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MASTER’S THESIS

RESERVOIR SIMULATION FOR OPTIMIZING OIL RECOVERY THROUGH CO_2 INJECTION IN DEPLETED RESERVOIRS

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MAGİSTR DİSSERTASİYA İŞİ

TÜKƏNMİŞ LAYLARDA CO_2 TƏSİRİ İLƏ NEFTİN ƏLDƏ EDİLMƏSİNİN OPTİMALLAŞDIRILMASI ÜÇÜN LAY SİMULYASİYASI

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INTRODUCTION

The relevance of the subject: There are several reasons for the relevance of the topic which is" Reservoir Simulation for Optimizing Oil Recovery through CO_2 Injection in Depleted Reservoirs".

Firstly, optimizing the production of the oil from the reservoirs which are either mature or depleted. It is known that most of the worldwide gas and oil fields are declining and indicated as depleted. Then, the known recovery methods, namely, primary and secondary ones only allow a certain amount of oil to be extracted (generally 20-40%). Therefore, this CO_2 injection method offers much more oil to be recovered from the mature (depleted) reservoirs.

Secondly, tackling the global energy demand and securing it. As it is known, there are two types of resources, which are conventional and unconventional. Once, the conventional ones, mainly, easily reachable reserves are decreased, unconventional resources should be extracted. However, the method of CO_2 injection, might increase the life of production and add its contribution to the global energy supply.

Thirdly, contributing to environmental protection. From the recent acceleration towards the environmental side, so many actions have been taken and there is a great emphasis on minimizing the carbon emissions and moving to the net zero, globally. So, the transition to the much more sustainable and renewable energy side is very important topic. Therefore, governments try to direct CO_2 injection-type enhanced oil recovery by applying some regulations and policies.

Lastly, accessing carbon capturing and storing. As it is clear that, there is a transition to carbon sequestration and these depleted reservoirs either oil or gas allow CO_2 storage and use it while it is required which is considered a long-term opportunity. So, it is obvious that, the combination of the CO_2 injection and carbon capturing and storing, is an incredible scenario, as it is said solving two tasks at the same time with only one single action. Which is, in particular, just optimizing the recovery of the oil with minimizing the emissions of the greenhouse gas.

In conclusion, to sum up, as far as it is concerned this topic is very relevant and the actuality of it is highly considered. As the industry of the petroleum (oil and gas) try to search to improve the hydrocarbon resources recovery, minimize the emissions of the greenhouse gases, and increase the energy conservation. Therefore, the simulation of the CO_2 injection for the optimization of the recovery in the mature fields makes it valuable to be taken into account.

The purpose of the research: It is possible to say that the major purpose of this research topic is to define the optimal parameters for the process of the CO_2 injection in order to maximize the recovery. As it is understandable that the high production of oil and gas leads to the reservoirs to be depleted. It is clear that the energy that helps to lift the petroleum to the surface lessens after each production. Therefore, it is required either to apply the recovery methods or drill another well. And drilling alone is so much just on the monetary side; thus, the recovery methods are applied. It is obvious that there are so many enhanced oil recovery methods and at the same time, they bring some certain advantages and disadvantages. The utilization of the CO_2 injection has an interesting outcome that it has great benefits in both the present and the future. As there is a focus on the transition to net zero carbon emission, it is possible to enhance oil recovery through CO_2 injection and storage. On the environmental side, it minimizes carbon footprint. About the depleted reservoirs, it can access the zones where the permeability is low and other methods might not be possible. The simulation of this process and understanding the improvement of oil recovery is very desirable. As it shows the whole process from injecting the CO_2 to on which parameters it affects. Applying the sensitivity analyses to certain parameters will indicate the dependence and alteration in the process.

The novelty and practical results of the investigation: The study of this simulation application for the specified EOR method is very important to understand how much effective to conduct this technique in depleted reservoirs. Here, the increment of the total rate has been defined, and it shows the effectiveness of CO_2 injection in matured reservoirs.

The objective of the research: It is possible to say that the major objective of this research topic is to build and apply model of reservoir simulation for optimization of production through CO_2 injection in depleted reservoirs, along with the maximization of oil recovery and efficiency. This research is completed based on a sequence of objectives.

1. To find and review all the works of literature that are related to the topic of this thesis.
2. To create a reservoir simulation model for certain depleted reservoir.
3. To investigate different scenarios for determining the performance of CO_2 injection as enhanced oil recovery.
4. To analyze certain parameters regarding the CO_2 injection EOR.
5. To optimize the production in regard to the simulation indications.

CHAPTER I. LITERATURE REVIEW

1.1. Conventional and Unconventional Reservoirs

As it is obvious that the petroleum products are considered one of the major energy sources in the globe (Caineng et al. 2014). It is possible to fall them into two broad categories, which are Conventional hydrocarbons and Unconventional hydrocarbons. There are enormous volumes of both types of hydrocarbons (conventional and unconventional) in the world, with a ratio of about 2:8, accordingly and altogether 5×10^{12} tons (Caineng et al. 2014, Caineng et al. 2013). There is a popular transition in the exploration and utilization of this type of hydrocarbons for the energy requirements because of the abundance of the unconventional hydrocarbons (Song et al. 2015). Furthermore, it is clear that vast majority of the oil and gas have been obtained using conventional type methods, and these resources are unfortunately running out daily. With the acceleration of technology, it becomes easier to develop unconventional type petroleum resources, that were previously thought to be unproducible (Hamada 2016). This is the rationale behind the current emphasis on the exploration and development of unconventional reservoirs.

Whereas about the conventional ones, as it is obvious, these types of reservoirs are very common worldwide and the most known types are sandstone, dolomite, and limestone. The petroleum located in these rocks are quite easier to produce and generally are in faults, anticlines or salt domes. About the advantages, it is possible to say that these ones are very predictable. After certain well and geological analysis, it is plausible to determine where petroleum is located and how much are there. So, it becomes easier for the drilling actions due to the decrease of the threat of dry holes. It is quite understandable that conventional reservoirs are considered to give a much higher recovery percentage than unconventional ones which means it is possible to produce more petroleum. (Conventional Reservoirs)

In order to understand it deeply, it can be said that conventional hydrocarbons are the petroleum hydrocarbons that are located in the discrete sections or pools. This rock formations generally contain greater porosity and permeability, plus they are located below the impermeable layer. This layer is very crucial as it does not allow the hydrocarbons to flow into other sections and trap under this. These aforementioned pools are basically developed with the help of the vertical wellbores and minimum stimulation actions. These conventional pools are divided into the some certain categories due to their trap mechanisms: (Ministry of Natural Gas Development 2016)

1. Structural traps (faults or folds)
2. Dome-type structures (diapiric rise)
3. Stratigraphic traps (rock type change)
4. Combinations of previous examples.

It is important to remember that unconventional type hydrocarbons are those that cannot be obtained using a standard production well by just naturally pressurizing them without any mixture and heat. It is necessary to have and utilize the unconventional and cutting-edge technologies. (Gordon 2012). As it is accepted that the characteristics of the reservoir geology (Song et al., 2015), the complicated petrophysical system (Hamada, 2016), and the hydrocarbon production procedures (Heikal 2008) are what set the unconventional reservoirs apart from the conventional ones.

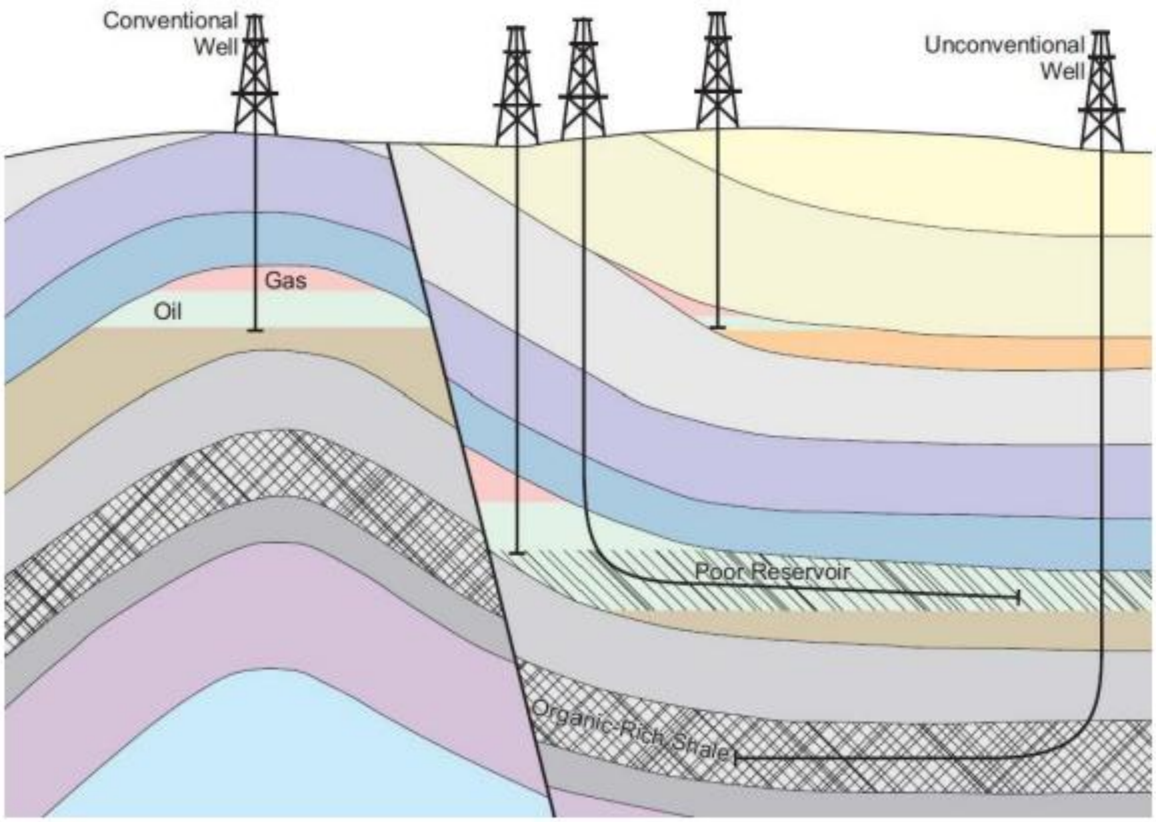

Figure 1.1.1. Comparison of Conventional and Unconventional wells

The conventional reservoirs have an oil-water contact and a consistent pressure system (Zou et al., 2013). It is possible to produce the hydrocarbons from these with a small number of wellbores, and the buried fluids can be recovered without the need for any stimulation techniques. However, due to the fact that unconventional hydrocarbon reserves do not naturally occur inside the rock, it becomes challenging to identify and produce them (Hamada 2016). They are considerably less permeable and porous. Moreover, in order to obtain a desired product, it is required to stimulate them and utilize additional production methods, such as the enhanced oil recovery (EOR) (Zou et al. 2013; Sprunger et al. 2021; Syed et al. 2021a; Kerr et al. 2020; Li et al. 2019a; Hawthorne et al. 2019; Jin et al. 2019). Thus, these unconventional procedures are considered more costly than the traditional ones from an economical point of view. Nonetheless, their substantial amount of volumes prioritizes them as more viable options for the future petroleum production in the world. From Figure 1.1.1., it is plausible to differentiate the wells of conventional and unconventional. (Ministry of Natural Gas Development, 2016)

Due to the easiness, the scientists generally refer to the resources in a resource triangle. As it is obvious that the upper part is way smaller rather than the lower part, here upper and lower are considered as the conventional and unconventional, respectively. So, it should be mentioned that from Figure 1.1.2. it is quite understandable to see the main features and characteristics.

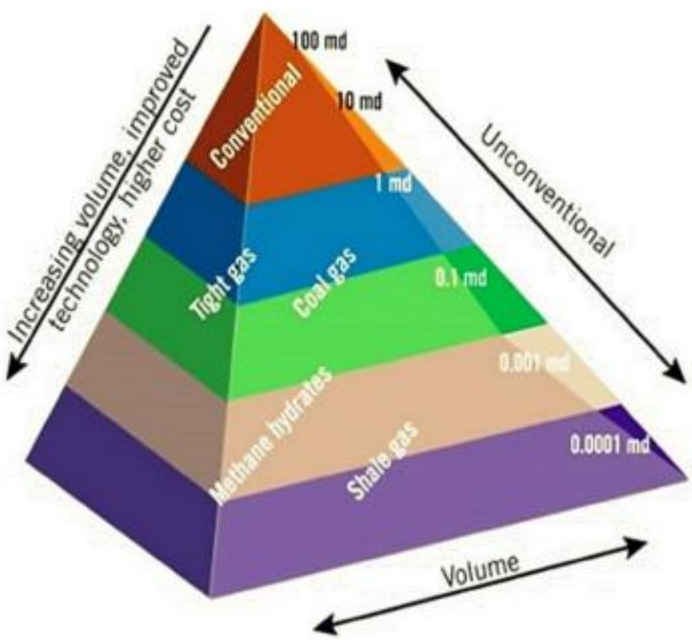

Figure 1.1.2. Resource Triangle (Rahim et al. 2012)

In order to analyze the unconventional hydrocarbons, it is required to consider them in two separate types which are unconventional liquids and unconventional gas. So, **Unconventional Liquids** need an unconventional production technique for the extraction of more liquid. Compared to the ordinary conventional oil, these liquids are measured substantially heavier (Gordon 2012). The following types of the unconventional liquids can be distinguished based on the density, viscosity, and the hydrogen/carbon ratio of the oil. Bitumen, shale oil, heavy and extra-heavy oil can be exemplified (Thakur and Rajput 2011). In addition to this, owing to some literatures biofuels, gas to liquid (GTL), and coal to liquid (CTL) might be classified as the unconventional liquids (Gordon 2012).

From Figure 1.1.3. it is quite possible to see that under the subsurface, the unconventional liquids make up a larger proportion of oil than conventional. It is estimated that the planet contains 45,000 billion barrels of unconventional oil, and it is mathematically possible to produce 1000 billion barrels of it (Thakur and Rajput 2011). It is worth to say that commercially recoverable reserves for these three aforementioned unconventional oils are estimated to be around 350 billion tons, according to the latest estimations. It is known that about 60% of them are found in South and North America, while a significant amount of it is located in Eurasian regions, and the remaining parts are dispersed equally throughout the globe (Kapustin and Grushevenko 2018).

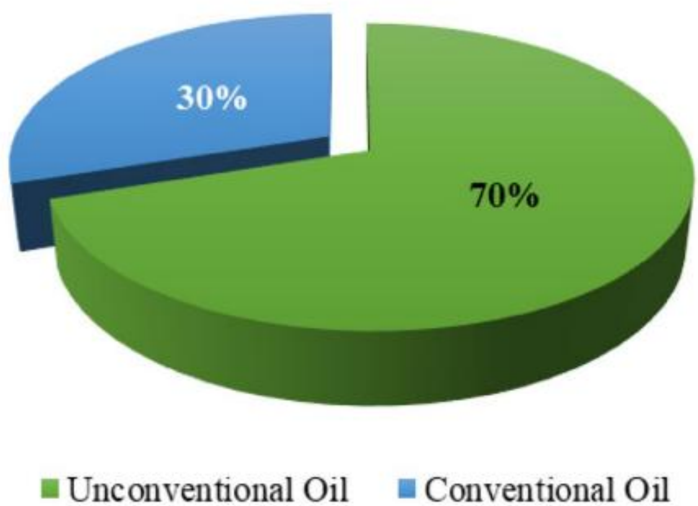

Figure 1.1.3. World Proven Oil Reserves (Thakur and Rajput 2011)

There will undoubtedly be a rise in the supply of the unconventional liquids because of a rise in the liquid demand and consumption. Furthermore, the development of the technology will also lead to the unconventional liquid production while increasing the global supply of these liquids. In Figure 1.1.4. the projected liquid supply till the year of 2040 is indicated. In total, in the y-axis and the x-axis, the liquid amount and the liquid types are illustrated, respectively. It is obvious to see that for the liquids, there are the biofuels, the natural gas liquids, the tight oil, the oil sands, the deep water, the conventional and other liquids. The NGLs, the deep water, the tight oil, and the oil sands have seen greater gains. It is forecasted that the worldwide supply of the tight oil and the NGLs in liquid form would surpass thirty percent by 2040. It is also important to say that these NGLs and the tight oil will cover a hefty amount of the total resources.

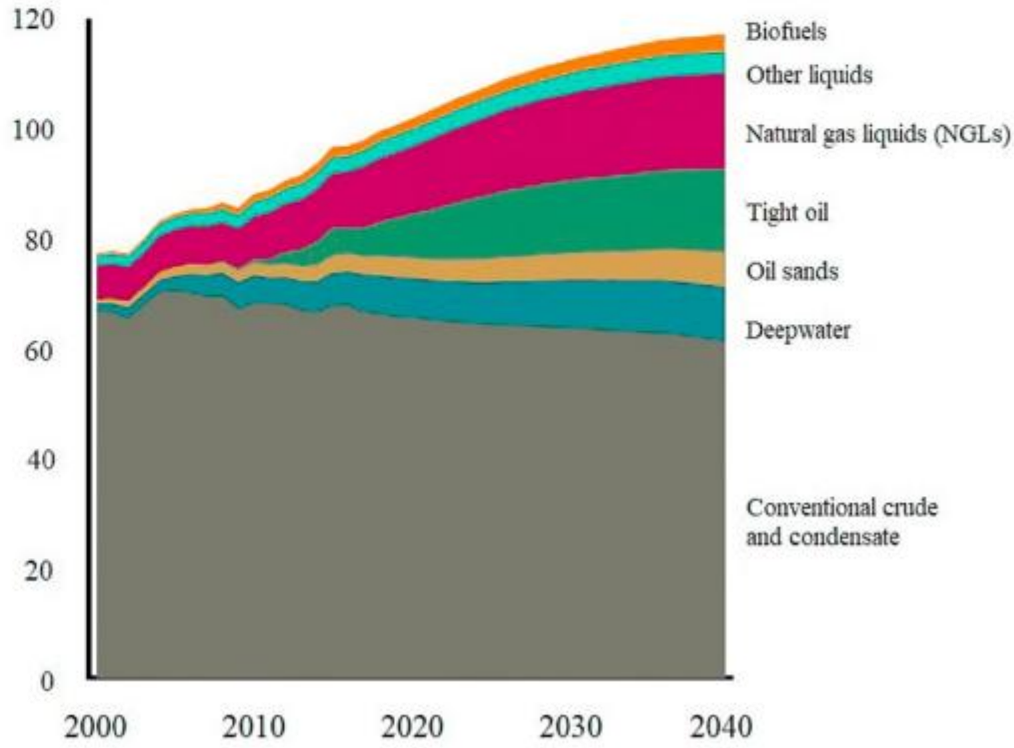

Figure 1.1.4. Liquid Supply Worldwide ExxonMobil (2018)

The total risky shale oil in place and the total theoretically recoverable risky shale oil resources are projected to be 5799 billion barrels and 286.9 billion barrels, respectively, based on the EIA 2013 study (Muther et al. 2022). Table 1.1.1. displays the distribution of this shale oil in the year of 2013. However, according to another recent assessment published by the World Energy Council in 2016, the United States has the largest tight oil reserves in the world, followed by the countries of Australia, China, and Argentina (World Energy Resources, 2020). From Figure 1.1.5. it is possible to see the tight oil distribution by nation.

It is known that Unconventional Gas products are unable to be produced at an economic condition if the well, no matter what type it is vertical or horizontal, is not stimulated by significant hydraulic fractures, a multilateral wellbore is dug, or alternative procedures are employed to extract substantially more from the resources. Due to their lateral extent, these resources are considered easier to find. 83400 trillion cubic feet of unconventional proved gas in shale, tight, and coal bed methane are known to exist worldwide, with potential reserves computed to be 184200 trillion cubic feet (Dong et al. 2011). Nowadays, it is maintained that shale, tight, and coal bed methane CBM) contribute considerably to global gas production. Natural gas derived from shale and tight resources is usually referred to unconventional gas.

Table 1.1.1. Worldwide Shale Oil Resources (Muther et al. 2022)

Continent	Risked oil in place (billion barrels)	Risked technically recoverable (billion barrels)
North America (exclude USA)	437	21.9
Australia	403	17.5
South America	1152	59.7
Europe	1551	88.6
Africa	882	38.1
Asia	1375	61.1
Sub-total	5799	286.9
USA	954	47.7
Total	6753	334.6

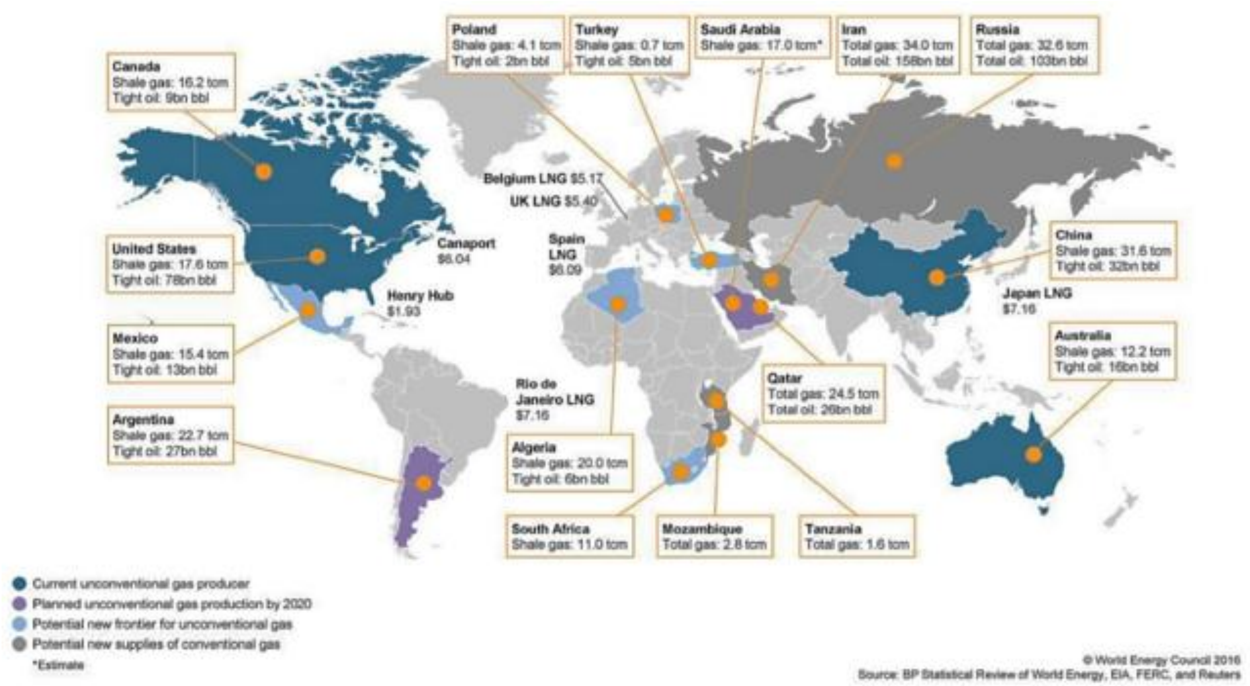

Figure 1.1.5. Worldwide Tight Oil Resources (World Energy Resources, 2020)

It is trustworthy to note that the term coal bed methane (CBM) refers to a substance that is present in coal seams and is formed when various gases, including the methane, are released. In order to generate it, it is required to inject the water inside the coal seams for the purpose of the pressure reduction. The majority of the coal bed methane is located in the shallow coal beds. Generally, the shale gas is linked to the source rock shale, that is able to possess very low permeability, whilst the tight gas is typically found in the sandstones whose porosity and permeability is quite high and very low, accordingly (Mokhatab et al. 2019). It is obvious that the gas hydrates are classified as an unconventional gas as well. When the water and hydrate-forming methane gas combine at low temperatures and high pressures, ice-like solids known as gas hydrates appear. These enormous volumes might be seen in the aqueous sediments of deep oceans. Although there are vast reserves of this resource, there is not currently a suitable development plan for its utilization. Several other gases are also included in the category of the unconventional gases with these resources. These generally consist of the landfill gas, the flue gas, the synthetic gas, the biogas, and the gas in the pressurized zone (Speight 2019).

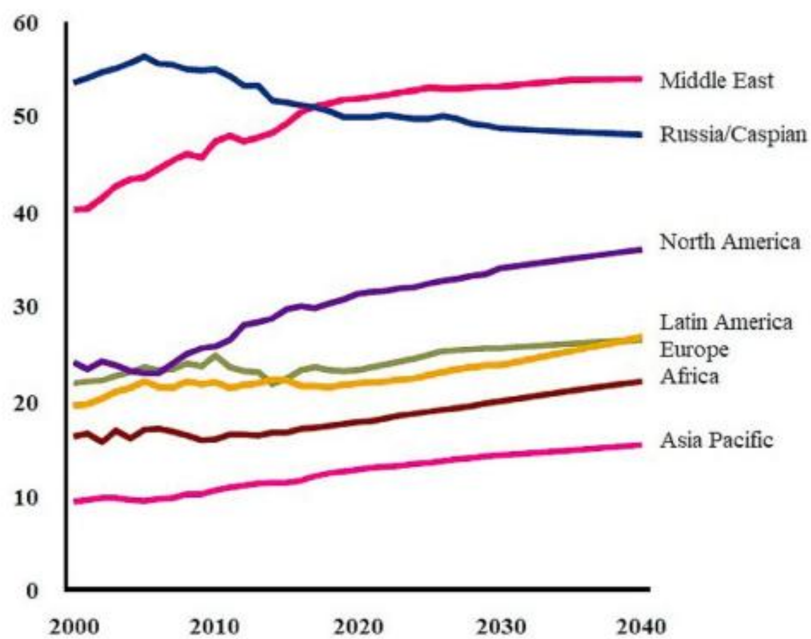

Figure 1.1.6. Prediction of Energy Demand

As seen in Figure 1.1.6., it is worth to mention that there is now a growing need for the natural gas. The demand is expected to rise globally by 40% during the 24-year period between 2016 and 2040. In order to meet this global demand, it is obvious that more unconventional gas must be produced. Less than 15% of the natural gas resources that are currently recoverable have been produced. It is thought that approximately 45% of the remaining natural gas resources might be generated from the tight gas, the shale gas, and the coalbed methane. In Figure 1.1.7., it is possible to see the figures exactly and detailly (ExxonMobil 2018). It is obvious to check that Table 1.1.2. displays the global distribution of tight, coal bed methane, and shale gas.

