AMERICAN UNIVERSITY OF BEIRUT

OIL RIM DEVELOPMENT: MECHANISTIC STUDY TOWARDS OPTIMAL EXPLOITATION

by
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A thesis
submitted in partial fulfillment of the requirements
for the degree of Master of Science
to the Department of Mechanical Engineering
of the Maroun Semaan Faculty of Engineering and Architecture
at the American University of Beirut

Beirut, Lebanon
September, 2020

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ACKNOWLEDGMENTS

First of all, I would like to thank my advisor Dr. Kassem Ghorayeb and Co-advisor Dr. Elsa Maalouf for their continuous guidance and advisory throughout my thesis work. I would like to thank Dr. Nisreene Ghaddar and Dr. George Saad for being active members of my thesis committee.

Moreover, I would like to thank the Mastercard foundation at AUB for awarding me the full scholarship to pursue my graduate studies at AUB. Special thanks to Mrs. Maha Haider, the program director, and Ms. Patil Yessayan for their endless support and motivation.

Finally, I would like to show deep gratitude and appreciation to my family and friends for their continuous support and motivation throughout my years at AUB.

ABSTRACT
OF THE THESIS OF

Kassem Alokla for Master of Science
Major: Energy Studies

Title: Oil Rim Development – Mechanistic Study towards Optimal Exploitation

Oil rims are categorized among marginal reservoirs characterized by challenging drive systems, unfavorable water and gas coning issues, and relatively high cost of development. Therefore, understanding the fluids dynamics and managing reservoir uncertainty are vital in such reservoirs. This paper presents the results of a comprehensive and systematic mechanistic study of an oil rim reservoir to determine the various factors that improve the oil recovery factor. The study includes the optimization of development strategies and the implementation of mitigation plans to reduce coning for a reservoir undergoing severe pressure drawdown.

The reservoir has an oil thickness of 50 ft and is examined through four depletion scenarios. These scenarios are as follows: (1) the production of oil followed by gas, (2) the production of gas followed by oil, (3) the concurrent production of oil and gas, and (4) the production of gas only. A sensitivity analysis is performed on the pressure depletion values, pressure maintenance strategies, gas cap size, reservoir fluid type, reservoir heterogeneity, well orientation, and completion methods using Eclipse composition simulator.

The development strategy applied limits unfavorable coning issues. Therefore improving the recovery factor from 9.8 % when producing the oil rim using vertical wells, to 30% when horizontal wells with smart completions. Results of the compositional simulation study show that the optimal development strategy (with the highest oil recovery factor of 45%) is the concurrent development of oil and gas by applying pressure maintenance using water injection at both the flank of the oil-water contact and the gas-oil contact. Moreover, the models show that using horizontal wells with smart completions is instrumental in reaching optimal recovery factors (above 30%), maintaining the reservoir pressure, and minimizing the cumulative water production, which enhances the economics of oil rim reservoirs, especially in the current volatile and low oil price era.

To the best of our knowledge, this study is the first comprehensive attempt to thoroughly investigate oil rim reservoirs and identify opportunities to optimize their performance under different scenarios accounting for pertinent reservoir uncertainties and potential complex depletion history. The results presented in this paper will form clear guidelines for understanding and optimizing numerous oil rim reservoirs at different stages of maturity and development.

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ABBREVIATIONS

GOC	Gas Oil Contact
OWC	Oil Water Contact
GC	Gas Cap
K	Permeability
WI	Water Injection
GI	Gas Injection
CoDev	Co-Development
Psat	Saturation Pressure
Pres	Reservoir Pressure
Sw	Water Saturation
So	Oil Saturation
Sg	Gas Saturation
GOR	Gas Oil Ratio
Sor	Residual Oil Saturation
Soi	Initial Oil Saturation
Swirr	Irreducible Water Saturation
Swcr	Critical Water Saturation
OOIP	Original Oil In Place
DOZ	Displaced Oil Zone
TZ	Transition Zone
CTZ	Capillary Transition Zone
GI/GP	Gas Injection Gas Production Ratio
ICD	Inflow Control Device
ICV	Inflow Control Valve
WBT	Water Breakthrough Time
PLT	Production Logging Tool
EUR	Expected Ultimate Recovery
MSW	Multi Segmented Well
RF	Recovery Factor
Pc	Capillary Pressure
Kr	Relative Permeability

CHAPTER 1

INTRODUCTION

1.1 Background

Oil rims refer to thin oil columns that are interlayered between two systems: a gas cap at the top and an aquifer at the bottom. Oil rim reservoirs may have a complex structure that includes faults and flow boundaries. Oil rims are found in many fields in the world and are defined as “the oil part of a gas reservoir that is less than the gas part irrespectively of its volume proportion” Fedorov, Samolovov, and Polkovnikov (2018). Oil rims occur usually when gas-oil or gas-oil-condensate reservoirs are present and they may have a ‘pancake’ or a ‘doughnut’ structure and thicknesses that range between 30 ft and 90 ft Masoudi, Karkooti, Othman, and Darman (2011). Oil production from oil rims has always been a challenge because they have a limited thickness and require complicated production mechanisms. Until this day, there is no reliable technique to manage and develop oil rim reservoirs in an optimum and cost-effective way. That is why reservoir simulation is used to develop oil rim reservoirs and to maximize the recovery efficiency of the fluids in place at a minimal cost.

The main obstacle that hinders the commercial exploitation of oil rim reservoirs is the coning of the unwanted fluids i.e. water and gas that work on retarding the flow of oil through the production system and thus increasing development costs Lawal, Wells, and Adenuga (2010).

Peter, Onyekonwu, and C. E (2019) showed that a wide range of recovery factors varying from 3% to 40% are achieved from different oil rim projects all over the world.

However, recovery factors depend on reservoir fluids, saturation, the initial pressure of the reservoir, and the production techniques implemented (i.e., development of oil alone or co-development of oil and gas).

The conventional method of developing oil rims is to produce the oil first and then apply a gas cap blowdown to produce gas resources Razak, Chan, and Darman (2010).

Objectives

The objective of this work is to perform a comprehensive and systematic mechanistic study for an oil rim reservoir in order to investigate the various factors impacting its production and injection performance, especially when undergoing severe pressure drawdown. Various development scenarios of oil rim reservoirs are reported and analyzed.

1.2 Significance of Proposed Research Work

This work highlights the factors that impact the oil recovery factor of the oil rim reservoirs. The best development strategy is identified allowing future users to initiate their modeling with a robust development strategy and optimize production.

1.3 Scope of Work

A synthetic reservoir model is built on Schlumberger's ECLIPSE Compositional and Petrel software to simulate the recovery factor and the performance of various development scenarios. The parameters varied in the modeling are SCAL and PVT properties, gas cap size, the order of depletion, pressure maintenance type and timing, well and completion type, and impact of heterogeneity. The conclusions obtained from this modeling apply to the chosen synthetic reservoir and are valid for reservoirs that have similar rock and fluid properties.

CHAPTER 2

LITERATURE REVIEW

2.1 General Overview

The following section will demonstrate the summarized approaches from the literature for the understanding and development of oil rim reservoirs:

Masoudi, Karkooti, and Othman (2013) summarized a robust workflow and guideline to oil rim reservoirs in terms of reservoir description and dynamics and the use of the existing techniques and strategies to better optimize production from such reservoirs in a cost-effective manner. The authors conclude that reliable modeling of the capillary transition zone and mobile water and oil saturation are crucial for recovery assessment and optimization.

The primary screening tool to understand the relation of the existing fluids and to assess the feasibility of the oil rim development project is to evaluate the gas cap to oil volume ratio (M factor) and the oil rim thickness Olamigoke and Peacock (2009). Olamigoke & Peacock (2009) came up with a particular screening tool that is shown in Figure 1.

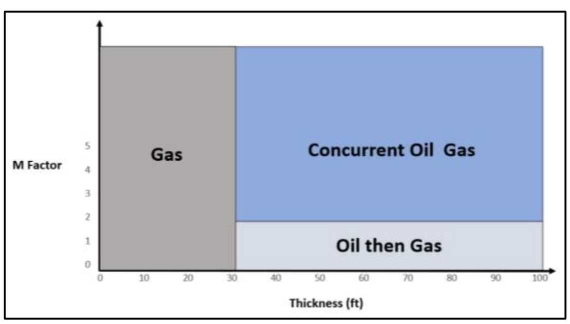


Figure 1.Oil Rim Production and Depletion Strategy Screening Tool based on the rim thickness and M factor

For an oil column thickness less than 30 ft, only gas should be produced. When the oil column thickness becomes larger than 30 ft, and the M factor is less than the 2, sequential development is considered where oil is produced first and then gas. When the oil column thickness is larger than 30 ft, and the M factor is larger than 2, a concurrent production of oil and gas with controlled rates is considered.

Olabode, Ikenna, Ojo, Oguntade, and Bamigboye (2018) carried a simulation study for an oil rim reservoir in the Niger delta to investigate the effect of well types, production schemes, and production rates on oil recovery. The results revealed that applying the concurrent oil and gas development yields the best oil recovery compared to other techniques, especially for horizontal wells. Ogbuagu et al. (2017) showed that in the Okan field, offshore Niger delta, thin and ultra-thin oil rim reservoir could be successfully developed by applying the right technology such as horizontal wells, intelligent completion, and planning strategies.

Onwukwe, Obah, and Chukwu (2012) established a first pass assessment for the development of oil rim reservoirs that are expected to suffer from water and/or gas coning during production. The model's results estimated the critical rate and the optimum horizontal well placement from the gas-oil contact (GOC). To identify the optimum well type to be used for thin oil rims with large gas cap and strong aquifers, a simulation study was carried for the GISO oil rim reservoir, and it was found that horizontal wells should be used and that the recovery increases with lateral length Ogiriki, Imonike, Ogolo, and Onyekonwu (2018). R. Recham and M. Bencherif (2004) demonstrated the benefits gained by using horizontal wells in the Hassi R'mel oil rim reservoir when severe water cut and pressure decline issues were encountered.

In an attempt to study the best development techniques for oil rim reservoirs, Chan, Kifli, and Darman (2011) found that periphery and fencing water injection at WOC and GOC, respectively, can improve the lateral and area sweep to augment vertical sweep by bottom water drive.

Uwaga and Lawal (2006) investigated the feasibility of serial production of the gas cap with the continuous production of oil. They found that swing gas production gave the best economic results and had a negligible negative impact on the recovery.

The small thickness of oil rims causes the hydrocarbon column of oil rims to be located in the capillary transition zone, as shown in Figure 2. Oil water contact (OWC) is the surface that separates the oil zone from the underlying aquifer, and it is usually determined from well-testing data. Up to the OWC, the water saturation (Sw) is 100%. Moving above the OWC, the transition zone begins where hydrocarbons appear, and Sw decreases up to the irreducible water saturation (Swirr) above which the displaced zone begins. The transition thickness is usually low in oil rim reservoirs, as shown in Figure 3.

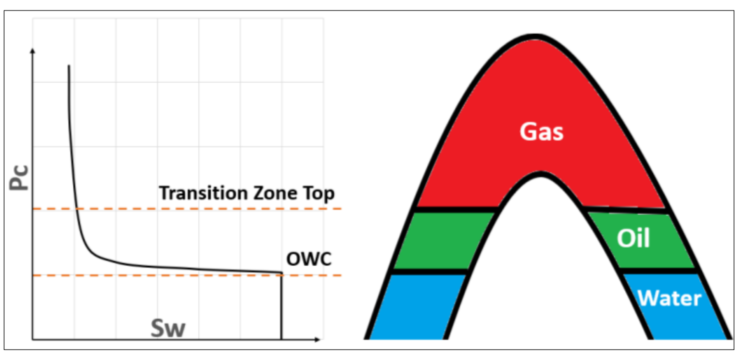


Figure 2.Schematic of an oil rim reservoir structure. The graph shows the variation of capillary pressure (Pc) vs. water saturation (Sw), Masoudi et al. (2011)

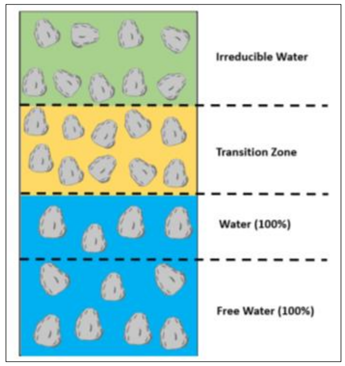


Figure 3.Illustration of the capillary transition zone in a porous media

Improving reservoir management involves locating the fluid contacts and optimizing the placement of the wells by choosing the best well completion techniques that prevent gas and water coning effects, which could severely hinder oil recovery.

Besides viscous forces that are dictated by the hydrocarbon nature, oil recovery depends on two important driving forces that are the gas cap expansion from the top and water encroachment from the bottom. Maintaining the balance of these forces may keep the oil rim fixed in place for many years with a minimum pressure drop, which yields a higher recovery factor Chan, Masoudi, Karkooti, Shaedin, and Othman (2014) as seen in Figure 3. Figures 4 and 5 illustrate the force balance in a gas-oil-water system and the importance of tracking the GOC and OWC. (Figure 5b) is the optimum as the balance is achieved between gas injection, and thus the completion (perforation) will be inserted in the oil zone. When aquifer influx is higher than gas influx, the GOC will recede (Figure 5a). On the contrary, when gas influx is higher than the water influx, the GOC will expand (Figure 5c). Obviously, the closer the completion to the GOC, the sooner the production of the free gas due to gas coning, which will lead to a faster pressure drawdown, and less effective driving and recovery of the oil. The same applies when the completion is located near the OWC; water will encroach, eventually affecting the oil recovery drastically Ogbuagu et al. (2017).

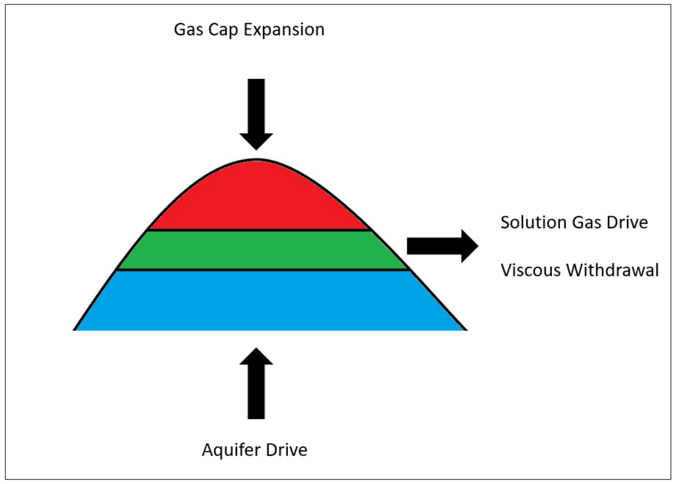


Figure 4.Sketch of an oil rim and the driving forces. Driving force balance in an oil rim reservoir is essential Chan et al. (2014)

When the aquifer drive is not adequate due to the weak aquifer support, water and gas injection should be implemented to keep the force balance and thus enhance oil production Chan et al. (2011).

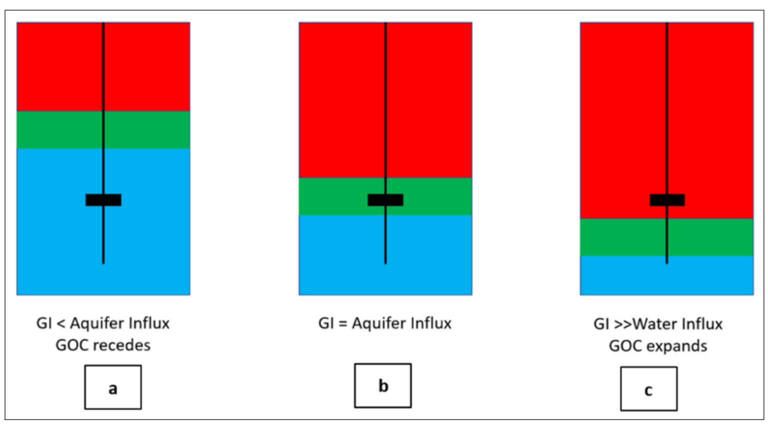


Figure 5.Schematic of force balance in an oil rim reservoir in terms of Gas Influx (GI) and Water Influx (WI)

According to the results of numerical simulations done before, no optimum or uniform development plan can be used for all oil rim reservoirs; thus it changes from one reservoir to another depending on the prevailing conditions and properties. Factors that are considered when choosing the development mechanism include the size of the gas cap, thickness of oil rim, strength of the water aquifer, and other fluid properties that will be discussed further.

2.2 Challenges in Oil Rim Development

As mentioned previously, the development of oil rims encounters particular challenges that must be taken into consideration in order to enhance productivity. The challenges became adverse for reservoirs characterized by high permeability and strong aquifer support Balogun, Adepoju, Ogbuli, and Chukwunweike (2015) The technical difficulties mainly include water and gas coning, complicated production, unusual drive mechanisms, oil smearing into the gas cap during production, low recovery factor, critical completion design, and generally a higher development cost than other conventional resources Masoudi et al. (2013).

Water and gas coning are two critical problems encountered while producing oil from reservoirs that are overlying an aquifer and underlying a gas cap. Water and gas coning in oil reservoirs causes serious hindrance to oil production optimization since the unwanted fluids try to replace the oil in the production stream, and thus decrease the ultimate oil recovery. The coning of water or gas into the producers is caused by pressure gradients established around the wellbore due to the produced fluids from the well. As a result, the OWC and GOC will move upward and downward, respectively. This will increase the gas-oil ratio (GOR) in the reservoir, the water cut, and gas breakthrough occurs, which prevents the production of heavier oils. An inherent problem that is associated with the production of oil from oil rim reservoirs is an early production of water as well as gas cusping. Early water production from an oil rim reservoir causes corrosion of tubular, scale/salt deposition, gas hydrate formation, disposal problems of the water itself, and high cost of lifting the water Sarkodie, Afari, and Aggrey (2014). Both water and gas coning become more critical in an oil rim reservoir due to the limited oil thickness, as seen in Figure 6, especially when dealing with vertical wells.

Besides the subsurface adverse effects of coning, water and gas will pose surface challenges with production due to the facility constraints and the additional time and cost needed to handle the produced water and gas.

Water production during the life of a well is inevitable, but early and massive production of the water can be managed. Identifying the most cost-effective method of managing water production and gas cusping is essential for the production engineer who aims is to maximize oil production by devising ways of delaying and/or minimizing water and gas production Sarkodie et al. (2014).

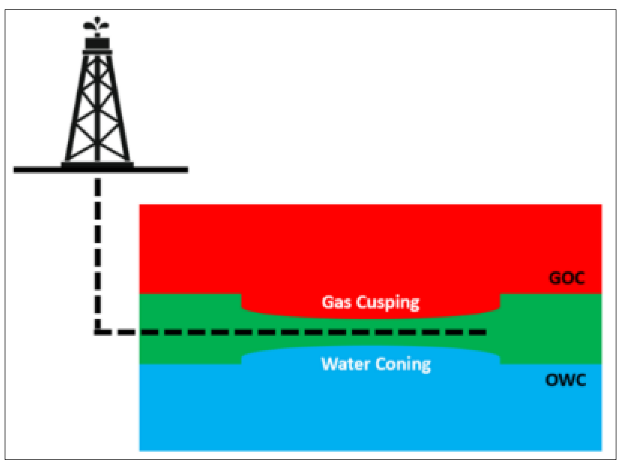


Figure 6.Horizontal well production from an oil zone in a reservoir encountering water and gas coning

2.3 Factors Impacting Oil Rims Development

Oil rims development is affected by several factors that can be summarized as follows Kolbikov (2012):

- Geological Factors: include the type of geological structure and oil rim, rock permeability and heterogeneity, oil and water saturations, viscosity, capillary pressure, mobility ratio, aquifer, oil-saturated thickness, gas to oil porous volume ratio
- Technological factors: the type of well completion determines oil rim development efficiency and the economics of the project. Well spacing is another important factor that plays a role in enhancing recovery
- Economic factors: mainly depend on oil prices and the availability of gas markets
- Operational factors: handling of produced water, coning issues, fluid production, and offtake rates

2.4 Mitigation of Coning Issues

During the well's life, water production is Water production during the life of a well is inevitable, but early and massive production of the water can be managed. Identifying the most cost-effective method of managing water coning and gas cusping is essential for the production engineer who aims is to maximize oil production by finding ways of delaying and/or minimizing water and gas production Sarkodie et al. (2014).

