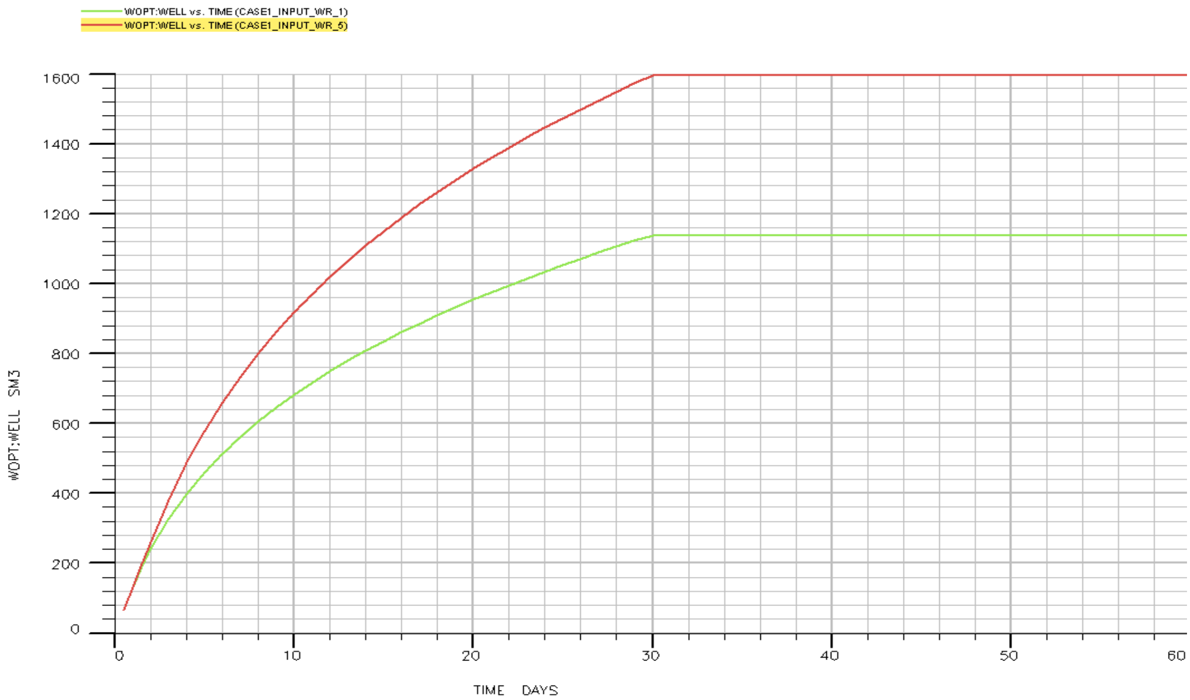


Figure 4-10: Comparison of BHP, Oil production rate and Oil cumulative profiles for different relative permeability, Set 1 (Red) and Set 2 (Green).

4.3 MODEL VERIFICATION AND HISTROY MATCHING

In the previous chapter a single phase of propped fractured well completed in single and homogenous reservoir developed to examine pressure and fluid behaviors of finite conductivity fracture. Several parameters were investigated such as fractured well and non-fractured well, matrix permeability values and production rate.

This chapter focused on a multi-phase propped fractured well with same completion and reservoir parameters as Chapter 3. Several fracture, formation and sensitivity parameters runs are presented in this chapter in order to examine the impact of each parameter of condensate buildup of a single fracture and layer reservoir. Parameters studied include fractures, relative permeability curve, fluid composition type and matrix permeability. Such parametric study is preformed to examine the effect of low permeability and other factors on condensate banking.

The results of the study indicate that the fracture conductivity play important rule in condensate build up, with other factors such as matrix permeability also contributing in causing such build up. This study provides an accurate, realistic and efficient simulation model of gas condensate flow around hydraulically fractured wells, based on flow physics.

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Chapter 5: Condensate Flow of Fractured Well
(Field Case Study-Tight Well)

In this Chapter, reservoir simulation model was developed for an actual tight condensate reservoir in a vertical well which had been hydraulically fractured. This field produces gas condensate from extremely low-permeability multi-layer rock. For such tight reservoir the situation is complex, where high drawdown leads to quick and early condensate build-up near the well-bore and hydraulic fracture. This example is representative of many tight reservoirs in North America and Middle East region, that are produced with horizontal wells and hydraulic fractures. The purpose of this chapter is to investigate the liquid drop-out effect on the performance of fractured wells. Similar analysis to Chapter 4 is developed in this chapter.

Additional challenges emerged during history-matching the actual production rates with simulation prediction. Moreover, it is necessary to look at the actual long-term production to history match that with simulation results and adjusting relative permeability and capillary pressure curves accordingly. The numerical simulation results show the significant impact of fluid characteristics on well performance in case of fractured wells in tight reservoir, and the results provide sufficient correlation to the condensate production.

This chapter investigates the elements that have a substantial influence on the development of gas condensate reservoirs. The study results improve the understanding of fluid flow and performance of tight gas condensate reservoirs and this will help to improve field planning and management. The Interpretation and history-matching (Gas Constraint) of actual field well data confirms the results obtained from numerical simulation.

Chapter 5 contains several topics, section 5.1 covers reservoir model description and section 5.2 covers simulation results for long- and short-term production. Additionally, this chapter will provide simulation forecasts.

5.1 RESERVOIR SIMULATION OF HYDRULICALLY FRACTUED WELL SIMPLIFIED SCENARIO (CONDENSATE GAS)

5.1.1 Reservoir model description

A 3D Cartesian compositional model (13 × 3 × 44) with a vertical well, two hydraulic fractures and 46 perforations are used to define the reservoir to simulate post-frac production rates and capture condensate banking behavior. Table 5-1 summarizes the reservoir characteristics, and grid distribution is illustrated in Figure 5-1 and Figure 5-2. The model has total of 44036 grid blocks with LGR (46 X 20 X 46) covering the fractures. The gas condensate fluid used in the simulation model has an API gravity of 50˚and CGR of 100 stb/MMscf.

Two main elements of history matching are applied in this chapter. First factor is the adequate input of hydraulic fracture model parameters with more accurate geometry and conductivity. The other element is the relative permeability curves and velocity dependent flow coefficient. In order to achieve better history match, reducing the range of uncertainty such as the relative permeability curves and the injected fluid volume have been done.

As history matching of the well test data is complex process; first, the sensitivity analysis was performed which was convenient in order to determine the most uncertain and influential variables such as grid size, hydraulic fracture properties, relative permeability curves and velocity dependant flow coefficient. Subsequently the intention was to first match the production data (Gas Constraint) and with this match the Bottom hole Pressure (BHP) of the well test data during the first drawdown and buildup period. After this first match had been accomplished, then the simulation results were conducted for the long-term production. The History match was achieved after several sensitivities of the uncertainty parameters such as relative permeability curves and velocity depend flow coefficient.

Table 5-1: Table of reservoir, fluid, fracture and completion parameters.