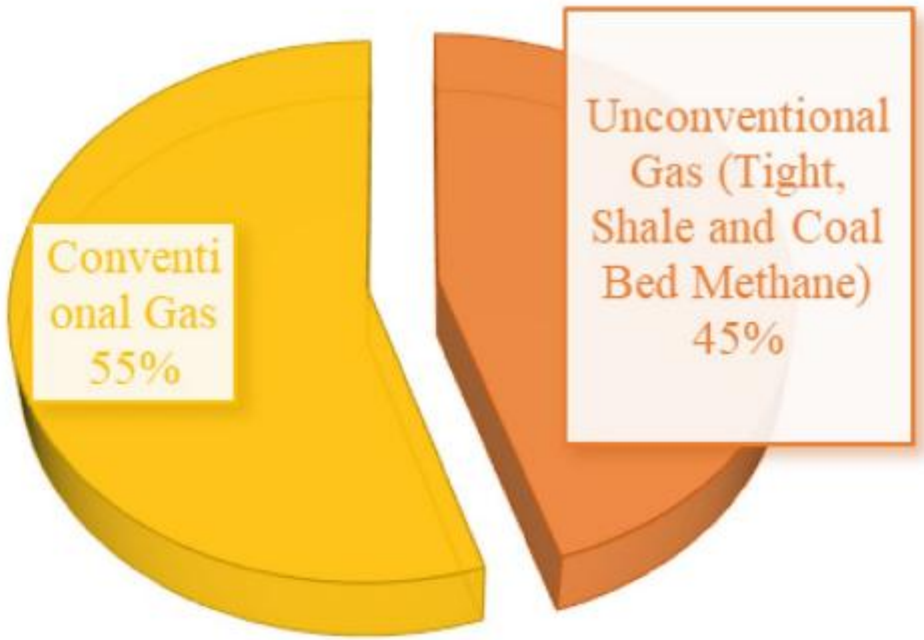

Figure 1.1.7. Worldwide remaining gas resources

As the figures for the unconventional resources are indicated for the globe, it might be quite interesting to know them country by country. Based on the unconventional resources, The United States, China, Canada, Australia, and others are, understandably, very popular.

With respect to **the USA**, wide spreaded unconventional resources can be found from the East Coast to the West Coast. It is estimated that the combined unproven technical recoverable tight/shale oil reserves from those basins are 195.4 billion barrels, while the estimated recoverable gas amounts are 1712.9 trillion standard cubic feet. Considering this, a newly released analysis (EIA 2022) estimates that the technically recoverable coalbed methane reserves of the United States are 76 TCF. It is important to note that the bottom 48 states account for the majority of the estimated 342135 billion cubic feet of proved US shale gas reserves, which are primarily from Texas and Pennsylvania, it is also possible to look at it in Figure 1.1.8.. As for the coalbed methane, Figure 1.1.9. demonstrate reserves of about 11878 BCF with contributions from the lower 48 states in 2019. Here, different countries or continents with the resources of hydrocarbons illustrated.

Table 1.1.2. Worldwide Distribution of Unconventional Resources (IEA 2009)

Continent	Resources/10^{12} m^3			
	Tight Gas	Coalbed Methane	Shale Gas	Total
North America	38.8	85.4	108.8	233
Latin America	36.6	1.1	59.9	97.6
Europe	12.2	7.7	15.5	35.4
Formal Soviet Union	25.5	112	17.7	155.2
Middle East & North Africa	23.3	0	72.2	95.5
South Africa	22.2	1.1	7.8	31.1
Pacific-Asia	51	48.8	174.3	274.1
Total equivalent oil	209.6	256.1	456.2	921.9

As regards **China**, the Yangtze Platform, Songliao, Sichuan, Jianghan, Junggar, Subei, Tarim, Ordos, Bohai Bay, and the other significant potential basins contain abundant unconventional resources (Zhu 2019; U.S. Energy Information Administration. 2015; Guoxin and Ruki 2020). It is believed that China possesses 95.16×10^{12} m^3 of tight gas and 650.44×10^{12} m^3 of shale gas. The recoverable resources of the tight gas and the shale gas are 15.89×10^{12} m^3 and 161.50×10^{12} m^3, accordingly. While the shale gas is primarily found in the Middle Lower Yangtze, the Ordos Basin, the Sichuan Basin, and the Tarim basins, the tight gas deposits are primarily concentrated in the Tarim, Songliao, and the Sichuan basins. It ought to be mentioned that the additional information about the gas reserves of China can be found in Figure 1.1.10. (Zheng et al. 2018) The reserves against the date graphs have been illustrated in order to understand these resources in detail.

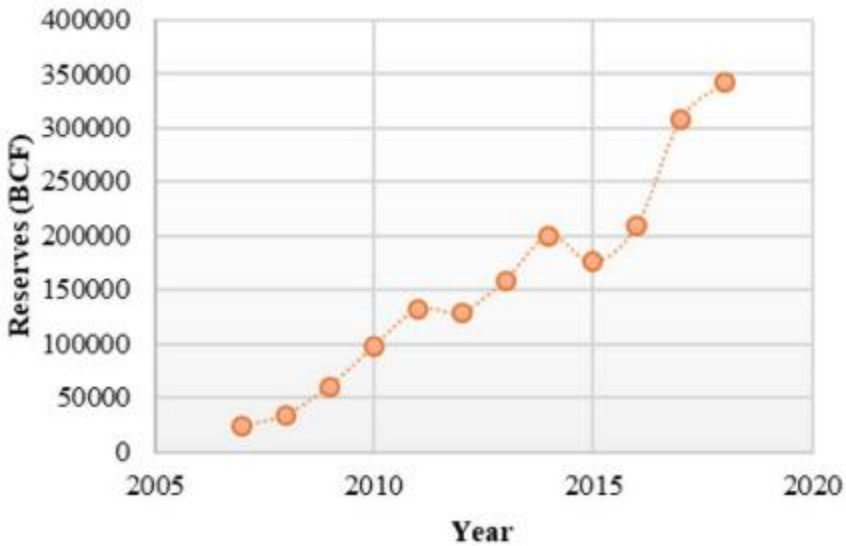

Figure 1.1.8. Proved Shale Gas reserves of the USA

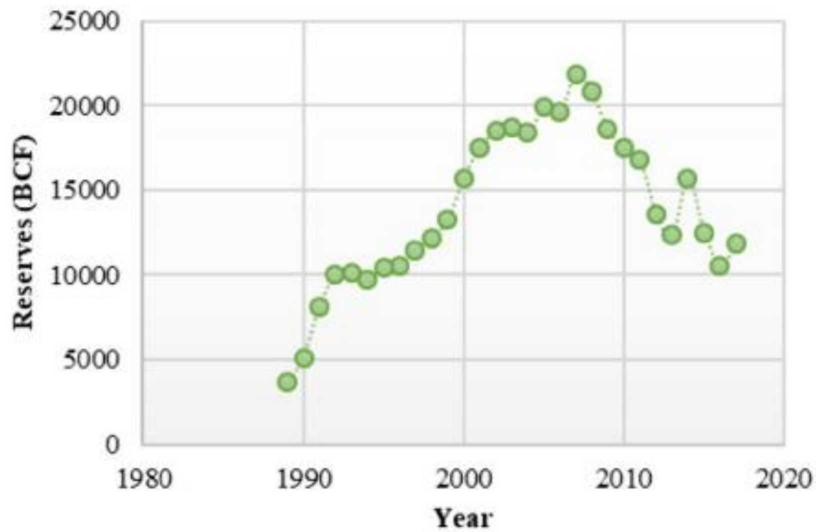

Figure 1.1.9. Proved Coalbed methane reserves of the USA

China has enormous potential for the tight and shale oil, but its estimations are imprecise and depend on the evaluation and analysis of certain several organizations. The US Energy Information Administration 2013 estimates that the recoverable reserves of the shale oil are 32.2 billion barrels, or roughly 45 × 10^8 t (U.S. Energy Information Administration. 2015). According to the recent research, the recoverable resources of low and medium-mature shale oil are projected to be between 700 × 10^8 t and 900 × 10^8 t, with a quantity that can be commercially recovered between 150×10^8 t and 200×10^8 t. Furthermore, it is discovered that the geological resources of medium and high-maturity shale oil are around 100×10^8 t. The tight oil geological resources of China are estimated to be approximately 178.2×10^8 t, of which 17.65×10^8 t are technically recoverable (Guoxin and Rukai 2020).

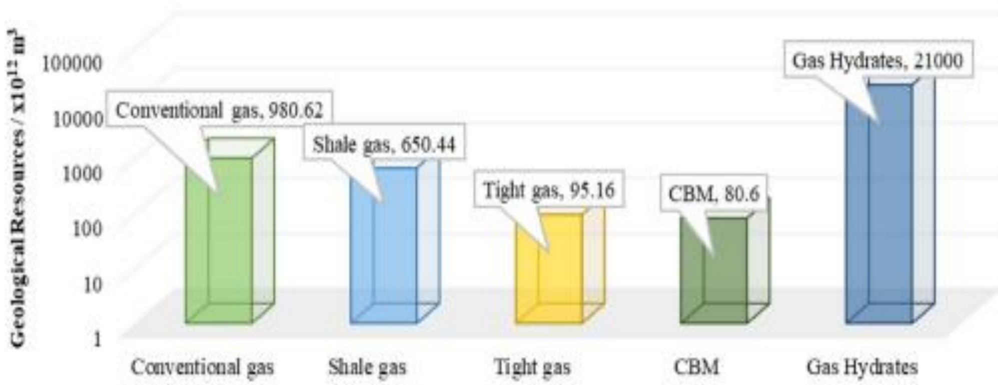

Figure 1.1.10. Gas reserves of China (Zheng et al. 2018)

1.2. Depleted Reservoirs

After considering the conventional and unconventional types of reservoirs, it is possible to differentiate them much more easily. So, the main topic of this thesis as it is related to the Depleted Reservoirs will be started here. As it is known that the depleted reservoirs whether it is oil or gas type are an undeniable part of the energy industry. It was, it is and it will be. It is obvious that these formations are mainly full of hydrocarbons, and they have been drilled to produce a hefty amount of oil and gas content. Thus, it led to a decrease in the volume. In order to figure these mature reservoirs out, it ought to be required to explore from their beginning to different characteristics.

Initially, mature fields are considered formations that contain commercially producible amounts of hydrocarbons, namely, the conventional resources, however, they have been utilized and generated via primary and secondary production. So, they are now at a point where it is quietly difficult and complicated to produce economically viable oil and gas with known methods, namely, the conventional attempts (Muggeridge 2014)

About the characteristics, there are the pressure reduction, the water increase, the porosity and the permeability changes and others. In detail, it can be said that the reduction in a pressure happens because as the amount of the fluid that is produced increases then the corresponding pressure of the reservoir decreases. Then, the next one is a water content. As the years pass, more production happens, and the well starts to extract the water to the surface. It is clear that most of the mature fields contain considerably high water cuts. It is maintained that the production of the fluid from the reservoir affects the rock properties, such as the porosity and the permeability. Even though, so many changes happen in the properties of the reservoir, it is still considered to be used for other purposes as it contains some valuable elements (Fanchi 2016). As it is written, it is important to know that in the depleted reservoirs the alteration of the formation strength and fracture pressure have been observed. It ought to be mentioned that the depletion rate might vary greatly with the effect on the fracture pressure towards the reservoir itself. Moreover, it is clear that the specific areas with the residual pore pressure might exist alongside the depleted pore pressure areas (Solve Depletion Challenges).

The process of reservoir depletion is quite complex and long. As it is obvious, firstly, it is required to be formed, then depleted. So, the first step is the formation itself, where the organic matter is deposited and buried through several millions of decades. Then it is called a maturation process, in which these organic mixtures have been transformed into the hydrocarbons with the applied heat and pressure which takes so much time again. The next step is called as migration. Here, the hydrocarbon moves upside down from the source rock to the reservoir rock with three migration steps. As it is clear, they are primary migration, secondary migration and tertiary migration. It is indispensable to say that the time factor is very important here. And there is cap rock which is an impermeable layer above the system. It is for the prevention of hydrocarbons to go through further (Tissot 2013).

With respect to the depletion of the reservoir, it is just mentioned beforehand, that as the production continues it starts to decline and deplete. So, firstly, it is owing to primary recovery. Here, the production of the oil and the gas happens based on the natural energy of the reservoir itself. Then there is secondary recovery, which is the injection of the fluid process for not only maintaining the pressure but also optimizing the production. After that Enhanced Oil Recovery comes which can also be called as an EOR method. This method is utilized when it is required to acquire the remained hydrocarbons which are obviously located in the farthest pores (Lake 2014). As the process of the oil and the gas extraction goes on, the pressure continues to decrease and reaches the level. That level is called an economic limit where it is possible to say that the production is not worth for continuing. The reason is the production costs become greater than the worth of the produced oil and gas (Walsh 2003). As from Figure 1.2.1, it is possible to see the depletion of the reservoir after the production (Maduabuchi 2019). Firstly, reservoir at original conditions can be seen, then the reservoir in which the half of it is depleted might be observed.

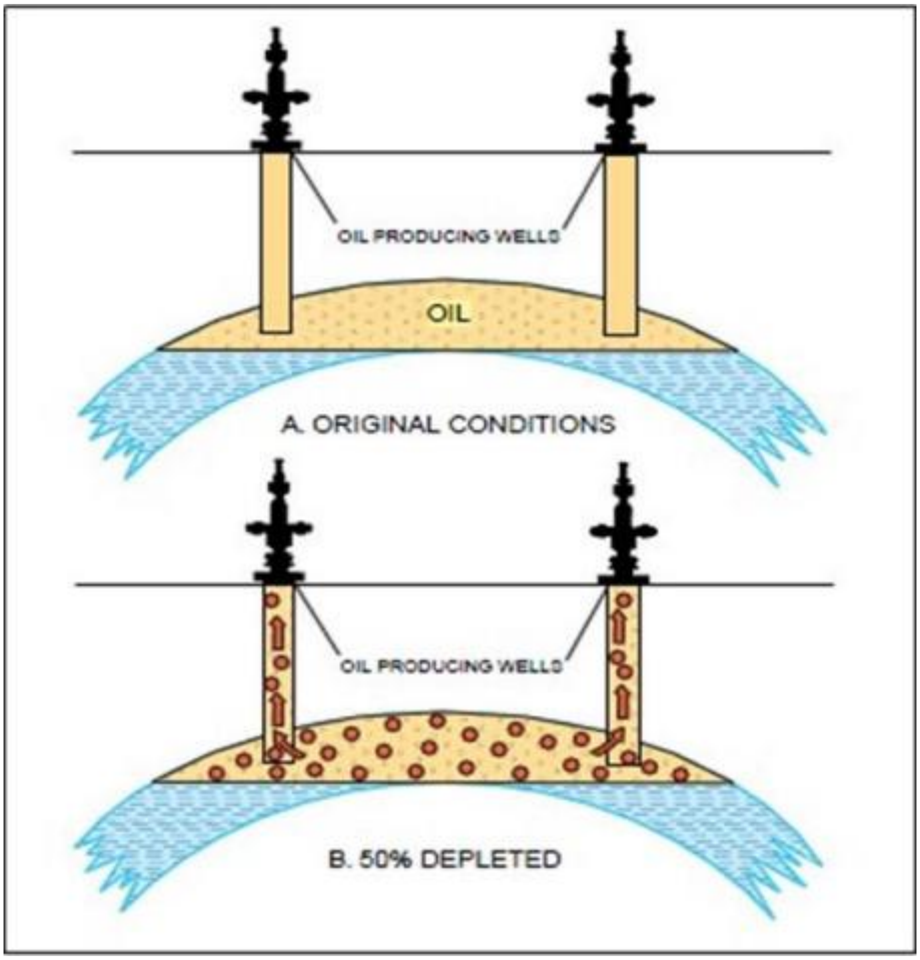

Figure 1.2.1. Reservoir Depletion

As it is aforementioned, the mature reservoirs contain some certain important characteristics which are considered crucial for specific reasons, even though their major aim has been reached. First of all, its holding capacity. In other words, the capacity of a storage can also be called which is for keeping the fluids inside it. It is also important to be informed that the depleted reservoirs should have greater porosity and permeability on the geological side. Owing to the fact that a porosity controls the holding ability of the reservoir as it measures the pore spaces of the rock. Whereas, a permeability indicates the gas withdrawal and the injection rate as it is the measure of the rate of the fluid. Thus, it is preferred to have quite good permeability and porosity. Not to mention, enhanced recovery methods might be applied in order to try to optimize it (Alvarado 2010). The next one is for repurposing. It is obvious that existing reservoirs might be utilized for incoming projects for various plans (Benson 2008). This one might be considered much more important which is using its data for the other fields. As reservoir data along with some other properties are very crucial because in order to get those, so much costs have been spent. So, basically, for just the nearby fields, its invaluable data can be utilized (Alvarado 2010). For the offshore and onshore, the usage of the depleted reservoirs is given below in Figure 1.2.2. (Singh 2010).

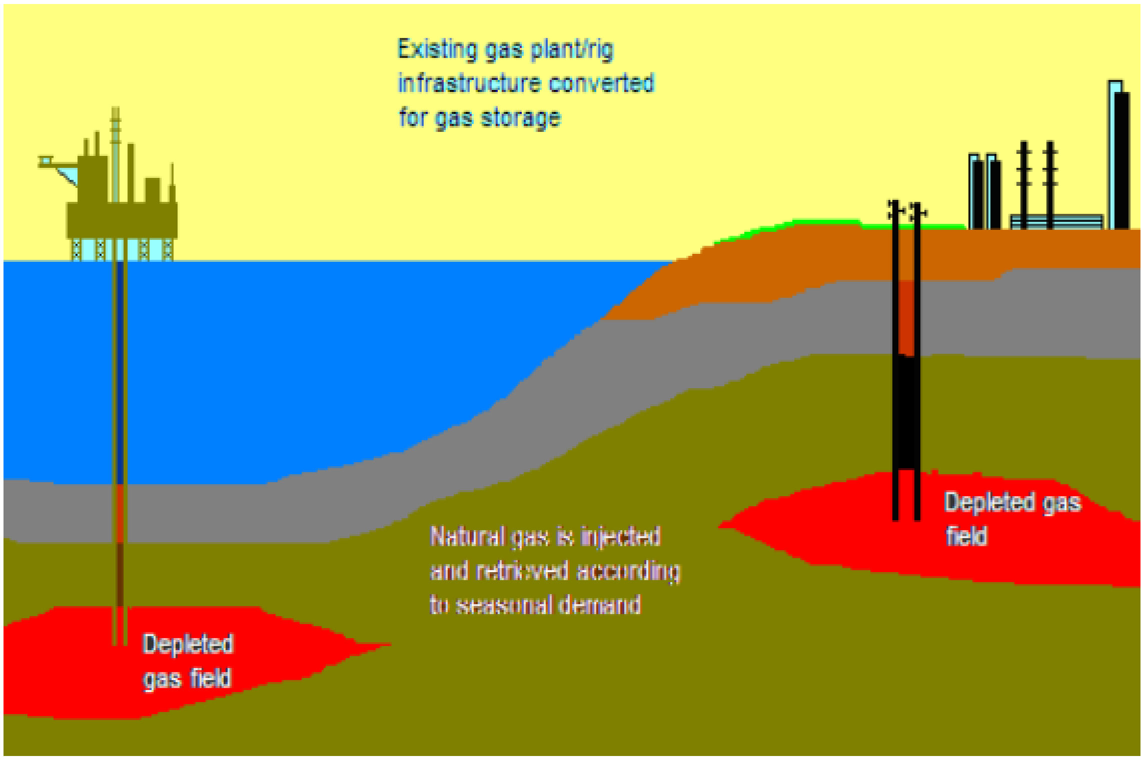

Figure 1.2.2. Depleted offshore and onshore field

After mentioning its advantages, now it is time for the challenges of those depleted reservoirs. First and foremost, its quietly low pressure is the downside of it, because in this case, it becomes very challenging to inject and produce the fluids. The reason for the movement of this fluid is the pressure changes. The next one is the problems with the well integrity. As production continues, the alteration in certain characteristics of the reservoir might have a detrimental effect on the well integrity. Here, the cavings or the subsidence can be exemplified (Settari 2008). It is important to note that an increased water content is another problem, too. As the water cut increases, in certain cases it even reaches up to 90 percent, it affects the content of the oil or the gas inside and even makes it difficult to produce. The merge of the pore pressure uncertainty and fracture pressure decrease is another challenge with the depleted zones. Plus, there might be lost circulation and some stability problems, as the depletion has a detrimental effect on the stress regime.

So, as both advantages and disadvantages are considered, the possible usage for the depleted reservoirs can be indicated below:

The first and the most important one is its application on the Carbon Capturing and Storage which is also called CCS. Here the mature reservoir is introduced as storage for keeping the CO_2 underground. It can not only be used for reducing the greenhouse gas emissions but also for later usage as the Enhanced Oil Recovery (Metz 2005). It is very interesting to say that some depleted type reservoirs with high temperatures might be optimal for the generation of the geothermal energy (Audigane 2007). As it is mentioned beforehand, it is important to say that these reservoirs are also open for the usage of this enhanced oil recovery. With the CO_2 injection type EOR, it becomes much easier as carbon dioxide is, firstly, stored and then used for the additional production of the hydrocarbons. And it is feasible to call it as the carbon capture and storage or the carbon sequestration. Nowadays, it has become very important topic and will be covered in detail later here.

1.3. Oil Recovery

As it is explained beforehand, the depleted reservoirs have passed the long time and they have reached to this point after some recovery methods being applied. It is clear that these are implemented in order to recover more petroleum to the surface. It is important to note that there are three recovery methods in total: Primary oil recovery, Secondary oil recovery, and Tertiary or Enhanced oil recovery. Among these oil recovery methods, Enhanced oil recovery is quite popular.

Between the methods that have been mentioned above, primary and secondary oil recovery attempts are called as the traditional ones. For the US Energy Department in 2014, these two methods just only used in the oil reserves with the amount of a quarter and a half of the wells. As this is not a large number, an enhanced oil recovery method has been applied for a greater number of the wells as it has been just mentioned above (Petro Industry News).

In detail, it can be said that, owing to the BP worldwide energy statistics, the oil and gas reserves are very limited (BP Statistical Review of World Energy, June 2018). Therefore, more and more actions have been taken in order to recover the oil from the depleted reservoirs. And, as it becomes quite challenging to produce it, the Enhanced Oil Recovery has been applied. It has been determined that primary method is able to recover up to 10-15% of the original oil in place (OOIP). Secondary method is even able to recover an additional 15-20% of the original oil in place (U.S. Department of energy 2011). With the tertiary method, which is known as the enhanced oil recovery, it is plausible to extract 15-20% more OOIP. From Figure 1.3.1. below, it is possible to see it clearly (The reservoir). It is crucial to know as well that depending on the oil type, the effect of the recoveries might differ. As it is known that there are four distinct types of the oil based on the density which are extra heavy, heavy, medium, and light. The figures for the primary and secondary production methods are illustrated according to the oil types in Table 1.3.1.:

Table 1.3.1. Recovery factors for Oil types

Oil type	Primary recovery factor (% OIIP)	Secondary recovery factor (% OIIP) additional
Extra heavy	1-5	-
Heavy	1-10	5-10
Medium	5-30	5-15
Light	10-40	10-25

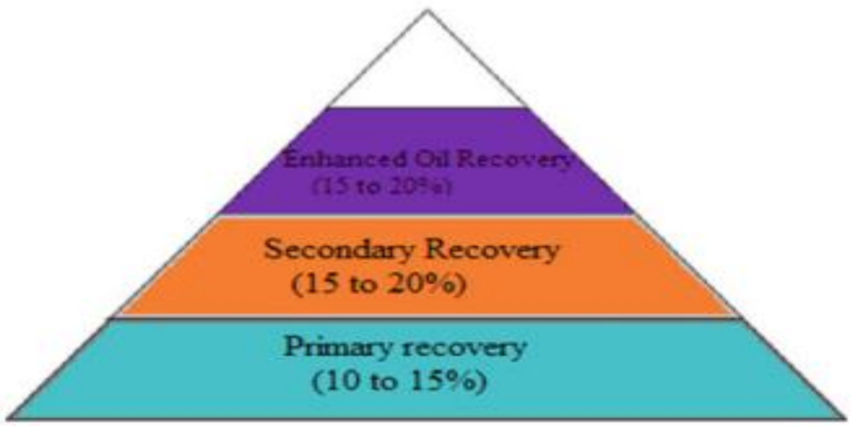

Figure 1.3.1. Percentage of Oil Recovery from different methods

Notwithstanding approximately 70% of the OOIP are still beneath the surface after the traditional recovery methods, and it is called as the depleted reservoirs. In order to understand the enhanced oil recovery deeply, it is firstly required to have basic information about other types of it (Mohammadi 2024). Figure 1.3.2. shows the flow rate and the recovery versus the time plots for the known recovery types which are Primary, Secondary, and Tertiary. At first glance, it is possible to say that once a decline is observed, immediately another method is applied. It more or less tries to increase the recovery every time higher than the previous one and goes constant for some time. About the flow rate, it almost reaches the previous one, however does not go on a par (Hasan 2021). From Figure 1.3.3., all three types of the recoveries can be seen very detailly as an illustration.