Historically, oil rims development depended on vertical or low angle wells. Due to the limited penetration into the oil column and the immense pressure drop encountered, a high GOR or water cut was faced, resulting in lower productivity and a decrease in the life of wells Chan et al. (2014).

An alternative option is to drill horizontal wells (i.e., well inclination above 80 degrees), which increases the lateral contact with the oil rim, Figure 7. The productivity of horizontal wells is up to five times larger than that of vertical wells Masoudi et al. (2013). Opposite to vertical wells that concentrate all the pressure drop at the bottom of the well like a pinpoint, horizontal wells penetrate the formation laterally and distribute the pressure drawdown over the whole length of the wellbore Ibuchukwu (2018).

In the 90s, several horizontal wells were drilled to solve problems encountered in oil reservoirs. Drilling horizontal wells to produce from offshore oil rims yielded much higher recovery. The first horizontal well HRZ-01 in Algeria was drilled in 1991 in the Hassi R'Mel to produce from an oil rim R. Recham and D. Bencherif (2004).

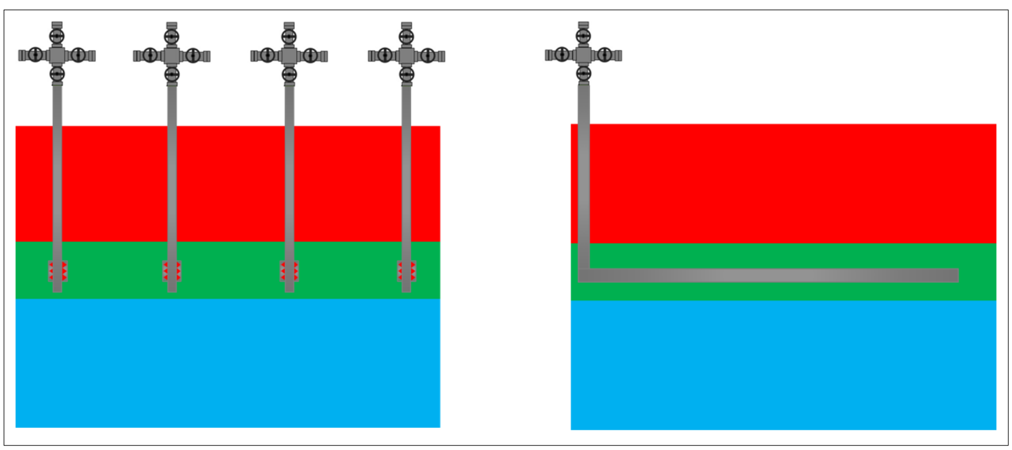


Figure 7.Vertical wells vs horizontal well

Horizontal wells may additionally enhance production by contact with naturally occurring fractures or by connecting disconnected drainage areas Novy (1995). Horizontal wells accomplish these production enhancements through a drainage pattern that deviates from that of a vertical well. The flow geometry in the near-wellbore region is typically radial but transitions to a linear flow pattern farther away from the well. Wells that are horizontally oriented are strongly influenced by the anisotropy of horizontal to vertical permeability, forcing analytical models of flow to consider these differences from conventional vertical wells (Economides 2013; Joshi 2003).

2.4.1 Reverse and Inverse Coning

Reverse Coning is a reservoir management strategy used for reservoirs with small gas caps and active aquifers, Figure 8. The horizontal well is located in the gas cap, and a gas cap blowdown is applied. When the gas is produced, the aquifer supports the pressure drop by expanding and pushing the oil into the gas cap Vo, Sukerim, Widjaja, Partono, and Clark (1999). However, some oil will not be displaced and remains as residual oil; hence analysis needs to be performed to assess and account for the lost oil.

Inverse Coning is another reservoir management technique used by placing the horizontal well in the water aquifer near to the OWC, Figure 9. When the well starts producing water, the oil will down-cones the water zone into the completion Haug, Ferguson, and Kydland (1991).

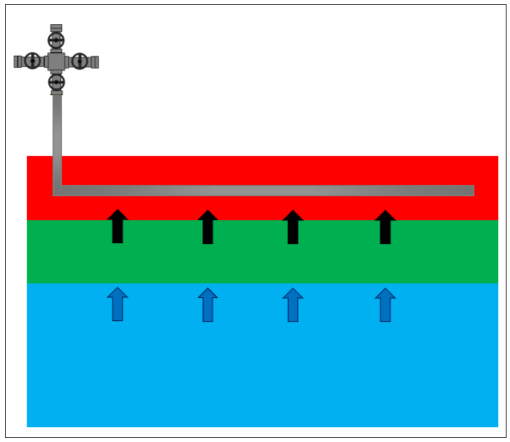


Figure 8.Reverse Coning Phenomenon

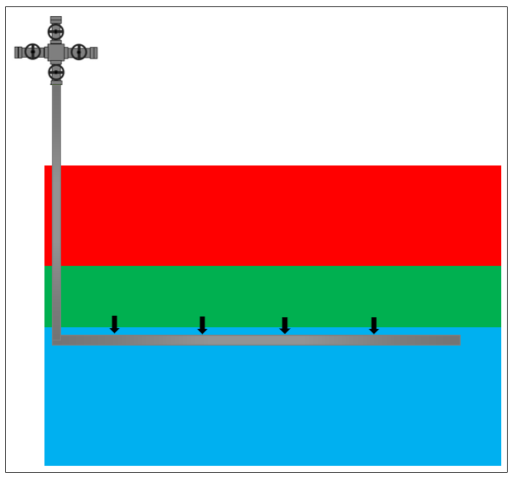


Figure 9.Inverse Coning Phenomenon

2.4.2 Smart Completions

Horizontal wells are usually equipped with smart completions that tend to create additional pressure drop to balance production flux and to retard the production of undesired fluids namely water and gas. In general, there are two available technologies for smart completions: control devices and control valves.

2.4.2.1 Control Devices (ICD's):

ICDs are passive as there is not much intervention from us once installed, which applies additional pressure drop to restrict high mobility fluids and hence cut back water cut and or GOR. The ICDs (Inflow Control Devices) that are fixed permanently with the horizontal well and work to enhance the sweep efficiency by controlling the influx of fluids into the well passively due to the added restriction to each completion joint. Figure 10 shows the combined effect of the Coning and Heel-toe effect in homogeneous reservoir and mitigation using ICD.

The first use of flow control devices was on the Troll field in the North Sea that is characterized by a thin oil rim overlain by a huge gas cap. Schlumberger's version of the ICD nozzle is called the FlowReg while other service companies have their own versions of the ICD. The ICD-completion design is a complex process that requires the selection of the ICD type, restriction size, and annular flow isolation. In Figure 11, a completion joint is equipped with two inflow control devices.

Despite the ability to balance the well inflow profile and achieving a uniform sweep efficiency, no optimal well design after unwanted fluids breakthrough is achieved by the ICVs.

The Autonomous Inflow Control Device (AICD), which was introduced later on, works to restrict the flow of unwanted phases (gas and water). Using the autonomous inflow control device (AICD) which is a new generation of ICD developed by Statoil company has the same function as ICD but also works on delivering a variable restriction to the flow of fluids in response to their properties, mainly the viscosity. When water or gas flows through the device, it will be restricted more than oil due to its higher viscosity. AICD is usually installed at the lower of the completion and is run as a part of the completion string Al-Khelaiwi, Birchenko, Konopczynski, and Davies (2008).

For example, in one of the offshore oil rim reservoirs in Malaysia, forty-five horizontal wells were drilled and accompanied by ICD completion. The water breakthrough that was expected was delayed Chan et al. (2014). In Sabah offshore oil rim reservoir, horizontal wells were drilled with ICV completed in the gas cap. This technology allows in-situ gas lifting operation while producing oil then changes to the gas-cap blowdown option to maximize hydrocarbon recovery. Extended horizontal wellbore with ICD design has also been used for another oil rim reservoir in Malaysia, and it was completed with dual-strings to optimize drawdown pressure distribution along the wellbore, improve oil drainage, and hence oil recovery Chan et al. (2014).

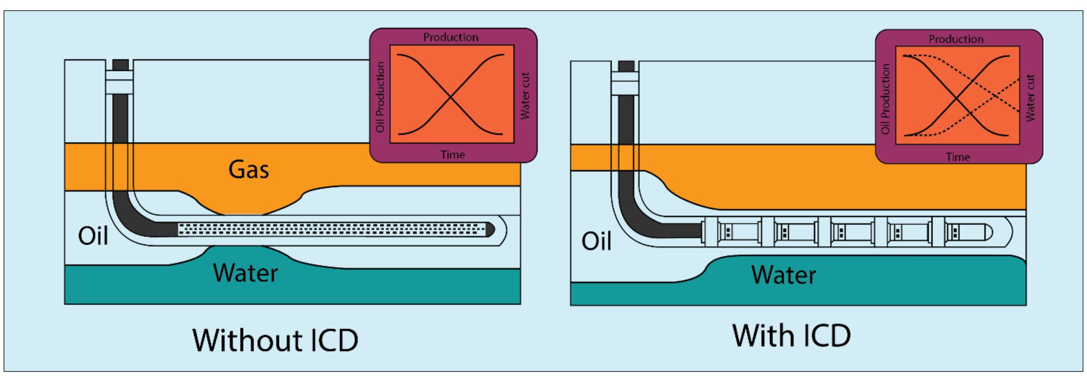


Figure 10. The combined effect of Coning and Heel-toe effect in homogeneous reservoir and mitigation using ICD

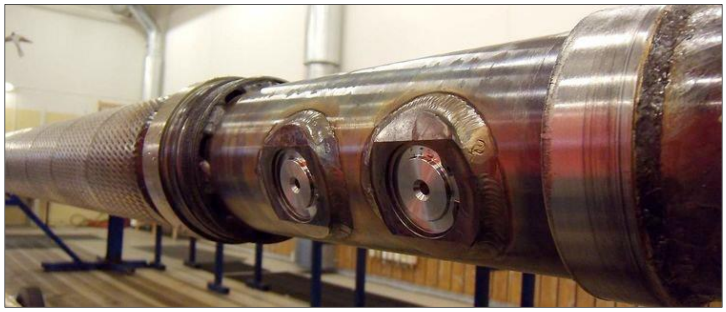


Figure 11. Completion joint equipped with two inflow control devices

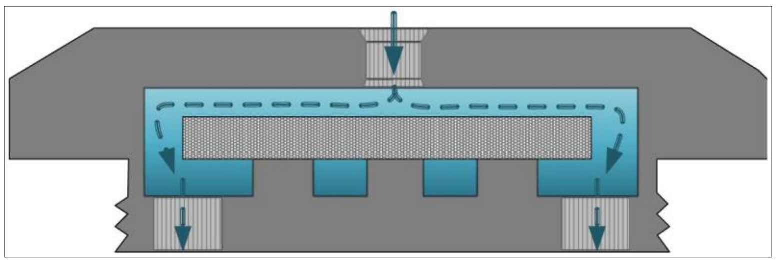


Figure 12. AICD flow path

The AICD operation is based on the Bernoulli equation that states that along the streamlined path the sum of the dynamic pressure, static pressure and frictional losses is constant. It is based on the following equation:

$$\boxed{P_1 + \frac{1}{2}\rho {V_1}^2 = P_2 + \frac{1}{2}\rho {V_2}^2 + \Delta P_{friction\ loss}}$$

Figure 13. Bernoulli equation

Where ΔP is the friction pressure loss, 0.5 ρ v is the dynamic pressure and P1 is the static pressure.

The Jasmine Field, JS-06, in the Gulf of Thailand, used horizontal wells of 2000 ft lateral length in the oil column having water from the bottom and oil from the top. Since the focus was on producing the gas, the AICD flow loop testing, performance modeling, completion design, and selection for this well was focused on gas production. Postimplementation and production, gas production has been controlled very well compared to the base case conventional completion. The gas-oil ratio (GOR) observed from nearby wells was within the standard production range, which increased oil recovery from the JS-06 well. The AICD implementation in the Jasmine field has been a significant success for Mubadala Petroleum, with cumulative production and field life both considerably in excess of original expectations Triandi, Chigbo, Khunmek, and Ismail (2018).

The AICD well completion was also successfully used in the East Belumut field, Malaysia Mohd Ismail et al. (2018). Because oil rim reservoirs are very abundant in the Niger Delta, intelligent wells were extensively used given their economic benefit and the ability to access oil rims for work-over during hydrocarbon exploitation Denney (2010).

The intelligent well technology is a highly needed ingredient for reservoir optimization, increasing recoverable reserves, enhancing oil recovery, and reducing water cut. Yet, it is evident that smart completion costs more; that is why a decision should be made before implementing the intelligent completions for horizontal wells to justify its benefits in terms of production and economics.

Even though horizontal wells, especially when equipped with smart completions, are more efficient than vertical wells for thin oil rim reservoirs, they are associated with very high costs; hence, an accurate geological interpretation and sophisticated equipment are required for the placement process especially in low thickness formations like oil rims. In fact, a vital issue to consider when considering horizontal wells is the reservoir heterogeneity. Heterogeneity can lead to uneven production and early water and gas breakthrough from some parts of the wellbore.

2.4.2.2 Control Valves (ICV's):

ICVs are controlled from the surface and used to choke down different compartments. The Autonomous Inflow Control Valves (AICVs) are a new design of flow control technology that is designed to restrict the flow of unwanted fluid inflows at the completion joints, Figure 14.

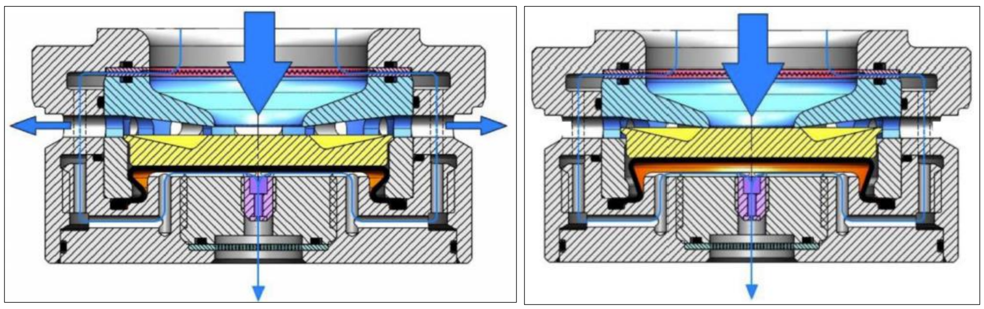


Figure 14. AICV in an open position for oil flow (left) and closed position for water and gas flow (right)

2.5 Development Strategies

Production from oil rim reservoirs dates back to 1965, and successful developments have been encountered. According to the critical literature done by Peter et al. (2019) on oil rim reservoirs, it has been reported that a wide range of recovery factors from 3% to 40% has been achieved in different oil rim projects all over the world. When developing an oil rim associated with a gas cap and a water aquifer, careful consideration should be taken to the proper timing of production in order to maximize the project's value and avoid anticipated problems. For example, developing the gas cap first can negatively impact oil recovery due to the drop of the drive energy and re-saturation losses. The different strategies for exploiting oil rim reservoirs are summarized below:

1. Gas cap blowdown: This method involves developing the gas cap only because the oil rim is too thin (i.e., below 30 ft). It is not common to produce the gas cap at the beginning. However, gas production can be used for commercial sales Clarke, Ayton, Lawton, Lean, and Burke (2006). The continuous demand for energy resources and the need to go to cleaner sources of energy has also shifted the focus of the petroleum industry to produce cleaner natural gas instead of oil whenever possible. Needless to mention, the early blowdown of the gas cap may result in significant loss of oil into the gas cap, lowering the reservoir energy.
2. Convention oil production: this method requires the production of oil rim first by applying a Gas Oil Ratio (GOR) control, then the production of the gas cap at later stages will occur. The central assumption is that there is no water or gas injection, so no alternative for pressure support. During the pressure depletion, the gas cap will expand to support the pressure drop. A major consequence of this strategy is the suffrage of field producers from a severe pressure drop and sudden water or gas breakthroughs. Usually, it is not feasible to produce the oil volumes without the usage of improved oil recovery techniques discussed in the following sections.
3. Concurrent development: this strategy is based on the production of both oil and gas simultaneously. The choice of producing gas from an oil rim reservoir depends on the gas market and the prices. This strategy requires careful and diligent reservoir management. Otherwise, it will destroy the hydrodynamic system and cause the locations of the OWC and GOC to change due to the pressure difference between the gas cap and the oil rim. As a result, a gas breakthrough in oil wells and oil invasion into the gas cap occurs Zhao Lun et al. (2011). In this method, the gas produced should be

reinjected back into the gas cap to increase pressure and avoid shrinkage C. S. Kabir, Agamini, and Holguin (2008). An essential condition is that the ratio of Gas Injection/Gas Production ratio (GIGP) is kept at high values Chan et al. (2011). The efficiency of the concurrent strategy is mainly controlled by pressure maintenance and balance of injection, the relative size of the gas cap, vertical permeability, gas off-take ratio, reservoir geometry, formation dip angle, and rock heterogeneity Sharif (2018).

4. Swing production: is another development strategy in which the gas cap is produced in a cycle where production can be closed-in and reopened later. This strategy is valuable as it manages the reservoir energy and thus maintains the oil recovery despite gas production. The choice for implementing such a plan depends on the high prices of oil or the existence of a gas market Uwaga and Lawal (2006).

2.6 Improved Oil Recovery

Improved oil recovery (IOR) is based on using specific techniques to increase oil recovery from reservoirs. Such techniques can be used equally in oil rims as they can contribute to better results than natural depletion methods. Studies showed that IOR could enhance oil rim recovery by up to 54%. These methods are summarized as follows:

2.6.1 Water Injection

To maximize oil recovery, the oil rim must be kept in contact with producing wells. Three scenarios of water injection are available that can achieve equilibrium of OWC and GOC:

2.6.1.1 Peripheral Water Injection (Down-dip Water Injection)

Peripheral water injection is the injection of water at or below the OWC Dandona and Morse (1975), which enhances the bottom water drive, and displaces the oil rim up towards the producing wells, Figure 15. It is mostly used when the oil rim is very thin, where pattern water injection cannot be used Khoury, Ali, Hassall, and Sinha (2016).

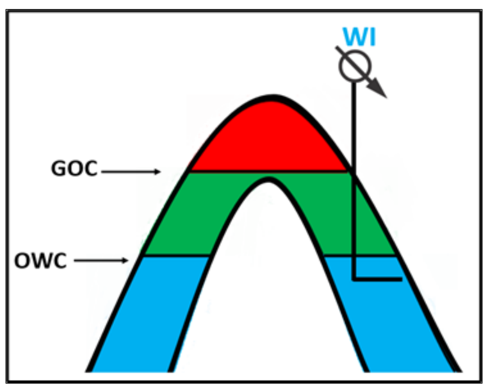


Figure 15. Peripheral water injector placed in the water aquifer to support the pressure

2.6.1.2 Barrier Water Injection

Barrier Water Injection is performed by injecting water at the GOC to separate gas and oil and maintain the pressure while producing gas or oil independently or simultaneously (Figure 16). By optimizing the water injection rate at an optimum viscous/gravity ratio, a water fence is built on top of oil rims and thus allowing the production of the remaining oil reserve.

Using barrier water injection for simultaneous development of gas cap and oil column is applied to reservoirs with a moderate size of the gas cap relative to the oil column (approximately m factor=1.5). It is crucial that the water is injected at a high rate to overcome the gravity effects and thus displace the gas up-dip Billiter and Dandona (1999). The main challenge of the co-development scheme is establishing a water barrier early to minimize oil loss and sustain pressure. For reservoirs with a large gas cap (e.g., with the gas cap to oil column pore volume ratio exceeding 1), a substantial amount of oil may be lost until barrier water injection scheme arrests early decline in reservoir pressure and sustain it. A considerable share of water injection, as high as 60% of total injection, may be needed to establish and maintain a barrier water injection scheme.