Properties	Values
Reservoir Characteristic	
Grid Dimensions	13 X 3 X 44
Datum (subsurface), ft	14400
Thickness (h), ft	172
Matrix permeability (k), mD	0.02
Matrix Porosity (), fraction	0.1

Water Saturation (S_w), fraction	0.20
Initial Pressure (p_i), Psi	7540
Dewpoint Pressure (p_d), Psi	7200
Temperature(T), F	273
Wellbore storage, bbl/psi	0.13
Fluid Characteristic	
Total Compressibility (c_g), Psi^{-1}	4e-006
Water FVF, rm3/sm3	1.02
Viscosity, cp	0.50
Fracture Characteristic	
Fracture half-length, ft	850
Fracture permeability, mD	137-20
Completion Characteristic	
Perforations number	46

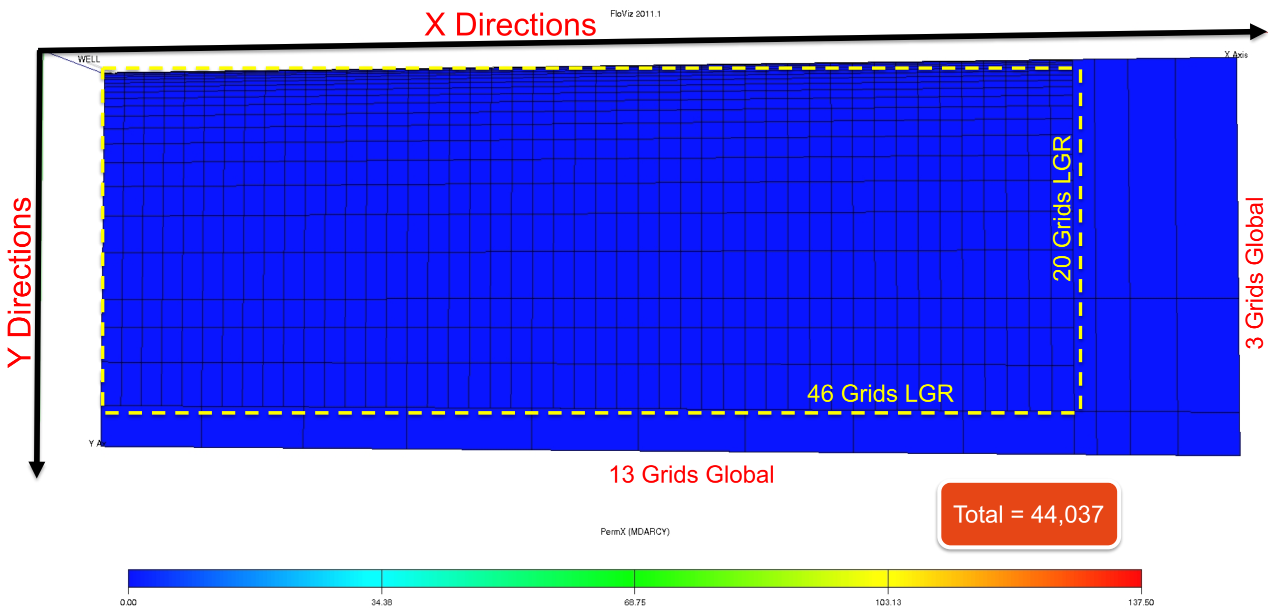


Figure 5-1:Top view of field case grid geometry.

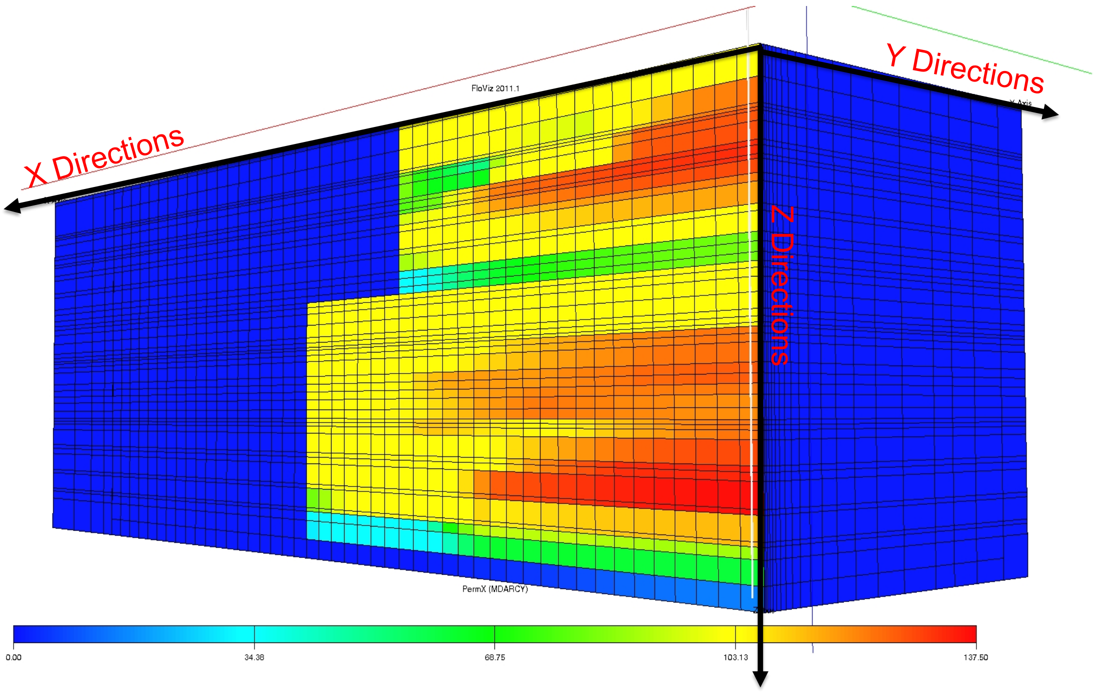


Figure 5-2:Side view of field case grid geometry and permeability profile.

5.1.2 Relative permeability model & Velocity dependent flow coefficient

Field case has relative permeability of fluids in tight gas condensate reservoir. Hydraulic fracture relative permeability is calculated using straight line approach assuming end point saturations of zero values.

Several Beta factor correlations were tested and applied based on Takhanov, D. (2011), and the final values used for the field case are 72 and 10 for matrix and hydraulic fracture respectively.

Figure 5-3 represents the characteristics of the matrix relative permeability sets that used in the field case as presented in Chapter 5. This is based on various tight gas reservoirs correlation. Relative permeability curves have a great impact in the well performance for gas condensate reservoirs, even more when the pressure is under the dewpoint level and multiphase flow occurs. Thus, an accurate laboratory measurement of this property would the ideal case. However, in this field case study no data of Special Core Analysis (SCAL) was available.