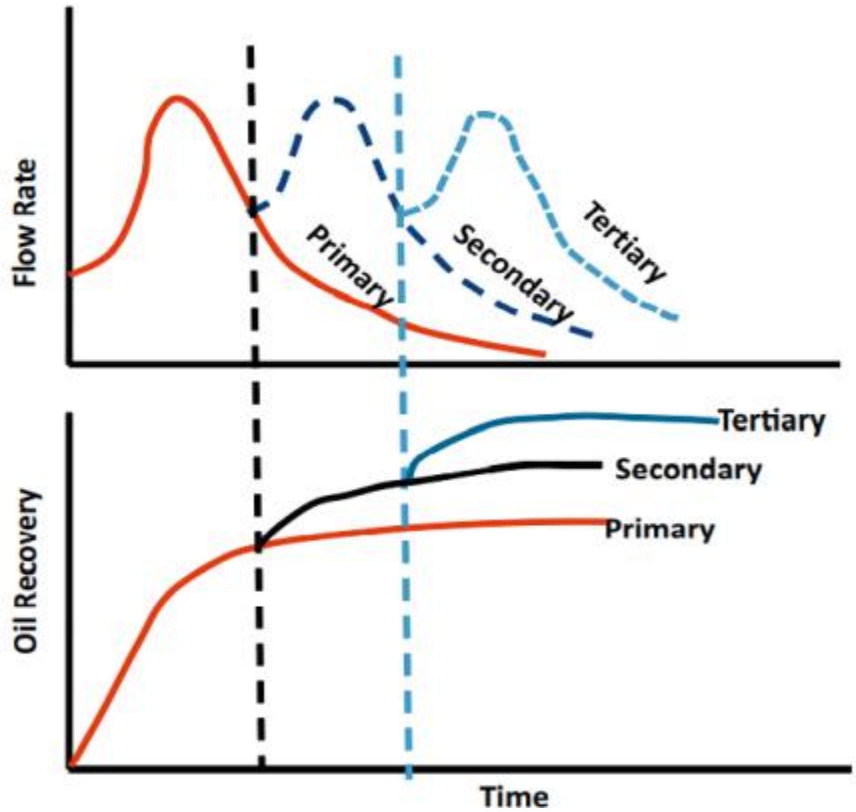

Figure 1.3.2. Oil recovery stages

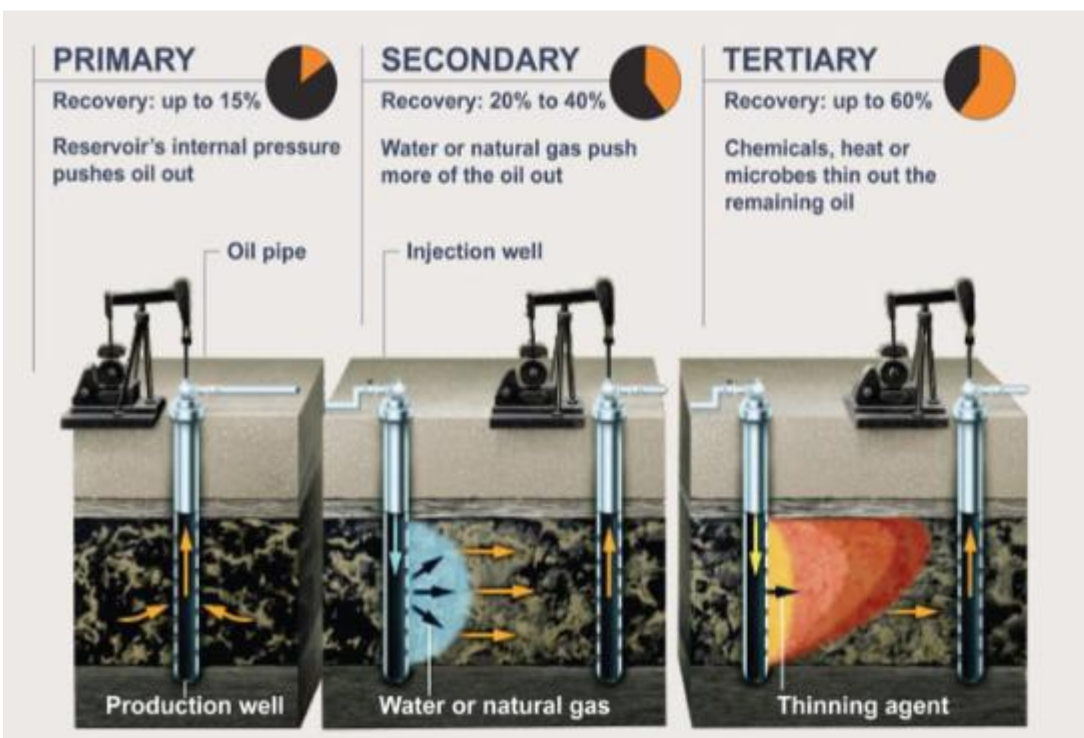

Figure 1.3.3. Recovery Factor for each process

1.3.1 Primary Oil Recovery

About the recovery types, the initial one is the Primary Oil Recovery. This one is considered a commencing stage for the production of the oil, which is just basically the natural energy that comes from the reservoirs. It is clear that the ones that lift the oil to the surface are the pressure and some several mechanical steps. This recovery type does merely depend on the reservoir pressure that can be considered the major reason for the extraction and the production of an oil from the subsurface. However, it ought to be known that this pressure of the reservoir or the drive mechanism decreases over in the initial reservoir production life. Therefore, it is required to maintain the pressure back to its initial pressure back for extending the reservoir producing life. And this is the reason for the usage of Secondary Oil Recovery methods as they try to increase the production life along with the production (Kalita 2022). For this recovery type, there are some methods that can include the reservoir pressure or the natural energy and the mechanical lifts. For the first one, it is possible to say that it is the pressure of the reservoir itself that is natural and is quite enough for raising the oil upwards. The second one is utilized when the natural energy of the reservoir is not sufficient, so the lifting method or the artificial lift is applied in order for the lifting the oil to the desired point. For the artificial lift, there are some pumps and other mechanisms which are included. However, this primary recovery method mostly recovers just a few percentages of the oil and leaves a hefty amount there (Artificial lift methods). There are a few types of the artificial lift methods which are very well-known. They are the Progressive Cavity Pump, the Electric Submersible Pump, the Plunger Pump, the Hydraulic Pump, the Sucker Rod Pump and the Gas-Lift. Figure 1.3.4. which shows all characteristics of these types is indicated below.

About each of the methods, it is possible to say that, Artificial Lift techniques are utilized because the pressure of the reservoir which lifts the fluid upwards is not enough.

The first one is the **Progressive Cavity Pump**. This is mainly characterized by the high viscosity of the oil and the high sand amount. Their operating cost is low and considered cost-effective.

Afterwards **Electrical Submersible Pump** comes, which is quite the preferred one nowadays. It is possible to apply this one not only at shallow but also at higher amount of offshore oil production. Special facilities activate its application for gas wells.

Subsequently, the **Plunger Pump** follows, that is quite clear. There is plunger that moves from the lower part of the pipe to the upper part which is the surface. And this movement happens thanks to produced gas. Here it should be known that it carries above periodically rather than at once.

The next one is the **Hydraulic Pump**. This one is considered very flexible including other types. Because hydraulic pump offers successful production where other types failed. Therefore, it might be a bit costly.

Last but not least, the **Sucker Rod Pump** is used in the majority of the fields and is considered the most used one onshore. Due to its successfully long history for lifting the oil, it is still quite popular. Although it gives relatively lower rates, this method is quite inexpensive.
The final one is the **Gas Lift** method. Here it is clear that highly pressurized gas is injected inside the well. So, it is mixed with the fluid inside the tubing and it helps the fluid to go up to the surface with making the column of fluid light (Duru 2021, Artificial lift methods).

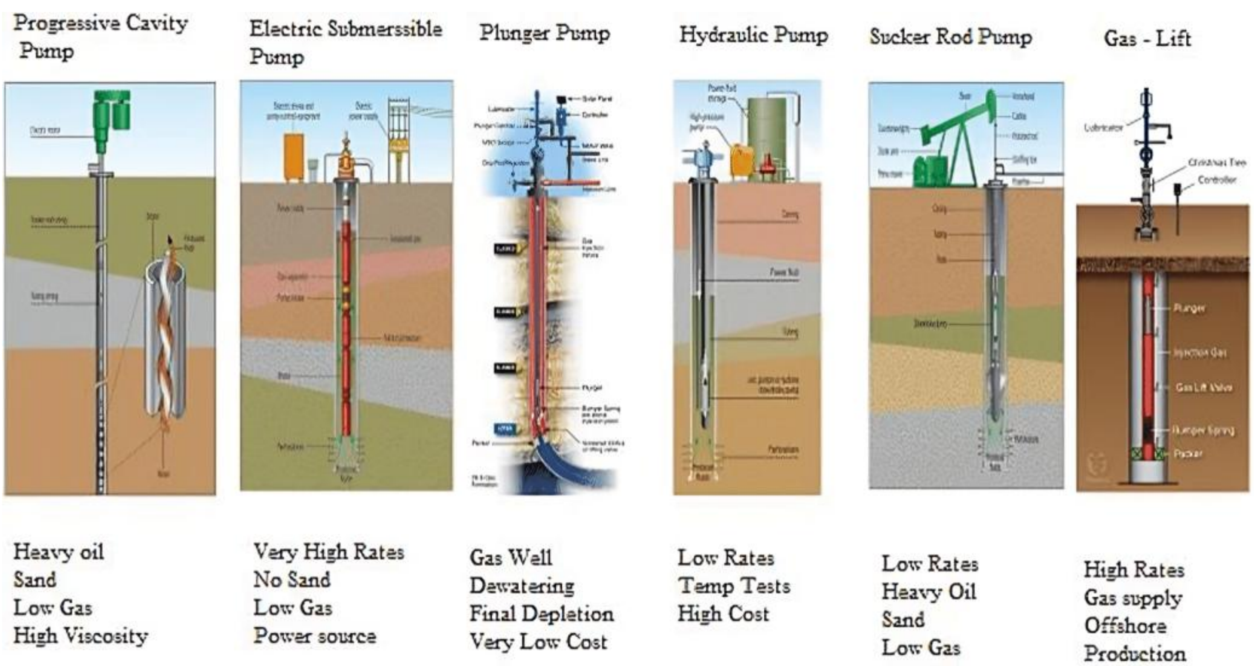

Figure 1.3.4. Artificial Lift Systems

1.3.2 Secondary Oil Recovery

The Secondary Oil Recovery techniques have a major role in increasing oil recovery when the primary technique is not applicable anymore. These strategies include the infusion of the external fluids in supply to process oil and further develop recovery factor. The main secondary recovery procedures include Water Flooding and Gas injection.

The **Water flooding** is a practical choice for bringing the wells back to production at higher rates through the pressure maintenance (Civan 2023, Phade 2008). After obtaining a certain amount of oil from the subsurface, the pressure goes lower and makes the recovery process decline too. By adding predecided water into the reservoir, it is possible to have some control over the reservoir pressure and manage the oil movement to the production wells (Speight 2015). The water infusion is quite practical due to some certain reasons. The first one is there are a myriads of the water zones and resources. The second one is certain features of the water which are density, viscosity, and wettability. Plus, it is important to know that there are two major ways which shows the water flooding application time and schemes. They are the driving mechanism of the reservoir and the volume of oil reserves that is economically producible. The one type for the application of the water flooding method might be the solution gas drive reservoirs which are quite popular.

After the preliminary information about the waterflooding, it is important to know the waterflooding process itself. Here, it is clear that the water is injected via the injection wells for the purpose of the maintenance of the reservoir pressure and sweep of the oil in the direction of the production wells. Figure 1.3.5. which shows the process is given below.

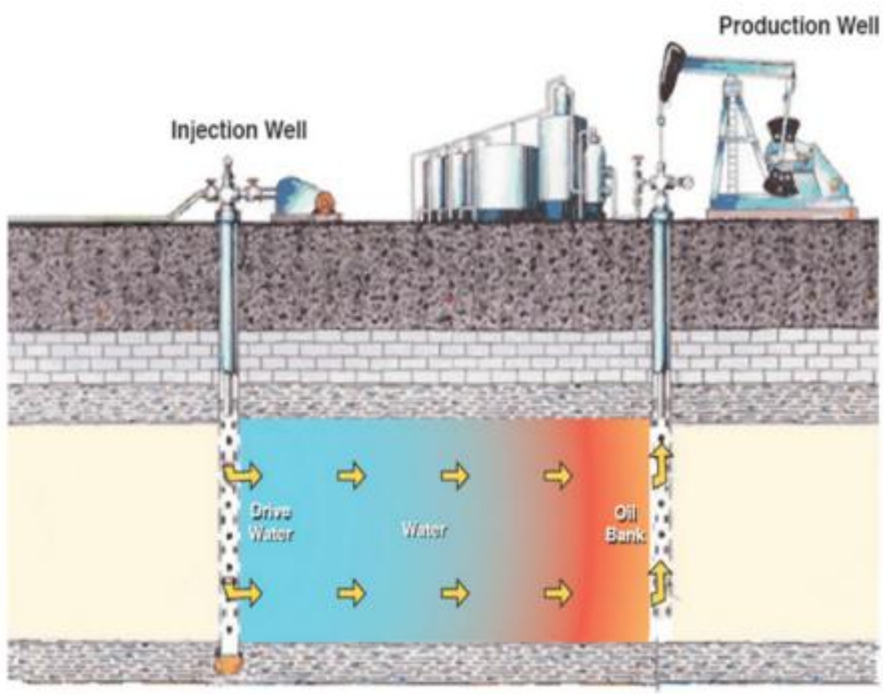

Figure 1.3.5. Waterflooding process

It is clear that the water displaces the oil inside the pore parts of the rock in this method. In order to make this method more efficient it is required to know the factors which affect it (mainly the viscosity of the oil and characteristics of the rock). The reasons for the popularity of the waterflooding method are indicated below:

1. Water is the effective agent that can displace the oil with a density of low to medium

2. Water is considered to be constantly easier to inject inside the formations of oil-bearing
3. Water is basically everywhere and has a low cost.
4. Waterflooding requires a comparatively lower amount of Capital and Operational expenditure (CAPEX and OPEX). (Kulynycz 2017)

It is mentioned that the waterflooding method was mostly utilized in the years of 1960 for the vast majority of the wells for the purpose of acquiring more oil. As it is written beforehand, in order to be successful in the utilization of this method it is required to have good properties of the crude oil and the rock formation, such as the saturation of the residual oil, the injection rate the saturation, and the pattern of the wells of the injectors and the producers (Kalita 2022).

It ought to be known that this type of the secondary recovery method is not considered effective enough for all the reservoir types. It is clear that in the carbonate type reservoirs, the water is not able to displace the entire oil from the pores. The reason here is the wettability of the reservoir rock and the difference in the capillary pressures (Jia 2012), (Shehata 2014). The Carbonate type reservoirs have mainly a fractured composition and there are so many fractures and cracks. So, it is not possible for the water to move inside those fractures. It should also be known that the carbonates are mainly related to the multiple porosity (the dual porosity), the vugs, and low reservoir homogeneity. And these have a detrimental effect on the oil sweep efficiency (Jiang 2019). There is a new technology in order for overcome this problem which is called the injection of the low saline water. It has been accepted that the usage of water with low salinity in the process of the water flooding, changes the direction and releases the stuck oil in the pore spaces as the rock wettability considers water-wet rock (Al-Harrasi 2012, Al-Shalabi 2014). It should be noted that this type of the waterflooding is considered an improved oil recovery method and the different aspects of this method have been examined (Dang 2015), (Derkani 2018). This method is preferred in the reservoir where there is mainly the light crude oil, as the presence of a certain amount of a clay is desirable but not that much. Whilst for the carbonate reservoirs, it is maintained that it is better to have a low acidity, a high temperature, and the existence of the ions of Ca^{2+}, Mg^{2+}, and SO_4^{2-} (Kalita 2022).

Another method for the Secondary Oil recovery is the **Gas Injection**. It is known that the injection of the gas is very important in order to maximize the recovery of the oil and gas from the subsurface. It is noted that the commencement of this technique was in the year of 1864 and it was considered very cost-efficient for the maintenance of the reservoir pressure at that time. The Gas injection process is very flexible that it can be injected before or during the recovery process when the pressure drop is observed (Rigzone). The process is illustrated in the Figure 1.3.6. below:

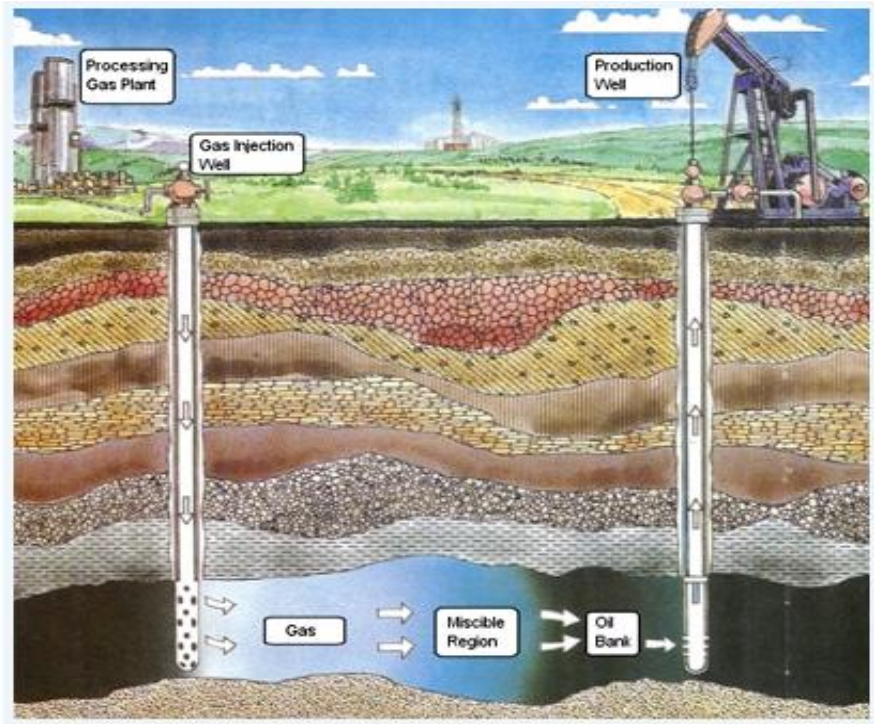

Figure 1.3.6. Gas Injection, Secondary Oil Recovery

It is required to know that for the application of this method there are two patterns that are generally utilized. They are the Crestal Gas Injection and the Pattern Gas Injection:

The first one is the **crestal gas injection** which is also called as the top-down method. The reason for the name of this method is its injection location and it is pumped into the upper part of the reservoirs. There are some certain advantages to this method. The one that can be exemplified is the potential to displace the oil in the bypassed paths and decrease the threat of early breakthrough of the gas to minimum so that this makes it possible to improvise the sweep efficiency of the gas that is injected.

The next one is the **pattern gas injection**. Here, it provides the distribution of the injection wells around the reservoir in such a pattern that the injection wells are directed to the reservoir (Donaldson 1999).

It is known that for the gas injection the methane, the carbon dioxide, the nitrogen, the air, and other petroleum gases are mainly utilized (Mohammadi 2024). It is crucial to be informed about the parameters throughout applying this method of the secondary oil recovery:

1. The rate of the gas injection and the period of the time is adequate enough.
2. The measurement and the monitoring are continuously done.

3. The time has been considered before and after the injection process.
4. The test run has been conducted before the main one in the field. (Kalita 2022)

It is required to know that there are some significant factors before considering to apply the gas injection method to the reservoir. They are the conditions of the reservoir pressure and the temperature, the net pay thickness of the reservoir, the gas cap relative thickness, and the gas shrinkage factor (Mohammadi 2024).

1.3.3 Enhanced Oil Recovery

As the other recovery methods have been shown in detail, the one and the most important type is left which is the Tertiary or Enhanced Oil Recovery technique. The reason to know the importance of the enhanced oil recovery is applying it in corresponding conditions. The characteristics that decides for which method should be applied is the porosity, the permeability, the saturation of the oil, the depth and others. There are reasons for the success of the enhanced oil recovery techniques as the first two methods are not enough to displace the oil due to the capillary force which holds the oil inside the rock. So, these tertiary recovery methods are able to minimize the capillary force and the interfacial tension amidst the phases. As it is clear that in order to increase the production and in the core in order to maintain the pressure recovery techniques are applied. Firstly, it is the primary oil recovery, then, the secondary oil recovery, and finally enhanced oil recovery. For the depleted reservoirs, as they considered the reservoirs where the pressure has declined more than it used to be it is required to try an enhanced recovery technique as there is no choice. So, based on the reservoir condition, the method that can be applied differs (Kalita 2022). It is required to know all the enhanced oil recovery methods, then the decision can be made for choosing the best option for the depleted reservoirs.

It is known that there are so many EOR types, and they have been utilized for many years, with the various success rates for the different types of the oil recovery. All of the methods contain some certain features, and they can be specific for different cases. It is known that, in simple terms, the enhanced oil recovery methods are divided into two types which are thermal and non-thermal. And for the non-thermal methods, there are mainly the chemical, the gas, and the microbial injections. It is also required to be informed that for each of the injection methods other types of injection agents are possible to be utilized. Figure 1.3.7. where all of these are elaborately indicated is given below: (Hasan 2021)

It ought to also be known that these methods and the injection agents are continuously developing and every time certain tests and trials are applied in order to check their effectiveness.

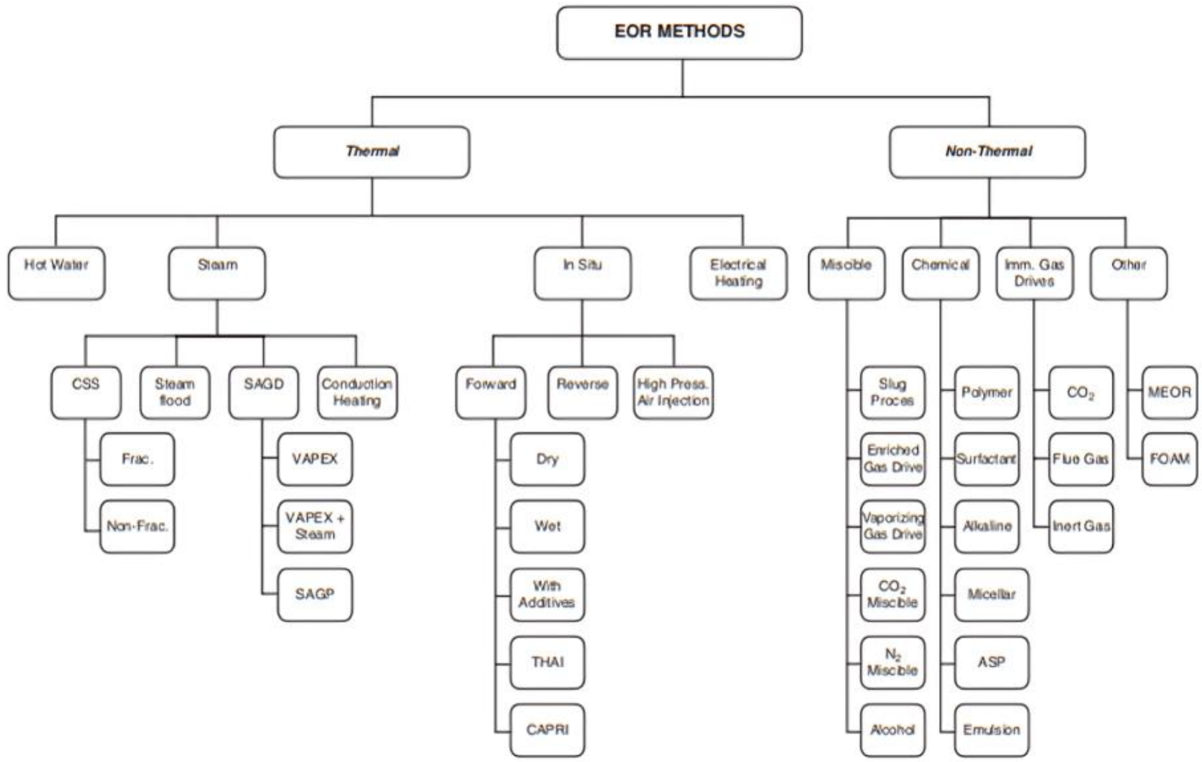

Figure 1.3.7. Enhanced Oil Recovery methods

As the information has been given beforehand about the conventional and unconventional reservoirs, it has been mentioned that the U.S. holds most of the fields itself. So, it is a long time since these EOR methods are applied and it is quite interesting to analyze it. In the U.S., in the time period between 1980 and 2005, there was a constant decrease in the chemical and thermal enhanced oil recovery projects. Figure 1.3.8. that indicates this change is given below (Oil & Gas journal EOR):

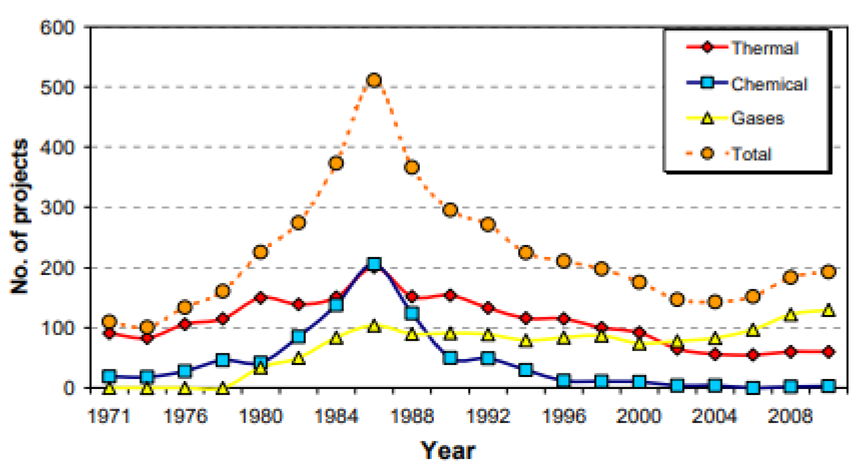

Figure 1.3.8. EOR projects illustration in 1970-2010 in the United States

It is also possible to see that the projects for the gas injection almost remained constant from the year 1984 to 2004 and then a slight increase was observed. The reason for the increase in these projects is mainly related to the CO_2 injection method. It is important to say that since 2002 the gas injection ranks first thanks to the CO_2 projects as it is noted. It is clear that from that time the depleted reservoirs were on point and the technique of the CO_2 injection has become very popular.