An Electrical Submersible Pump (ESP) may be required in this method. That is why the gas production volumes must be very low for the ESP in order to work efficiently. Water can also be injected at the periphery of the oil column to enhance oil production. The economic feasibility of this process depends on the tradeoff between early gas sales and trapped gas since the oil recovery is virtually the same, regardless of whether or not the gas cap is produced as long as the water is injected at the gas-oil contact.

The method of barrier water injection has been implemented in many fields, such as the Algyö field, Hungary, where it led to an increase of 10% oil recovery Werovsky, Tromboczky, Miklos, and Kristof (1990). In the Adena field, Colorado, this strategy was also used to produce from the oil rim. The operator was capable of maintaining the producing GOR very close to solution GOR, so there was no free gas, and hence a 47% ultimate oil recovery was estimated from oil initially in place (OIIP). Moreover, in the

Badri Kareem reservoir in Egypt, water was injected using four vertical injectors at the GOC to reduce the GOR and lead to an estimated 9.4 million STB of OIIP Ader, Williams, and Hanafy (1997). In these cases, the barrier water injection was implemented to prevent the migration of gas cap down the structure.

Numerical simulation studies were performed to investigate the use of barrier water injection for concurrent development, and results showed a high potential of improving both oil and gas recovery Ben Sadok, Koeck, and Abudaqa (2016); Billiter and Dandona (1999). For example, a numerical simulation was made to verify the applicability of injecting water at the GOC on the Kaybob South field in Canada Deboni and Field (1974).

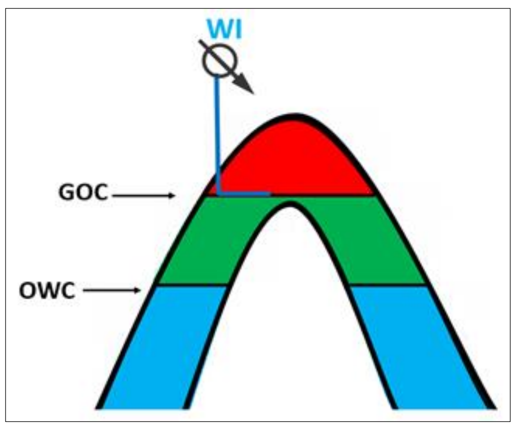


Figure 16. Barrier water injector placed at the GOC

A combination of peripheral and barrier water injection could improve oil recovery in thin oil rims significantly by increasing the pressure support Chan et al. (2011). Figure 17 shows an example of this combination strategy where two water injectors are placed: one at the GOC and the other at OWC.

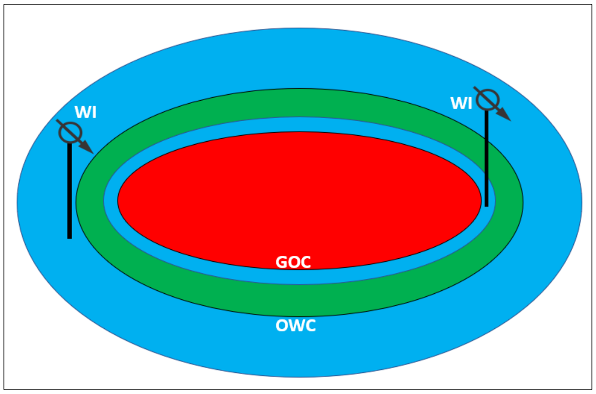


Figure 17.Combination of peripheral and barrier water injection strategies (top view)

2.6.2 Gas Injection

Gas injection is an efficient way to control the depletion, maintain reservoir pressure, and to permit further development of oil rims. This technique is not a new concept in the targeted oil field or elsewhere in the world M. Kabir, McKenzie, Connell, apos, and Sullivan (1998).

The gas is either injected into the gas cap or directly into the oil rim (Figure 18). The injected gas can be the one produced initially from the reservoir such as Methane, or it can be imported from nearby fields. Carbon dioxide or Nitrogen can also be used for injection. The gas injected displaces the produced oil and provides efficient pressure maintenance. The Mareenie field in Australia is an excellent example of gas injection into oil rim reservoirs, where the recovery factor increased by 2-3% M. Kabir et al. (1998). Onyeukwu, Peacock, and Matemilola (2012) investigated the technical feasibility of gas and water injection to produce an oil rim reservoir under various subsurface uncertainties Onyeukwu, Peacock, Matemilola, and Igiehon (2012). The development involves the completion of a horizontal gas injector well in the gas cap while the horizontal oil producer was completed in the oil rim. The results of the work show that simultaneous water and gas injection could increase oil recovery, an observation similar to the outcome of Kabir et al. (1998), except that more recovery is achieved using water injection in cases where weak aquifer support is predominant.

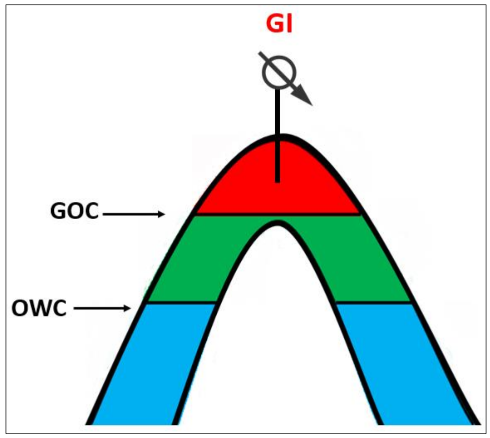


Figure 18.Gas Injection in an Oil Rim Reservoir

A comparison of the recovery factor from several techniques using numerical simulation studies showed that injecting gas at the OWC yields a higher recovery efficiency than other methods, and minimal displacement of the OWC Ogolo, Molokwu, and Onyekonwu (2018).

2.6.3 Simultaneous Down-dip Gas Injection and Up-dip Water Injection

The combination of down-dip gas injection and up-dip water injection results in the equilibration of the oil and its movement to the center of the reservoir. This strategy of re-injecting gas into the aquifer and injecting water at gas cap or near to gas oil contact allows for the re-pressurization of the reservoir, and the enhancement of productivity and recovery Chan et al. (2011). Both oil and gas are important resources so it is important to protect the gas in the gas while producing the oil. Injecting gas downdip will prevents oil and water from excessive movement to the gas cap and hence increases the pressure.

2.7 Gas Condensate Reservoirs

Gas condensate reservoirs are gas systems that exist as a single-phase gas reservoir at a temperature lying between the critical temperature and the cricondentherm. They are considered an important source of hydrocarbon reserves that initially have at the initial reservoir conditions. Figure 19 shows the schematic of a condensate reservoir along with its phase diagram. As the pressure drops in a condensate gas reservoir, the fluid will pass through the dew point, and this will lead to the condensation of large liquid volumes in the reservoir. Since the gas bypass oil, vast amounts of oil remain in the reservoir. When the condensate accumulates at the vicinity of the wellbore The accumulated condensate in the vicinity of the wellbore causes formation damage known as condensate banking that tends to reduce the effective permeability affecting well productivity negatively and reducing the recovery factor of heavy components at the surface Shi and Horne (2008). Zones of high condensate gas ratio in the reservoir are a good target to enhance condensate production. Recovery efficiency from such reservoirs is not only impacted by condensate blockage, relative permeability for imbibition and drainage is a key factor that impacts the degree of production loss blow the saturation pressure (dewpoint) Shi and Horne (2008).

Gas condensate reservoirs that are associated with oil rims require unique treatments such as gas recycling. Recycling of the gas cap will lead to pressure maintenance and consequently increase the condensate recovery at the surface facilities Khoury et al. (2016).

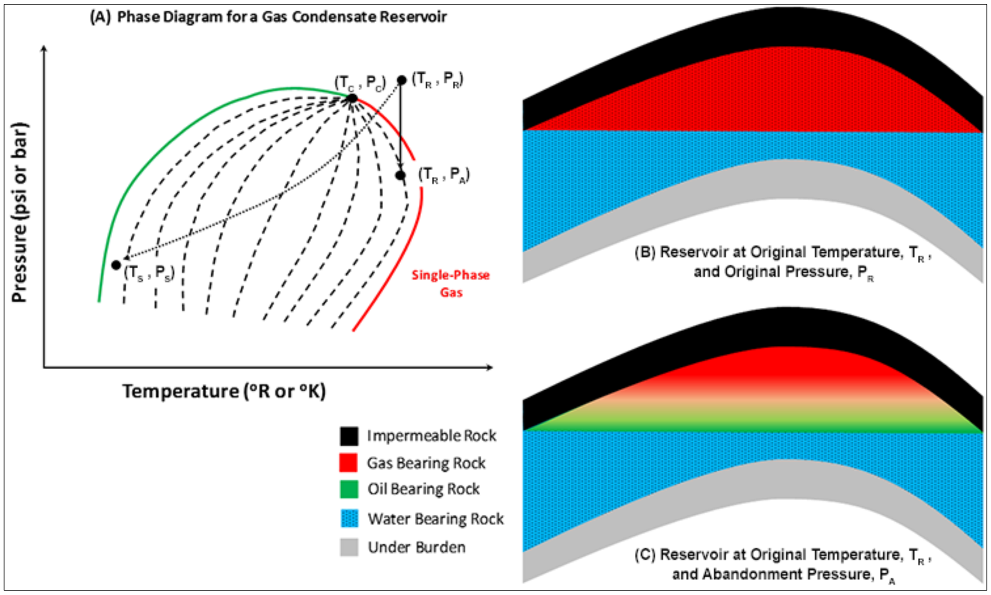


Figure 19. Phase diagram for gas condensate reservoir. Figure 19b. Scheme of gas condensate reservoir at original temperature and pressure. Figure 19c. Scheme of gas condensate reservoir after pressure drop

2.8 Monitoring Contacts Movements

In order to appropriately maximize oil production from the reservoir, many researchers have studied the impact of the reservoir fluid contacts movement.

Ariwodo, Kanfar, Al-Qatari, Saldungary & Rose, (2012) have shown that the Pulse Neutron Capture (PNC) Log is one of the most popular slim cased-hole formation evaluations logging tools, which allow running the survey without having to pull out the production string. The PNC Logs can be run periodically in the time-lapse mode to monitor changes in water saturation and movements in the oil-water contact and gas-oil contact.

Gil, Perez, Cuesta, Altamar & Sanabria, (2009) used an integrated interpretation of 3D seismic attributes, spectral decomposition, and pseudo impedance for the identification of fluid contacts within heavy oil reservoirs in block II of the Uraco field, Eastern

Venezuela. The combination of spectral decomposition data and pseudo impedances led to the identification of fluid contacts in the three-phase reservoir. Log data was used to calibrate the attribute at well locations and to forecast lateral continuity.

Ogbunude, Egelle & Afoama (2014) presented a methodology for fluid contact monitoring using calibrated material balance models. To perform this calibration, pulsed neutron generated fluid contact was required. With the fluid contact determined by the pulsed neutron logs, the tuning of the model's sweep efficiency was done until a good match is obtained. The match obtained at a given sweep efficiency was described as a calibrated model that can be used to predict future fluid contacts. A case study was used to validate the theory proposed and a good match was obtained showing that a calibrated material balance can be used to predict fluid contacts to a reasonable accuracy.

Delauretis,Yarranton & Baker (2008) developed a methodology to estimate current oil-water-contact (OWC) and gas-oil-contact (GOC) in the field from initial fluid in place, production and, rock and fluid properties. The methodology was based on the volume of remaining fluid in the reservoir using material balance techniques and calculation of the fluid contacts assuming the whole reservoir as a single tank and with the best estimate of initial contacts and residual saturations. The result showed that in order to increase oil production from the current wells, the gas injection could be increased in a way that takes into account the effect of fluid movement and the wells need, to be operated as much as possible at a low gas oil ratio that is possible due to strong water drive.

CHAPTER 3

METHODOLOGY

3.1 Reservoir Model Description

A synthetic reservoir simulation model is built on Schlumberger ECLIPSE Composition Simulator (E300). The grid block is defined by NX = 83, NY = 53, and NZ = 45, and the total number of cells equal to 197955. Each cell of the network mesh has dimensions of 100*100 m. Table 1 describes the rock and fluid properties of the reservoir. The GOC is at a depth of 7500 ft while the OWC at 7550 ft and the rim thickness is 50 ft.

Table 1. Reservoir Properties

Property	Value	Unit
GOC depth	7500	ft
OWC depth	7550	ft
Rim Thickness	50	ft
Reservoir Pressure	4333	Psi
Saturation Pressure	4312	Psi
Temperature	233	Deg F
Porosity	0.214	-
Permeability (X, Y, Z)	30, 33, 3	mD
Oil Formation Volume Factor	0.46	RB/STB
Gas Formation Volume Factor	0.3	RB/SCF
Critical Water Saturation	0.22	-
Connate water saturation	0.2	-
Oil initially in Place	280.025	MM rb
Gas initially in Place	454.16	MM rb
Average Oil Saturation	0.14	-
Average Water Saturation	0.55	-
Average Gas Saturation	0.3	-
Rock Compressibility	$1.96*10^{-5}$	Psi^{-1}

3.2 Work Plan

A mechanistic study is implemented to investigate the different factors impacting oil rim development when the reservoir undergoes severe pressure drop. A representative synthetic (compositional) Reservoir Model is considered where both Full Field and (high resolution) Sector Modeling are implemented. The Parameters considered in the mechanistic study and sensitivity analysis are:

Order of Depletion

- Deplete the gas cap first down to low pressure
- Develop the oil rim only
- Co-develop the oil rim and the gas cap
- Development of oil then gas

Well / Completion Type

- Vertical well in both Oil Rim and Gas Cap
- Vertical wells for the gas producers and injectors, horizontal wells for oil producers and water injectors
- Use of smart completions for the oil producers and water injectors to delay and minimize water production

Pressure Maintenance

- Water injection only at the flank of the OWC
- Water injection at the flank of the OWC and right above the GOC
- Gas injection in the gas cap

- Water injection at the flank of the OWC and gas injection in the gas cap
- Water injection at the flank of the OWC and right above the GOC and gas injection in the gas cap

Gas Cap Size

- Run sensitivity on the gas cap size by moving the OWC and GOC up and down

Impact of Heterogeneity

- Mimic a Thamama B formation (Abu Dhabi) in which the upper part of the reservoir has higher permeability and, hence, different SCAL properties.

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Order of Depletion

4.2.3 Gas Cap Depletion

Two regions are identified: FIP=1 (Above GOC), FIP=2 (Below GOC). The volumes of Oil and Gas are determined within these regions. A total of 12 vertical wells are drilled for the gas cap depletion. The simulation time is within the interval: 1/1/2018 - 1/1/2048 (i.e., 30 years). Figures 20, 21, and 22 show the net HCPV for oil, completion design, and the development strategy, respectively. The bottom hole pressure was decreased to 1000 psi and the gas rate is 100,000 MSC/d.

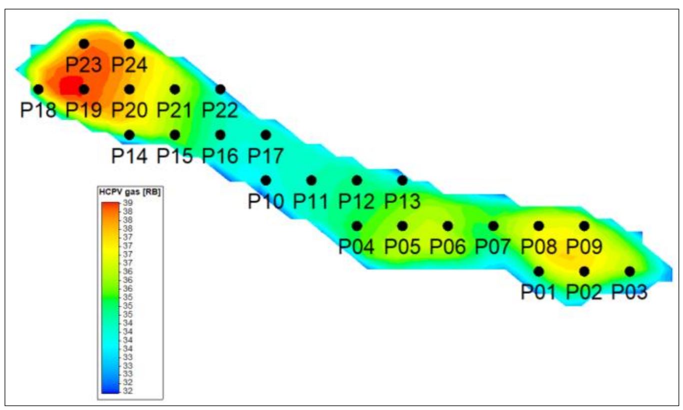


Figure 20. Net HCPV map with vertical wells locations

Figure 21. Completion Design for GCD

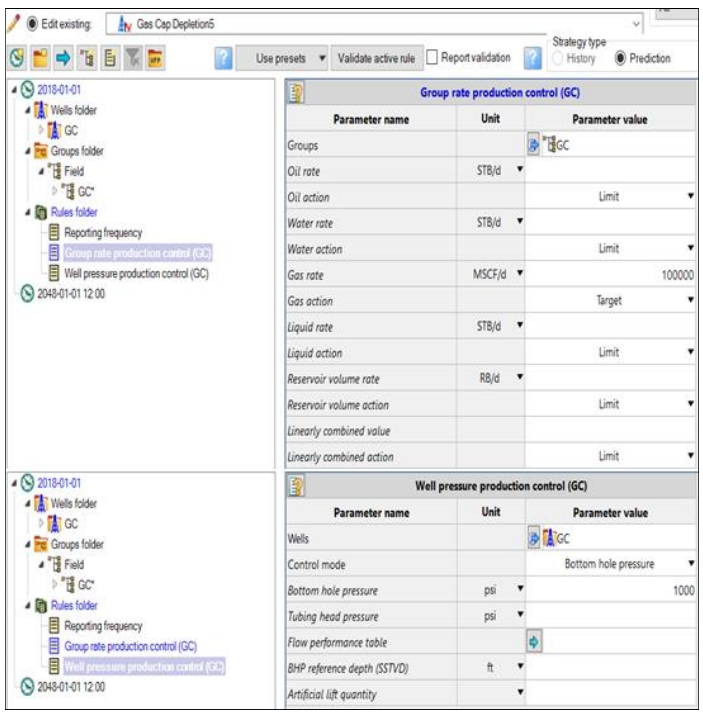


Figure 22.Development Strategy for GCD5

Figures 22 and 23 show the initial and final fluid in place after implementing gas cap depletion at both reservoir and standard conditions.

- Initial Fluid in Place:

Total Oil (MM rb)	Total Gas (MM rb)
280.025	454.159

FIP1:

Oil (MM rb)	Gas (MM rb)
0	454.159

FIP2:

Oil (MM rb)	Gas (MM rb)
280.025	0

- Fluid in Place (After Gas Cap Depletion):

Total Oil (MM rb)	Total Gas (MM rb)
206.109	397.182

FIP1:

Oil (MM rb)	Gas (MM rb)
105.367	300.386

FIP2:

Oil (MM rb)	Gas (MM rb)
100.743	96.796

Figure 23. Initial and Final FIP @Reservoir Conditions

- Initial Fluid in Place:

Total Oil (B STB)	Total Gas (TSCF)
0.183	0.884

FIP1:

Oil (B STB)	Gas (TSCF)
0.076	0.585

FIP2:

Oil (B STB)	Gas (TSCF)
0.107	0.299

- Fluid in Place (After Gas Cap Depletion):

Total Oil (B STB)	Total Gas (TSCF)
0.155	0.194

FIP1:

Oil (B STB)	Gas (TSCF)
0.078	0.132

FIP2:

Oil (B STB)	Gas (TSCF)
0.077	0.062

Figure 24. Initial and Final FIP @Standard Conditions

- Analysis of Pressure

Pressure drops dramatically due to the depletion mechanism applied for which the bottom hole pressure decreased to 1000 psi. The pressure drops in both the gas cap and oil rim. Figures 25 shows the cross-section of the reservoir pressure before and after gas cap depletion.

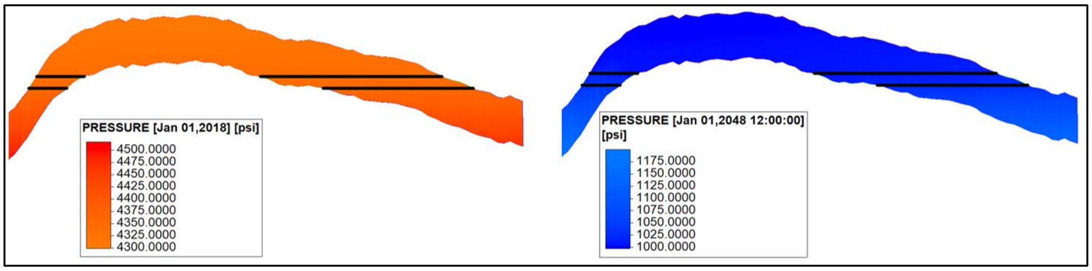


Figure 25. Cross-section of the reservoir showing the initial and final pressure values (GCD)

- Analysis of Saturation

As a result of gas cap depletion, fluid saturation changes as well. Figures 26 shows the cross-section of oil saturation before and after gas cap depletion. Initially, oil was only present in the oil rim sandwiched between the gas cap and the water aquifer. With time, the saturation of oil decreases in the oil rim and started to move up to the gas cap (oil smearing) as can be noticed by the increased oil saturation values in the gas cap. Figure 27 shows gas saturation distribution that was initially present only in the gas cap. However, with the depletion of the gas cap, gas saturation starts decreasing in the gas cap due to gas production and increases in the oil rim region due to gas coning.