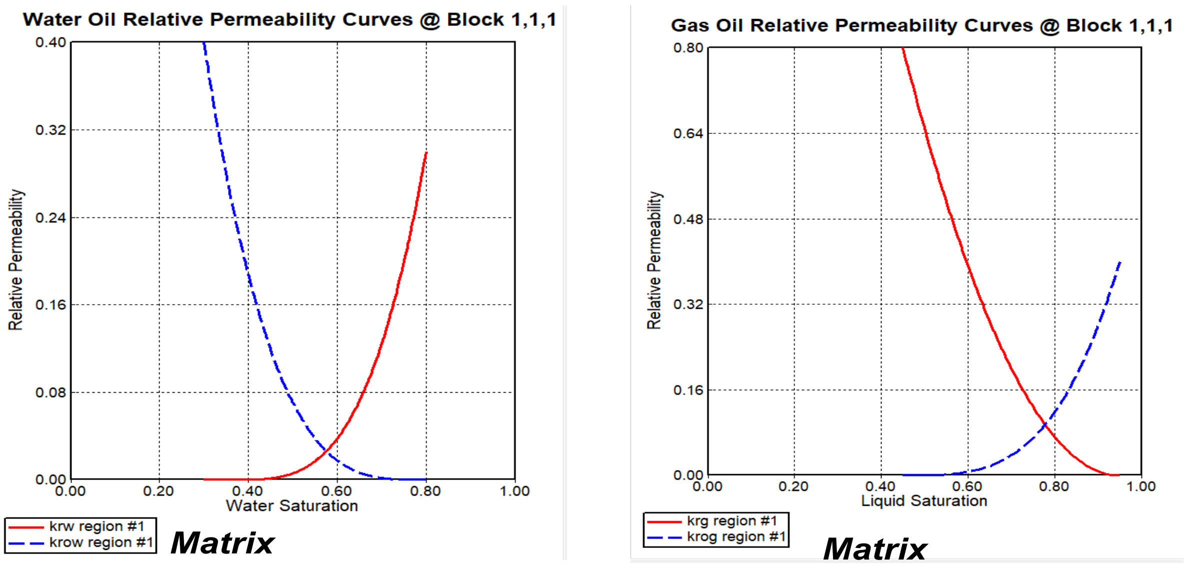


Figure5-3:Matrix relative permeability curves for field case. This figure also displays the three-phase relative permeability ternary diagram for the oil phase for both matrix and fracture.

5.1.3 Fluid model (PVT)

This study applies two gas condensate compositions: the first one is based on (Kenyon, 1987) study and the second one in Chapter 5 is extracted from field report of a tight reservoir in the Middle East. The available lab-report that was used for the gas-condensate fluid analysis contains: (1) compositional analysis, (2) Constant Volume Depletion (CVD) and (3) Constant Composition Expansion (CCE). The fluid presented in this study is a rich condensate gas as per the lab-report with maximum liquid-dropout of 16%, CGR of 102stb/MMscf and C7+ of 5.97%. Reservoir fluid properties are modelled using Schlumberger's PVTi package.

The report outcome is used in the model to quantify recovery as a function of pressure below dewpoint. The PR EOS is used and corrected to model reservoir fluid behavior and characterization. PVT modeling of such reservoir is fundamental due to the impact of phase behavior on well productivity. This study incorporates a nine-components model according the PVT lab-report as shown in Table 5-2 for the field case. The reservoir fluid phase diagram is depicted in Figure 5-4. Lab measured dewpoint pressure is 7365 psi with 134 ^{o}C reservoir temperature.

Table 5-2:Table of reservoir composition
field case

Component	Mol %
N2	2,29
CO2	1,10
H2S	0,00
C1	77,86
C2	6,50
C3	2,91
IC4	0,72
NC4	1,11
IC5	0.47
NC5	0,56
C6	1,01
C7+	5,43
TOTAL	100,00

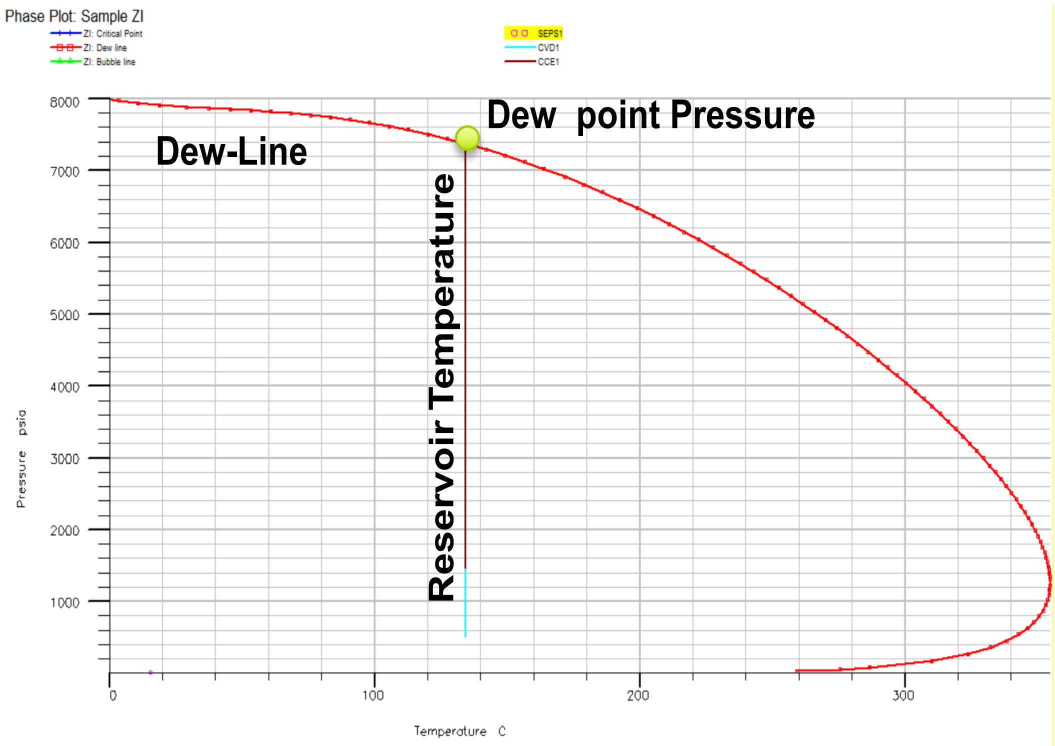


Figure 5-4::Phase diagram of the reservoir fluid for the field case as presented in chapter 5.

5.2 SIMULATION RESULTS

The results presented in this sub-section are an outcome of two vertical stages propped fracture well using compositional reservoir simulation. In this analysis, several simulation runs were executed with a different pattern of rock, fluid and well properties including rock compaction, matrix and relative permeability, reservoir pressure and production rate to match the actual production rates with simulator results. The section below will also demonstrate the sensitivity of the liquid gas ratio under varying conditions.

5.2.1.1 History Matching with Welltest Data Short Term Data (4-Months)

The first case is a representation of first drawdown and buildup period, that drained by a finite conductivity in a vertical fractured well see Figure 5-5.

In this case the objective was to history match welltest. Figure 5-5 and 5-6 depicts the reservoir simulation gird of fracture and matrix, and output results in Figure 5-7. Pressure drop is initially detected around the well-bore and hydraulic fracture.