The other reason was the availability of the CO_2 from the natural sources. As it was cheap to obtain it, it was very convenient to apply it as the EOR. From Figure 1.3.9. it is possible to see the relationship between the CO_2 projects and the oil price (Oil & Gas journal EOR). As this is an example from the U.S. that it was very convenient and popular usage of the CO_2 for enhanced oil recovery, it does not mean this method is the best. Based on the conditions of the reservoir and the country, the optimal one ought to be selected. It is also clear that the details of the reservoir conditions are mainly accepted as the lithology of the reservoir, onshore or offshore production, access to the infrastructures, and others (Alvarado 2010).

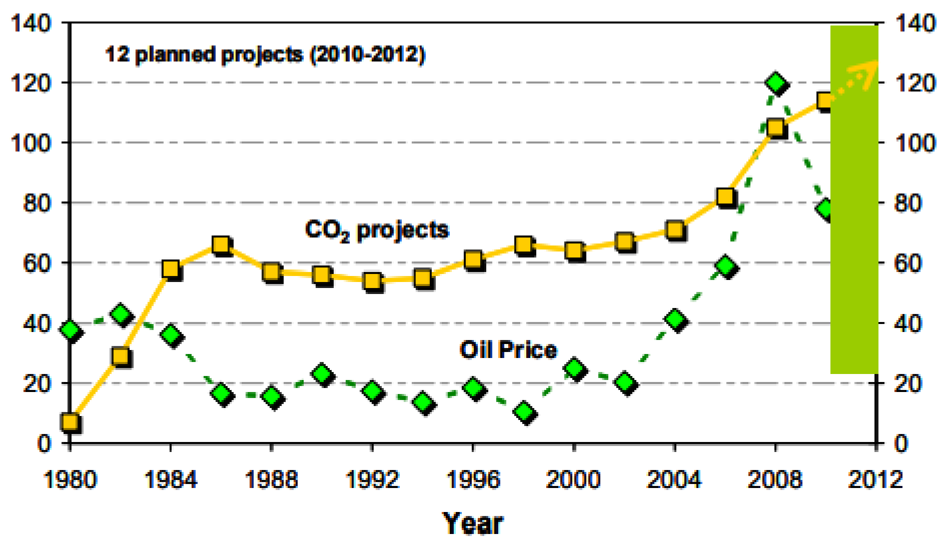

Figure 1.3.9 Interaction between CO_2 projects and oil prices in the United States

As the lithology has been named while the selection of the enhanced oil recovery method, it is required to understand and analyze the case. There was an experiment where 1507 onshore and offshore projects were considered. The numbers are illustrated for each lithology of the reservoirs which type of the enhanced oil recovery method was applied. The Figure 1.3.10. is indicated below (Alvarado 2010):

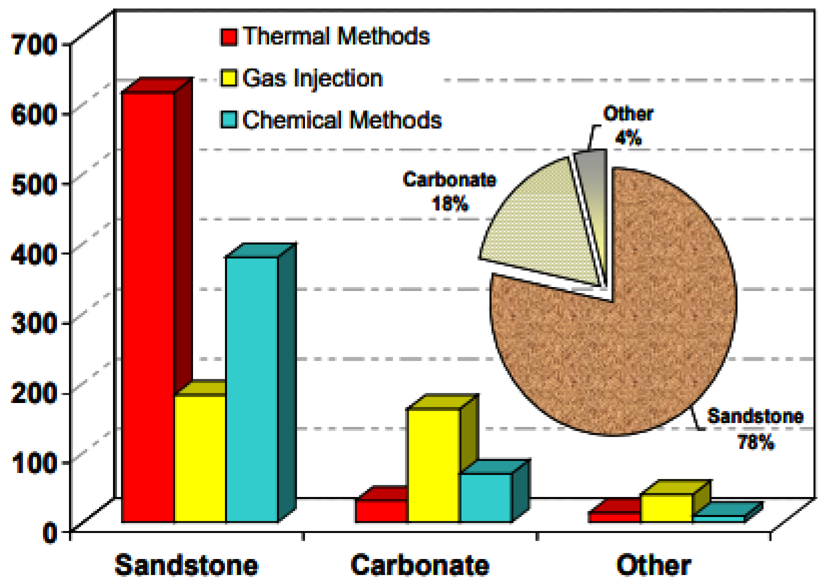

Figure 1.3.10. Application of EOR methods based on the lithology

It is possible to see that for the lithology the most well-known two types are considered which are sandstone and carbonate and the rest of them are combined as other. About the EOR methods, thermal, gas, and chemical ones are taken into account. With respect to the sandstones, throughout 1507 projects the thermal methods were mainly utilized, whereas as regards the carbonates, the gas injection was popular. For the other types, the gas injection was also the most used one. Here, it becomes clear once again that depending on the conditions mentioned above, the EOR methods might change (Taber 1997).

For the depleted reservoirs, there are some considerations for determining the optimal one as each of them has its own advantages and disadvantages. As it is possible to see from the Figure 1.3.7., EOR methods are divided into two main branches which are thermal and non-thermal. So, it is required to look through all of them to choose the optimal enhanced oil recovery method.

Firstly, it is required to consider the **Thermal EOR** methods. In the thermal methods, heat is conveyed into the reservoir through various forms, such as hot air, steam, or fire. So, in the end, it alters certain characteristics of the reservoir rocks and fluids (Kokal 2010). It is maintained that thermal methods are basically utilized while recovering the heavy oil. The heavy oil is known for its really high density and viscosity and the API specific gravity of it is generally less than 22 (Santos 2014). So, the application of this method changes some properties which can be the increase in the reservoir temperature, the decrease in the oil viscosity. So, these alterations direct the oil or heavy oil to the production well (Green 1998). The thermal methods do consist of other techniques and they are mainly named as aqueous and non-aqueous. For the first one, the steam flooding, the steam injection, the combustion, the steam-assisted gravity drainage, and the others can be exemplified (Kalita 2022). For the second one, the electric heating is popular (Mokheimer 2019). It is possible to see that the thermal EOR procedures are generally applied in the high-porosity sandstones (Carcoana 1992). In Figure 1.3.10 it is also illustrated like this. The thermal methods are very popular and applied globally. Its first application was in the year of 1950 (Hasan 2021). While looking at the projects in progress like in the United States, Venezuela, Canada, China and Brazil, these methods are utilized here. The downside of this technique might be indicated by its disability to reach the high depths and the thin pay zone (Gbadamosi 2019).

Owing to the thermal EOR methods, there are various types as it is said beforehand. The first one to consider is the **Continuous Steam Injection**. In other words, it is called as the steam drive, where the steam is non-stop injected into the reservoir via an injection well. The application of this technique alters certain features of oil, which are the viscosity decrease, the thermal cracking and expansion, and others. So, aforementioned changes have an effect on reservoir rock wettability and activate the gas drive. Basically, with the drop of the temperature, the transition from steam to hot water happens. The temperature of steam is mainly about 300-400 °C and then decreases to 200-250 °C. And because of the pressure gradient water applies pressure to the oil in order to make it flow in the direction of production well. It can be said that the recovery of oil from this method is generally at a maximum of 50%. About the disadvantage of this procedure, it is possible to say that the wide difference between the crude oil and steam density might cause the steam to override (Kalita 2022). The process of this method is indicated below in Figure 1.3.11. (Vishnyakov 2019).

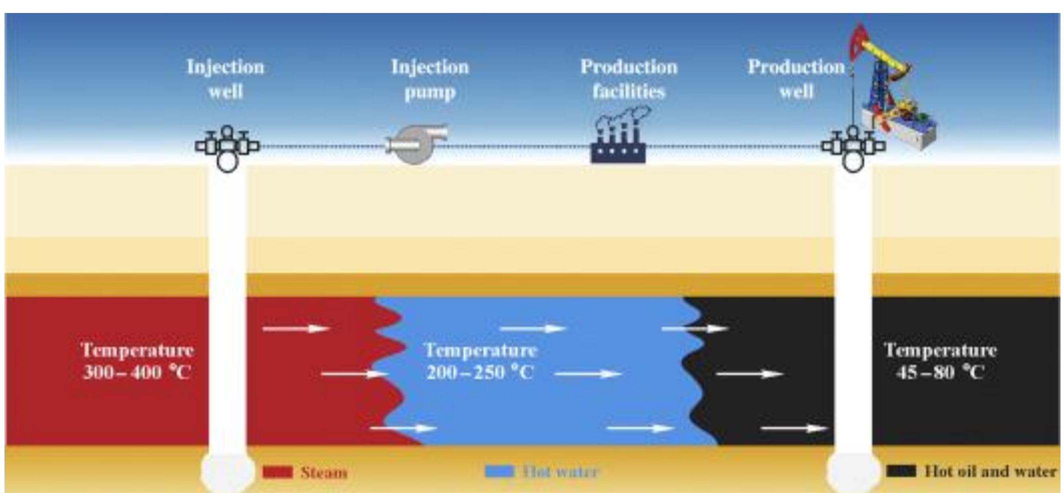

Figure 1.3.11. Continuous Steam Injection into the reservoir

The next method of the thermal enhanced oil recovery is the **Cyclic Steam Injection**. It is also called “Huff and Puff”. This method was initially discovered in Venezuela in 1959 by the oil company Shell (Alvarez 2013). After this invention, this method started to be applied globally in the countries of Canada, Venezuela, Brazil and others in order to recover the heavy oil products (Ghoodjani 2012). It is required to know that in this method which is different from others, only one well is utilized for two purposes that are the injection of the steam and the production of the oil. This process is done periodically which is also called time to time. Therefore, it took the name from here as cyclic. For every one cycle, there are three major steps to be done. They are the steam injection as the initial phase, the soaking as the middle, and the oil production as the last one. So, the oil firstly is heated via the steam and then it is left for the soaking process (Saripalli 2018). It is important to know that the injected steam volume should be enough for the aforementioned process and the well ought to be closed during this time. So, due to the steam, the oil viscosity will decrease and it will go up easily. This method might be repeated once the oil production does seem to be lower. It is required to know that with the repetition of this method, the ratio of steam to the oil ought to be changed from 3:1 to 4:1 throughout the process (Shah 2010). The processes of the cyclic steam injection are indicated in Figure 1.3.12. (Hasan 2021).

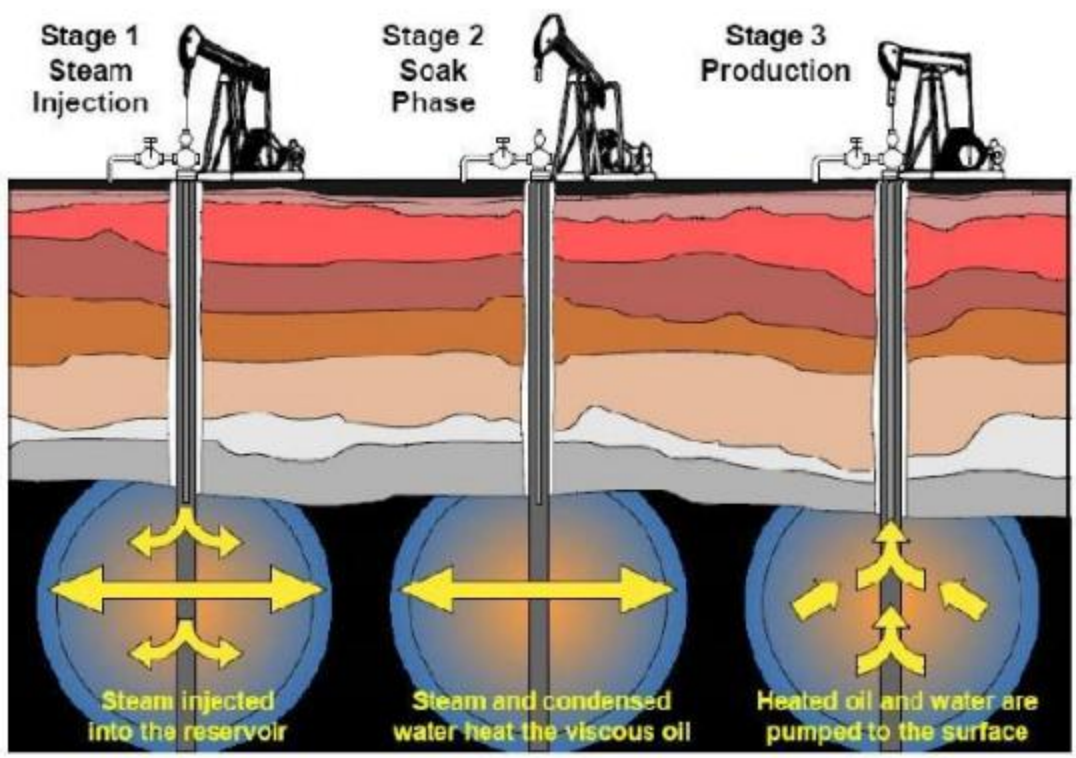

Figure 1.3.12. Cyclic Steam Injection

Last but not least, there is the method called **Steam-Assisted Gravity Drainage**. It should be known that this method is very well-known and widely utilized in myriads of the fields in order to recover the crude oil whose viscosity is high or very high. For the application of this method, there is a requirement of having two wells. As this method is implemented in the horizontal wells, these two wells should be located a bit further from each other. So, upper and lower-located wells are for the purposes of the injection and the production, respectively (Kalita 2022). The upper well which is for the injection of the steam supplies the thermal energy in order to reduce the viscosity of the highly viscous oil. Then, the steam chamber is formed because of the movement of the steam to the top. And the gravity makes the oil move the surface via the production well (Mokheimer 2019). It has been reported that steam-assisted gravity drainage or SAGD is considered the best one for the effective production of the heavy oil in the carbonate reservoirs (Hosseini 2017). The process is elaborately indicated in Figure 1.3.13.. About the pros and cons of this technique, the recovery of the oil in this method is so high with the figure in the vicinity of 70%, however, the cost for the steam generation is considerably high too as it requires so much gas and water (Pang 2015, Hosseini 2017).

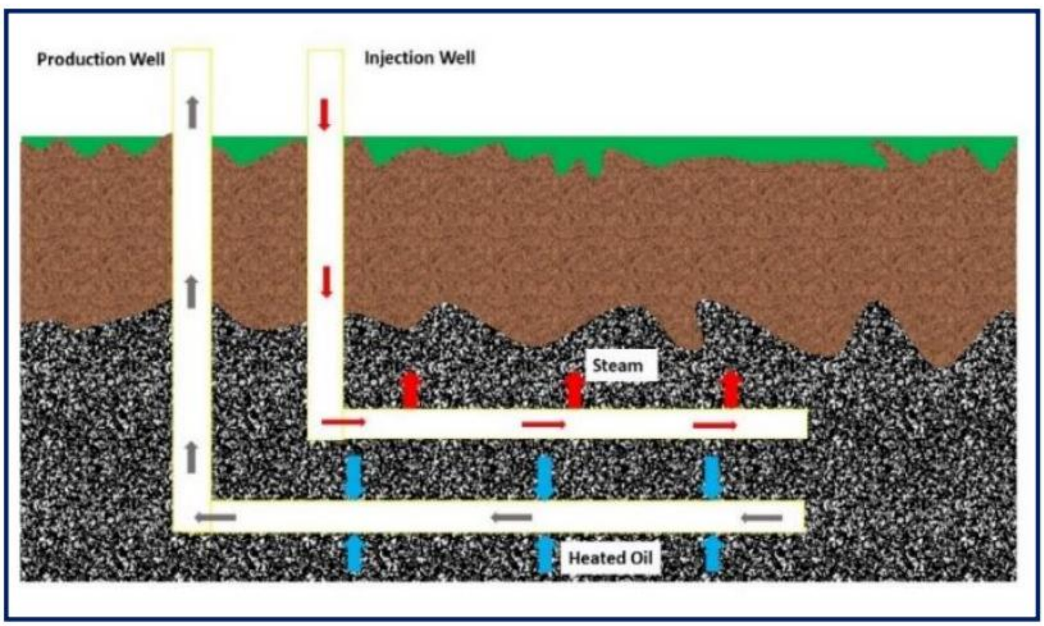

Figure 1.3.13. Detailed illustration of SAGD process

Furthermore, the **In-Situ Combustion** is also another type of the thermal EOR method that was considered widely before. Another name for this method is the fire flooding. The first time that it was utilized was in Pennsylvania in the 1950s (Ghoodjani 2012). So, here, the main procedure is an injection of air that contains a high amount of the compressed oxygen into the reservoir with almost the same pressure of the reservoir via the injection well. From the interaction between the air and the oil, the combustion happens that lead to the burning of roughly 10% of oil in place (Kalita 2022). The temperature at which this process is conducted is around 500-900 °C and it continues to increase up to the ignition temperature of the fluid in the rock (Ursenbach 2010). In the end, the fluid is ignited and that leads to the emission of CO_2, CO and H_2O via the combustion. So, these gases are dissolved and then this directs the oil to the production well (Mokheimer 2019). It is possible to see the process in Figure 1.3.14., in detail.

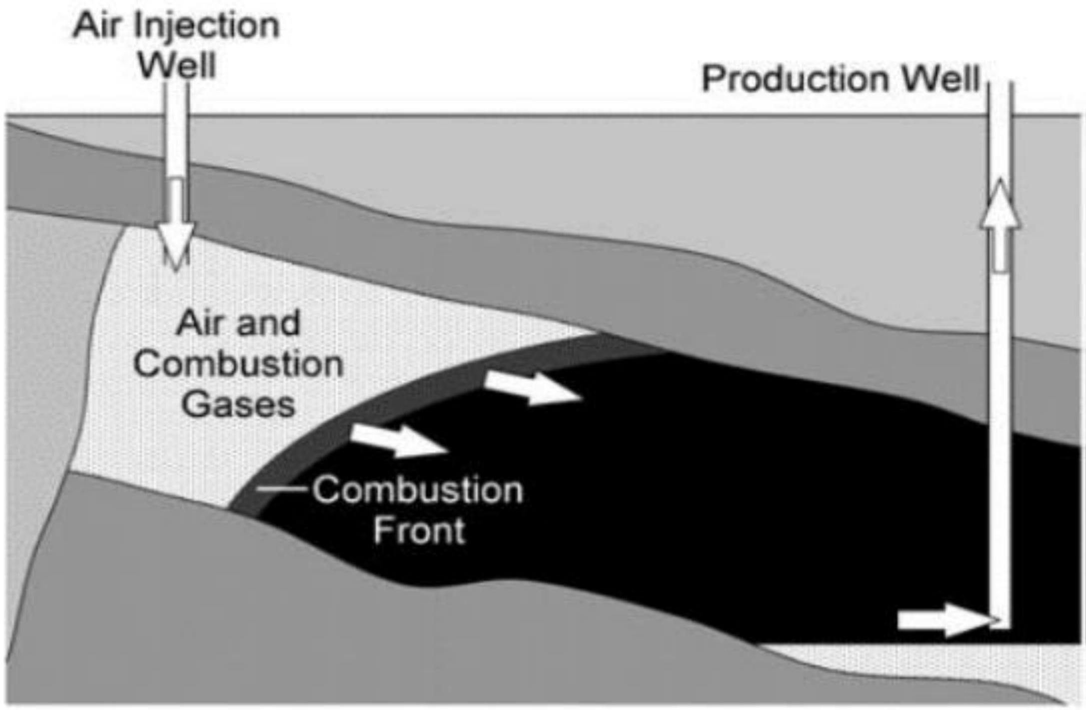

Figure 1.3.14. In-Situ Combustion Method

It is trustworthy to say that the application of this method has been increased in the carbonate reservoirs since the years of 1990s. So, it is possible to say that for the projects, the United States, Canada, Romania, and India might be indicated for its application. About its advantages, it is considered quite energy-effective as the energy amount for producing the oil is low (Mokheimer 2019). Whilst, the disadvantages might be the corrosion, the generation of the unwanted poisonous gases, the gas override, and others (Thomas 2008). It is maintained that the gas overriding is the situation where the steam, the vapor light hydrocarbons, and the gases from the combustion go up to the top of the reservoir which reduce the efficiency of the process itself (Guerra 2005).

Toe-to-Heel Air Injection is another type of the thermal enhanced oil recovery method. This one is considered as a relatively new one. The purpose of the invention of this method is to tackle the problems which bring about the In-Situ Combustion method to fail. In this method, instead of the vertical well as in ISC method, the horizontal well is utilized. The pattern of the injection and the production wells in this method minimizes or even prevents the gas override which is the downside of the technique of ISC (Ado 2020). Thus, the Toe-to-Heel Air Injection is known as more stable rather than the In-Situ Combustion. It is important to know that the area surrounding the injector should be heated beforehand for making sure there is an interaction between the injector and the producer (Rabiu 2017). Due to the combustion, the temperature might reach around 600 °C. The higher temperature means lower viscosity and then the oil which is immobile is displaced via the thin zone which is the mobile oil zone (MOZ). Furthermore, the heavy hydrocarbons that formed in the combustion zone owing to the higher temperature are mainly open to be thermally cracked and produce a light oil. The produced oil and other mixtures move via the MOZ to the production well. This increases the recovery of the oil to a considerably high amount. From Figure 1.3.15., the details of this method can be closely seen.

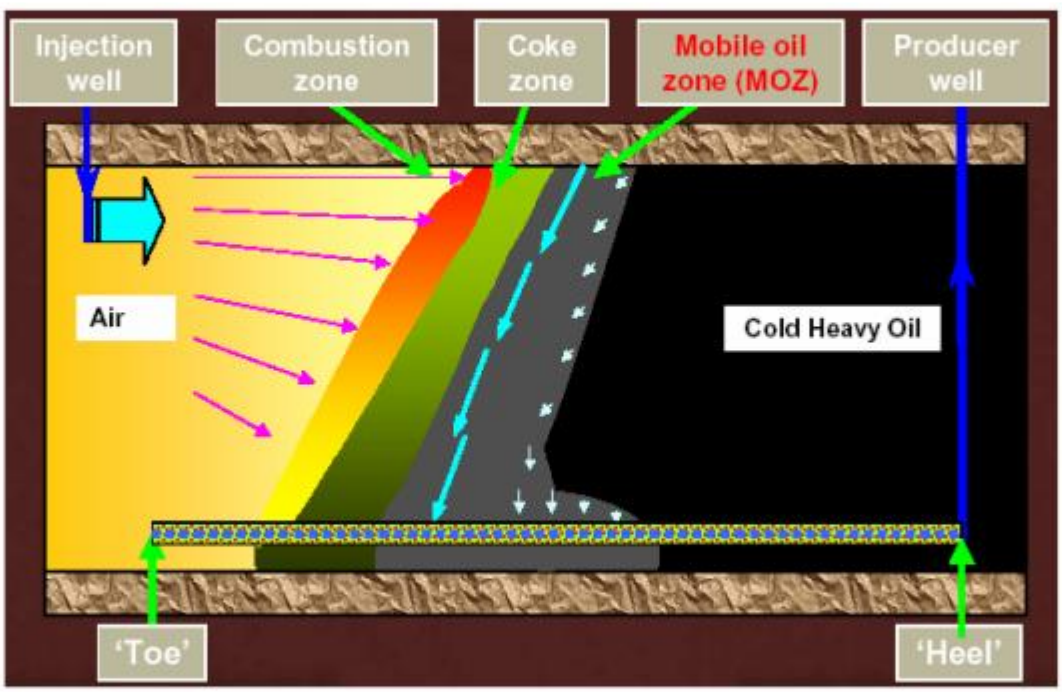

Figure 1.3.15. Detailed Indication of the Toe-to-Heel Air Injection process

After looking through the Thermal Enhanced Oil Recovery methods, it is time to consider the non-thermal methods. From Figure 1.3.16., it is plausible to know the non-thermal EOR techniques: (Bera 2011)

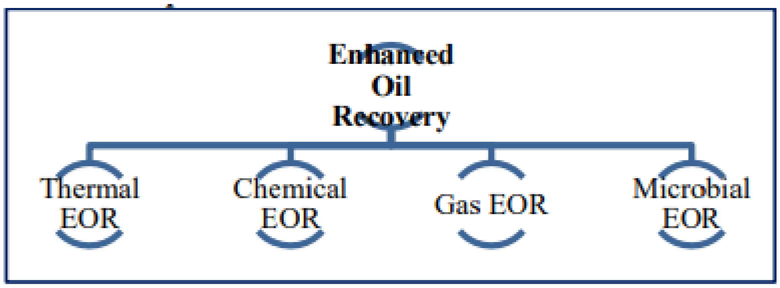

Figure 1.3.16. EOR classification

So, the next procedure to consider is the **Chemical EOR**. It should be known that the chemical techniques are one type of the non-thermal recovery methods and started to be used in the years of 1980s. At that time, the crude oil price considerably rose (Gbadamosi 2019). It is possible to say that this method is actually utilized in the reservoirs of the heavy oil with a thin pay zone (Dong 2015). It is crucial to be informed that the purpose of this method is to alter the physical-chemical properties of the reservoir fluids and the rock with the use of the certain raw chemicals and even some combinations of them, such as the polymers, the surfactants, and an alkali. The relative permeability, the interfacial tension, and the wettability are the properties that are going to be changed via these methods. Better to know that the alteration of these properties helps to recover the trapped oil that is inside the reservoir rock capillaries (Mandal 2015). As it is said beforehand, the chemicals that are injected are various, therefore, the Chemical EOR is composed of two crucial sections which are the Conventional techniques and the Modern techniques. For the conventional one, there are the surfactant flooding, the alkaline flooding, and the polymer flooding, whereas, for the modern one, there are the alkaline-surfactant-polymer flooding (ASP flooding), the nanotechnologies, and the others.