Figure 28 shows the fluid type distribution between regions before and after GCD. As noticed, oil smearing into the gas cap is clear as well as gas coning from the gas cap and water coning from the aquifer into the oil rim.

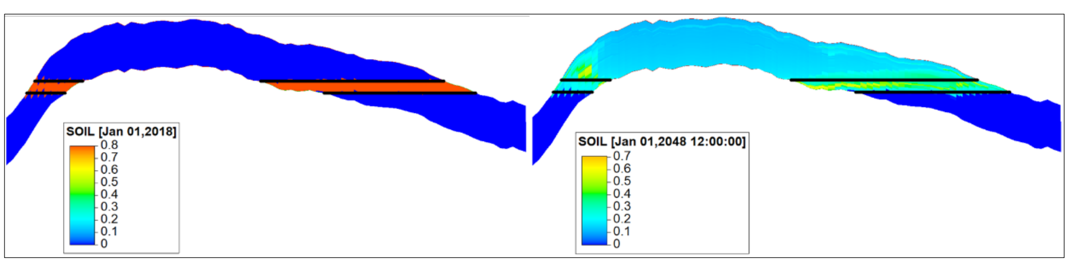


Figure 26. Cross-section of the reservoir showing the initial and final oil saturation

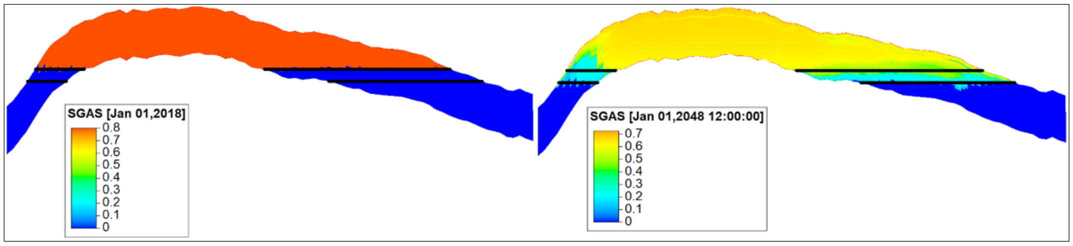


Figure 27. Cross-section of the reservoir showing the initial and final gas saturations

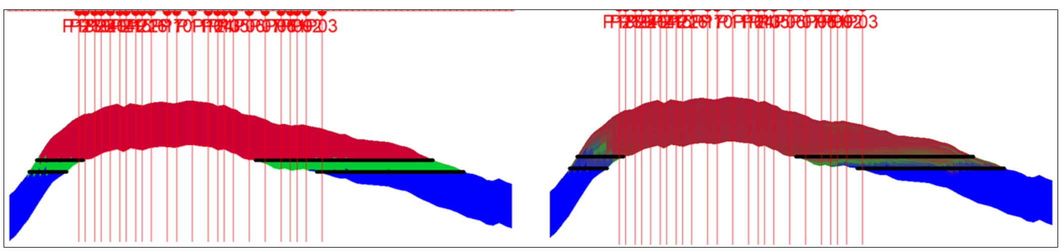


Figure 28. Cross-section of the reservoir showing the initial and final fluid types in regions

- Field and Region Scale Results:

The results obtained at the field scale of the GCD are shown in Figure 29. As seen the pressure drops down to 1000 psi in 2040 while the gas-oil ratio (GOR) increases with time due to gas production. The oil in place decreases although we are producing from the gas cap and not from the oil region; however, this oil is mainly from the condensation in the gas cap and oil rim smearing up to the gas cap. On the other hand, water cut increases with time which is not surprising when we have a huge pressure drop when depleting the gas cap. The oil recovery factor achieved for GCD is 12% while the gas recovery factor is about 75%.

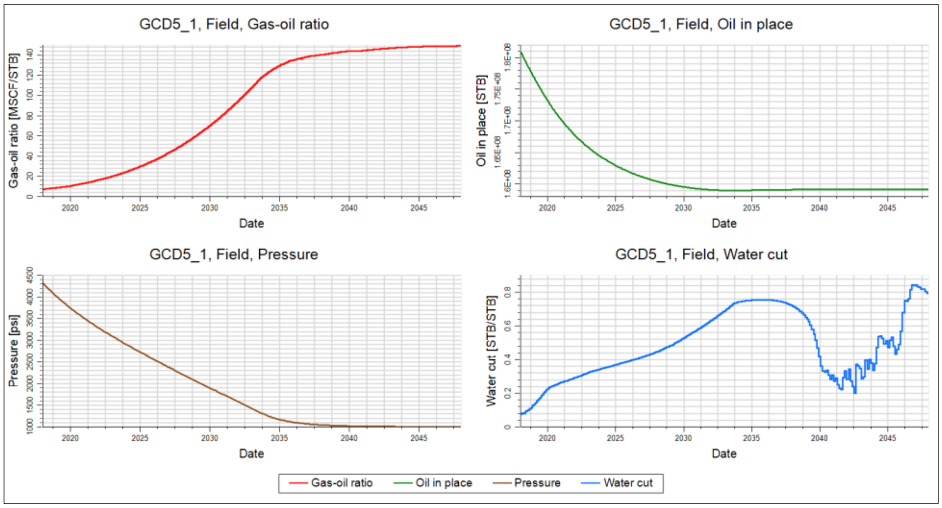


Figure 29.Field Scale Results (GCD)

- Contacts Movement:

Early gas cap blowdown can result in significant oil loss into a gas cap, Al-Hammadi et al. (2019). Due to the huge depletion in the gas cap in the present days, the upward movement of GOC is also observed in some areas. The plausible explanation of the upwards movement of the GOC is the presence of high permeable rocks combined with pressure sinks in those areas. With depletion, OWC and GOC may move up or down. To understand these contacts movements we need to look at PVT, SCAL, and maximum liquid dropout. So, dropout depends on PVT while liquid flow depends on SCAL.

In reality, we use surveillance data (RST: Saturation Logs) to track the contact movements by doing time-lapse measurements of saturation in the well. GOC was supposed to move up due to the condensation however results revealed that there is an unusual movement of fluids (up and down). Figure 30 shows the fluid in place at both the field and the region scale before and after gas cap depletion. The recovery factor achieved for the oil is 12% while that of the gas is 74%.

Total oil produced= 21.7

Total gas produced= 0.65

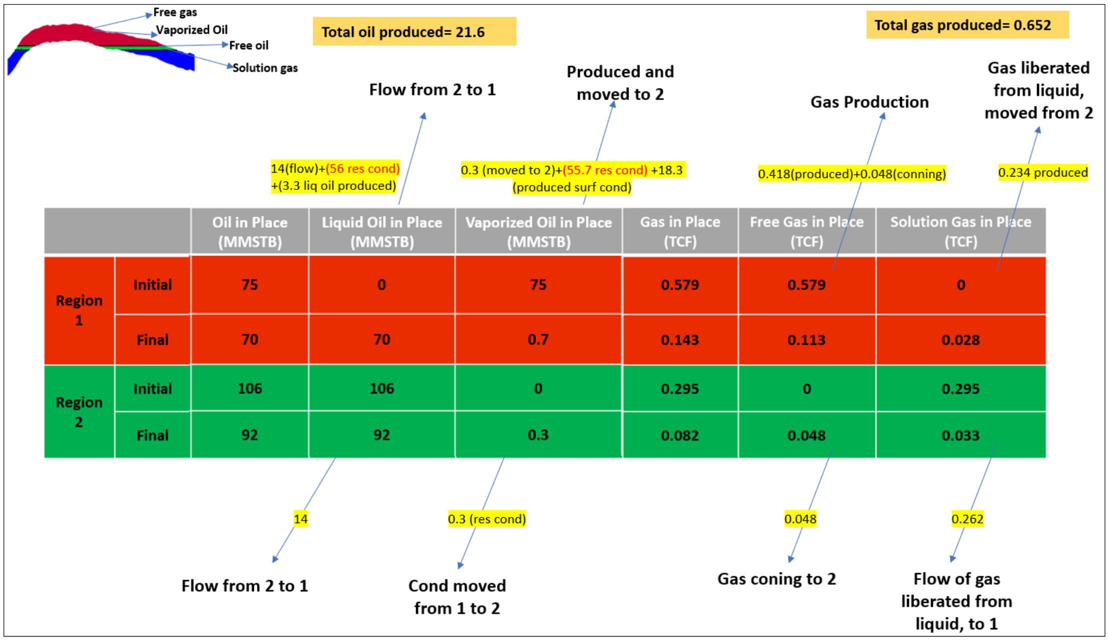
		Oil in Place (MMSTB)	Liquid Oil in Place (MMSTB)	Vaporized Oil in Place (MMSTB)	Gas in Place (TCF)	Free Gas in Place (TCF)	Solution Gas in Place (TCF)
Field	Initial	181	106	75	0.875	0.579	0.295
	Final	159	162	0.98	0.226	0.161	0.061
Region 1	Initial	75	0	75	0.579	0.579	0
	Final	70	70	0.7	0.143	0.113	0.028
Region 2	Initial	106	106	0	0.295	0	0.295
	Final	92	92	0.3	0.082	0.048	0.033

Oil RF= 12 %
Gas RF= 74 %

Figure 30. Initial and final fluid volumes for the GCD scenario

The saturation in oil was changing with time, although we were not producing from the oil rim, since oil is vaporized due to the pressure drop and gas is coming out of it. As seen from the Fingerprint plot (Figure 36), most of the components are volatiles, so when the pressure is decreased due to the production from the gas cap, a volume of gas will be released from the oil rim and will consequently move up to the gas cap. As a result of that, the oil rim thickness will decrease.

When the pressure is decreased more and more in the gas cap, there will be a condensation of the heavy components and that is why we see oil in the gas cap. Another part of liquid oil smears from the oil rim to the gas cap. On the other hand, the upward movement of water is a result of the huge pressure drop due to the depletion of the gas cap.



		Oil in Place (MMSTB)	Liquid Oil in Place (MMSTB)	Vaporized Oil in Place (MMSTB)	Gas in Place (TCF)	Free Gas in Place (TCF)	Solution Gas in Place (TCF)
Region 1	Initial	75	0	75	0.579	0.579	0
	Final	70	70	0.7	0.143	0.113	0.028
Region 2	Initial	106	106	0	0.295	0	0.295
	Final	92	92	0.3	0.082	0.048	0.033

Figure 31. Analysis of fluids flow between regions as a result of GCD

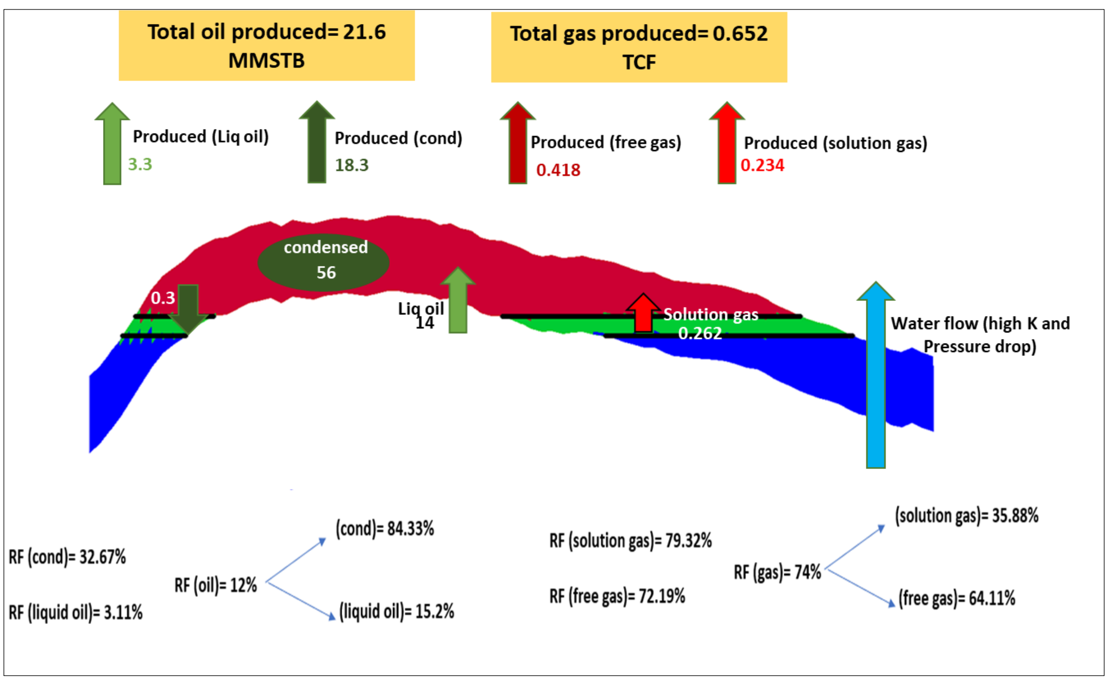


Figure 32. Initial and Final Pressure Cross Section

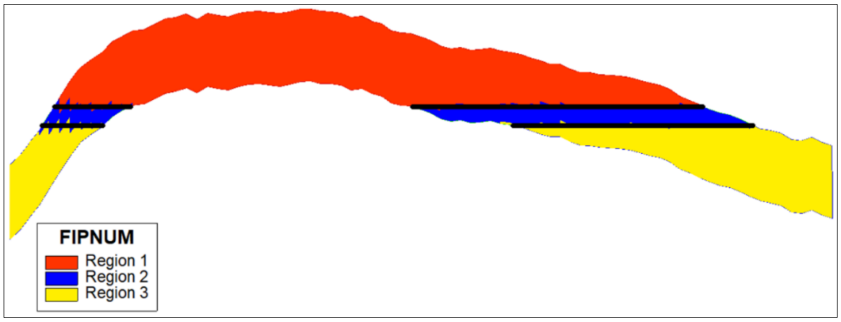


Figure 33. Cross-section of the reservoir showing regions considered

- Phase Behavior Analysis

Phase behavior analysis is vital to understand what is happening in the reservoir in terms of changes in volumes concerning pressure and temperature. 122 pressure measurements were taken at various depths of the reservoir. Figure 34 shows the phase diagram of Sample 1 which was taken from the gas cap while Figure 35 presents Sample 46 taken from the oil rim.

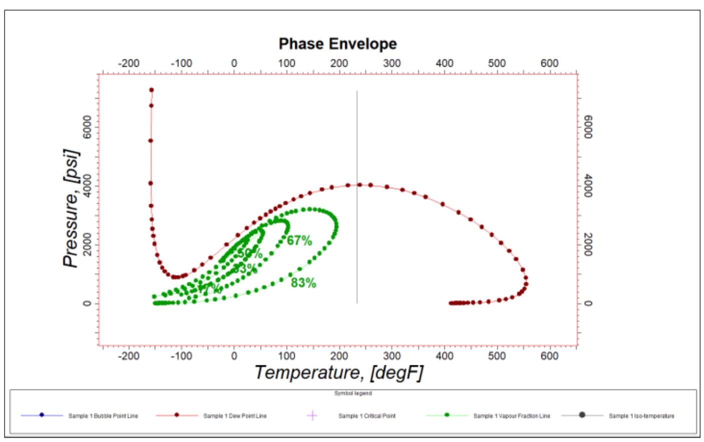


Figure 34.Phase diagram for sample 1

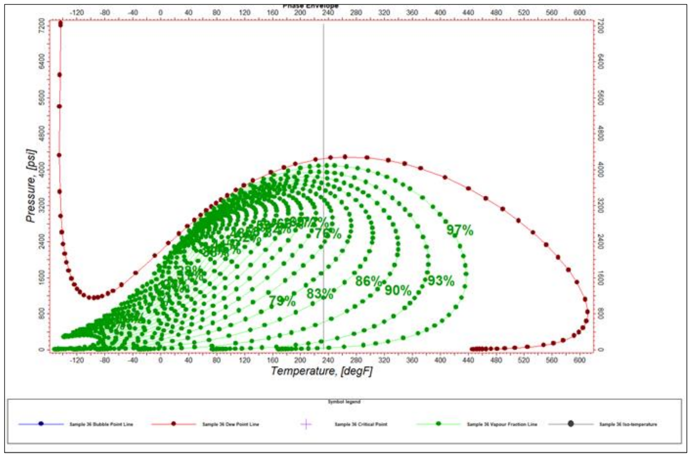


Figure 35.Phase diagram for sample 46

The dropout is the amount of liquid that the gas has at a certain pressure. The reservoir has an initial pressure Pres >Psat (no liquid in the reservoir gas cap).

When production begins, Pres decreases and hits Psat (saturation pressure), then the condensate forms inside the reservoir. The more the pressure drops, the more condensate we will get. But this condensate is immobile until it reaches the critical saturation. After reaching this critical saturation, the condensate will start flowing into the well through the pore media. How much liquid we will have in the reservoir below the Psat can be determined from the phase diagram.

To calculate the liquid dropout, we need to check first the pressure drop in the perforation. Then we determine the composition of the fluid belonging to that depth and match it with the corresponding phase plot and then we can get the dropout pressure in the well. Sample 46 was chosen to calculate the liquid dropout (Table 2) and plotted vs pressure in Figure 37.

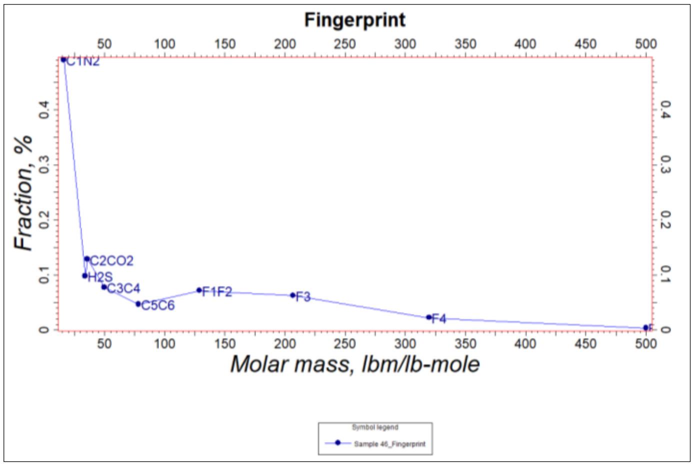


Figure 36. Fingerprint for sample 46

Table 2. Liquid dropout of sample 46

Pressure (psi)	Liquid dropout (%)
4333	0
4241.6	0
4086	3
3943.25	7
3818.06	10
3685.4	14
3560.1	17
3340.6	21
2340.4	21
1730.6	17
1153.9	14
613.2	10
236	7
32.7	3
7	0

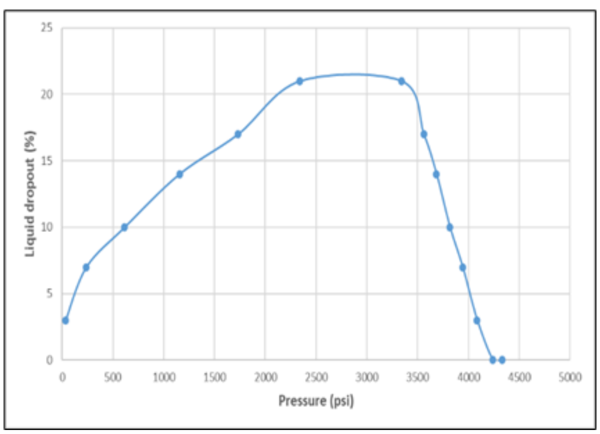


Figure 37.Liquid dropout of sample 46

4.2.3 Oil Rim Development Only

A total of 13 vertical wells are considered for the oil rim development (ORD) scenario. The simulation time is within the interval (1/1/2018- 1/1/2048). The completion design along with the development strategy are shown in Figures 38 and 39. The bottom hole pressure is decreased to 1000 psi and the oil rate is 5000 STB/d.