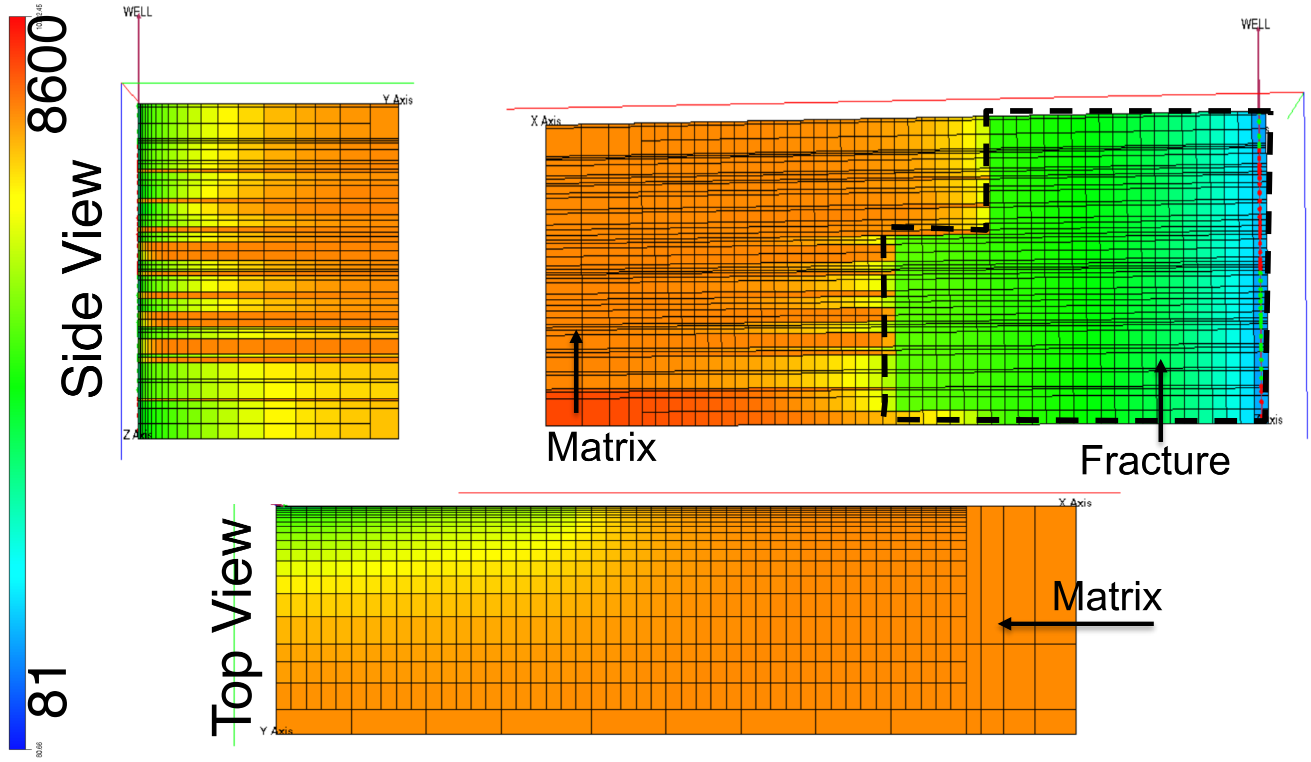


Figure 5-5: Pressure disruption in PSIA of a vertical well with two fracture stages in a tight permeability condensate reservoir. (20 Days of drawdown.)

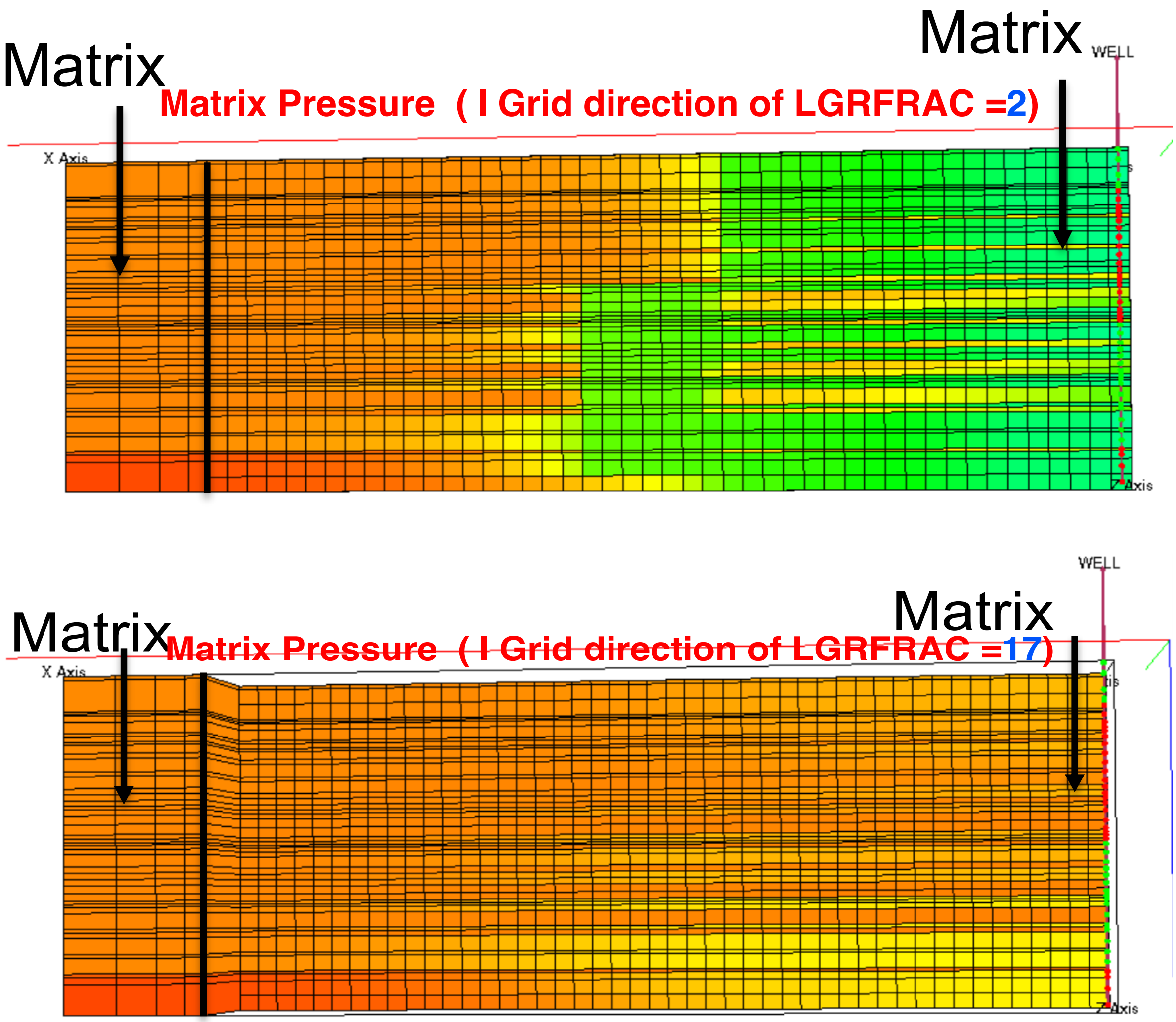


Figure 5-6: Matrix pressure disruption in PSIA of short-term production 2 grid inside fracture plane (I Grid direction of LGRFRAC =2) in top- side and 17 grid inside fracture plane (I Grid direction of LGRFRAC =17) in bottom- side . (20 Days of drawdown.)- Same Scale as Figure (1-1)

During this short-time period the production fluctuation after the fracture job was because of fracture clean-up and changes in pressure flowlines. The model shows that the average pressure dropped below the 7200 Psi dewpoint pressure during this production period.

Through production time condensate will start to build-up near fracture and wellbore region, which leads to a higher oil saturation. Drawdown in the hydraulic fracture increases the condensate saturation buildup along the fracture. The results illustrate the impact of condensate build-up in the production. After accomplishing the first match, simulation run for long term production was applied.