Starting from the conventional ones, the first one to take into account is the **Alkali flooding**. It is maintained that it is one of the most utilized chemical EOR methods. The usage of the alkali increases the efficiency of the oil sweep in the reservoir, in return more oil is recovered. The objective of this method is a natural reaction between an alkali and the organic acids. The alkali is the one that is going to be injected which might be Na_2CO_3, $NaOH$, and $NaBO_2$, whilst other organic acids are existed in the reservoir itself. The chemicals that are going to react with one another are illustrated in Figure 1.3.17.. The alkaline flooding process itself is indicated in detail in Figure 1.3.18. based on the injection and the production wells.

It is feasible to see that from the reaction of these two ingredients, the product is obtained which has a soup-like appearance and it has characteristics which reduce the interfacial tension amid the oil and the water (Khlaifat 2022). In order to know whether this method is applicable or not it is required to check the characteristics of the oil, the reservoir rock, and the fluid. As an example, the alkali flooding can be an optimal choice if the reservoir has a low mobility ratio and high acid number (Schumi 2020), (Deng 2021).

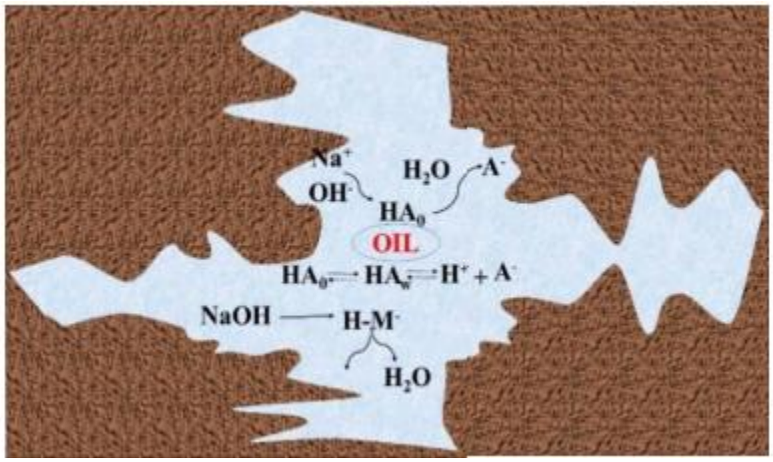

Figure 1.3.17. EOR technique of Alkaline flooding

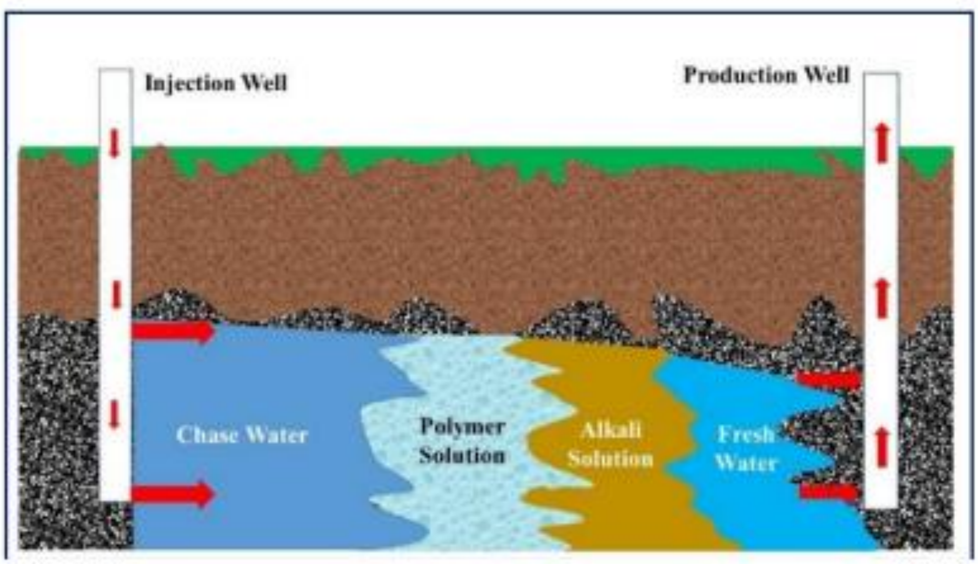

Figure 1.3.18. Alkaline flooding

This process starts with the softened water injection which is the water which has a low number of minerals. It is clear that then the alkaline is injected with a dose volume between 10% and 30% depending on the porosity of the reservoir. It goes without saying that the role of the alkaline that is injected is to decrease the oil and the water interfacial tension, increase the capillarity, and decrease the mobility ratio of the water and the oil (Mohammadi 2024). This method is considered cost-effective because the alkalis are very cheap. It is possible to exemplify the western Canada clastic reservoir as being a successful field where the alkali flooding is utilized.

The next method of the chemical injection that is quite popular is the **Surfactant injection**. It is required to know that the purpose of these surfactants is to lower the surface tension amid a liquid and a liquid, a gas and a liquid, and a solid and a liquid (Gbadamosi 2022). As it is said about its popularity, in order to obtain the residual oil after the recovery methods of primary and secondary this one is utilized widely. So, reducing the oil-water interfacial tension in order to make a different fluid interaction in the reservoir is the major purpose here.

It is proved that from the application of this method, so many fields have been successful in recovering the oil with a maximum of 60%. The United States, Canada, China, Oman, and a few others might be an example where the surfactant flooding has been done (Emegwalu 2010).

As it is said beforehand, the main mechanism here is to reduce the interfacial tension (IFT). Thanks to the specific characteristics of the surfactants, the interactions happen between both of them, namely, the water and the oil. It should be known that the surfactants create the layers on each of those and reduce IFT, therefore, the oil is recovered much more easily (Schramm 1992, Gbadamosi 2019). Another mechanism of the surfactants is to alter the wettability. As reservoirs are considered oil-wet, the usage of these shifts it from the oil-wet rock to the water-wet rock. So, this change results in decreasing the capillarity and increasing the permeability of the oil, so it is possible to recover much greater oil than before. From Figure 1.3.19., the wettability alteration is indicated due to the usage of surfactants (Paternina 2022).

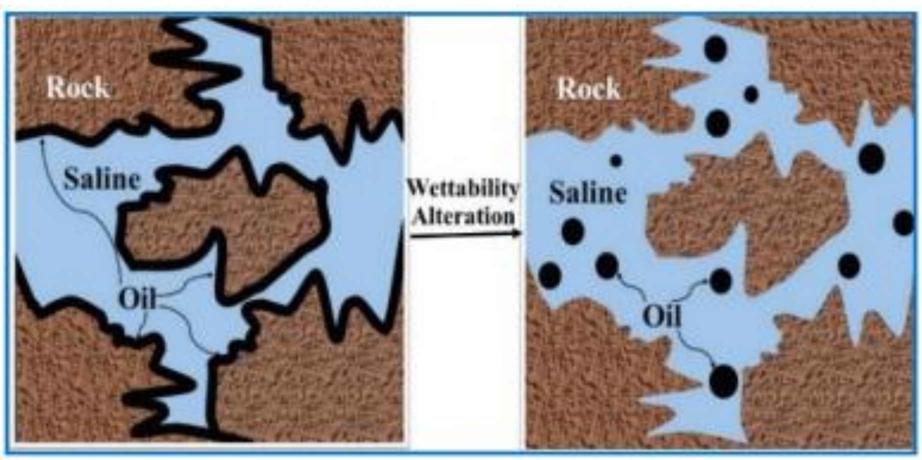

Figure 1.3.19. Wettability alteration by the surfactant flooding

From the recent research, the surfactants are divided into six various groups based on their compounds. The first one is the anionic surfactants. They contain negatively charged hydrophilic and are utilized in the sandstones. Then, the next one is the cationic surfactants which contain positively charged ions. This one is quite popular in the carbonates. Subsequently, the third one is the non-ionic surfactants that have no charge. Moreover, the next one has both of the charges and it is called the amphoteric surfactants. Furthermore, the Gemini surfactants are another type which has two polar groups. The last but not least, it is called the biosurfactants which are the products from the plants and the animal residue. The process of the surfactant flooding consists of several stages and is indicated below in Figure 1.3.20..

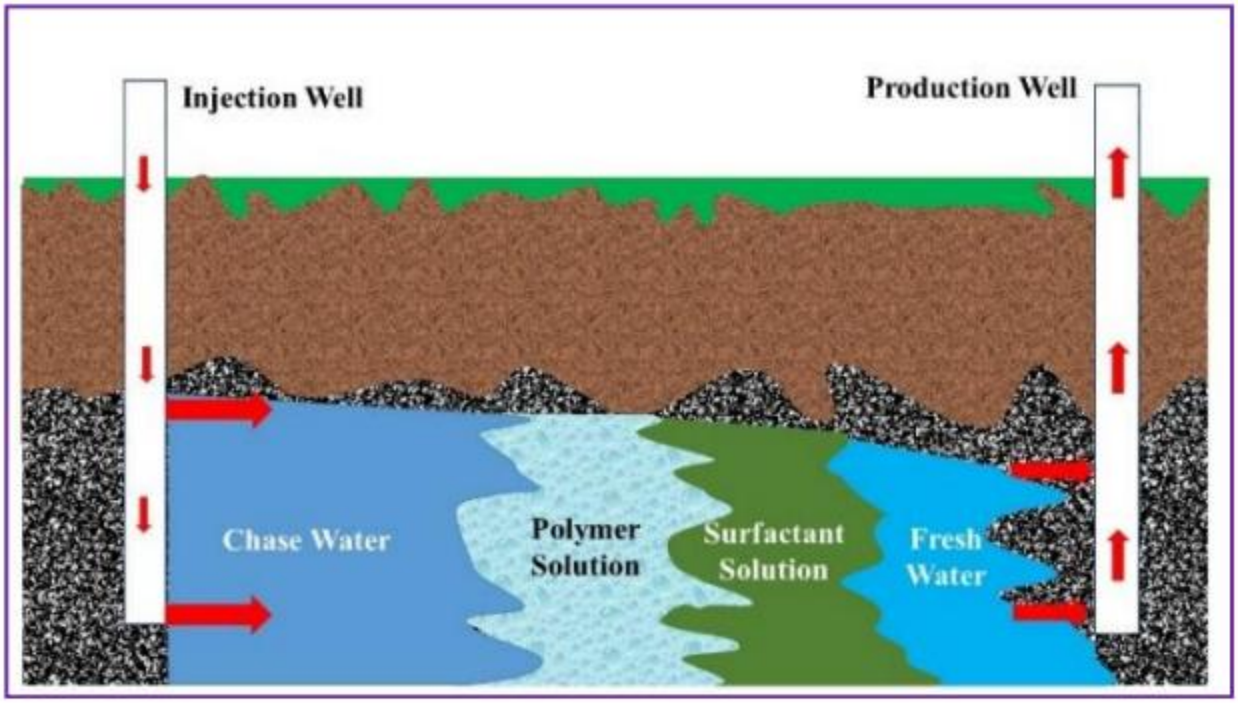

Figure 1.3.20. Surfactant flooding

Firstly, the water is injected in order to decrease the salinity, then the surfactants are injected. This follows the polymer injection for the purpose of the viscosity increase. Lastly, the water is added again to remove the injected fluids (Paternina 2022).

The **Polymer flooding** is another method of the chemical EOR which is utilized for optimizing the recovery of the oil. It is a compound composed of a heavy polymer and the water and the polymer increases the water viscosity. This results in the water mobility boost and removes the viscous fingering effect which does not allow the oil to be fully recovered (Samanta 2013). It is trustworthy to say that this technique is also applied around the globe, such as China, Canada, and Oman (Sheng 2013).

The Polymer flooding affects certain characteristics in the reservoir. Firstly, as it is said it increases the viscosity of the water which is injected into the reservoir. This changes the mobility of the water and eliminates the process of the viscous fingering in order to displace more oil

(Zaitoun 2012). It is clear that the Polymers are also able to minimize the disproportionate the permeability throughout the reservoir. It is clear that the permeability is not the same in all directions. So, the polymers increase the viscosity and the sweep ability of the water which is injected. This change allows the water to flow where there is low permeability (Wei 2014).

The last one is called as the **Alkaline-surfactant-polymer flooding**. This method uses the combination of the aforementioned three chemicals which are the alkaline, the surfactant, and the polymer. The use of these mixed chemicals rather than individually shows better results. It is important to say that, nowadays, the application of this method has become much more popular. There is a total of four combinations that might be utilized which are the alkali-surfactant, the polymer-surfactant, the alkali-polymer, and the alkali-surfactant-polymer. Information about each of them is given below:

The first one is the alkali-surfactant. Here, a certain amount of the alkali and the surfactant are injected in a sequence. So, the alkaline interacts with the oil and creates a soaping, and then the surface of the rocks is altered because of the reaction with the alkaline. It is maintained that the role of the surfactants is to reduce the oil and the water interfacial tension, so, together the alkali and the surfactant enhance the recovery of the oil (Hirasaki 2011).

The second one is the alkali-polymer. Better to mention that, the major principle here is to compensate for the weaknesses of both methods. It is possible to say that the mobility control is difficult for an alkali, so with the use of the polymer the water viscosity is increased and the mobility can be maintained. Plus, with the alkali, the efficiency is enhanced (Sheng 2017).

The polymer-surfactant injection is another method. This one generally depends on the situation and the purpose of the project. So, either polymer or surfactant might be injected, first. From certain analyses, it has been confirmed that it is possible to obtain an additional 14-20% oil recovery (Yusuf 2022). It is obvious that mixing the chemicals increases the recovery of the oil to a higher percentage than using them individually (Mohammadi 2024).

The last one to take into account is the usage of the alkali-surfactant-polymer (ASP) injection as the enhanced oil recovery. From a huge amount of analysis and applications, it has been observed that this technique is considered the most optimal chemical enhanced oil recovery procedure (Pogaku 2018). From Figure 1.3.21, it is plausible to elaborately observe the ASP injection process. Initially, the alkali and the surfactant are injected together for the purpose of displacing the oil in the pore parts of the rock. It is clear that after that the polymer is added in order for enhancing the mobility (Dang 2018). Lastly, the freshwater is injected to obtain the effective

Enhanced oil recovery.

As it is mentioned beforehand, the enhanced oil recovery methods are divided into two parts which are thermal and non-thermal. It is feasible to know that the Non-thermal technique consists of the chemical, the gas, and the microbial methods on its own. The thermal, and the chemical ones are examined in detail to choose the optimal one for the depleted reservoirs. It is required to analyze the microbial technique for a better understanding.

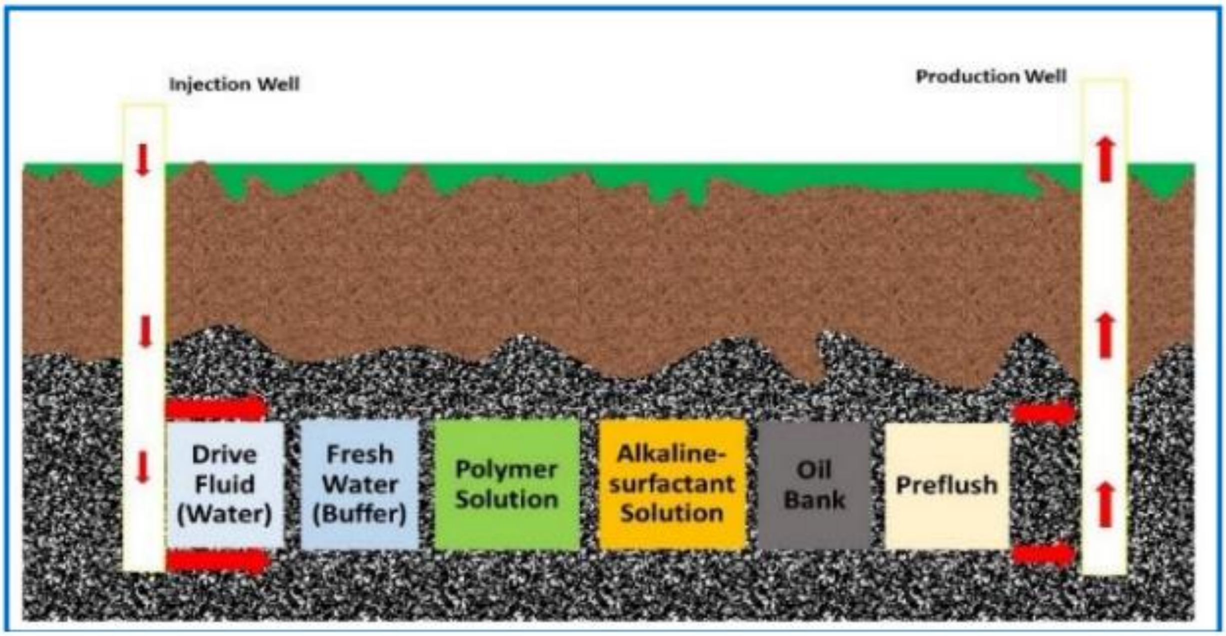

Figure 1.3.21. Multistage ASP flooding

The **Microbial EOR** is one type of the recovery method that has been used recently. There are some types of the microorganisms, such as the biopolymers, the biosurfactants, the bioacids, and the biogases. These are utilized for the recovery of the stuck oil inside the pore spaces of the reservoir rocks. It is maintained that some major modifications are applied to the microbial particles in order for certain reasons. They are the reservoir porosity and permeability changes, the rock wettability changes, the interfacial tension decrease, and the mobility ratio decrease (Datta 2018).

It is important to be known that the MEOR can be conducted in two ways which are in-situ and ex-situ. Initially, the **in-situ** method contains the action of the bacteria injection via the injector inside the reservoir (Geetha 2018). Then it is required to wait some time for adapting it to the conditions of the reservoir. It is clear that after some time, those microorganisms start to form some particles that help to enhance the recovery of the oil. The **ex-situ method** involves the microorganisms that are formed before injecting them to the reservoir. It is feasible to differentiate them as they are almost opposite to each other. Each of them has their own pros and cons. The In-situ method is considered cost-efficient, but owing to the productivity side, it sometimes is a bit questionable. Whilst, ex-situ gives much better results and is considered much more productive, however it is required to have a higher budget to conduct.

The are some advantages of Microbial EOR over other methods to consider. Firstly, this procedure is considered inexpensive because of the ease with the production of the microorganisms. Then, this method is considered environmentally friendly. As the products are biodegradable, there is no any harm to the environment. It ought to be known that owing to the reasons that are mentioned before, the MEOR is globally utilized and some innovations are still under the research to be improved (Niu 2020).

The last enhanced oil recovery type to consider is the **Gas Injection**. The application of this method is very popular in the depleted and the heavy oil fields. In simple terms, the process of the gas injection covers the oil displacement with the use of the hydrocarbon lean gases or the non-hydrocarbon pressurized gases. From Figure 1.3.16., it is clear to see that two different gas injection methods are indicated there. They are the miscible gas injection and the immiscible gas injection. It goes without saying that for the **miscible gases**, the nitrogen, the carbon dioxide and the other gases are included. As regards the **immiscible gases**, the inert gas, the flue gas, and the carbon dioxide gases can be indicated. It is known that the main principle of the miscible gas flooding is quite simple. Firstly, these gases are mixed with the reservoir fluid (oil) in order to change the viscosity, so it is going to be much easier to displace the oil and produce it to the surface. The usage of the gases which are miscible and immiscible generally changes the depending on the reservoir conditions which are the pressure and the temperature (Phukan 2022).

It is maintained that the liquified petroleum gases are not recommended to be utilized as the gases for a gas injection due to their riskiness and cost. As it is mentioned, the hydrocarbon gases are implemented rather than the liquified gases. However, it is also important to know that the hydrocarbon gases do also possess some challenges, such as the requirement to reach the minimum miscibility pressure.

It is important to know that one method to consider is the **N_2 flooding**. It is known that this type of the gas injection is generally utilized for the reservoirs which are deep and pressurized (Manrique 2007). However, the implementation of this method is not widely utilized. It is confirmed that several years ago, in the United States and Mexico, the projects of the N_2 flooding were recorded. The reasons for the low application are the greater CAPEX and OPEX. It is required to know that the N_2 flooding is still considered a choice when there is the high pressure and the temperature in the reservoir (Mungan 2000, Linderman 2008).

The next method to consider is the **Water Alternating Gas injection (WAG)**. It is clear that this method is invented in order to prevent some downsides of the technique of the gas injection. It is obvious that this method is globally utilized and it can be considered very successful (Awan 2008, Christensen 2001). Here, the gas slugs and the water slugs are injected together into the reservoir. So, the injected water decreases the gas volume which is required for the reservoir pressure maintenance. It is also important to know that this water-alternating gas minimizes the fingering effect owing to the mobile water in the pores.

It is interesting that notwithstanding the successful application of the WAG injection, the incremental recovery is lower than it should be. So, the early breakthrough of the gas is very common in the WAG injection (Muggeridge 2014).

1.4. CO_2 Injection

Among all the types of the gases, the **CO_2 gas flooding** technique is considered as the most optimal and the most productive one because of its heavy density, low cost, sequestration possibility and others. It should also be known that this technique has been very popular nowadays and can be very suitable for almost 80% of all oil-type reservoirs (Chen 2010). The first time when the CO_2 injection was applied was in 1930. Better to know that, since 1970 a lot of development and improvement have been seen in the method of the CO_2 injection (Srivastava 2000). It is known that it is better to inject the CO_2 in low or medium oil reservoirs. This is confirmed that an additional 15-25% of oil recovery might be achieved via this type of the gas EOR method (Yongmao 2004). It is feasible that there are so many examples where this method has been applied, such as in the United States, Canada, Brazil, and others (Mohammadi 2024).

As it is said the injected CO_2 is going to be mixed with the oil in the miscible gas injection method. So, the requirements for this method are a temperature of 300-310 °K and a pressure which is higher than 10 MPa. It is required to know that there are some cases when the asphaltene and the resin composition inside the oil might precipitate and affect the miscibility conditions. Therefore, it is important to exceed the critical values in order to be successful (Ifeanyichukwu 2014).

Another way to use the CO_2 as a recovery method is by injecting the water that contains dissolved CO_2. Owing to the chemical interactions, this mixture loosens up the rock paths, and an oil is easily displaced. So, in the end, an injection of this mixture helps to enhance the recovery of the oil (Goharzadeh 2022). Plus, it has other types which are the continuous and cyclic CO_2 injection. As it is said beforehand, the CO_2 injection is considered one of the best EOR methods for the depleted reservoirs. Its storage ability and other specific characteristics make the depleted reservoirs valuable assets. As it is clear the CO_2 is injected inside the reservoir via an injector and it displaces the oil from the pore spaces of the rock (National Research Council 2013). From Figure 1.4.1., it is clear to look at the process of the CO_2 injection.

As a result, from the interaction of the carbon dioxide and the oil, some changes occur related to the fluids. They are an oil density, a viscosity, and a surface tension decrease between the oil-carbon dioxide and the oil-water.