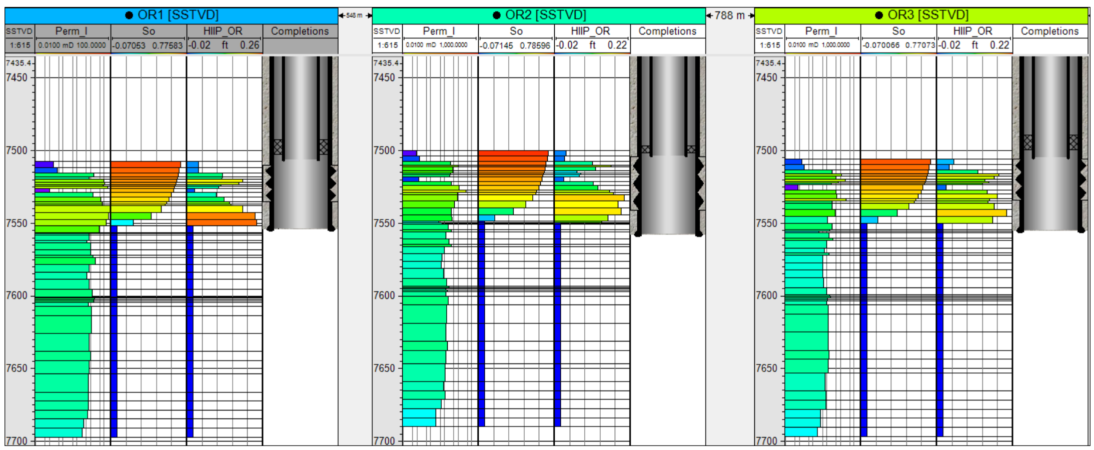


Figure 38. Completion design for ORD

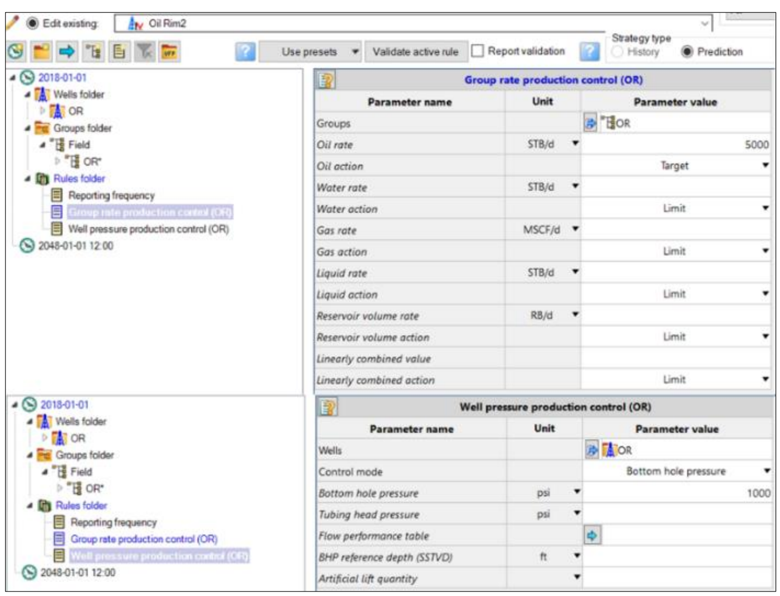


Figure 39. Development strategy for ORD scenario

Figures 40 shows the initial and final fluid in place after implementing oil rim development at standard conditions. Gas volumes decrease significantly while a minimal volume of oil is produced using this strategy.

- **Initial Fluid in Place:**

Total Oil (B STB)	Total Gas (TSCF)
0.183	**0.884**

FIP1:

Oil (B STB)	Gas (TSCF)
0.076	**0.585**

FIP2:

Oil (B STB)	Gas (TSCF)
0.107	**0.299**

- **Fluid in Place (After Gas Cap Depletion):**

Total Oil (B STB)	Total Gas (TSCF)
0.162	**0.287**

FIP1:

Oil (B STB)	Gas (TSCF)
0.061	**0.16**

FIP2:

Oil (B STB)	Gas (TSCF)
0.101	**0.127**

Figure 40. Initial and Final FIP @Standard Conditions for ORD scenario

- Analysis of Pressure

Upon producing from the oil rim, and by setting a bottom hole pressure of 1000 psi, the pressure decreases significantly in both the oil zone and the gas cap down to values of around 1300 psi, Figure 41.

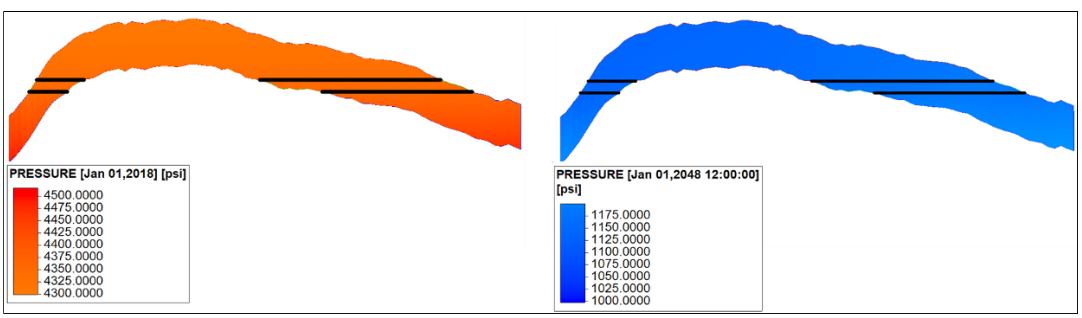


Figure 41. Cross-section of the reservoir showing the initial and final pressure values for ORD scenario

- Analysis of Saturation

As a result of developing only the oil rim, the fluids saturation distribution changes to a noticeable degree. Figure 42 shows the cross-section of fluid types distribution between regions before and after ORD. The remaining volume of oil is irreducible oil saturation. Obviously, there is a noticed gas coning issue on which significant volumes of gas moves down to the oil rim due to the early coning that happens as a result of oil production from the gas cap without any implementation of pressure maintenance that will balance the forces and retard the production of the undesirable fluid.

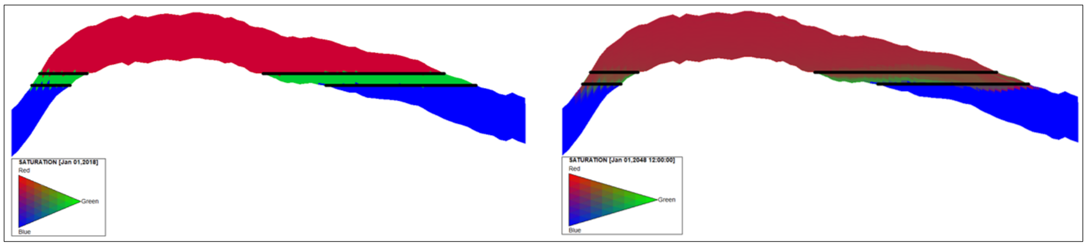


Figure 42. Cross-section of the reservoir showing the initial and final fluid types in regions for ORD scenario

- Field Scale Results:

Figure 43 shows the field scale results of the oil rim development scenarios. The GOR increases at a later stage due to the production of gas with oil and gas coning up to around 120 MSCF/STB. The pressure decreases due to the low bhp applied down to values of around 1300 psi. The water coning issue occurs as early as the first year of production as can been seen in the water cut chart. The oil recovery factor achieved for this strategy is 9.22% while that of gas is 67%.

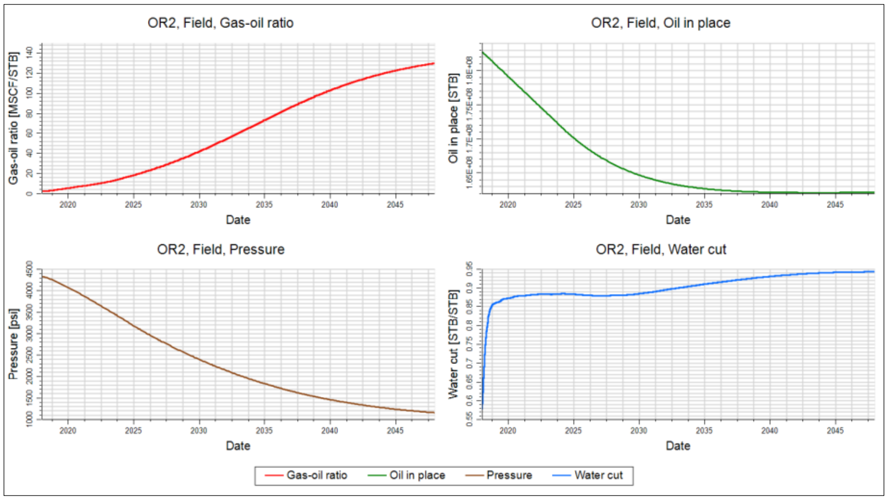


Figure 43. Initial and Final Saturation Distribution Cross-Section (ORD)

4.2.3 Co-development of oil and gas

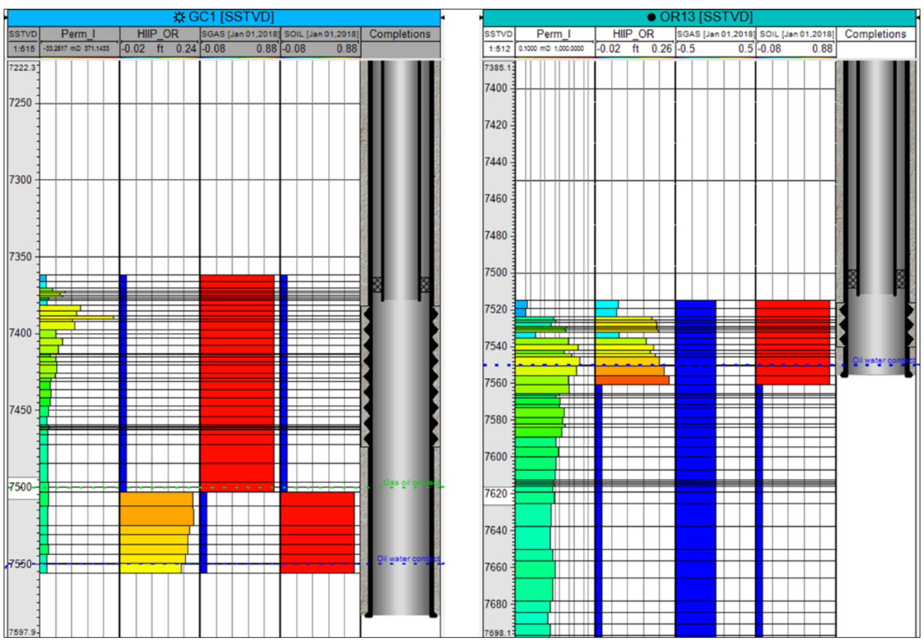


Figure 44. Completion design for CoDev scenario

A total of 13 vertical wells to produce from the oil rim and 20 vertical wells to produce the gas cap were considered for the Co-development (CoDev) scenario. The simulation time is within the interval (1/1/2018- 1/1/2048). The completion design along with the development strategy is shown in Figures 44 and 45.

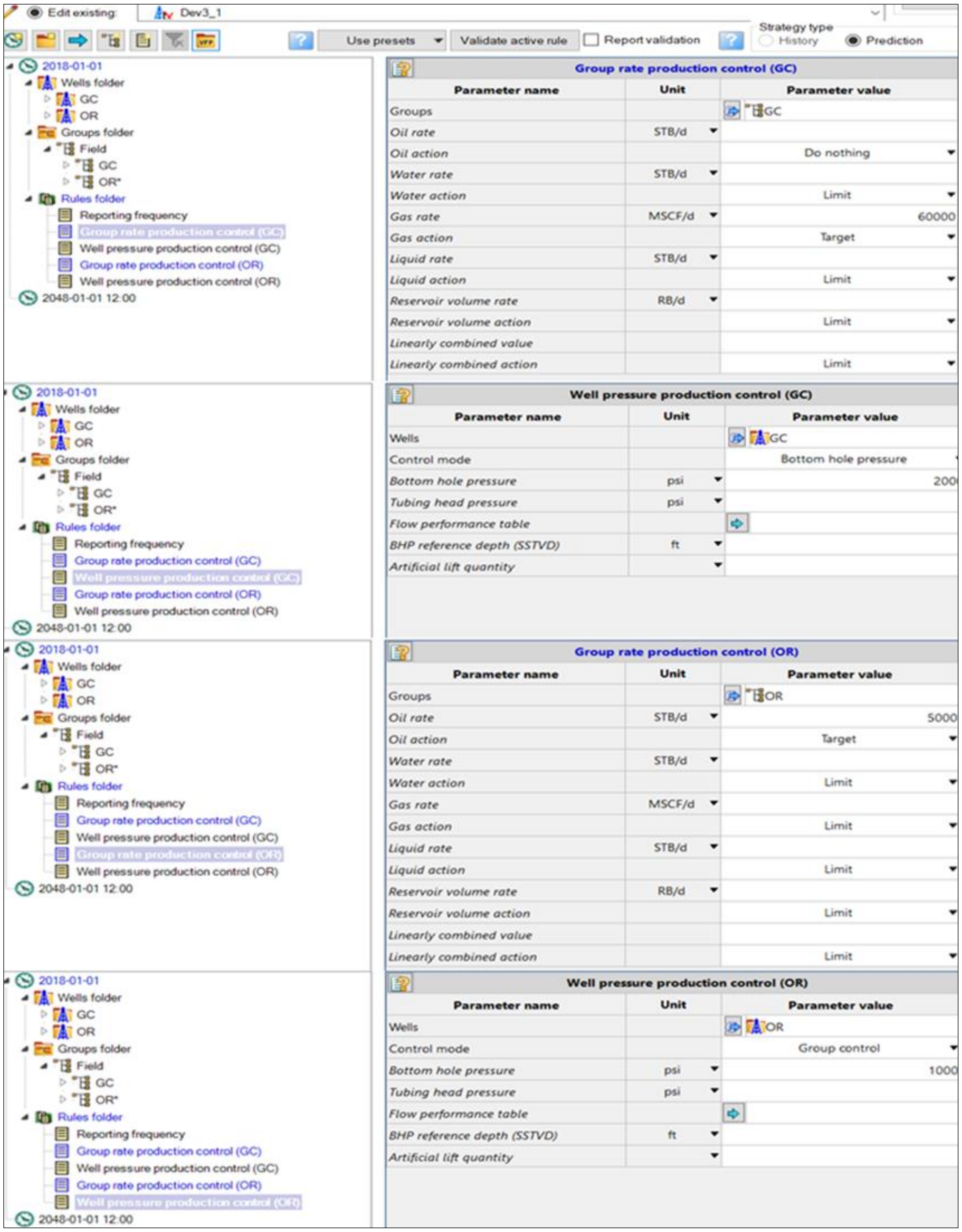


Figure 45. Development strategy for CoDev scenario

- Analysis of Pressure

By applying Co-Dev producing from both the oil rim and the gas cap, the pressure decreases down to 1200 psi in both the oil rim and the gas cap due to the low bottom hole pressure of 1000 psi set, Figure 46.

- Analysis of Saturation

As a result of applying Co-Dev, the fluids saturation distribution changes with time. Figure 47 shows the cross-section of oil saturation before and after ORD. The remaining volume of oil is irreducible oil saturation. Moreover, there is a well-noticed gas coning issue on which significant volumes of gas moves down to the oil rim.

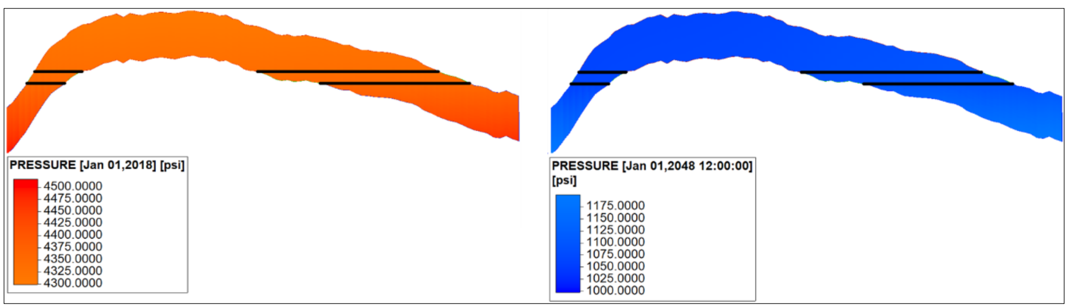


Figure 46. Cross-section of the reservoir showing the initial and final pressure values for Co-Dev

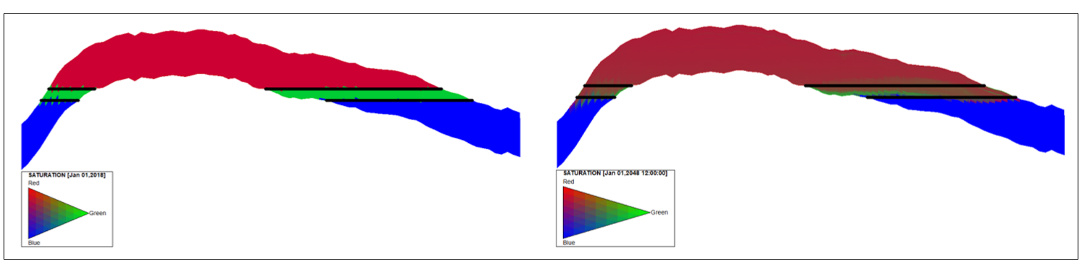


Figure 47. Cross-section of the reservoir showing the initial and final fluid types in regions for Co-Dev

- Field Scale Results:

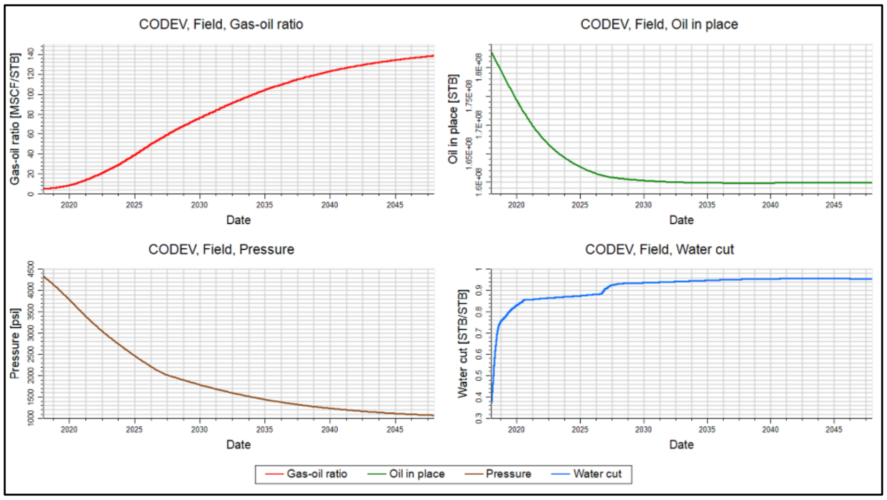


Figure 48. Field-scale results (Co-Dev)

Figure 48 shows the field scale results for the Co-Dev scenario. The GOR increases at a later stage due to the production of gas with oil after gas coning up to values of 137 MSCF/STB. Pressure decreases down to 1100 psi due to the low bhp applied. The water coning issue occurs as early as the first year of production as can been seen in the water cut chart. The oil recovery factor achieved is 10.2% while that of gas is 71%.