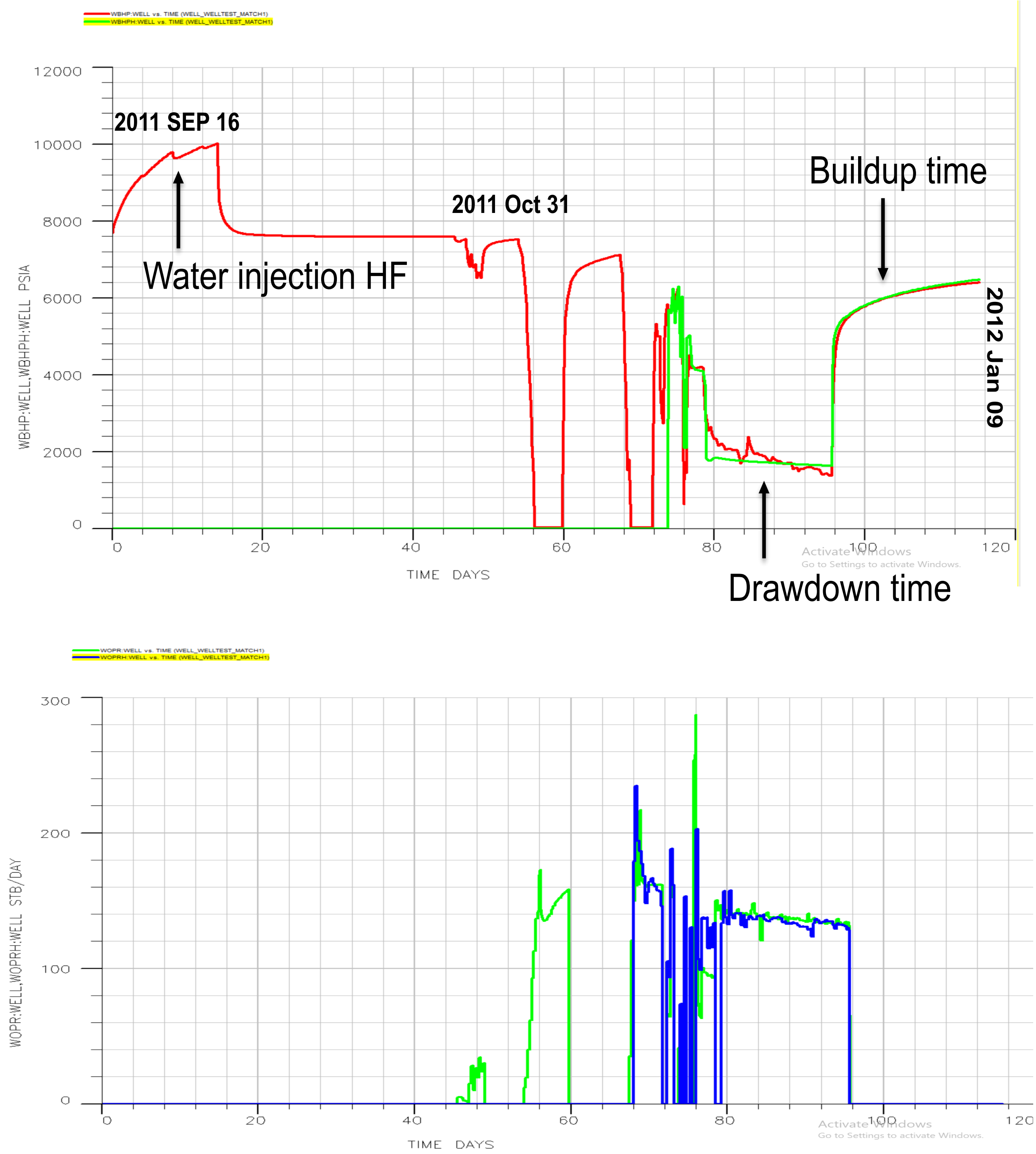
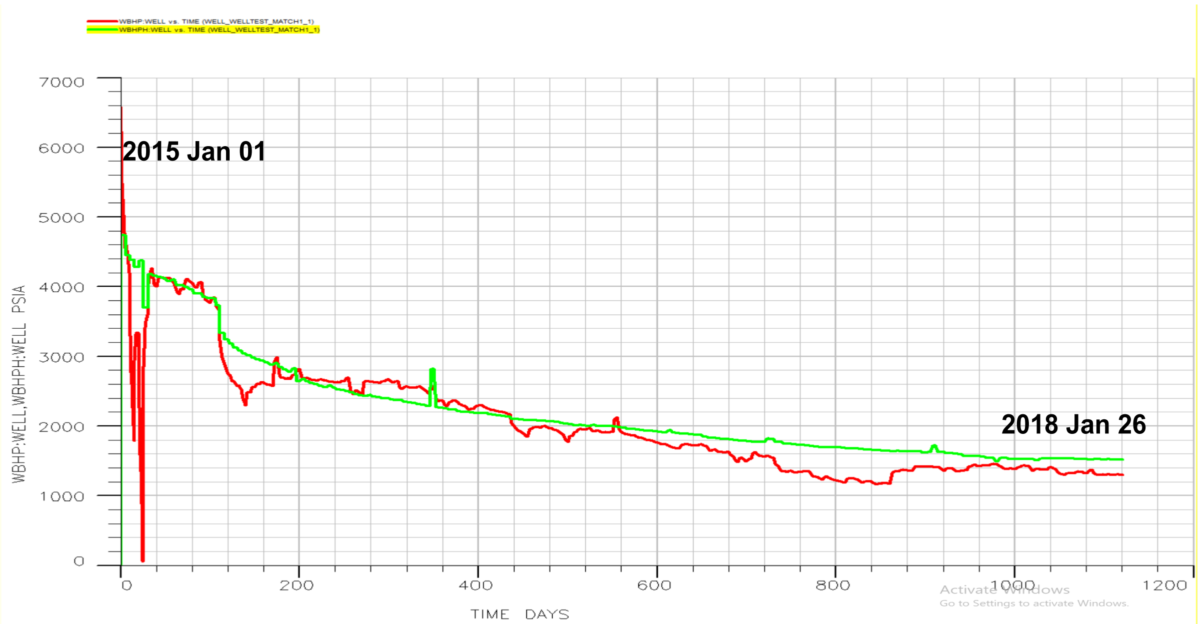


Figure 5-7:Short period History Match of BHP (Top- Green WBHPH and Red WBHP) and condensate production (Bottom- Blue WOPRH and Green WOPR) profiles for Field Case Tight reservoir.

5.2.1.2 Production History Matching with Long Term Data (3-years)

The second case has same properties as in Case 1, except with longer production time see Figure 5-8. The purpose of this case is to history-match the long-term production rates and model condensate build-up as shown in Figure 5-9. A condensate banking can quickly accumulate around well-bore as the WBHP drops below dewpoint. Condensate starts to build-up around the fracture and nearby matrix as a result of pressure decline. This is clearly shown in Figure 5-9 and 5-10, where gas relative permeability (decreases) and oil relative permeability (increases), resulting in a decline of well performance and decrease of heavy components fraction. This decrease in gas relative permeability is a result of liquid build-up, and the reduction becomes even more distinct as WBHP declines. The long-term pressure profile starts below dewpoint along the hydraulic fracture and through the SRV, the build-up extends into the whole SRV enveloping the matrix blocks into a layer of condensate liquid while some free gas is locked in the central zone (see Figure 5-8). The initial condensate drops will start in the close vicinity of well-bore and hydraulic fracture face, where reservoir pressure approach its lowest value as shown in Case 1. With more gas produced, the reservoir pressure will begin to decrease, and condensate bank will slowly grow and expand into the reservoir matrix. This process continues and liquid will build-up and act as blockage to the free flow of gas till condensate reaches the critical saturation point. The low gas permeability on the vicinity of HF at later time steps suggests the condensate build-up as shown in Figure 5-9. Different saturation zones develop around the well-bore showing improved gas mobility due to capillary number effects, and condensate drop-out stabilization.