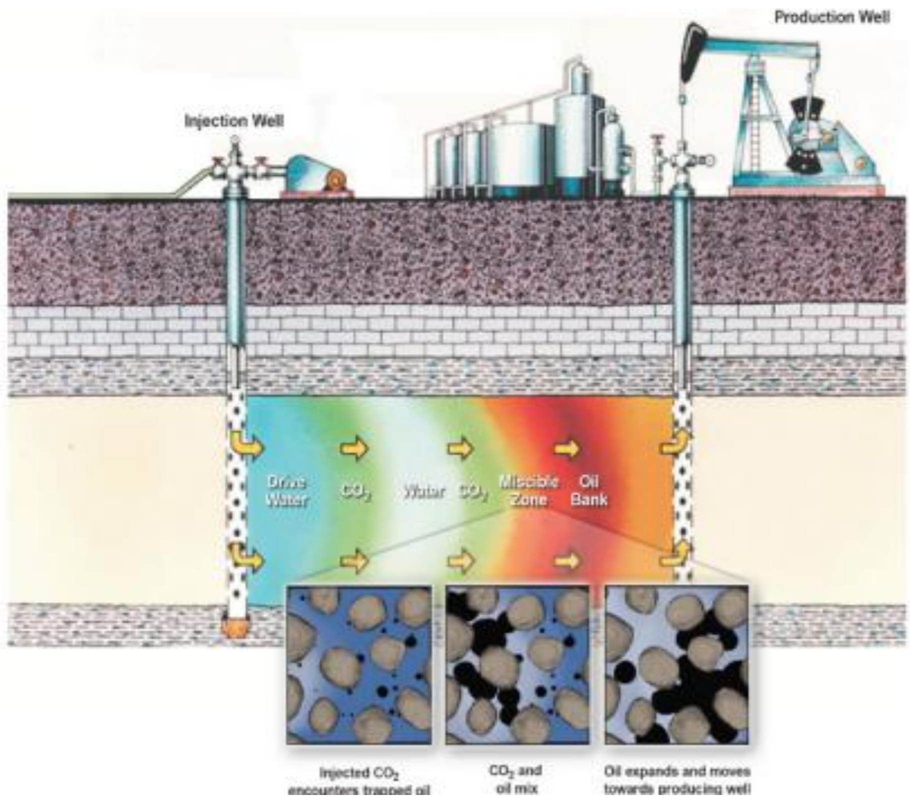

Figure 1.4.1. CO_2 injection technique

As it is obvious based on the miscibility, the oil composition, and the reservoir conditions, there are two types of the gas injection which are miscible and immiscible. In Table 1.4.1., basic information about each of these methods is indicated (Kulynycz 2017).

In simple terms, it is possible to exemplify several benefits for the injection:

1. Its minimum miscibility pressure is lower than other gases (hydrocarbon gases).
2. As the density of the carbon dioxide is heavy, the gas override rarely occurs.
3. The carbon dioxide might be stored beforehand and then utilized for the injection.
4. The hydrocarbon gas which can be used for other purposes is emitted after the application of the carbon dioxide injection. (Ghedan 2009)

Table 1.4.1. Miscible and Immiscible CO2 injection

Miscible CO_2 injection	Immiscible CO_2 injection
Oil and CO_2 is mixed where reservoir pressure is greater than the minimum miscibility pressure.	No mixing of oil and CO_2 happens.
As they mixed, a single liquid is formed.	CO_2 is partly dissolved in oil phase.
It is possible to use the previous infrastructure for the injection process.	It is required to inject high amount of CO_2 and drill a new well for injection. Therefore, it shows low efficiency on economical side.
This method can be utilized on a small scale, such as a part of the reservoir.	This method on a whole reservoir and it is very difficult to use it on a small scale.

It is reported that the CO_2 injection has been utilized as an enhanced oil recovery type in both types of the reservoirs which are mature (depleted) and carbonate reservoirs (Koottungal 2008). The CO_2 injection has been considered the most crucial process in the United States. The reason for the popularity of this technique is the plentiful availability of the CO_2 sources and the location of the transportation pipelines next to the oil fields (Hustad 2009). It is clear that the CO_2 will be considered the safest recovery method if the CO_2 is available. It goes without saying that there are many projects that involve the CO_2 injection. For the information in 2008, it is said that there was a total of 125 projects of the CO_2 injection. About 105 of them were conducted in the United States. In Figure 1.4.2., the projects and the sources are indicated (Causebrook 2012). The project of Saudi Aramco company can be exemplified where they are going to inject the CO_2 for not only the enhanced oil recovery but also the storage strategy in the field of Uthmaniyah. It is crucial to mention that the benefits of this application are the increase of the oil production, the reduce of the gas emissions, and the others (Saudi Aramco 2024).

It is maintained that nowadays, the CO_2 EOR and the climate change are somehow connected to each other. The climate change has become a hot topic over the last two decades. It is important to know that there is an action that simultaneously both meets the energy demands and limits the greenhouse gases (Hamilton 2009). So, the topic of the CO_2 storage is very popular, however, the storage capacity of the reservoirs is limited (Bachu 2005, Manrique 2008).

It is important to know that the CO_2 injection and the storage process has become very popular due to the reason of the greater price of the hydrocarbon. As the price is high, the financial capital increases and it leads to do such projects with high turnover (Ghomian 2008, Imbus 2006). So, it is possible to understand that the application of the CO_2 storage might be a costly process, however, owing to the environmentally friendly characteristics and two-in-one (CO_2 EOR and storage) processes it is still considered very viable.

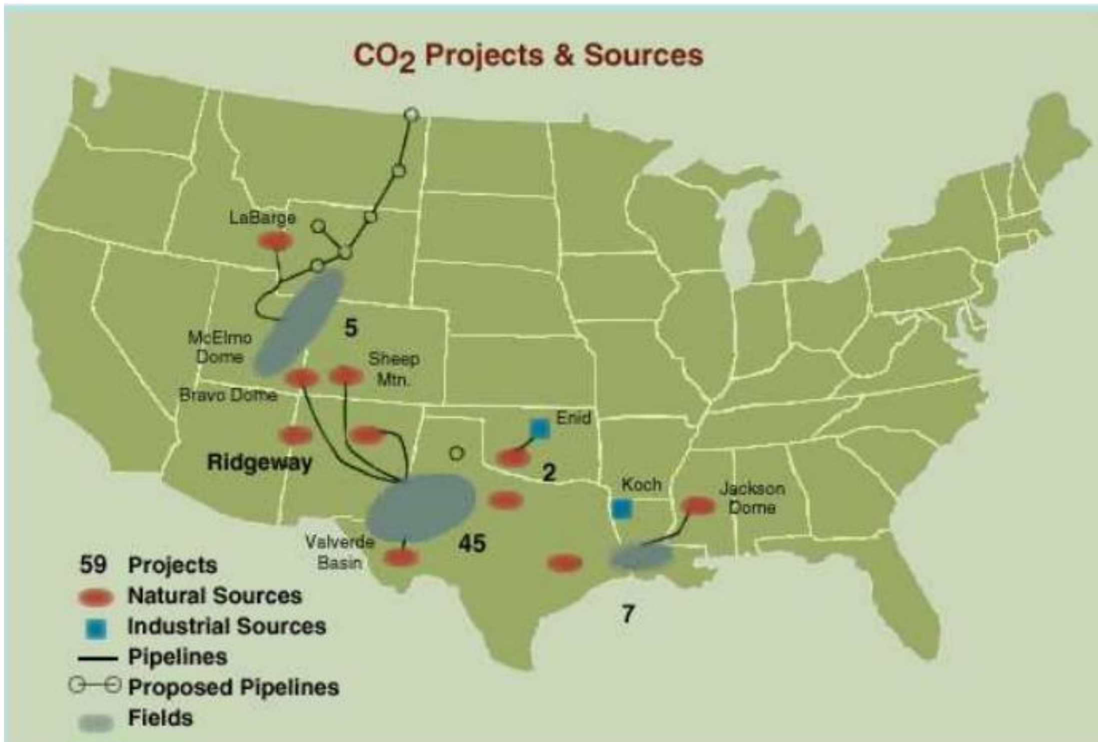

Figure 1.4.2. Carbon dioxide projects and sources in the U.S.

After careful consideration, it is clear that based on the environmental perspective, the greenhouse gas emissions, the global warming, and the other undesired events are very hot and crucial topics to consider. For the production of the oil, there is an emit of the gases. Therefore, it is required to take some actions in order to prevent this. The application of the CO_2 injection and the storage is one of the best options that both considers to enhance the oil production percentage and to store the CO_2 subsurface. In order to apply this, the depleted reservoirs are an undeniable choice for this. Later on, this paper will cover the application of the CO_2 EOR injection in the depleted reservoirs for a specific field. Additionally, the reservoir simulation is going to be applied in order to show the optimization of the recovery.

1.5. CO_2 Sequestration

The technologies and the fuels utilized to have the growth in the demand of the energy over the course of 100 years have changed significantly, since the successful attempts of the technological innovations have an effect on the sector of the energy. It is known that the initial attempts extensively involved the utilization of the oil. The next waves increased the usage of the natural gas as a medium fuel, which is followed by the development of the nuclear-type power and, more importantly, the power production technologies of the no-hydrogen renewable energy in the recent years. It is obvious that it is required to have a number of other sources of energy and sophisticated technologies, such as modern bioenergy, low-carbon hydrogen, and carbon capture, usage, and storage (CCUS) for the direct transition to a more sustainable world where low carbon is desired (Manrique 2008). It also ought to be noted that the growth of the total energy demand has been quite faster than the progress itself that made in the clean energy technological advances. It is going without saying that according to the forecasts of the International Energy Agency, emissions of the carbon dioxide from the combustion of the fossil fuel might be able to reach just more than 37 billion tonnes in the year of 2025. It is important to know that for decades, it has been stated that the percentage of fossil fuels in the worldwide energy consumption has gone steadily and persistently high, at over 80%. It should also be known that this figure is anticipated to drop to only 60% by the year of 2050. It is obvious that the carbon emission most importantly increases air pollution, which in the end leads to increased health problems among the world population, such as cardiovascular and respiratory diseases and extensive hazard to the environment (Zheng 2018).

It is understandable that the several types of the energy sources and technologies are required such as the bioenergy, the electric vehicles, the renewable energy, blue and green hydrogen, and the carbon capture and storage (CCS), for having high-quality decarbonization to the worldwide energy system. The major worldwide international companies are quickly and steadily aligning their policies and starting to proactively adopt the wind type and the solar power type renewable energy technologies. It should even be mentioned that the improving social demands towards the sustainability has supported these initiatives further. On the other hand, it is clear that the developing countries also need to reach to the transition of the energy as their economies are challenged to flourish in an environment of the renewable energy type. So, it becomes a challenge that the developed countries have not experienced in the recent years. It is also crucial to consider that a fact that does not noticed is that accepting the predefined demands for the minerals and materials that are related to the renewable resources requires a vast amount of mining operations, which is able to pose the detrimental short term and the long term environmental hazards. Thus, it is confirmed that the decrease in the fossil fuel usage will significantly decline over the course of the next few decades which makes it essential. Nonetheless, it has never performed more apparent than before to know how crucial it is for the global community to conduct a collaborative effort for the significant transition toward the net zero future (Manrique 2008).

It is maintained that efficient carbon dioxide sequestration is defined generally by the capacity of the reservoir to ensure having the long term safe confinement and the possibility of greater pore spaces, and the cap rock (Hustad 2009). The depleted oil and gas reservoirs and the deep saline aquifers are the most preferred types of the reservoirs to meet these requirements. It is maintained that there are so many studies in the literature that describe the numerical and experimental simulation methodologies for the saline aquifer reservoirs, but it should also be mentioned that only a few researches have been done about the carbon dioxide storage in the depleted reservoirs. On the one hand, the deep saline aquifers with some confining layers inside are extensively studied since it is exposed to believe to have a greater storage capacity than the Depleted oil and gas reservoirs. On the other hand, in spite of this, the Depleted Reservoirs are preferable according to their proven storage capacity for storing the buoyant fluids safely and soundly over the geological time and without any capital expenditures into new or existing infrastructures (Metz 2005). In addition, it is feasible to say that the carbon dioxide injection into the depleted reservoirs provides the advantages of the carbon dioxide storage, the simultaneous optimization with the recovery of the oil and the gas (Imbus 2006).

CHAPTER II. METHODOLOGY

As it is known that the Literature Review for this topic has been done thoroughly. Then it is important to indicate the Methodology. In the methodology of this research, the major focus is on the development of the model for the reservoir simulation in order to assess the success of the CO_2 injection which is an Enhanced Oil Recovery (EOR) method in a depleted reservoir. So, this methodology covers several crucial stages, including the data collection, the model building, the simulation of the CO_2 injection, the production optimization, and the sensitivity analysis. All the aforementioned steps will be tried to perform with the usage of the software called, T-Navigator which can be considered as a leading solution for the purpose of simulating, most importantly, the CO_2 injection. In order to understand the phases, in detail, all the information is outlined below. From the Figure 2.1.1., it is possible to observe the phases more thoroughly.

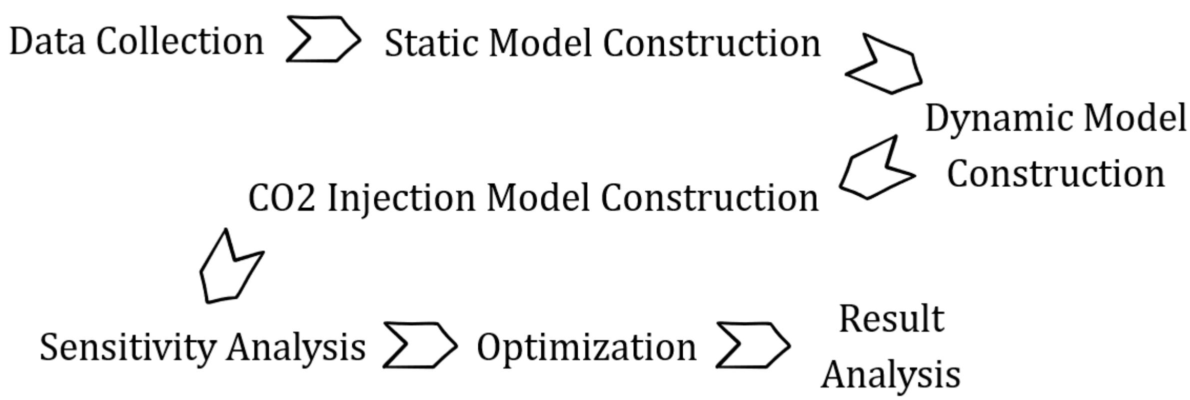

Figure 2.1.1. Methodology of the Research

2.1 Data Collection and Reservoir Characterization

As it is obvious that the first stage for conducting any reservoir simulation is to collect, bring altogether and characterize all types of the data. In this research, it should be noted that data from the depleted sandstone reservoir is utilized. Furthermore, different steps of the data collection are illustrated which are considered very essential in order to develop an accurate model. As regards the data, they are generally geological, petrophysical, production data and others.

For the Data which are required to collect is given below in detail:

- **Geological Data:** With respect to the geological data, the reservoir dimensions, the stratigraphy, and the heterogeneity can be understood from the first glance. In this research, the modeled reservoir can be illustrated as a 3D grid with certain porosity and permeability profiles which change grid by grid. Additionally, the well log data and the seismic data should be utilized in order to build the geological structure and layers.
- **Petrophysical Data:** The major petrophysical data, generally, includes the porosity, the permeability, the saturation values, and the capillary pressure. It is trustworthy to say that these figures are considerable for determining the fluid flow characteristics in the reservoir model building. In the depleted reservoir, the primary production properties are the remaining oil reserves and the initial oil saturation.
- **Fluid Properties:** Another important factor is the fluid characterization. Especially the parameters for the CO_2 and the oil can be considered. Using PVT analysis that is a pressure-volume-temperature test, the oil, and the CO_2 characteristics might be determined, including the density, and the viscosity. The miscibility amid the CO_2 and the oil will be modeled with the help of the T-Navigator in order to ensure accurate results.
- **Production Data:** The historical production data is also very important while analyzing the reservoir. It is possible to exemplify the oil production rates, the trends of the reservoir pressure, and any previous recovery methods, such as the injection. This data is crucial while constructing the simulation model.

The reservoir type selected for this research is a depleted sandstone reservoir. Considering this, the synthetic field data is taken into account. It ought to be noted that it has been exposed to the primary production and the secondary recovery which is the water injection. This type of the reservoir particularly shows a significant drop in the pressure and the production of the oil after a certain time period. Here, the CO_2 injection is taken into account as an EOR method in order to keep the pressure in the desired level and improve the recovery in the remaining regions.

It may be said that while building the reservoir model the grid design should be considered. In the T-Navigator, the 3D grid is created to represent the geological layers and the properties of the reservoir, making sure to have an adequate design for both flows which are vertical and horizontal. The grids show certain part of the reservoir and somehow reflect it in the software.

2.2 Construction of the Reservoir Simulation Model in T-Navigator

T-Navigator is a very cutting-edge technological software where the reservoir modeling and the simulation might be performed. It offers a quite wide range of solutions in the geoscience, the reservoir, and the production engineering. For this case, it can be said that it has very advanced features in order to model the EOR techniques, the multi-phase flow, and most importantly the CO_2 injection. In this research, the T-Navigator is utilized for the simulation of the effect of the CO_2 injection as an oil recovery method. Once entered the T-Navigator software, the screen that can be seen is shown in Figure 2.2.1. below.

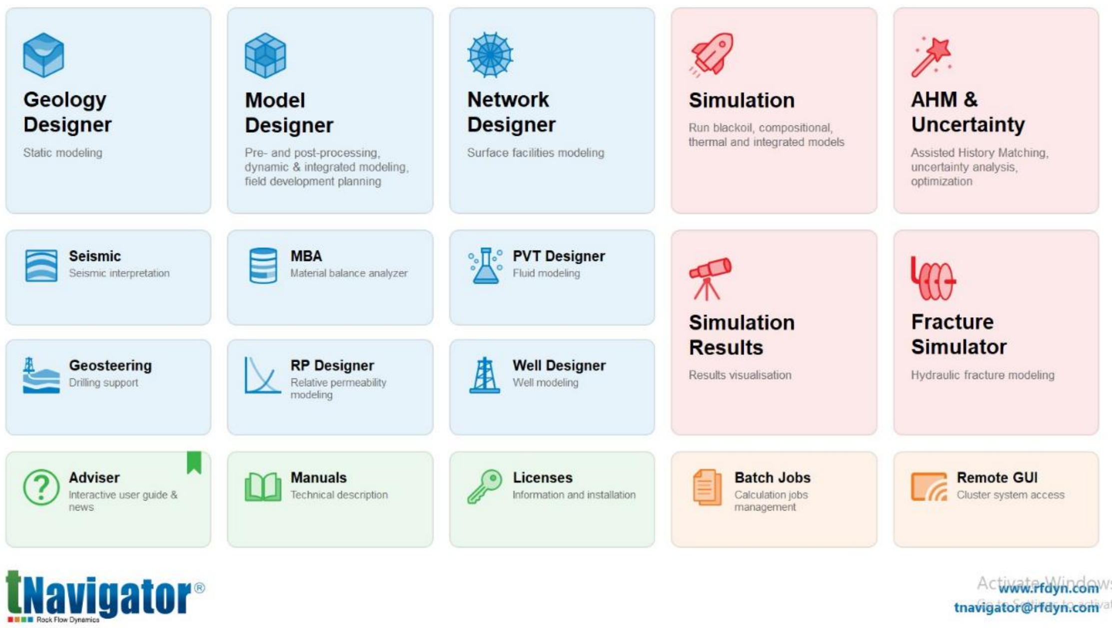

Figure 2.2.1. T-Navigator Control Panel.

In order to set up the model in the T-Navigator software, the following need to be considered:

- **Grid Definition:** Firstly, the reservoir can be discretized into a grid with 3-dimension with a certain quantity of the layers which represent the geological and the fluid specifications of the reservoir. A fine grid resolution is applied to ensure the accuracy in simulating the injection of the CO_2.
- **Boundary Conditions:** Here it can be assumed that the CO_2 is injected inside the reservoir through a predetermined injection well, where oil is produced from the production well. The reservoir is considered a semi-closed structure, where the injection of the CO_2 goes on

once the target recovery factor is succeeded or till a CO_2 breakthrough takes place in the wells of the production.

- **Initial Conditions:** Owing to the historical data, including the reservoir pressure before the injection, the initial oil saturation, and the remaining oil after the recovery processes, the saturation values and the initial reservoir pressure are determined.
- **Fluid Properties in T-Navigator:** The fluid properties which are an oil and a carbon dioxide in this case are input into the T-Navigator software for the PVT Designer section. In the T-Navigator, with the fluid model the CO_2 phase behavior and the relationship amidst an oil and a CO_2 in the reservoir can be illustrated.
- **CO2 Injection Parameters:** CO_2 injection pressure, the rate, and the location for the well are considered as input parameters. Additionally, various injection schemes might be tested.

2.3 CO_2 Injection Simulation

CO_2 injection is the major EOR method applied in this research. It can be said that from the simulation of CO_2 injection which is in a depleted type reservoir, determination of optimal pressure, injection rates, and the displacement efficiency of CO_2 might be conducted.

- **Injection Rate and Pressure:** It is possible to test injection rates of CO_2 in order to evaluate the possible changes in oil recovery, whereas the injection pressure is put owing to the CO_2 injectivity profile and the initial pressure of the reservoir that might be regulated based on conditions of well.
- **Injection Well:** As it is clear that the location of the well of CO_2 injection is selected while looking at the geological model, considering not only the heterogeneity of the reservoir but also the most reasonable location to achieve the most optimal sweep efficiency.
- **CO_2 Distribution:** T-Navigator might also analyze the movement of CO_2 throughout the reservoir using a combination of gravity override, miscibility, and relative permeability curves. From the simulation it is feasible to evaluate the movement of CO_2 inside the reservoir, displacing oil and improvising efficiency of recovery.

So, the miscibility condition amidst the oil and CO_2 is a key factor to succeed in CO_2 EOR. Through the T-Navigator software, the interaction of CO_2 interaction with the oil might be assessed.

- **CO_2 Migration:** The direction of CO_2 is typically upwards as density is lower compared to oil. So, it is possible to simulate this case for analyzing the sweep efficiency and the behavior of CO_2 with the help of T-Navigator.
- **Impact on Oil Recovery:** It can be said that displacement efficiency can be improved with the miscibility of carbon dioxide and oil, basically in high viscous oily reservoirs. And T-Navigator is able to model these phase alterations and the rise in recovery efficiency.

It is trustworthy to say that in order to assess the effectiveness of CO_2 injection in production optimization oil production rate, recovery factor, and carbon dioxide rate ought to be utilized which are known as key performance indicators. These properties might aid to assess the amount of additional oil which can be recovered via the injection of CO_2 and the efficiency of utilized carbon dioxide.

2.4 Production Optimization Using Carbon Dioxide Injection

It is obvious that the objective of this research is to advance the utilization of the injection of CO_2 to make greater the oil recovery while restricting expenses and carbon dioxide utilization. This might be accomplished by utilizing improvement tests to track down the best case, and fluctuating key injection boundaries.

It goes without saying that the advancement cycle includes characterizing a goal capability to augment the oil recovery while limiting CO_2 injection costs. For this goal, the attempts might be:

- **Recovery Factor (RF):** Boosting the recovery factor, which can be the proportion of all out recoverable oil to the initial oil in place.
- **Carbon Dioxide Utilization Efficiency:** Limiting the carbon dioxide considered for each barrel of recovered oil.

It is clear that optimization might be performed using a set of certain properties, such as:

- CO_2 injection rate
- Injection pressure
- Well placement and number of wells

As regards the sensitivity analysis, to comprehend the impact of various boundaries on CO_2

injection execution, it might be conducted. This includes changing certain boundaries, such as porosity, rate of injection and others, and evaluating their effect on oil recovery. The aftereffects of this analysis will assist with recognizing the most basic elements for oil production optimization.

RESULTS

Reservoir Simulation Model:

In this chapter, all the results and outcomes related to this are indicated. Firstly, it is required to know that using the software, T-Navigator, the model is built. The data of the field and all others are considered as synthetic data and generated by the software itself. Later, reservoir simulation is performed in order to realize the CO_2 injection and the crucial factors that affect this process.

In Figure 1 below, the basic model of the reservoir is indicated for this study which is based on a synthetic model.

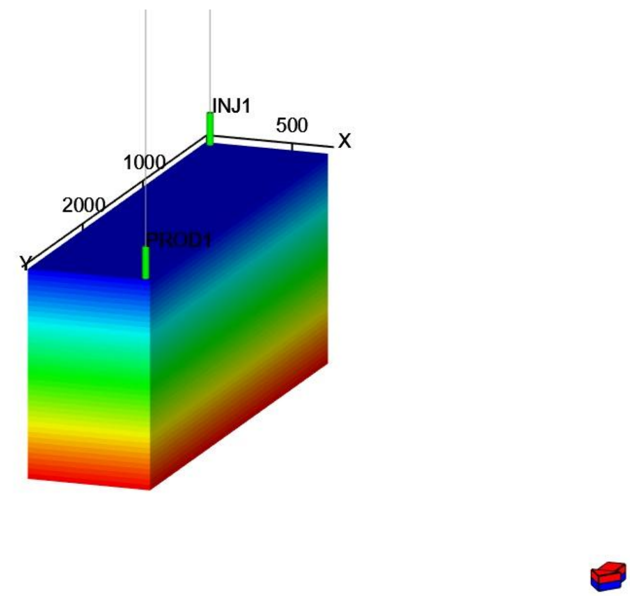

Figure 1 Reservoir Simulation Model by T-Navigator

This indicated model shows that this reservoir is a conventional oil reservoir that mainly consists of sandstone. It is considered a single porosity reservoir, and the figure is 19%. It is also obvious that this oil section is located at a depth of 6000 ft. The model of this oil reservoir is built and regulated by the number of grids, that is according to length, width and thickness.

So, related to the dimensions of this model, it is trustworthy to say that, they are 9, 36, and 40 in the directions of X, Y, and Z, respectively.

It is also known that in order to keep the equilibrium in the model, depth, pressure and temperature are calibrated to the specified Oil-Water Contact. Another important part to consider here is the well locations. From the figure it is clear to see that, the wells of injection and production are drilled at two opposite corners of the reservoir. It is also required to know that for the base case, the injection well supplies 2000 mscf/d of CO_2 as injection rate.