4.2.3 *Development of oil then gas*

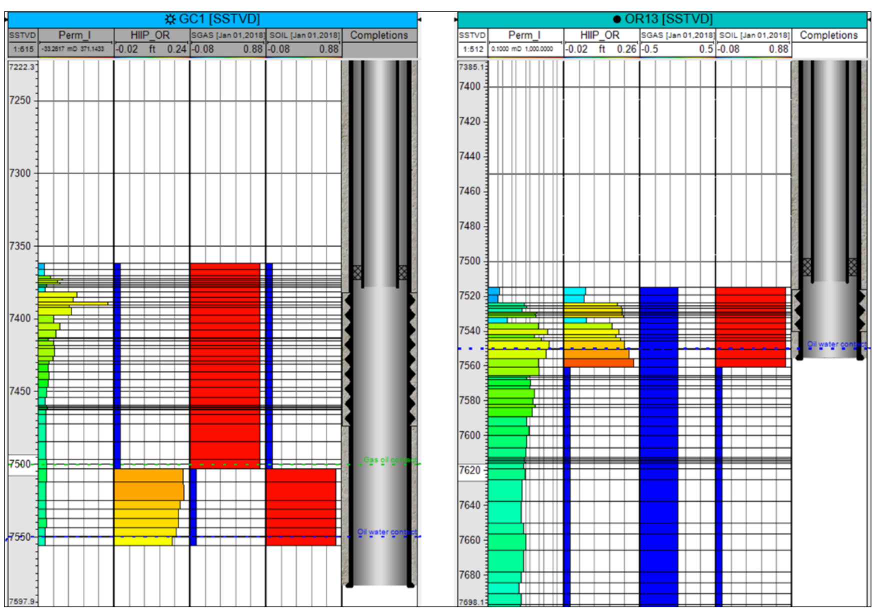


Figure 49. Field-scale results (Oil then Gas)

A total of 13 vertical wells perforated in the oil zone are allowed to produce from the oil rim for the first 20 years then the gas cap is depleted using 12 vertical wells perforated in the gas cap for the following 20 years. The completion design along with the development strategy is shown in Figures 49 and 50.

Group rate production control (OR)

Parameter name	Unit	Parameter value
Groups		OR
Oil rate	STB/d	5000
Oil action		Target
Water rate	STB/d	
Water action		Limit
Gas rate	MSCF/d	
Gas action		Limit
Liquid rate	STB/d	
Liquid action		Limit
Reservoir volume rate	RB/d	
Reservoir volume action		Limit
Linearly combined value		
Linearly combined action		Limit

Well pressure production control (GC)

Parameter name	Unit	Parameter value
Wells		GC
Control mode		Bottom hole pressure
Bottom hole pressure	psi	1000
Tubing head pressure	psi	
Flow performance table		
BHP reference depth (SSTVD)	ft	
Artificial lift quantity		

Well pressure production control (OR)

Parameter name	Unit	Parameter value
Wells		OR
Control mode		Bottom hole pressure
Bottom hole pressure	psi	1000
Tubing head pressure	psi	
Flow performance table		
BHP reference depth (SSTVD)	ft	
Artificial lift quantity		

Group rate production control (GC)

Parameter name	Unit	Parameter value
Groups		GC
Oil rate	STB/d	
Oil action		Limit
Water rate	STB/d	
Water action		Limit
Gas rate	MSCF/d	100000
Gas action		Target
Liquid rate	STB/d	
Liquid action		Limit
Reservoir volume rate	RB/d	
Reservoir volume action		Limit
Linearly combined value		
Linearly combined action		Limit

Figure 50. Field-scale results (Oil then Gas)

- Analysis of Pressure

By producing oil then depleting the gas cap, the pressure decreases in both the oil rim and the gas cap due to the low bottom hole pressure of 1000 psi, Figure 51.

- Analysis of Saturation

As a result of producing the oil then the gas, the fluids saturation distribution changes significantly. Figure 52 shows the cross-section of oil saturation before and after ORD. The remaining volume of oil is irreducible oil saturation. Moreover, there is a well-noticed gas coning issue on which significant volumes of gas moves down to the oil rim and water aquifer.

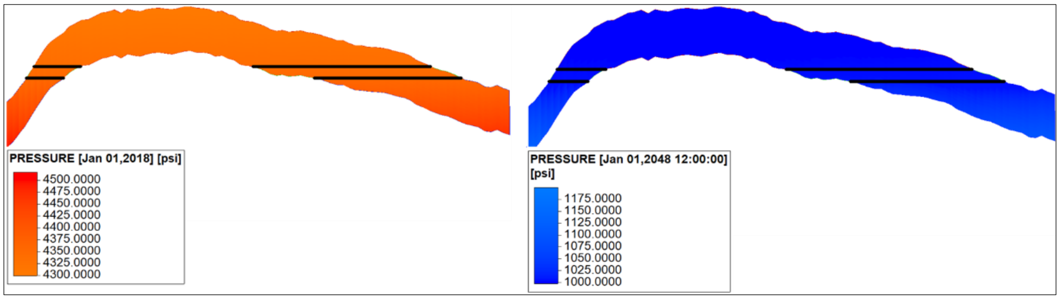


Figure 51. Cross-section of the reservoir showing the initial and final pressure values (Oil then gas scenario)

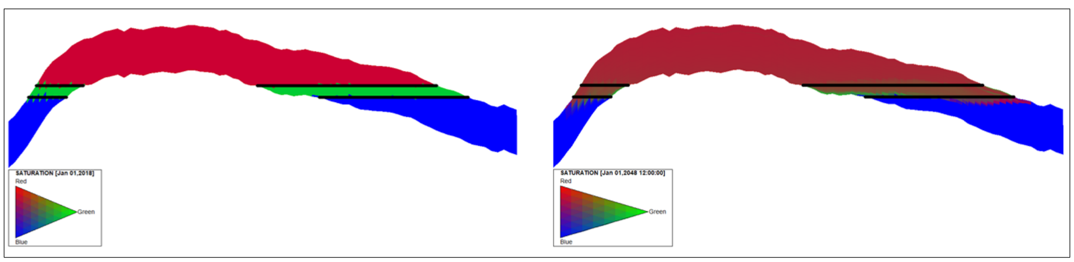


Figure 52. Cross-section of the reservoir showing the initial and final fluid types in regions (Oil then gas scenario)

- Field Scale Results:

Figure 53 shows the field scale results for the oil then gas development scenario. The GOR increases at a later stage to 140 MSCF/STB due to the production of gas with oil after gas coning. Pressure decreases down to 1000 psi in 2037 due to the low bhp applied. The water coning issue occurs as early as the first year of production as can been seen in the water cut chart. The oil recovery factor achieved is 9.18% while that of gas is 69.7%. The results are almost the same as in the previous scenario.

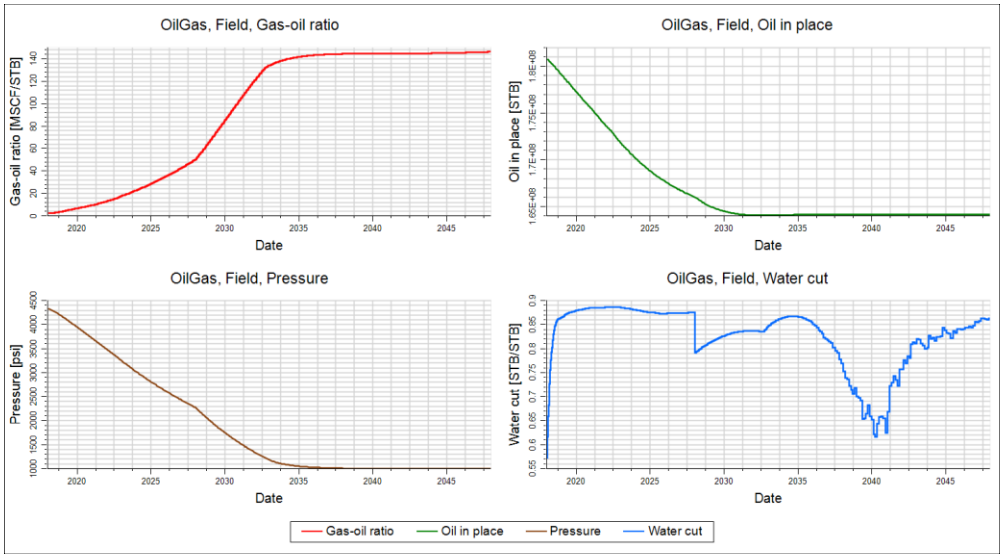


Figure 53. Initial and Final Saturation Distribution Cross-Section (Oil then Gas)

4.2.3 Results Comparison (Order of Depletion)

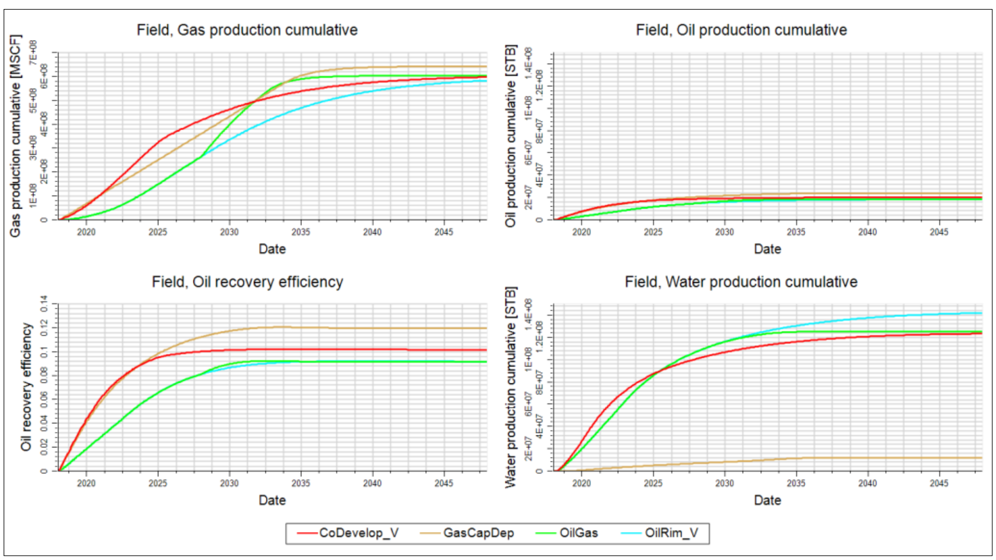


Figure 54. Field-scale results for the three order of development scenarios

Figure 54 shows the field scale results for the four scenarios investigated. The highest oil recovery is obtained by a gas cap depletion scenario with a maximum oil recovery factor

(12%), Table 3. However, all the results are very near and thus this is not enough to decide as the results might change by using horizontal wells. So, the order of depletion is not considered one of the impacting parameters when developing oil rims using vertical wells without any pressure maintenance method.

Table 3. Oil recovery factor for the order of depletion four scenario

Strategy	Oil RF
Gas Cap Dep	12.01%
Co-Dev	10.20%
Oil only	9.20%
Oil then Gas	9.18%

4.2 Wells Type and Completion

For the well types and completion sensitivities, the Oil Rim Development only (ORD) will be considered.

4.2.3 Vertical Wells

The first case that undergoes the sensitivity is oil rim development only (ORD) using vertical wells where the well completion design is shown in Figures 55. Results obtained from oil rim development only using vertical wells gives an oil recovery factor of 9.8%.

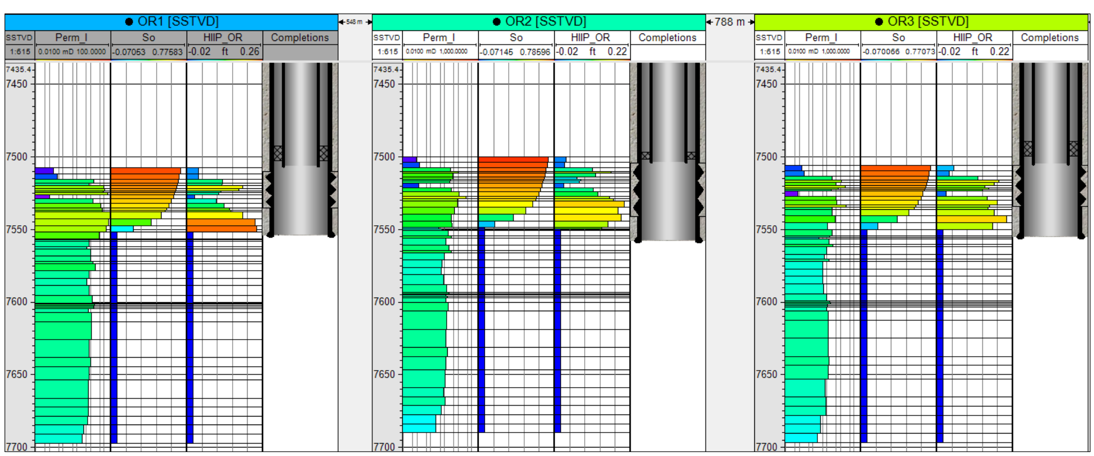


Figure 55.Completion design for ORD

4.2.3 Horizontal Wells

The second case is the horizontal wells that are used to produce from the oil rim. Various scenarios are suggested to produce from different horizons using different sets of horizontal wells as seen in the cross-sections of oil saturation in Figure 56. The completion design for horizontal wells considered is perforated liner where the liner is run in the open hole and hung off in the production casing is shown in Figure 57. Results obtained show an oil recovery factor of 12.9%.

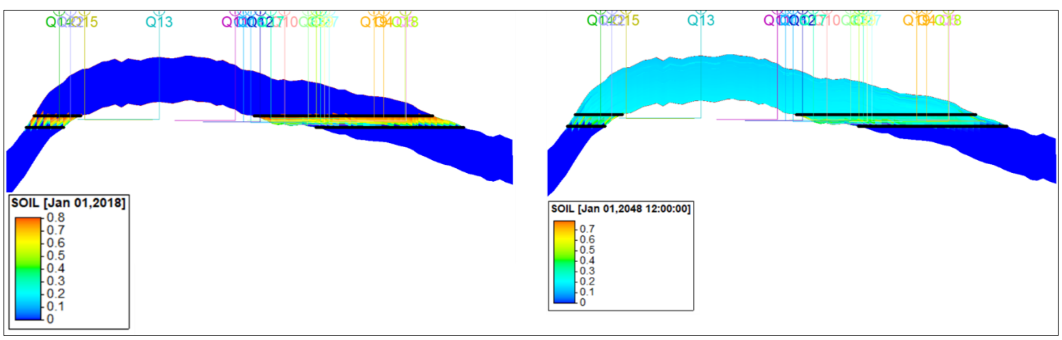


Figure 56. Cross-section of the reservoir showing the initial and final oil saturation values using vertical wells

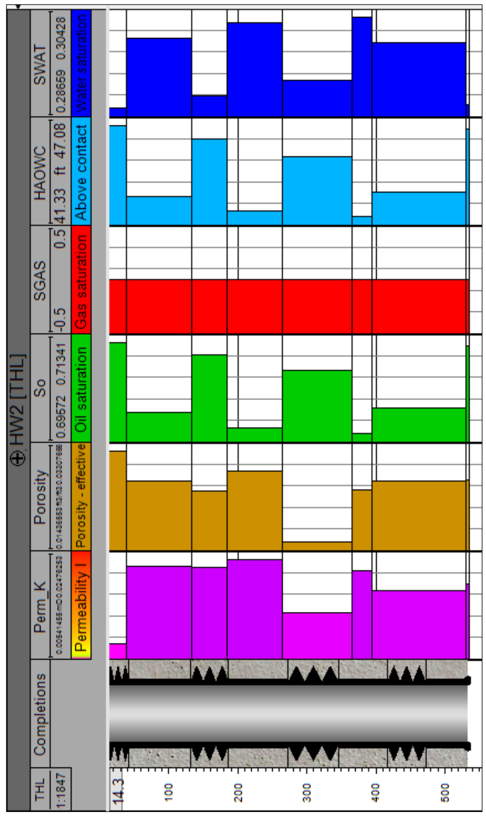


Figure 57. Horizontal wells completion design

4.2.3 *Smart Completions*

The third case is for smart completions applied for oil producers, gas, and water injectors. To approach this scenario surface constraints are applied on GOC and OWC to represent, to a certain degree, the function of smart completions that are normally installed in the completion string for this purpose. Once these constraints on water cut (0.6 STB/STB) and GOR (70 MSCF/STB) are reached, the well's worst connection will be shut. Figure 58 shows the completion design for smart wells. The completion string is equipped with Inflow Control valves that are remotely controlled from the surface.

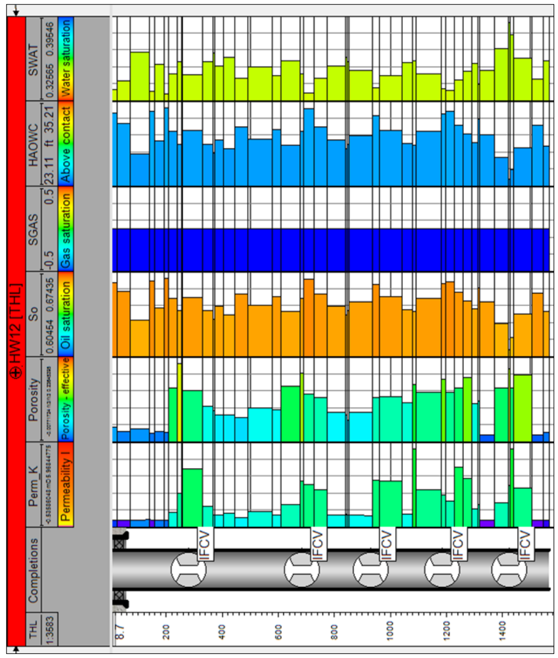


Figure 58. Completion design for smart wells

4.2.4 Results Comparison (Well Type & Completion)

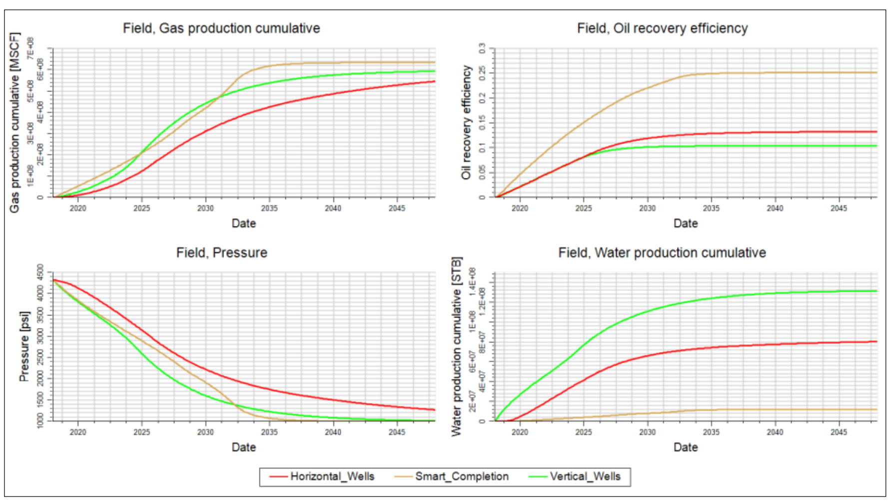


Figure 59. Field-scale results for the well types and completions scenarios

Figure 59 shows the field scale results for the three scenarios investigated in well type and completion. The highest oil recovery is achieved with the smart completion scenario with a maximum oil recovery factor (25.25%), Table 4. As predicted before, using a different type of wells rather than vertical wells, the best order of depletion scenario might change. The lowest oil recovery factor is for vertical wells (10.5%) while horizontal wells achieved a recovery factor of 13.36%. An important note here is that no pressure maintenance has been applied for these oil rim development scenarios. It is obvious how horizontal wells resulted in lower water and gas production and hence higher oil production over vertical wells. Smart completions also manages to reduce water breakthrough to a great degree than using horizontal wells alone.

Table 4. ORF for well type and completion scenarios

Strategy	Oil RF
Vertical	10.5%
Horizontal	13.36%
Smart	25.25%

4.3 Pressure Maintenance Sensitivity

For the following scenarios, the case considered is ORD (oil rim development only) using vertical wells to see the impact of pressure maintenance alone on the recovery factor. In later stages, a combination of various well types and development strategies is tested for these four pressure maintenance cases.

4.3.1 Water injection @ flank of OWC

Water is injected at the OWC using 16 horizontal injectors, Figure 60. Figure 61 shows the pressure distribution before and after applying this pressure maintenance technique. It can be noticed the pressure was maintained between 3200 to 3600 psi which was not achieved in previous cases. Figure 62 presents the fluids type within the regions of the reservoir. Due to water injection, the reservoir witnessed a harsh water coning issue that is noticed by the breakthrough of water and thus high-water production cumulative. Figure 63 shows the Field-scale results for WI@OWC.