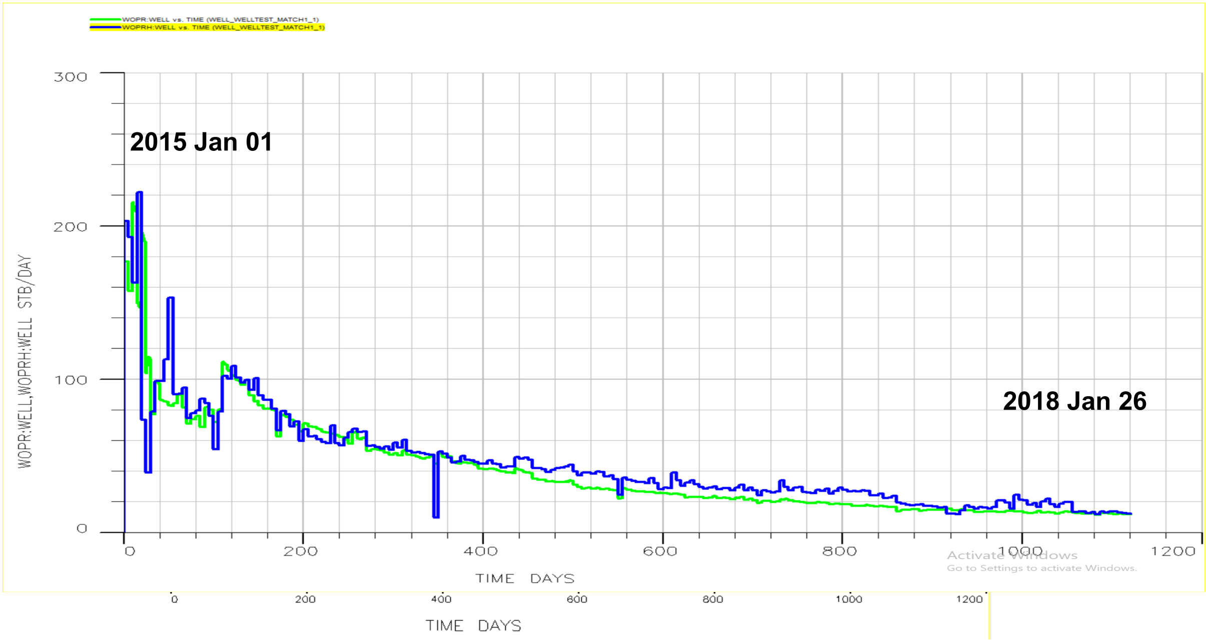


Figure 5-8:Long time History Match of BHP (Top- Black dots WBHPH and Red line WBHP) and condensate production (Bottom- Green dots WOPRH and Blue line WOPR) profiles for Oman Tight reservoir.

The simulation model results and runs clearly demonstrate a reasonable similarity with the actual measured data. It also supports that the condensate will build-up in the fracture and matrix around fracture and illustrate the condensate banking effect on the well productivity as shown in Figure 5-10. Results from the above case study indicate the advantage of long hydraulic fracture through minimizing the condensate build-up behaviour. Hydraulic fracturing of tight gas-condensate wells is undoubtedly an efficient method to improve well productivity. The hydraulic fracture decreases the rate at which condensate build-up through reducing pressure depletion close to the fracture face and well-bore. Furthermore, the created condensate bank size will rely on: (1) fluid characteristic (syntactic vs field case), (2) production rate (low vs high) , (3) duration (short vs long time) and (4) fracture length (short vs long) and (5) reservoir heterogeneity (single layer, multi-layer). Simulation results show that liquid saturation near hydraulic fracture matrix for long term production time is higher than the case of short production time period. Production time effect on condensate bank development after 1200 days of production is clearly reflected on the CGR ratio as shown in Figure 5-10. Condensate banking has a double effect; (1) it decreases the relative gas permeability to matrix-to-fracture and (2) allows heavy compounds to get trapped in the matrix that decreases the CGR at the surface. Figure 5-10 shows the CGR of produced fluid, and it indicates a sharp decline of heavy components production at surface.

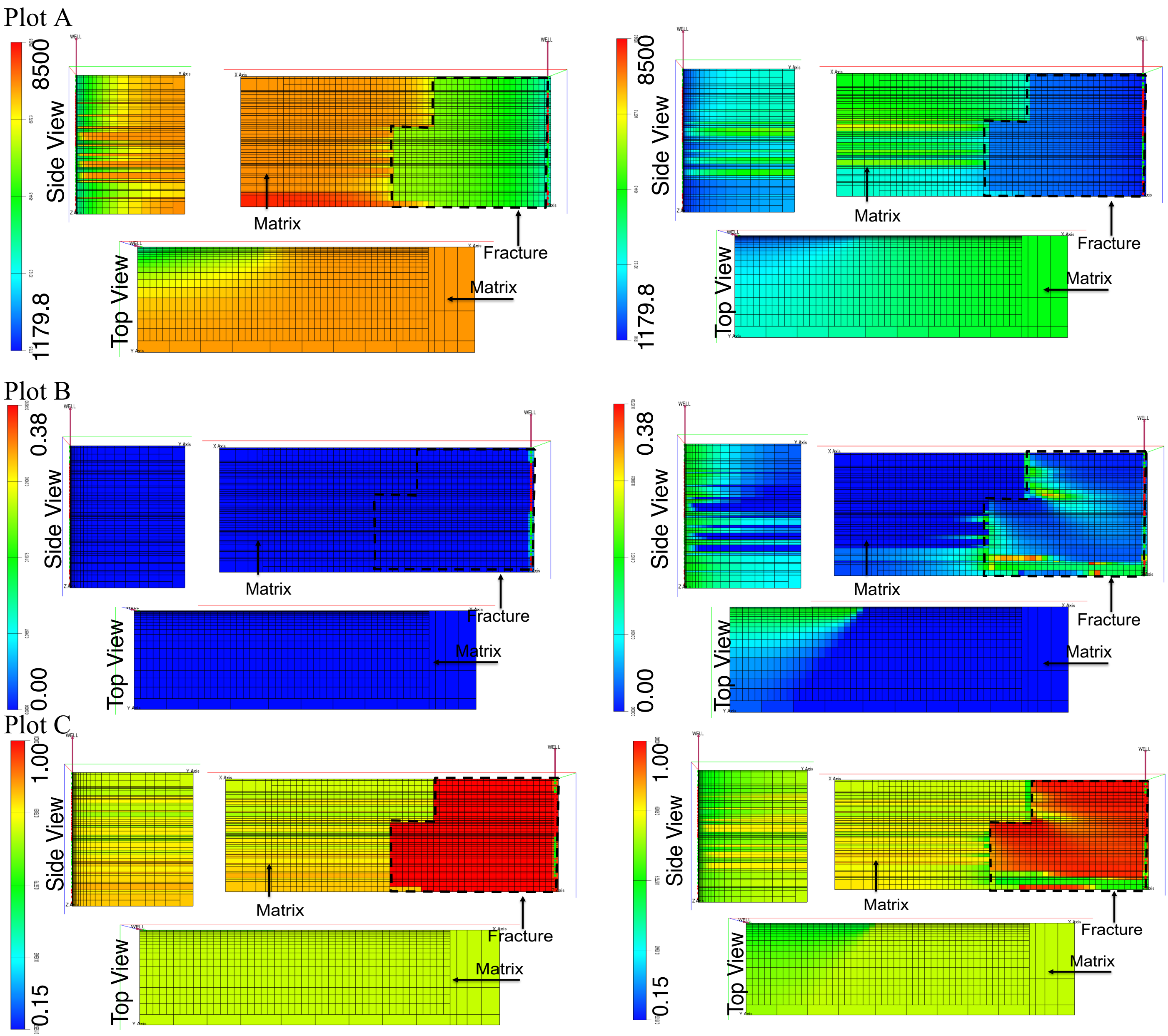


Figure 5-9:Simulation results of hydraulic fracture cross-section shows production time effect on condensate bank development after 1200 days of drawdown (Plot A: Representing Pressure Distribution in PSIA: Top left at the start and Top Right at the end of production) and (Plot B: Representing Oil Saturation Top left at the start and Top Right at the end of production). and (Plot C: Representing Gas Saturation Top left at the start and Top Right at the end of production)