Table 1 Base Case of Reservoir Simulation

Property	Value
Reservoir Type	Single Porosity
Reservoir Depth	6000 ft
Thickness in Z direction	65 ft
Dimensions in X direction	9
Dimensions in Y direction	36
Dimensions in Z direction	40
Reservoir Pressure	3000 psia
Porosity	0.19
Permeability	10 md

Figure 2 illustrates the curves of relative permeabilities of water and oil based on water saturation. As it is clear, oil relative permeability decreases with the water saturation increase, whereas water relative permeability increases with that trend. Oil relative permeability trend means decreased pore space availability for the flow of oil, on the other hand, water relative permeability curve shows enhanced mobility for water phase.

The crossover point from these curves is approximately at 50% of water saturation.

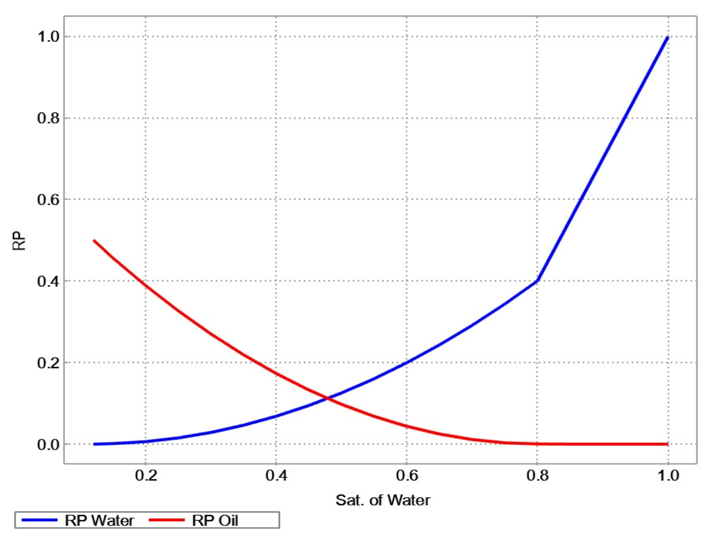

Figure 2 Relative Permeability curves

Comparison of Different CO_2 Injection Rates for Different Production Years in Oil Production:

For this research, three injection rate cases are considered in order to simulate the CO_2 injection process for 3 production cases. It is required to know that those three injection rates are 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d and the injection has been applied after 5-year, 6-year and 7-year production. As it is mentioned beforehand, there are two wells which are injector and producer. The injector injects CO_2 in order to enhance production, whereas the producer produces the oil to the surface. It is important to say that injection has been done for 3 years. Below, all the cases have been shown in detail:

Case 1:

For Case 1, these characteristics are considered: Firstly, production is continued for 5 years. Then, after the production, injection has been applied with the injection rates of 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d. For each case, Reservoir Model, Total Oil Rate vs Date and Injection Rate vs Date graphs are indicated. Figure 3, Figure 5, Figure 8 and Figure 11 show Reservoir Models for only production, production + injection (2000 Mscf/d), production + injection (4000 Mscf/d) and production + injection (6000 Mscf/d), accordingly. Figure 4, Figure 6, Figure 9 and Figure 12 indicate Total Oil Rate vs Date for above cases, accordingly. Whereas Figure 7, Figure 10 and Figure 13 show Gas Injection Rate vs Date graphs for the injection rates of 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d. In Y-axis and X-axis, Rates and Dates are indicated, respectively.

In Table 2, the outcome for Case 1 is indicated. Below, all the Figures are given:

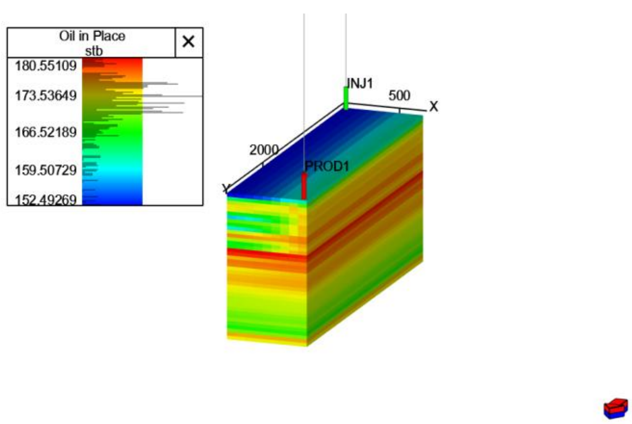

Figure 3 Reservoir Model after 5 years of Production

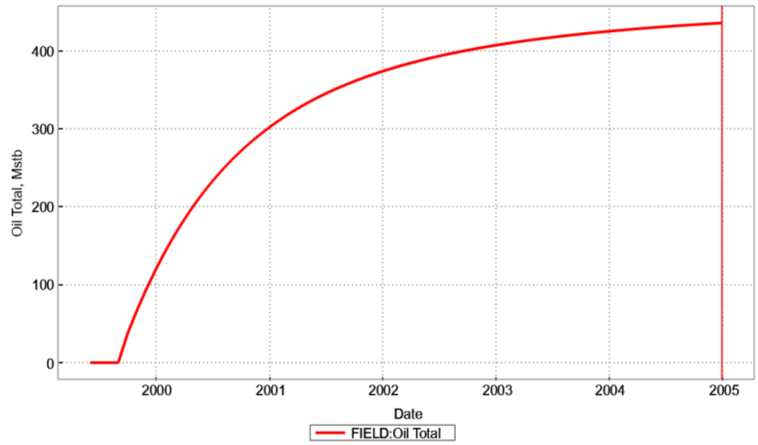

Figure 4 Total Oil vs Date after 5 years of Production

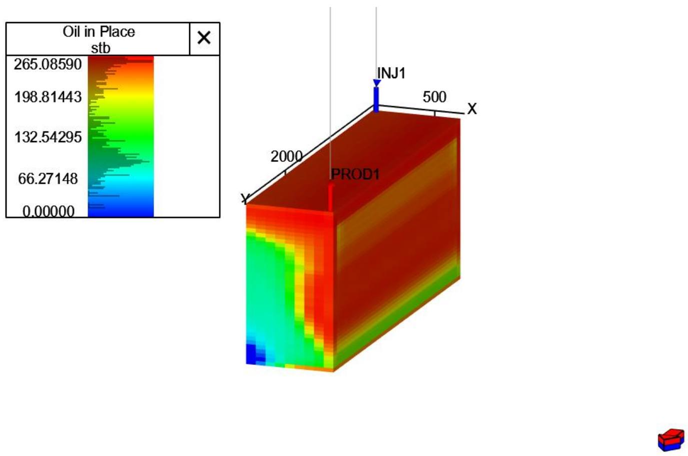

Figure 5 Reservoir Model after 5 years of Production and Injection (2000 Mscf/d)

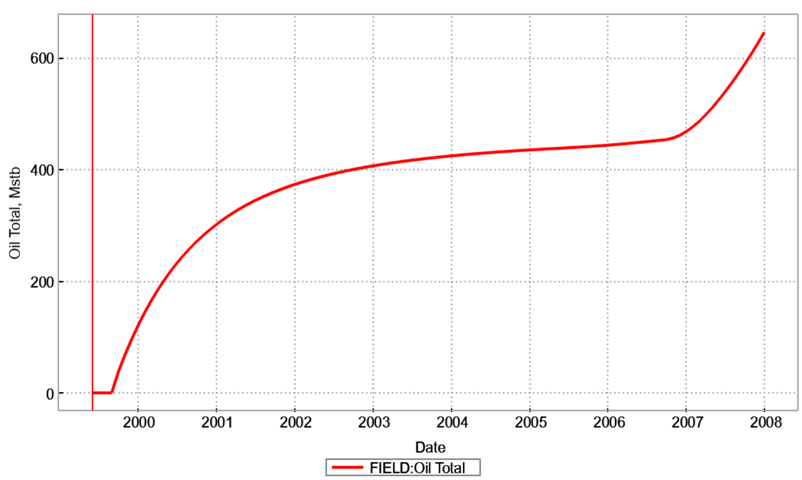

Figure 6 Total Oil vs Date after 5 years of Production and Injection (2000 Mscf/d)

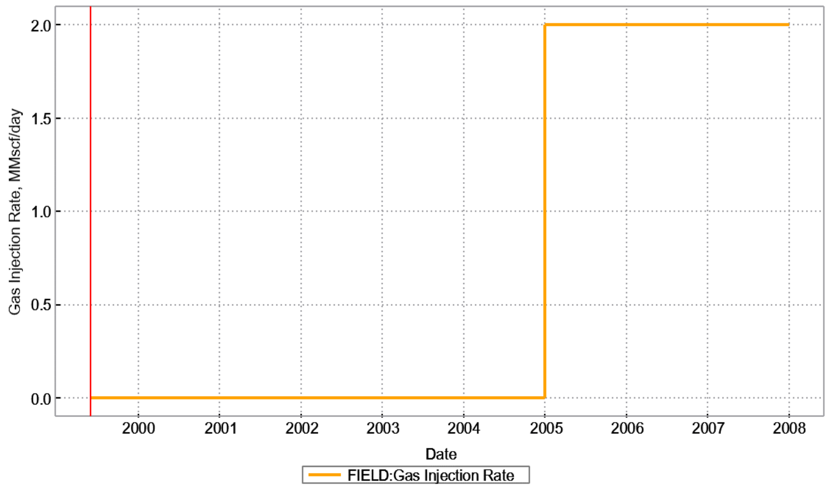

Figure 7 Injection Rate vs Date (2000 Mscf/d) after 5 years of Production

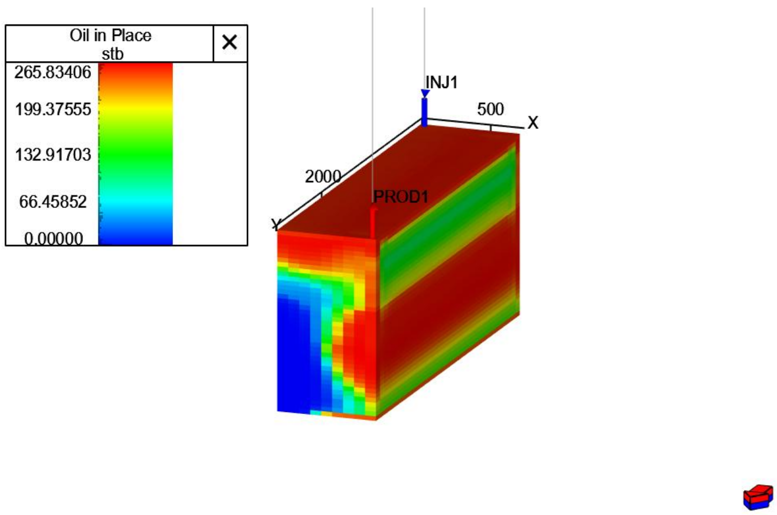

Figure 8 Reservoir Model after 5 years of Production and Injection (4000 Mscf/d)

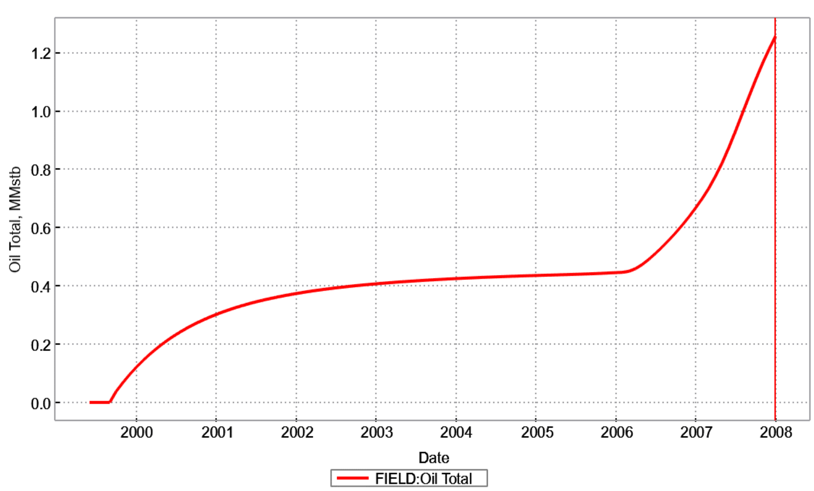

Figure 9 Total Oil vs Date after 5 years of Production and Injection (4000 Mscf/d)

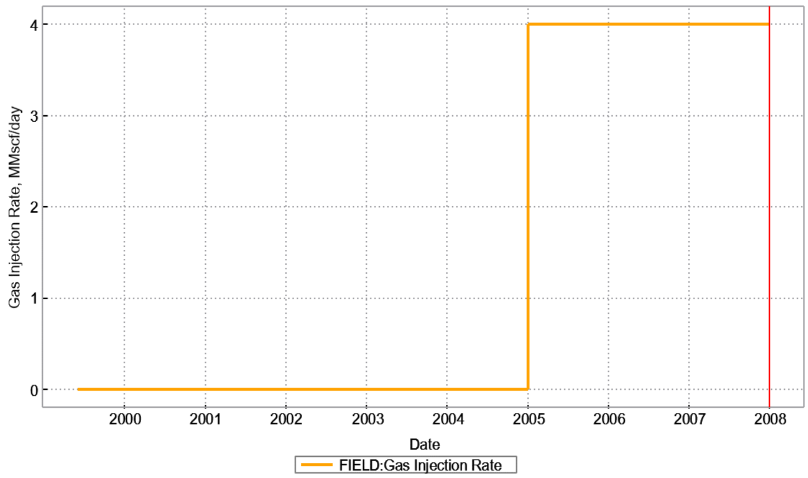

Figure 10 Injection Rate vs Date (4000 Mscf/d) after 5 years of Production

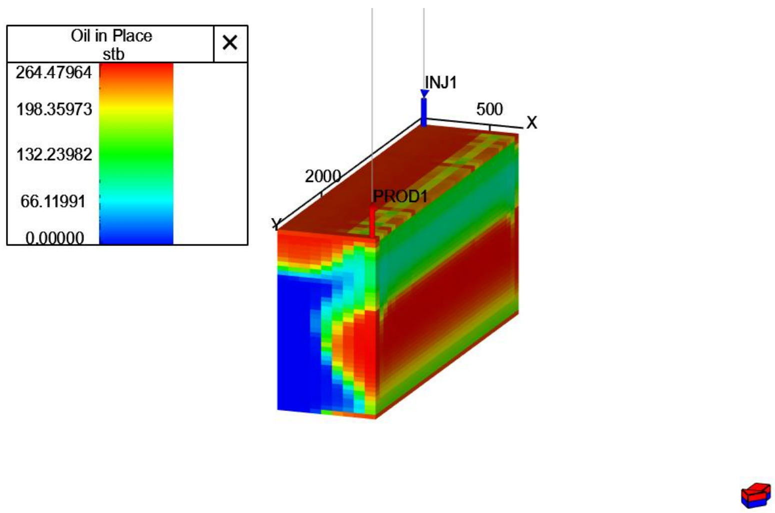

Figure 11 Reservoir Model after 5 years of Production and Injection (6000 Mscf/d)

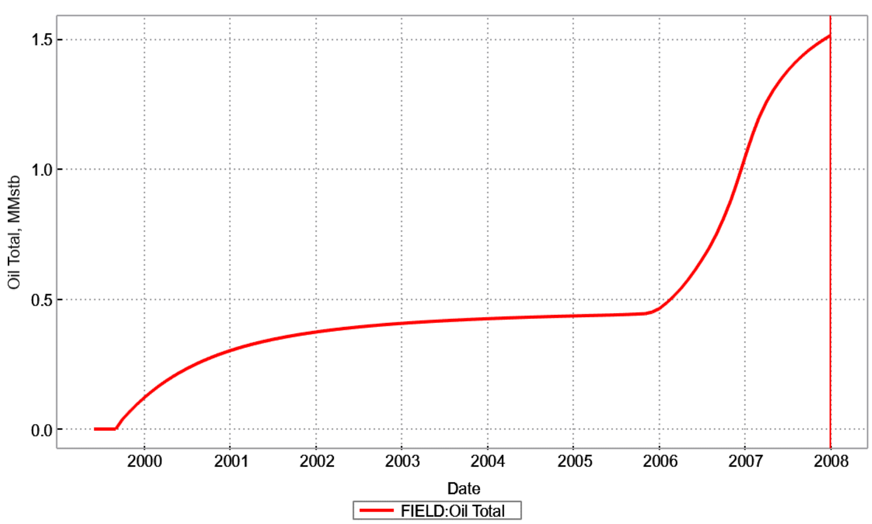

Figure 12 Total Oil vs Date after 5 years of Production and Injection (6000 Mscf/d)

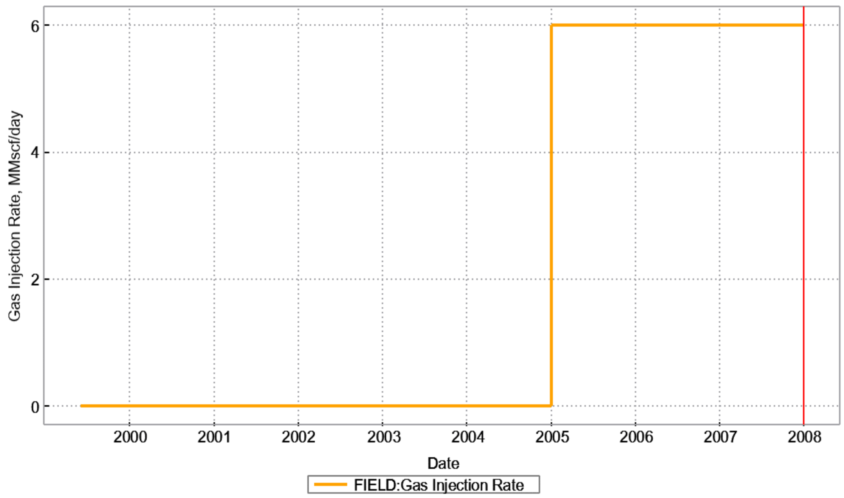

Figure 13 Injection Rate vs Date (6000 Mscf/d) after 5 years of Production

Table 2 Outcome of Case 1

Production	Injection	Injection Rate	Total Production
5 Years	-	-	0.436 MMstb
5 Years	3 Years	2000 Mscf/d	0.641 MMstb
5 Years	3 Years	4000 Mscf/d	1.250 MMstb
5 Years	3 Years	6000 Mscf/d	1.511 MMstb

Case 2:

For Case 2, the following steps are taken into account: Primarily, production is lasted for 6 years. Later, injection has been implemented with the injection rates of 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d after the production. For each of these cases, Reservoir Model, Total Oil Rate vs Date and Injection Rate vs Date curves can be demonstrated. Figure 14, Figure 16, Figure 19 and Figure 22 indicate Reservoir Models for solely production, production + injection (2000 Mscf/d), production + injection (4000 Mscf/d) and production + injection (6000 Mscf/d), respectively. Figure 15, Figure 17, Figure 20 and Figure 23 show Total Oil Rate vs Date for aforementioned cases, respectively. Whilst Figure 18, Figure 21 and Figure 24 indicate Gas Injection Rate vs Date curves for the injection rates of 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d. In Y-axis and X-axis, Rates and Dates are demonstrated, in respective order.

Whereas in Table 3, the results for Case 2 are demonstrated. Below, all the Figures are given:

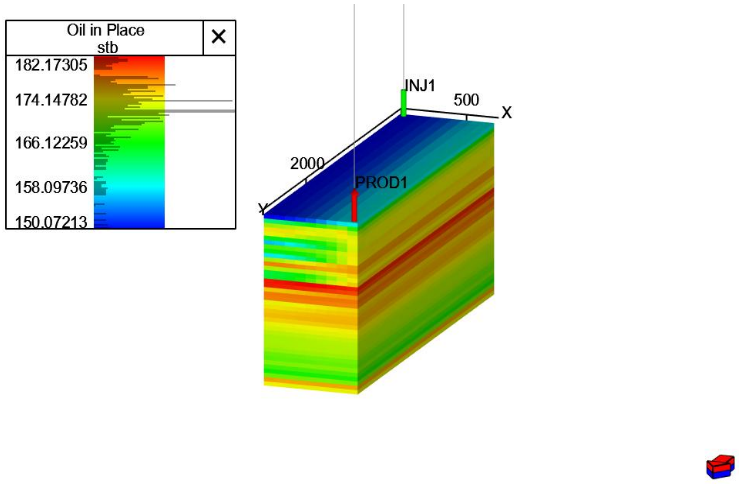

Figure 14 Reservoir Model after 6 years of Production

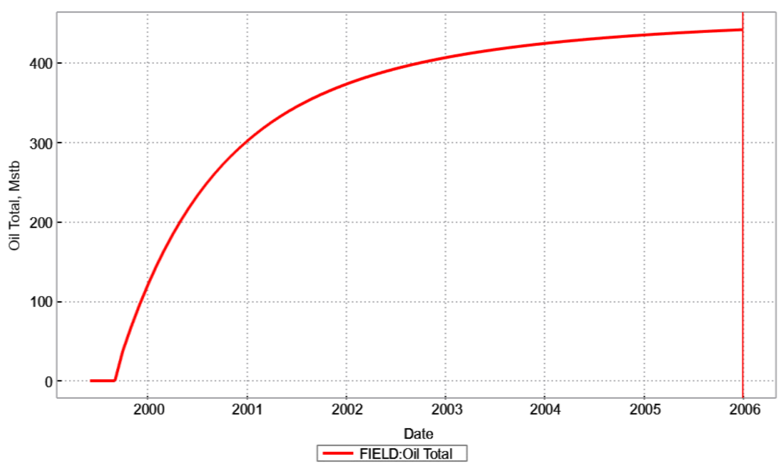

Figure 15 Total Oil vs Date after 6 years of Production

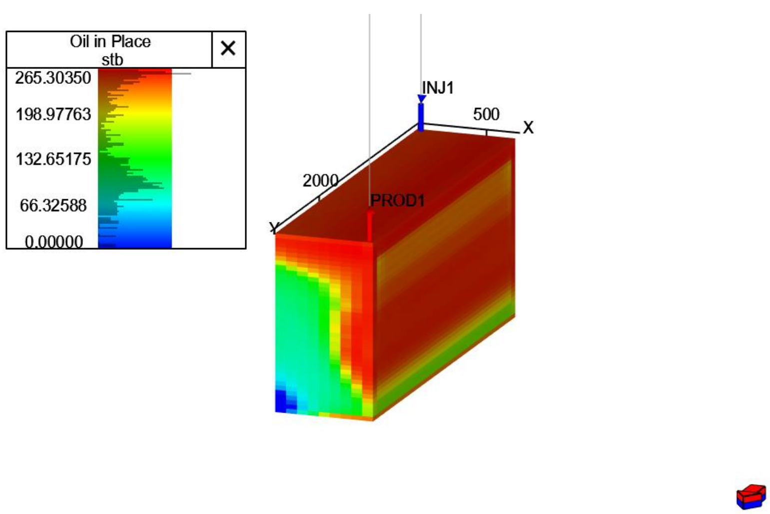

Figure 16 Reservoir Model after 6 years of Production and Injection (2000 Mscf/d)

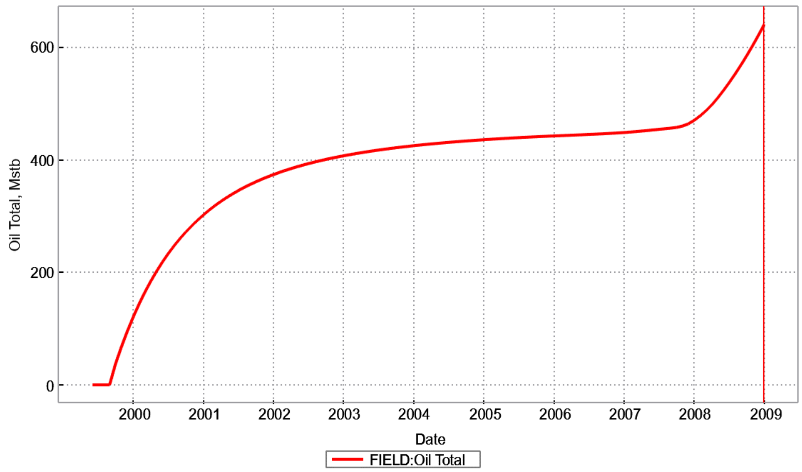

Figure 17 Total Oil vs Date after 6 years of Production and Injection (2000 Mscf/d)