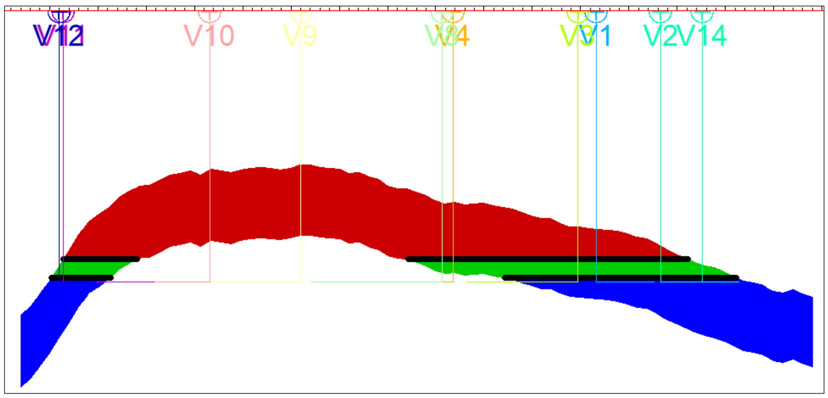


Figure 60. Cross-section of the reservoir showing the fluid types in regions and wells positions using water injection at the flank of OWC scenario

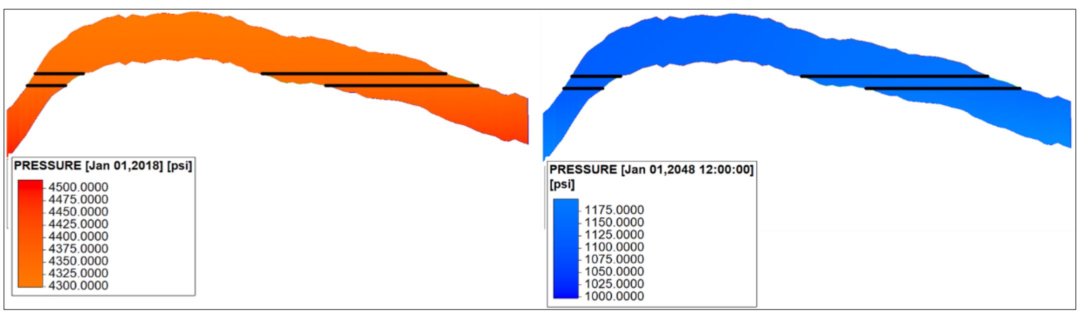


Figure 61. Cross-section of the reservoir showing the initial and final pressure values for WI@OWC

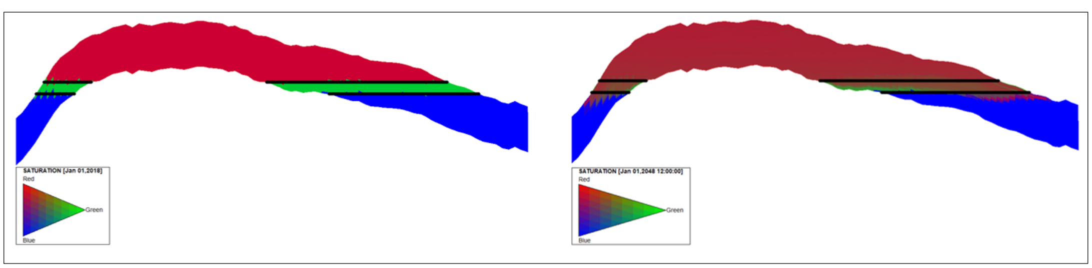


Figure 62. Cross-section of the reservoir showing the initial and final fluid types in regions for WI@OWC

Water coning is a major problem that resulted from this strategy that can be viewed by high water production cumulative. The oil production is low (RF=10%) but of course higher than the base case (9.22%) which is without any water injection. As noticed, using horizontal water injectors at the flank of OWC does not contribute to an improvement in the oil recovery factor and pressure maintenance.

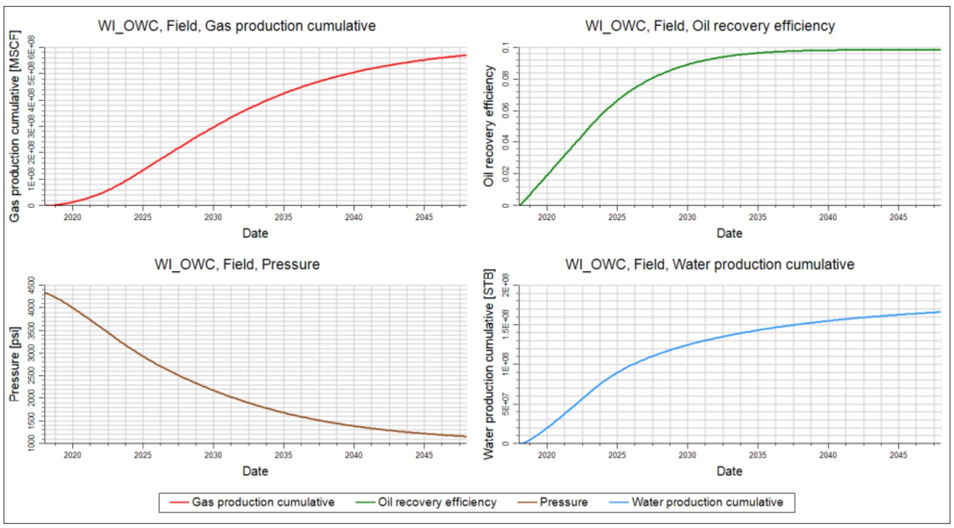


Figure 63.Field-scale results for WI@OWC

4.3.2 Water injection @ flank of OWC and GOC

Water is injected at the OWC using 16 horizontal water injectors and at right above the GOC using 10 horizontal water injectors as shown in Figure 64. Figure 65 depicts the pressure distribution before and after applying this pressure maintenance technique. Figure 66 presents saturations changes within the reservoir by using this pressure maintenance strategy. Due to water injection, the reservoir witnesses a harsh water coning issue that is noticed by the breakthrough of water up to the oil rim.

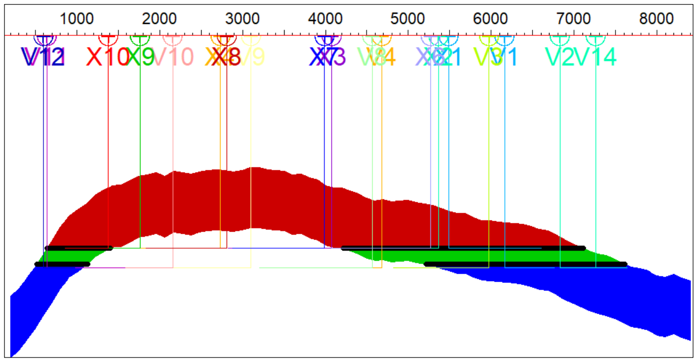


Figure 64. Cross-section of the reservoir showing the fluid types in regions and wells positions using WI@OWC and GOC scenario

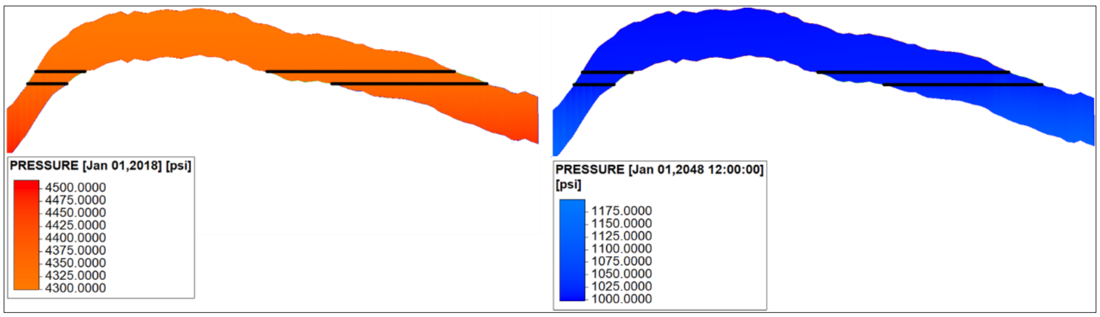


Figure 65. Cross-section of the reservoir showing the initial and final pressure values for WI@OWC and GOC scenario

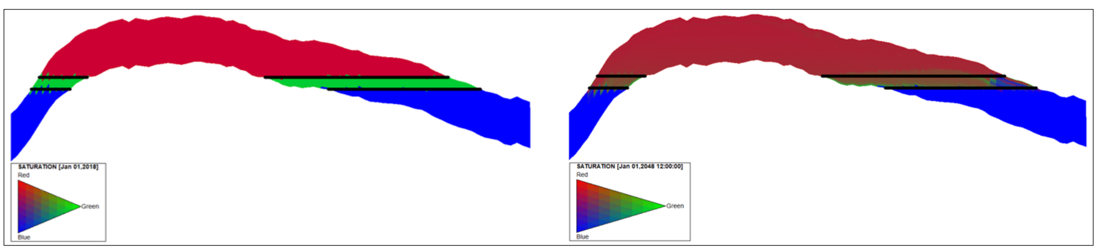


Figure 66. Cross-section of the reservoir showing fluid types in regions for WI@OWC and GOC scenario

Figure 67 shows the field scale results for WI at OWC and GOC. The field pressure decreases due to production, but this drop is much lower than the drop that happened in the base case without any pressure maintenance. Water coning is a major problem that results from this strategy and can be viewed by high water production cumulative. The oil production is better than the base case and the previous case (WI@OWC) with a value of 18.3%. We can notice here the impact of the balance that results from injecting water at the OWC and GOC and enhances oil production.

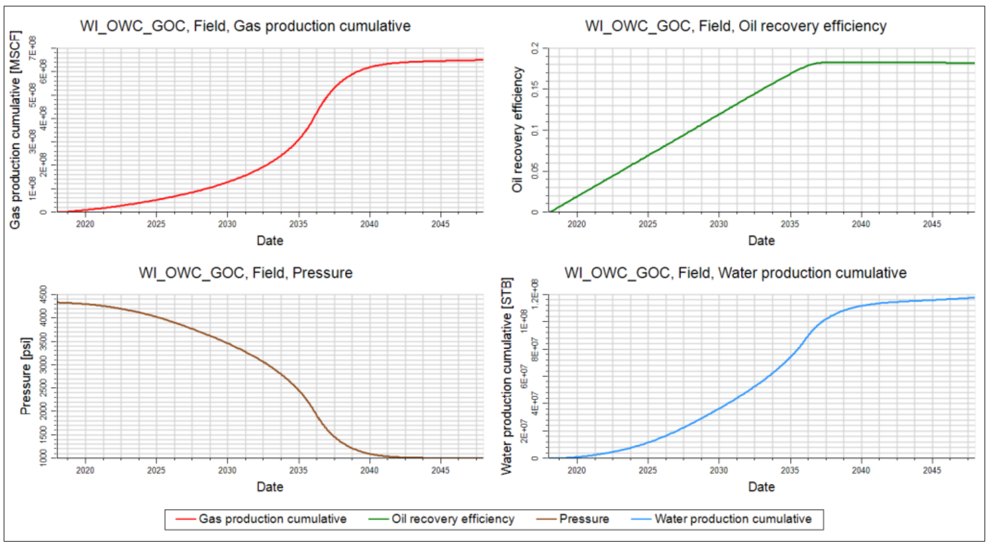


Figure 67. Field-scale results for WI@OWC and GOC

4.3.3 Gas injection in the gas cap

Gas is injected in the gas cap using vertical wells as seen in Figure 68. Results showed that an oil recovery factor of 27.12% is obtained using these gas injectors. Consequently, injecting gas in the gas proved to result in better oil production from the oil rim that water injection at the contacts, Figure 69. The improvement is also noticed in the pressure which did not witness the same drop as the previous case and was maintained at the end at 2800 psi. On the contrary, the gas injection was higher than the two previous scenarios due to gas injection. Due to the increased oil production, water coning was quicker in this case and resulted in higher water production cumulative than the two previous cases.

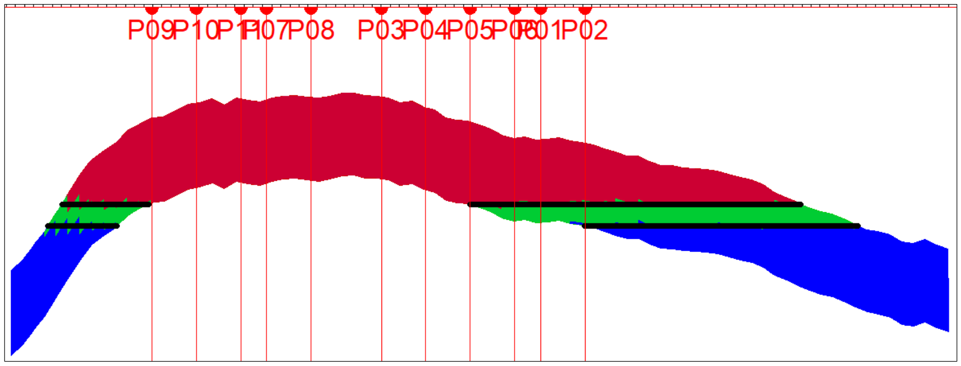


Figure 68. Cross-section of the reservoir showing the fluid types in regions and wells positions using a gas injection in the gas cap

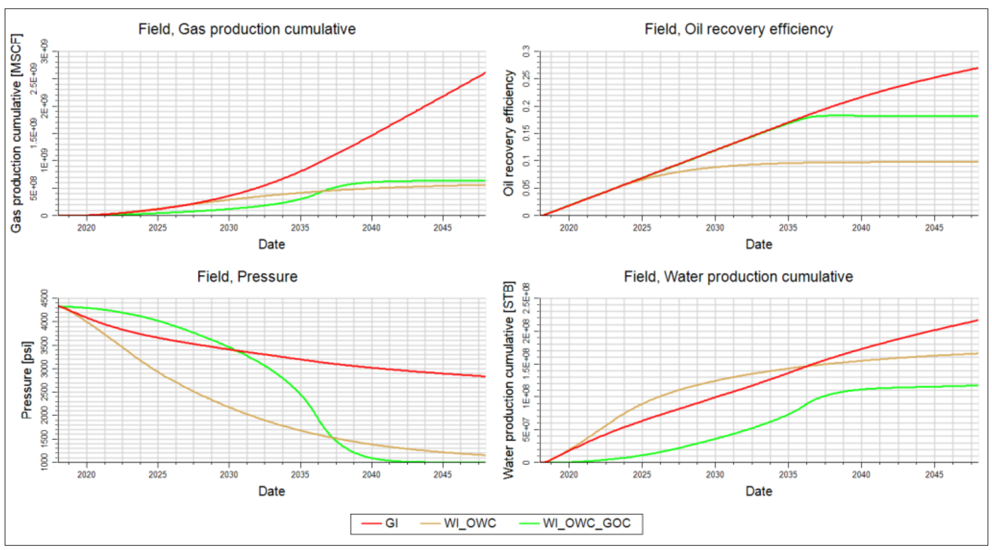


Figure 69. Field-scale results for WI@OWC and GOC

4.3.4 Gas injection in the gas cap and Water injection at the OWC

Gas is injected in the gas cap and water is injected at the OWC using the same number of wells as the previous respective cases, Figure 70. Results show that an oil recovery factor of 25.95% is obtained using these gas injectors. Thus the oil production is lower than the previous case of gas injection alone (27.12%). This is due to the even faster water coning and thus larger water cumulative, Figure 71.

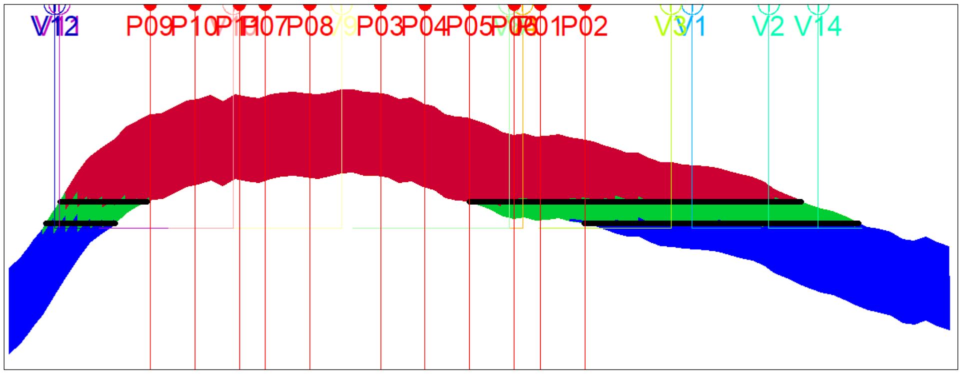


Figure 70. Cross-section of the reservoir showing the fluid types in regions and wells positions using gas strategy in the gas cap and water injection at the OWC scenario

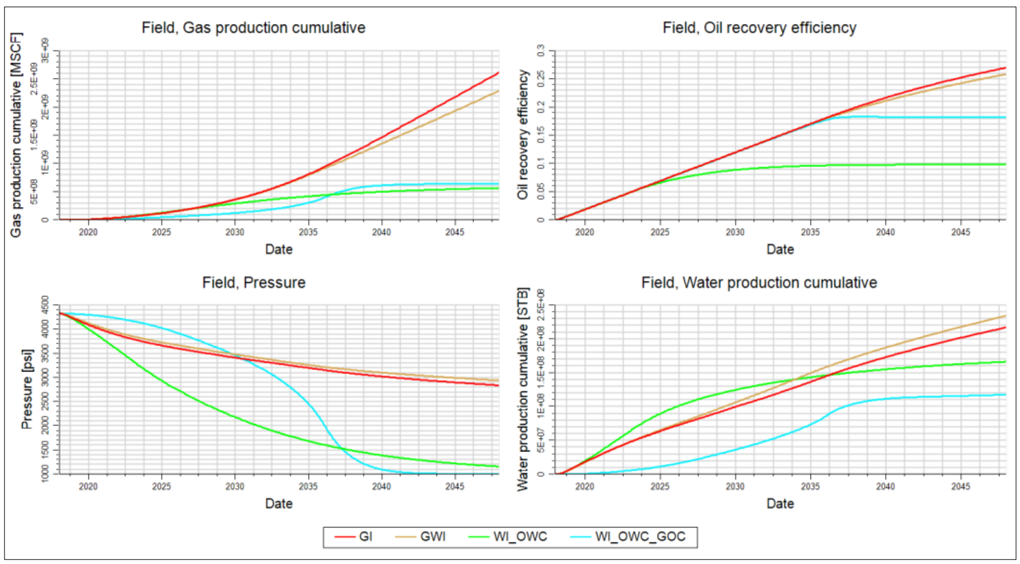


Figure 71. Field-scale results for WI@OWC and GI in the gas cap

4.3.5 Gas injection in the gas cap and Water injection at the OWC and GOC

Gas is injected in the gas cap water is injected at the OWC and GOC. Results show that an oil recovery factor of 30% is obtained and thus it is the best strategy to implement given the largest oil recovery among all cases.

4.3.6 Results Comparison (Pressure Maintenance)

Figure 72 shows the field scale results for the three scenarios investigated in pressure maintenance. The highest oil recovery is achieved by a combination of WI@ OWC and GOC and gas injection in the gas cap with an oil recovery factor (30.25%). Not only that, but this case also results in the lowest gas production cumulative and oil production cumulative due to the pressure maintenance and the force balance achieved retarding gas and water coning into the oil producers. Table 5 summarizes the oil recovery factor resulted from such pressure maintenance techniques.