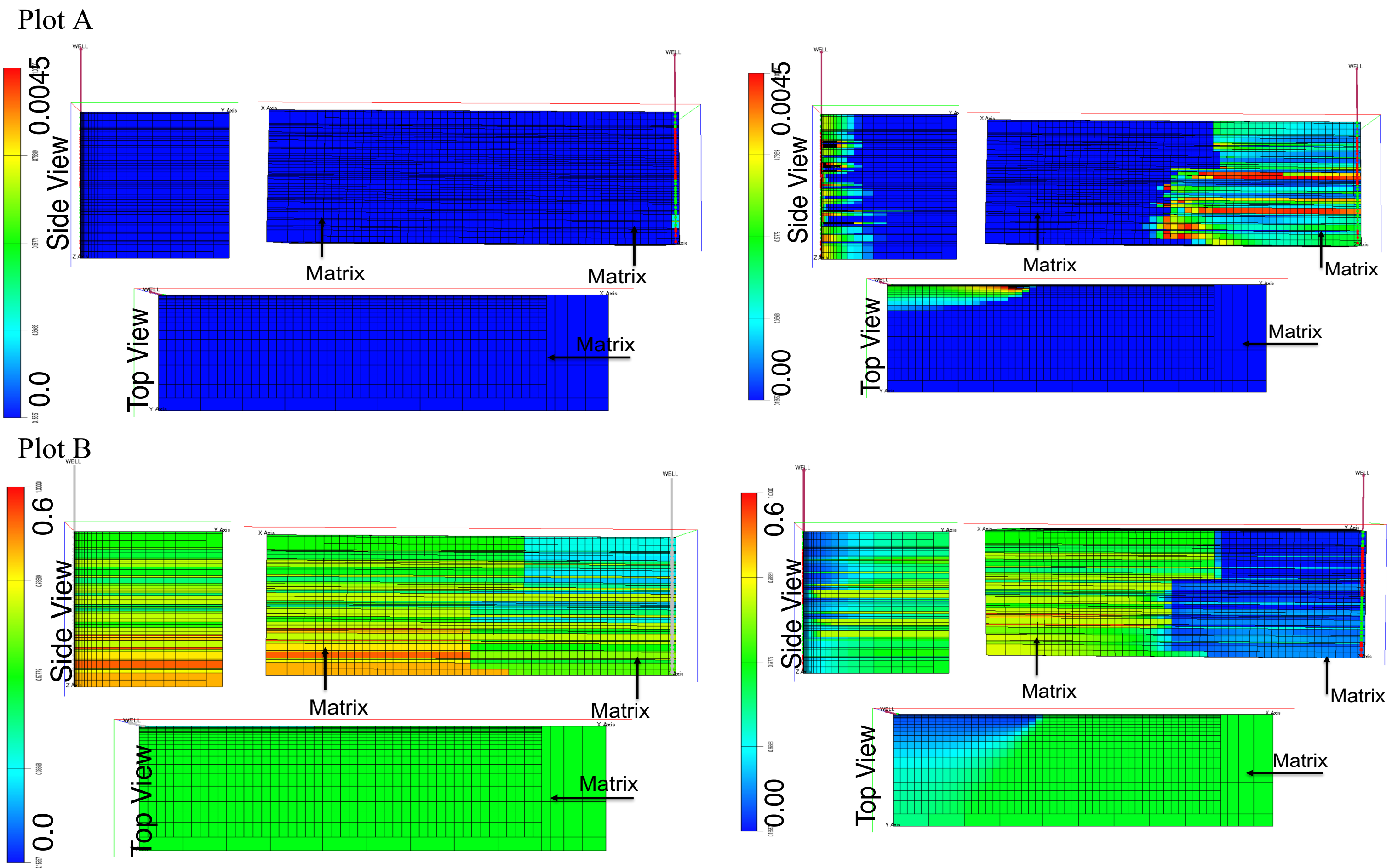


Figure 5-10: Simulation results of matrix cross-section 2 grid inside fracture plane (I Grid direction of LGRFRAC =2) shows production time effect on condensate bank development after 1200 days of drawdown (Plot A: Representing Oil Relative Permeability (KRO): Top left at the start and Top Right at the end of production) and (Plot B: Representing Gas Relative Permeability (KRG): Top left at the start and Top Right at the end of production)

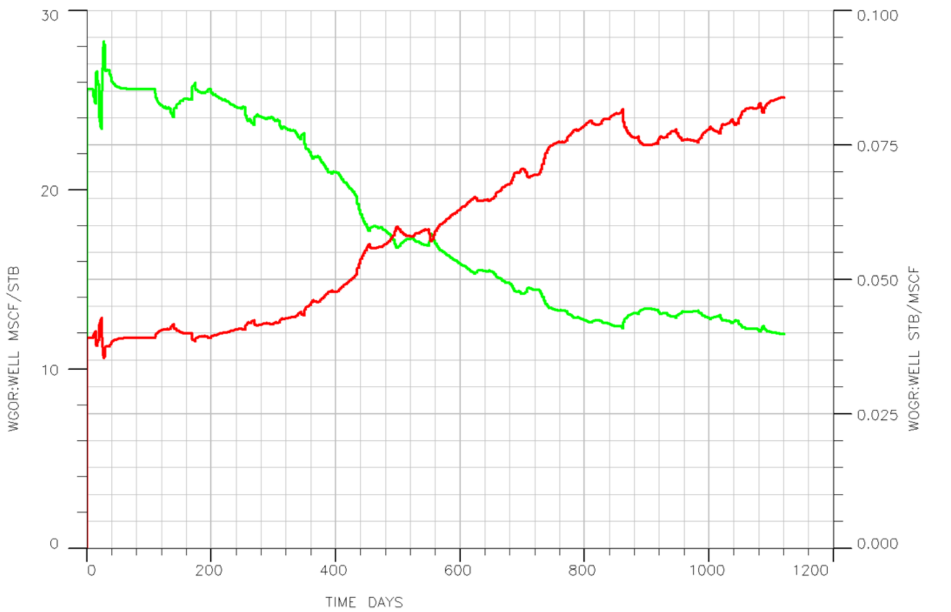


Figure 5-11: Oil Gas Ratio (CGR-Green Line) decrease during production is an indication of condensate banking, which prompts significant decreases in well deliverability and rate. Gas Oil Ratio increases during production (GOR-Red line)

5.3 MODEL VERIFICATION AND HISTROY MATCHING

In the previous chapter a single phase of propped fractured well completed in a single and homogenous reservoir was developed to examine pressure and fluid behaviors of finite conductivity fracture. Several parameters were investigated such as fractured well and non-fractured well, matrix permeability values and production rate.