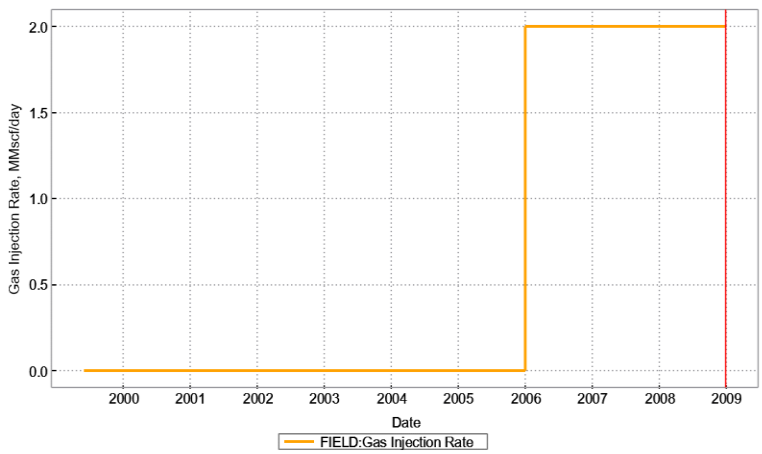

Figure 18 Injection Rate vs Date (2000 Mscf/d) after 6 years of Production

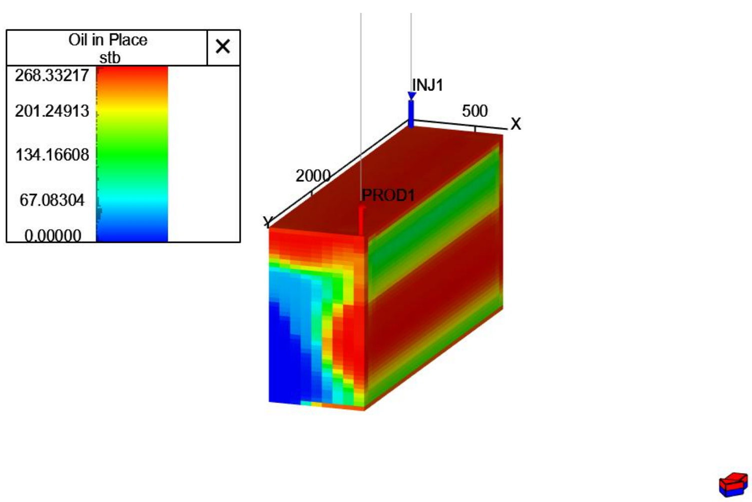

Figure 19 Reservoir Model after 6 years of Production and Injection (4000 Mscf/d)

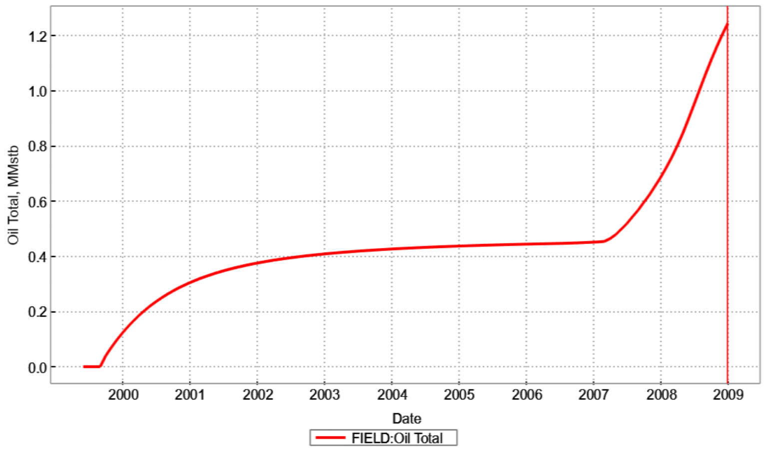

Figure 20 Total Oil vs Date after 6 years of Production and Injection (4000 Mscf/d)

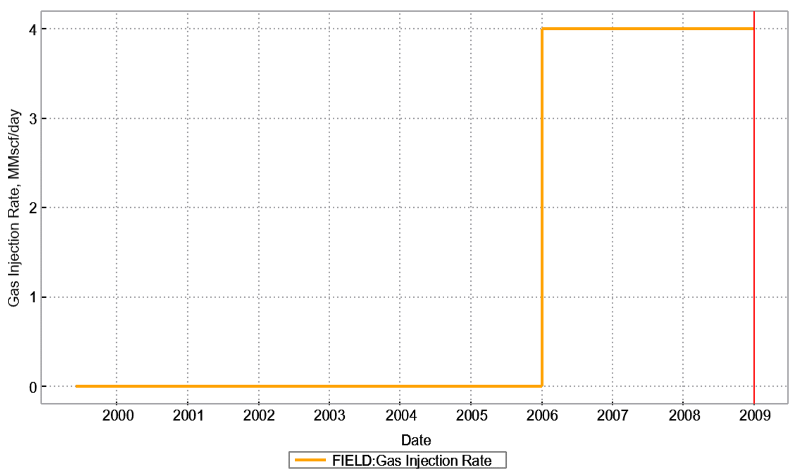

Figure 21 Injection Rate vs Date (4000 Mscf/d) after 6 years of Production

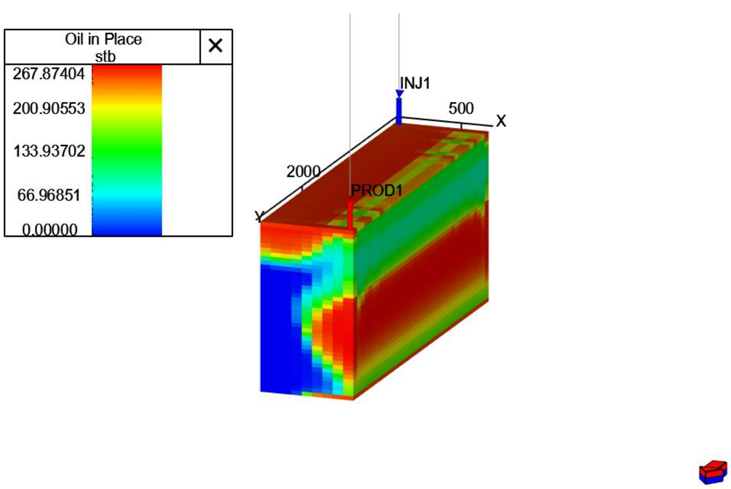

Figure 22 Reservoir Model after 6 years of Production and Injection (6000 Mscf/d)

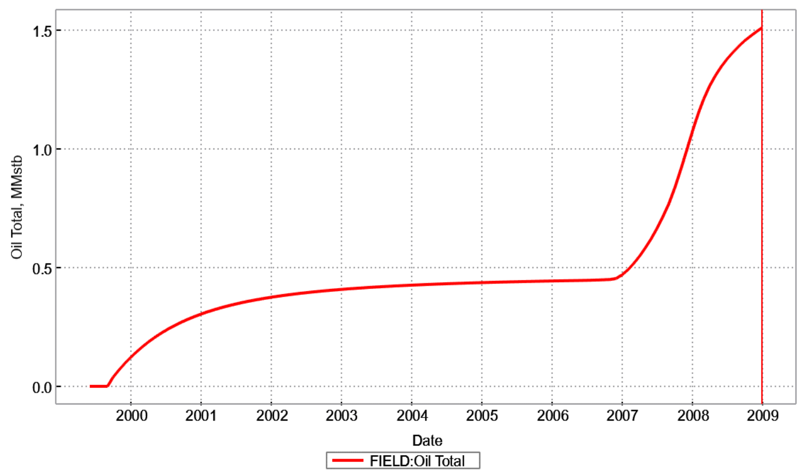

Figure 23 Total Oil vs Date after 6 years of Production and Injection (6000 Mscf/d)

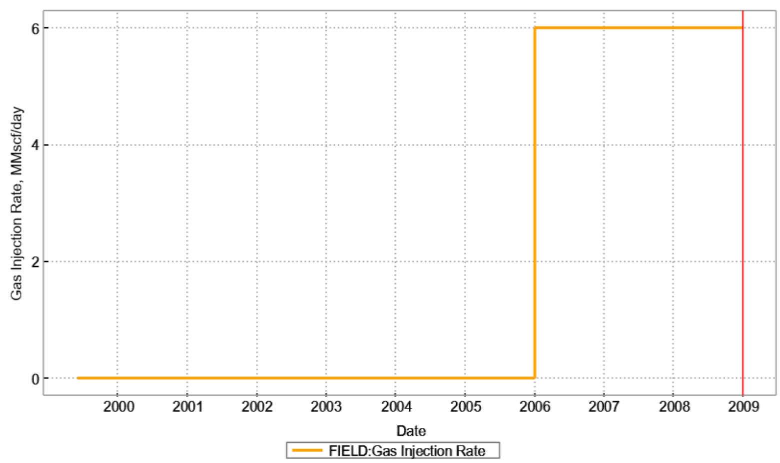

Figure 24 Injection Rate vs Date (6000 Mscf/d) after 6 years of Production

Table 3 Outcome of Case 2

Production	Injection	Injection Rate	Total Production
6 Years	-	-	0.443 MMstb
6 Years	3 Years	2000 Mscf/d	0.667 MMstb
6 Years	3 Years	4000 Mscf/d	1.257 MMstb
6 Years	3 Years	6000 Mscf/d	1.520 MMstb

Case 3:

In Case 3, the same steps are considered again: In the first step, production is completed for 7 years. After that injection process has been implemented with the rates of injection of 2000

Mscf/d, 4000 Mscf/d and 6000 Mscf/d after the production. It is clear that for every one of the cases, Reservoir Model, Total Oil Rate vs Date and Injection Rate vs Date figures could be shown. Figure 25, Figure 27, Figure 30 and Figure 33 demonstrate Reservoir Models just for production, production + injection (2000 Mscf/d), production + injection (4000 Mscf/d) and production + injection (6000 Mscf/d), respectively. Figure 26, Figure 28, Figure 31 and Figure 34 demonstrate Total Oil Rate vs Date for mentioned cases, in respective order. Whereas Figure 29, Figure 32 and Figure 35 visualise Gas Injection Rate vs Date curves for the injection rates of 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d. In Y-axis and X-axis, Rates and Dates are indicated, accordingly.

It should also be known that Table 4 shows the results for Case 2. Below, all the Figures are given:

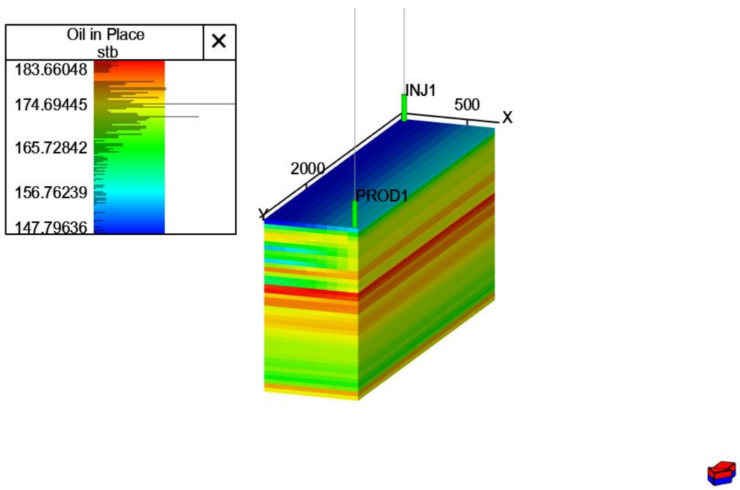

Figure 25 Reservoir Model after 7 years of Production

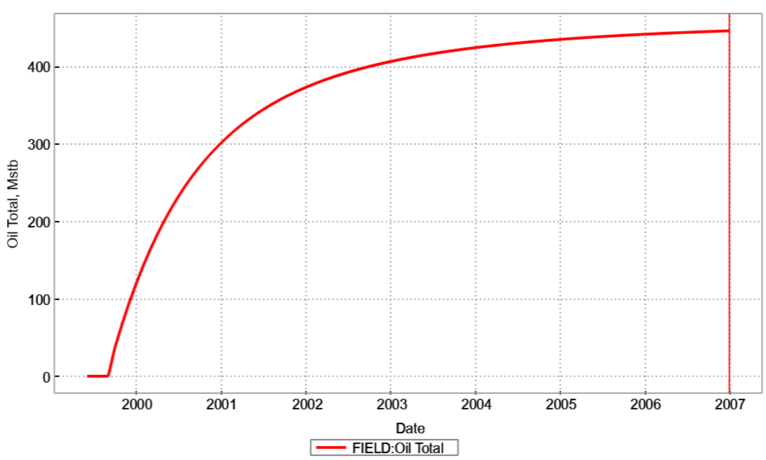

Figure 26 Total Oil vs Date after 7 years of Production

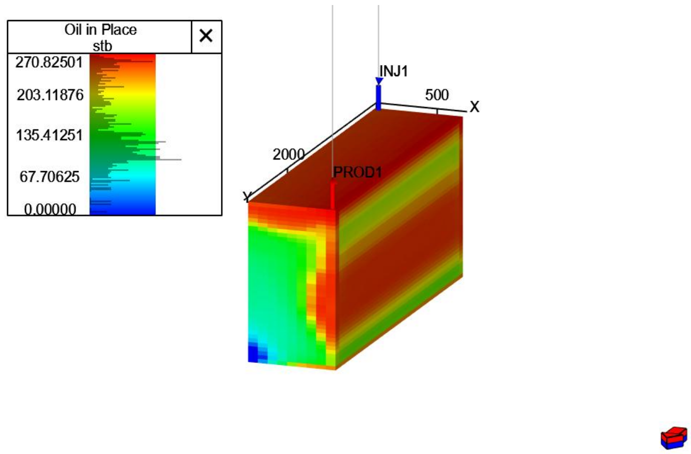

Figure 27 Reservoir Model after 7 years of Production and Injection (2000 Mscf/d)

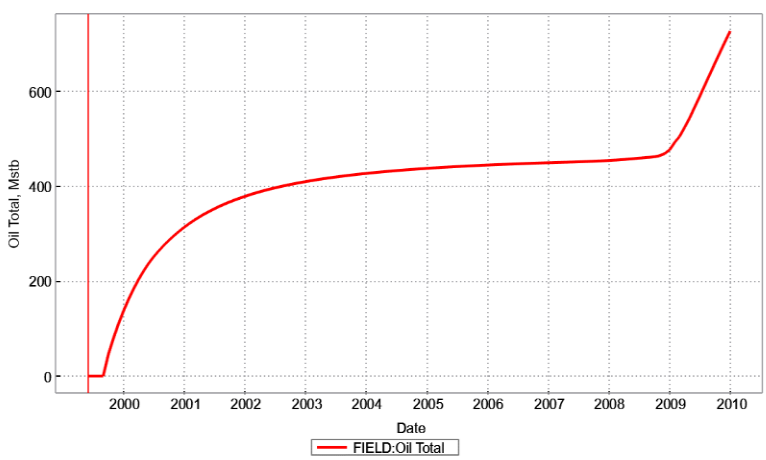

Figure 28 Total Oil vs Date after 7 years of Production and Injection (2000 Mscf/d)

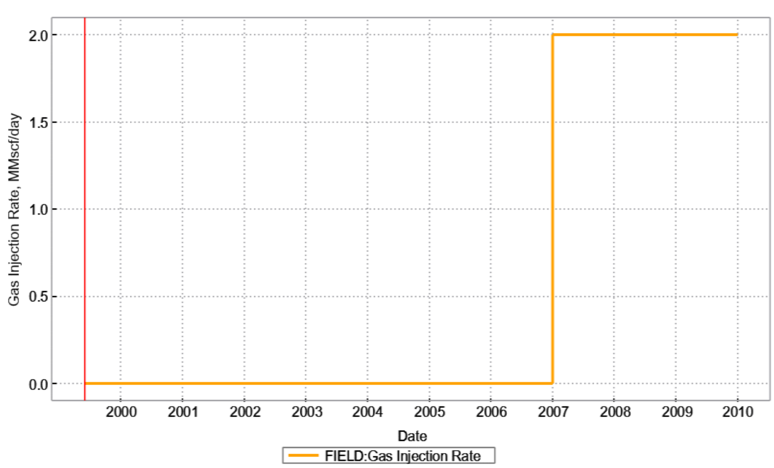

Figure 29 Injection Rate vs Date (2000 Mscf/d) after 7 years of Production

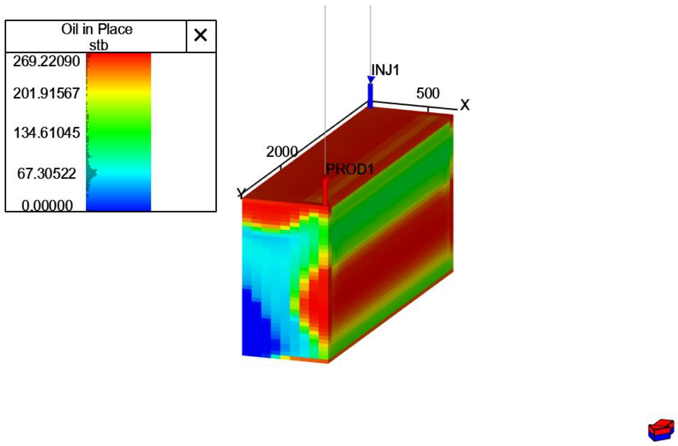

Figure 30 Reservoir Model after 7 years of Production and Injection (4000 Mscf/d)

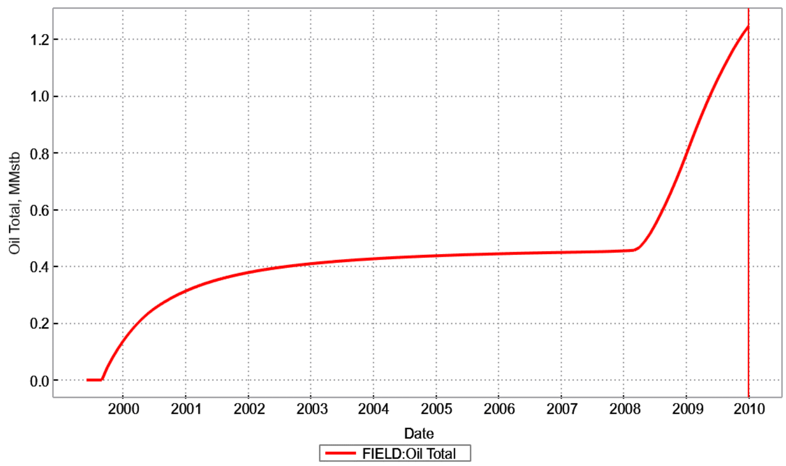

Figure 31 Total Oil vs Date after 7 years of Production and Injection (4000 Mscf/d)

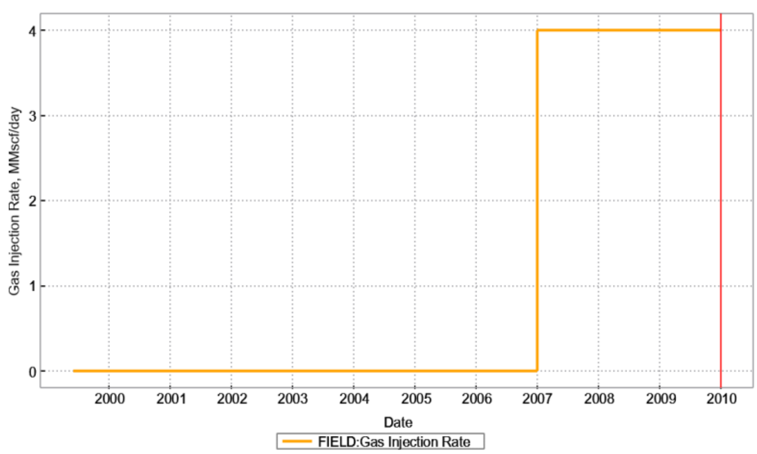

Figure 32 Injection Rate vs Date (4000 Mscf/d) after 7 years of Production

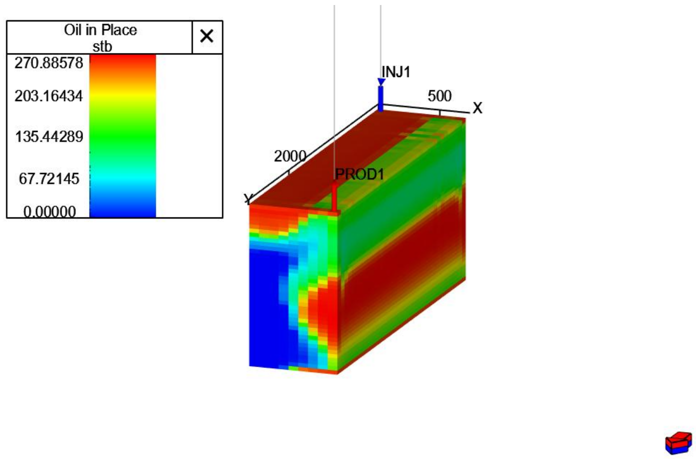

Figure 33 Reservoir Model after 7 years of Production and Injection (6000 Mscf/d)

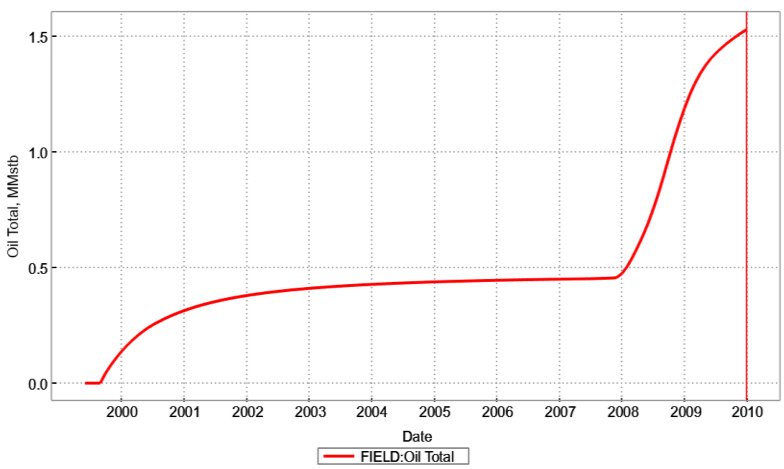

Figure 34 Total Oil vs Date after 7 years of Production and Injection (6000 Mscf/d

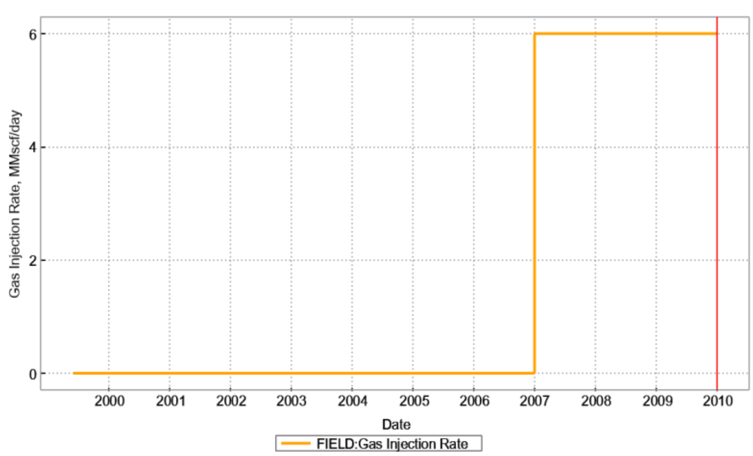

Figure 35 Injection Rate vs Date (6000 Mscf/d) after 7 years of Production

Table 4 Outcome of Case 3

Production	Injection	Injection Rate	Total Production
7 Years	-	-	0.447 MMstb
7 Years	3 Years	2000 Mscf/d	0.757 MMstb
7 Years	3 Years	4000 Mscf/d	1.264 MMstb
7 Years	3 Years	6000 Mscf/d	1.530 MMstb

CONCLUSION AND RECOMMENDATIONS

So, from the beginning to the end this study has been written precisely and in detail. Firstly, the relevance, the purpose, the novelty and the objective of the topic and research have been identified detailly. After that the 1st Chapter which is called Literature Review starts. This chapter, totally, is about application of CO_2 injection EOR method in depleted reservoirs. Firstly, it starts with about conventional and unconventional reservoirs, then it is mentioned that depleted reservoir is considered as conventional one. After this, depleted reservoirs are explained in detail from how they are formed to the advantages and disadvantages. Furthermore, one of the most important terms, oil recovery, is explained. Here, main techniques for oil recovery improvement are indicated. As for depleted reservoirs, it is required to apply enhanced oil recovery methods. For depleted reservoirs, the importance of CO_2 injection is explained and shown in detail. Later the 2nd Chapter commences of this study. This is about the Methodology. So, the workflow in order to conduct the simulation is indicated in detail and explained for each step. The simulation software for this study is shown, and the required modules in order for the indication of this injection process are mentioned. It should also be known that, the required data for the simulation of this CO_2 injection process are demonstrated as well. What factors are going to affect, what steps should be known and other important questions are answered here. Last but not least, one of the most important chapters, which is Results, starts just after Methodology. This chapter is very important and the final indication for this study. Here, all the data that are collected are indicated one by one. Then, using these data, desired reservoir model is built. Moreover, some important graphs and figures are obtained. After this, the simulation process started. Based on certain schedule steps, different graphs and curves can be obtained. And all of these are indicated one by one with certain explanation.

After conducting all the study, in this research it has been appeared that the production has been optimized using the CO_2 injection as Enhanced Oil Recovery. The production optimization is achieved using different amounts of CO_2 and the effect of this change has been indicated in detail. So, to sum up, it ought to be said that there are injection rates with 2000 Mscf/d, 4000 Mscf/d and 6000 Mscf/d are considered with 3-year injection time after 5-year, 6-year and 7-year production. Each of the possibilities are taken into account. It is going without saying that the optimal amount of oil is produced when the injection rate is higher. So, the optimum volume of oil can be achieved when the injection rate is 6000 Mscf/d and around an increase of 1.075 MMstb, 1.077 MMstb and

1.083 MMstb oil are computed for 5-year, 6-year and 7-year production, respectively. Considering the base case which is without injection, then the injection is applied the production can be considered quite considerable. So, it means the basic concept of this study has been succeeded.

About the recommendations, it can be composed that economic analysis might be done in detail in order to check whether it is worth to do this injection or not. Additionally, CO_2 injection in other reservoir types might be attempted in order to compare the results. And most importantly, carbon sequestration can be applied. Application of CO_2 injection make it possible to further improve the reservoir for carbon storage process. Carbon storage is the permanently storage of CO_2 which is injected. This is not only economical but also environmental method which should be taken into account.

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