Table 5. ORF obtained for pressure maintenance

Technique	Oil RF
WI @ OWC	10%
WI @ OWC & GOC	18.3%
GI	27.2%
GI & WI@OWC	25.95%
All	30.25%

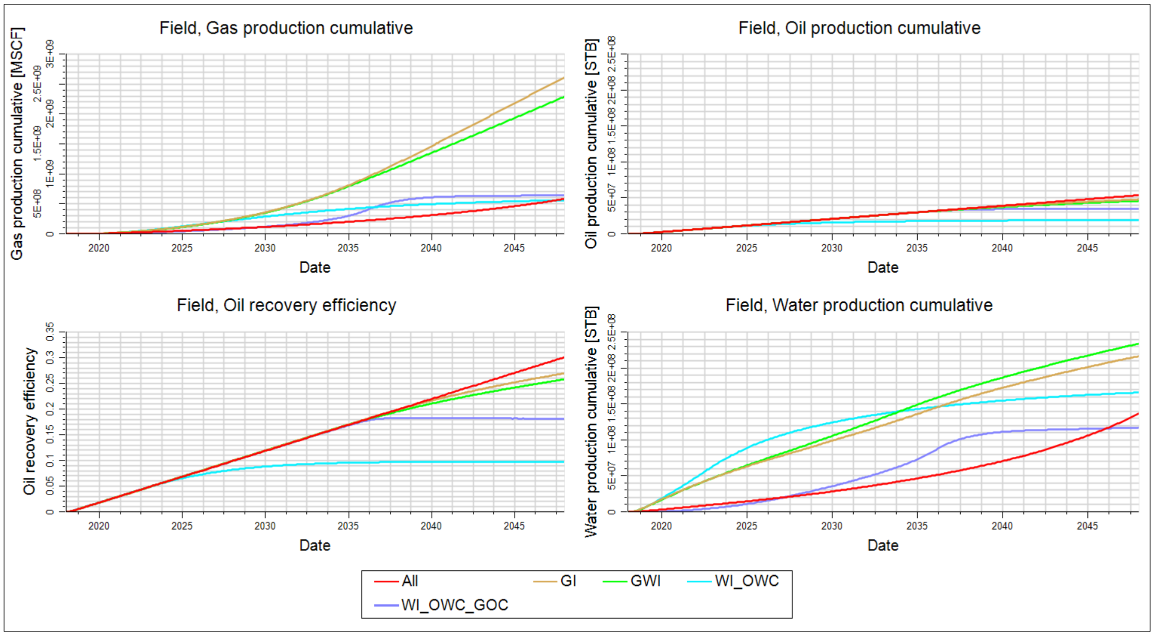


Figure 72.Field-scale results for pressure maintenance scenarios

4.4 Gas Cap Size

A sensitivity analysis is done on the M factor. Figure 73 shows the variation of oil and gas volumes by changing the GOC up and down each time by 10 ft. To see the impact, 5 scenarios of gas cap size are taken with the base case at the initial GOC (7500 ft). The results of oil RF are shown in Table 6. As the GOC moves up, the oil RF increase and vise versa; Maximum oil recovery is for Sen 9 with 14.3% while the lowest RF is for Sen3 (6.89%). The oil RF is generally low because we are using only vertical wells without any pressure maintenance to produce oil alone from the oil rim.

GOC (ft)	Case	Gas 1 (MM rb)	Oil 1 (MM rb)	Gas 2 (MM rb)	Oil 2 (MM rb)	Total Oil	Total Gas	m factor
-7440	Sen6	239.096	215.159	0	280.101	495.260	239.096	0.85
-7450	Sen5	269.474	184.765	0	280.088	464.853	269.474	0.96
-7460	Sen4	302.344	151.877	0	280.075	431.953	302.344	1.08
-7470	Sen3	336.732	117.471	0	280.062	397.533	336.732	1.20
-7480	Sen2	373.322	80.868	0	280.050	360.918	373.322	1.33
-7490	Sen1	412.078	42.098	0	280.037	322.135	412.078	1.47
-7500	**Base**	454.160	0	0	280.025	280.025	454.160	1.62
-7510	Sen7	454.143	0	45.685	234.327	234.327	499.828	1.94
-7520	Sen8	454.130	0	96.269	183.735	183.735	550.399	2.47
-7530	Sen9	454.116	0	150.948	129.045	129.045	605.064	3.52
-7540	Sen10	454.102	0	213.381	66.601	66.601	667.483	6.82

where *m* is the ratio of the free gas phase and free oil phase volumes and is defined by:

$$m = \frac{V_{fgi}}{V_{foi}} = \frac{G_{fgi} B_{gi}}{N_{foi} B_{oi}} \quad \text{.....................(5)}$$

Gas 1 is the free gas phase volume (MM rb)	Region 1 above GOC
Oil 2 is the free oil phase volume (MM rb)	Region 2 below GOC

Figure 73. Gas cap size sensitivity

Table 6. Oil RF for Gas Cap Size Sensitivity

Case	Oil RF
Sen 3	**6.89%**
Sen 1	**8.48%**
Base	**9.53%**
Sen 7	**10.85%**
Sen 9	**14.3%**

Figure 74 shows the field scale results for the 5 cases considered. Best results are achieved for Sen 9 cases in terms of pressure drop, water cut, oil production, and GOR.

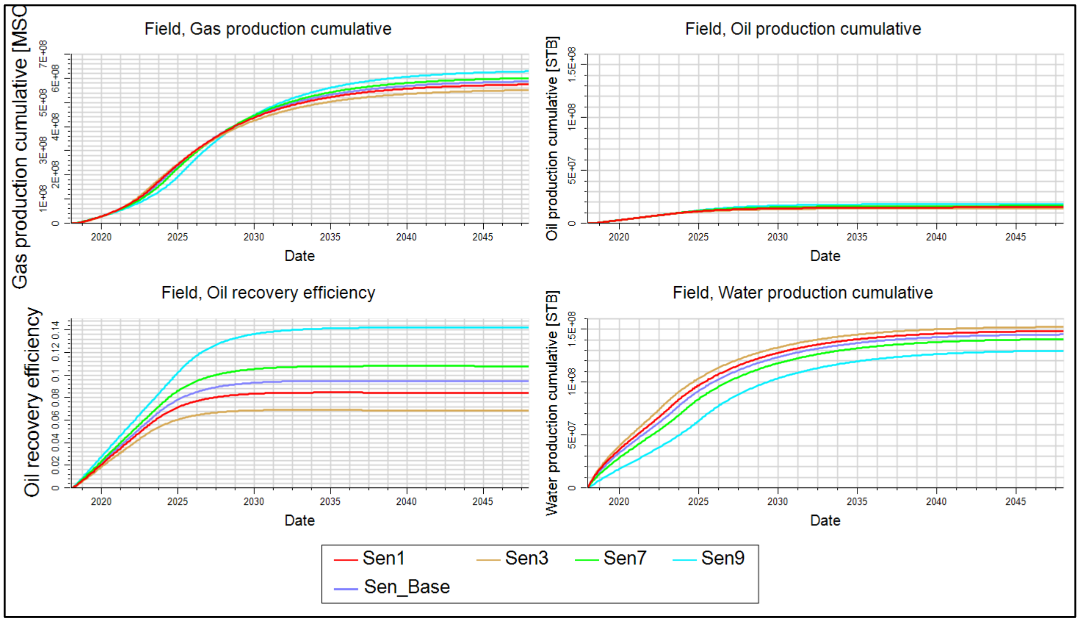


Figure 74. Field-scale results for gas cap size sensitivity

4.5 Heterogeneity

To represent the real case scenario, it is important to mimic the Thamama B formation in which the upper part of the reservoir has higher permeability and hence different SCAL properties. Heterogeneity sensitivity is done by taking different K (i,j,k) values using permeability multipliers. The case to consider is oil rim development only strategy using vertical wells without any pressure maintenance. Figure 75 shows the Cross-section of the permeability with the various cases considered below:

- Base case: multiplier=1
- Hetro1: multiplier= 10, (K1)
- Hetro2: multiplier= 100, (K2)

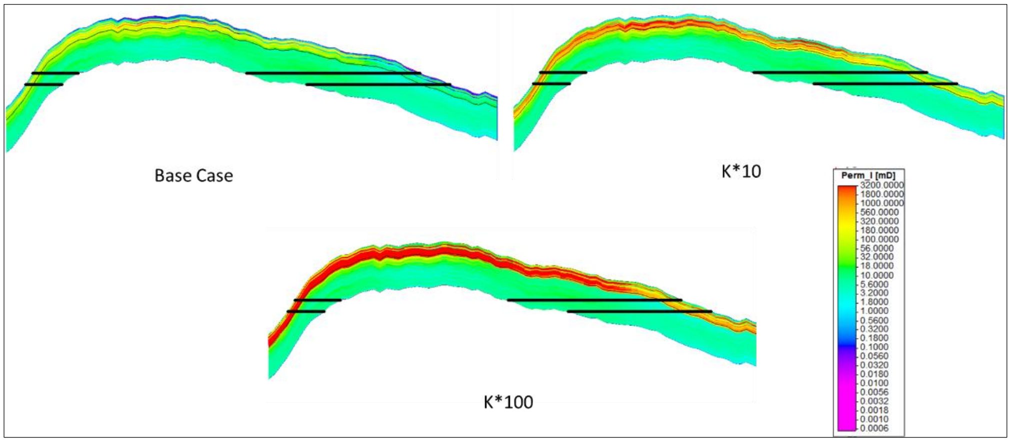


Figure 75. Cross-section of the reservoir showing the permeability X in the base case and the scenarios considered for heterogeneity sensitivity

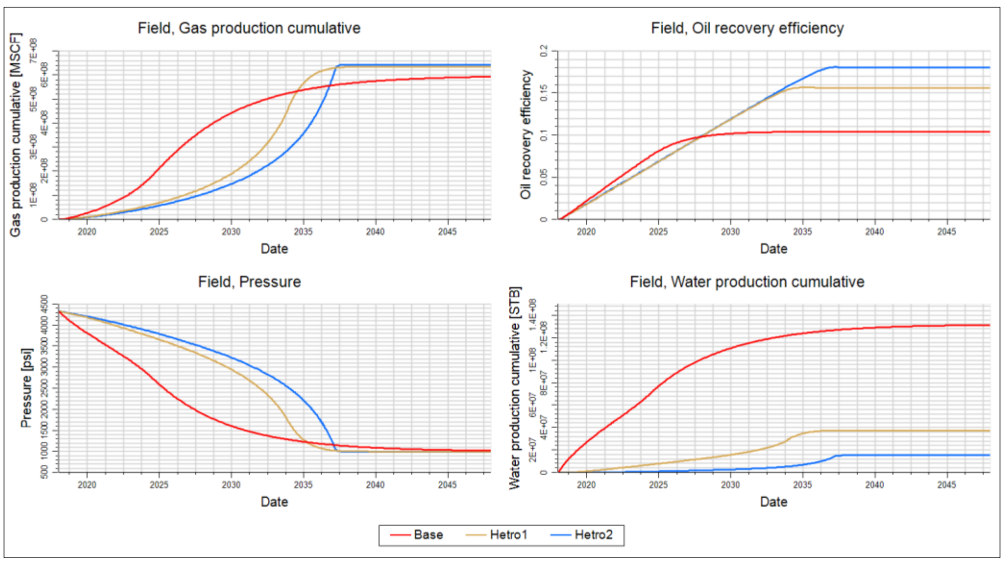


Figure 76. Field-scale results for gas cap size sensitivity

Figure 76 shows the field scale results for the 3 cases considered. Best results are achieved for the Het 3 case in terms of pressure drop, water cut, oil production, and GOR. The oil recovery factors are improved from 9.8% (base) to 15% (K1) to 18% (K2).

4.6 Sensitivity Analysis Results

The results of the sensitivity analysis are summarized in figure 77 which shows the impact of each of the 5 parameters considered on the oil recovery factor. Based on the results, the oil recovery factor is most sensitive to pressure maintenance and less sensitive to the order of depletion, especially when using vertical wells. Figure 78 shows the journey of the oil recovery factor resulted from most of the tested scenarios. From as low as 9.85% using vertical wells only to develop the oil rim up to 30.25% using water and gas injection as pressure maintenance.

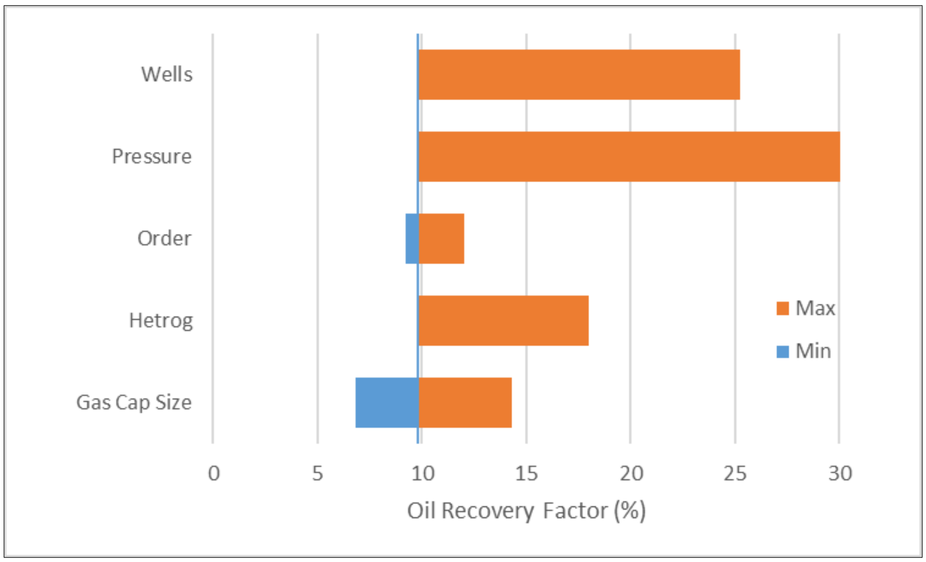


Figure 77. Sensitivity analysis results

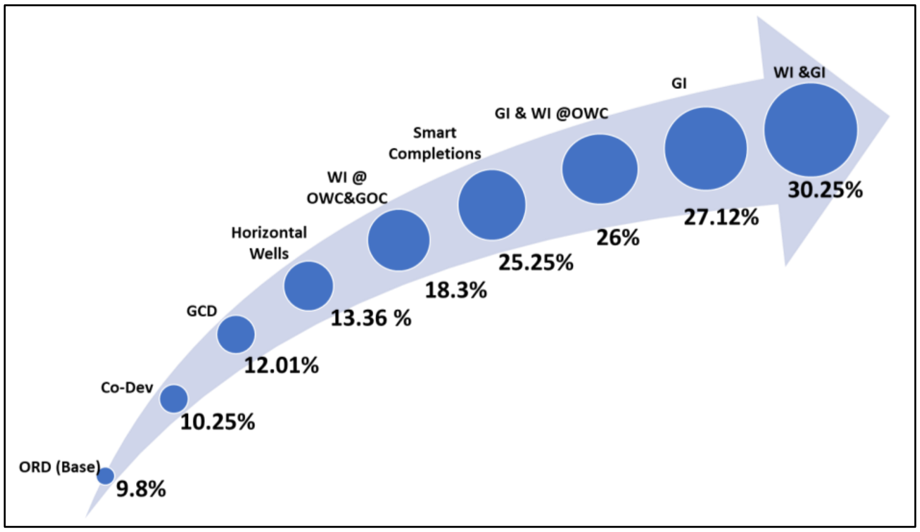


Figure 78. The journey of oil recovery factor for various scenarios

Moreover, to see the impact of more than one parameter together on the oil recovery for example wells type, the order of depletion, and pressure maintenance, an extra case was run for the purpose. The result of this case can guide the operator on the best oil recovery factor that can be resulted from developing such an oil rim reservoir. Results showed that combining smart completions (constraining GOC and Water cut from the surface) using the co-development strategy along with injection gas in the gas cap and water at the contacts, an oil recovery factor of 45% can be achieved with very good maintenance of pressure as seen in Figure 79. Therefore this is the recommended scenario that can be implemented for such an oil rim reservoir given the uncertainties and complexities available.

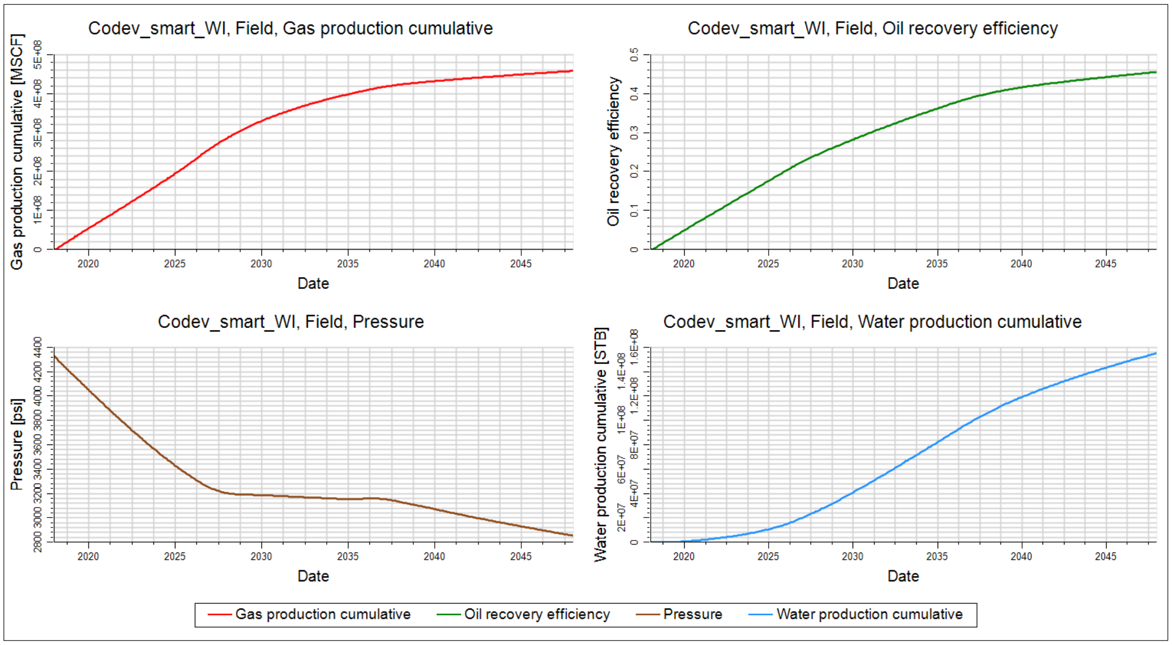


Figure 79. Field results obtained for the recommended scenario

CHAPTER 5

CONCLUSION

- Applying the right technologies and robust technical initiatives can turn an uneconomical development of an oil rim reservoir into a valid one
- It is very important to understand the physical flow of the fluids during the development of an oil rim to mitigate the future challenges represented by limited recovery factor due to gas and water coning.
- The order of depletion is not considered one of the impacting parameters when developing oil rims using vertical wells without any pressure maintenance method.
- Results of well type and completion sensitivity showed better recovery factors for horizontal wells than vertical wells. Wells that are equipped with smart completions also showed better results of oil rim efficiency than horizontals wells alone.
- The sensitivity made on the gas cap size and the location of the GOC, resulted in better recovery factors when moving the GOC down and thus larger gas cap size due to the condensation of gas that adds to the oil produced at the surface.
- Accurate permeability estimation is essential for an accurate estimate of the oil recovery.
- Sensitivity analysis on pressure maintenance showed that applying water injection at the flank of OWC and GOC with gas injection in the gas cap yield the highest oil recovery factor of 30.25%.

- The final results of the sensitivity analysis proved that the oil recovery factor is most sensible to pressure maintenance then to the type of wells and completions. Order of depletion is the lowest impacting parameter on the oil recovery efficiency.
- The best-recommended strategy for the future development of such a reservoir is by implementing co-development of oil and gas using horizontal wells equipped with smart completions for producing from the oil rim and vertical wells for gas gap production. The pressure maintenance suitable for this strategy is injecting water at both contact and gas injection in the gas cap. Such a case resulted in the maximum oil recovery factor achieved ever in this study which is 45%. However, it is very important to assess project economics, especially when using intelligent horizontal wells.
- This work done showed that it is possible to develop a thin oil rim under depletion mode and enhance the oil recovery to a good level

CHAPTER 6

FUTURE WORK

The following scenarios will be further investigated at a later stage:

SCAL and PVT properties

- Consider different PVT models with the different richness of the gas in the gas cap
- Consider different Gas/Oil and Oil/Water Kr curves and run sensitivity on the residual oil saturation
- Impact of the combinations of PVT and Kr curves on the movement of the GOC vs. time
- Sensitivity on the Imbibition Capillary pressure curves and their impact on the water injection/production

Smart Completions

- Actual presentation and simulation

Aquifer Strength

- Do sensitivity on the aquifer strength to see its impact on the oil recovery factor

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