This chapter focused on a multi-phase propped fractured well with same completion and reservoir parameters as in Chapter 4. Several formation parameter and sensitivity case runs are presented in this chapter to examine the impact of each parameter in condensate buildup. Parameters studied include fractures, relative permeability curve, fluid composition type and matrix permeability. Such parametric study is preformed to examine the effect of low permeability and other factors on condensate banking.

To evaluate the condensate build-up effect and measure the error and consequences of running e100 model for a condensate reservoir (as a rule of thumb industrial approach) a run of 20 years was developed with the same reservoir and completion properties. This approach can give an indication of the banking effect and consequences of using e100 in condensate reservoir as a quick solution. Although, e100 case history matched, it shows considerable error compared to a proper model. Figure 5-12 depicts the cumulative production of gas and the initial gas in place for the condensate case compared to the e100 case where the results display a cumulative production reduction due condensate build-up of 22%. The condensate banking impacts the well performance as gas relative permeability decreases severely leading to lower recovery factor in comparison with the dry gas wells. The conclusion is in rich condensate field, the proper compositional simulation model is needed to have an accurate result.

The results of the study indicate that the fracture conductivity play an important role in condensate build-up. Other factors such as matrix permeability also contribute in causing such build-up. This study provides an accurate, realistic and efficient simulation model of gas condensate flow around hydraulically fractured wells, based on flow physics. The study outcomes show that the further away from the vicinity of the wellbore and hydraulic fracture, the lower the impact of pressure decline on the cell grid. The condensate formation is immobile till the critical saturation is reached.

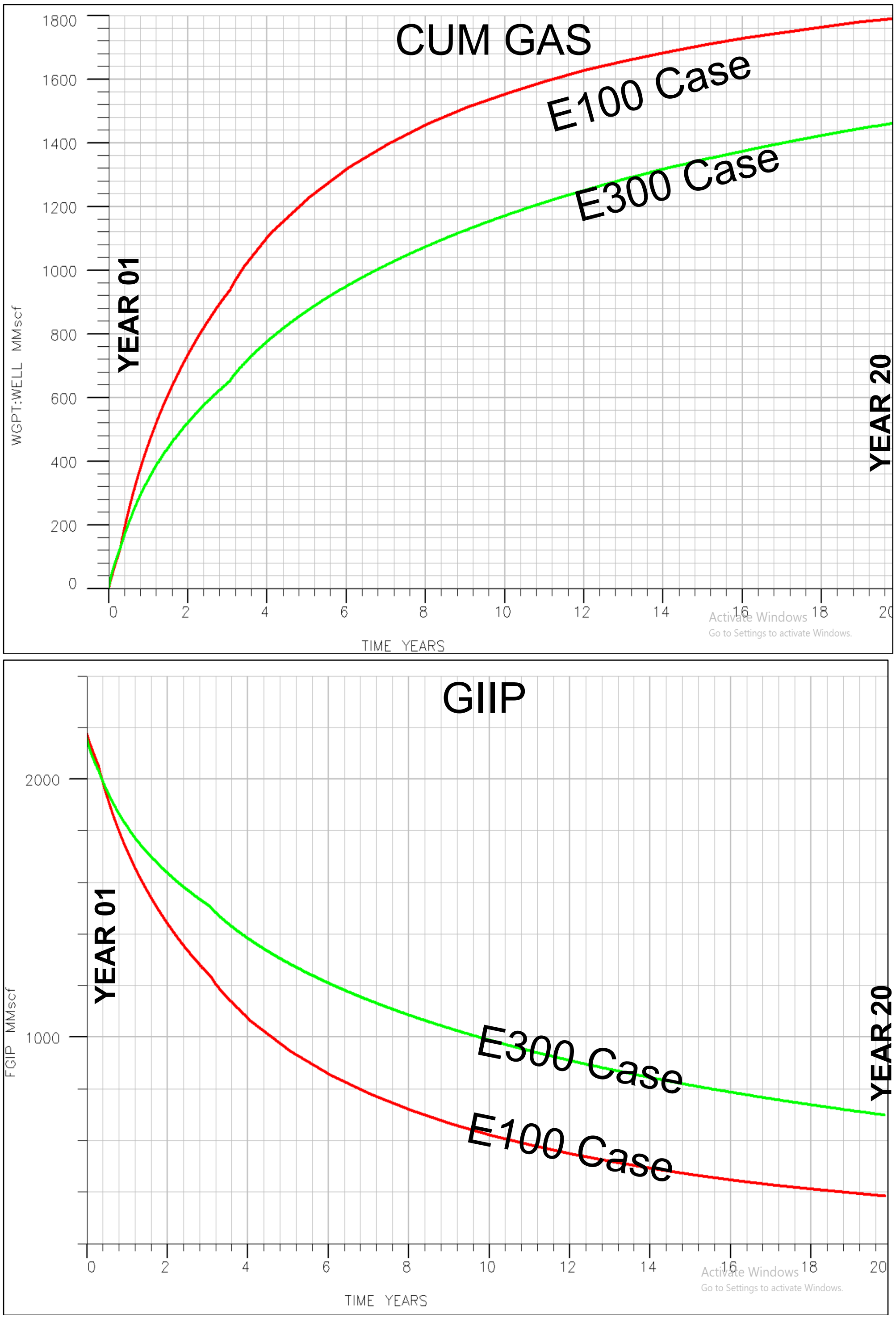


Figure 5-12:The results depict the initial gas in place and cumulative gas profiles of E300 compared to the E100 case over 20-years period.

5.4 CONCLUSIONS AND RECOMMENDATIONS

A new approach to model condensate dropout is discussed and demonstrated, using fracture and reservoir simulators. Actual well-test behaviors were comparable with the predicted behaviors from compositional simulations. Several adequate history matches were obtained by changing various uncertain input parameters.

Results indicate a sharp decline in flow rate when the bottom hole flowing pressure drops below dewpoint level. This decline is due to reduction of relative permeability to gas until it exceeds critical liquid saturation. Condensate build-up in hydraulically fractured tight reservoir occurs both near the wellbore, on the hydraulic fracture face, and deep in the reservoir. Condensate accumulation increases with decreasing pressure. Such condensate blockage hinders the gas flow from inner matrix into the hydraulic fracture, thereby reducing the recovery of hydrocarbons.

The model result shows that coarser grid model configuration has a higher grid block pressure, and this causes a delay of dewpoint pressure arrival. Therefore, the condensate buildup effect in coarse grid will be delayed and this is will cause recovery overestimation. Finally, forecast over 20-years was performed in order to evaluate the impact and difference between the two different modelling approaches. The forecast confirms the negative impact that the condensate dropout has on well productivity. The NPV calculations for tight gas condensate reservoir can be greatly improved when considering compositional simulation numerical model that accounts for the condensate build-up through time.

The significant advantage of this research method is that it is simple to assess the time and location of condensate dropout near well-bore and hydraulic fractures, compared with other methods. The results of this study contribute to a better understanding of hydrocarbon changes in gas condensate reservoirs behavior around well-bore and hydraulic fracture face. The proposed approach to monitor the time and location of condensate build-up can guide engineers to manage and optimize the production of condensate and select suitable condensate optimization techniques to improve recovery such as gas injection.