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Different Pattern of Development in One of the Oil Reservoirs in Order to Propose the Optimal Pattern of Injection and Production

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Background: The goal of well production is to find the best production solution for each well in order to maximize the net present value (NPV) or hydrocarbon output from a reservoir, which is categorised as production optimization. The optimization process includes Nei, or the creation of the future, and numerical simulations are widely used for this purpose. Individual simulations can be time-consuming, and comprehensive optimisation may require many simulation cycles.
Objectives: Analyze present injection operations to optimise oil extraction efficiency, Sophisticated simulation models are developed and evaluated to estimate reservoir performance under various injection and production scenarios, Developing and testing new injection methods, such as CO2 or particular compounds, to improve oil extraction efficiency , Environmental impact analysis examines the environmental implications of injection and production practices, including mitigation strategies.
Conclusion and Future Prospects In the oil and gas industries, the displacing fluid and volumetric sweep efficiency determine microscopic displacement efficacy in the reservoir rock system. This review looked thoroughly at the factors that influence oil recovery, including primary, secondary, and tertiary recovery methods. This study investigates how porosity, permeability, temperature, reservoir pressure, fluid viscosity, wettability fluctuation, fluid displacement efficiency, mobility variables, fluid-rock interactions, and fluid volume affect the oil recovery factor.

1. Introduction

The purpose of well production is to discover the ideal production solution for each well in order to maximize the net present value (NPV) or hydrocarbon output from a reservoir, which falls under the category of production optimization. The optimization process involves Nei, which is the creation of the future, and numerical simulations are commonly employed for this purpose. Are utilized. Individual simulations can be time-consuming, and full optimization may need numerous simulation repeats [1]. As a result, it is critical to develop effective solutions to these difficulties. Currently, there are two types of approaches that are often utilized for well production: optimization algorithm-based methods and reinforcement learning methods. Optimization algorithm-based approaches include mostly of Gradient and derivative-free methods. Algorithms based on gradients employ gradient data to determine search direction [2, 3, 4, 5]. The approaches based on the gradient of the main flow that have been utilized for production optimization issues, the method based on the additive gradient [6], and the random gradient method [3]. There exist simultaneous random perturbation approximations [7], etc. These methods have been proven. Be able to provide quick and accurate solutions for optimal production issues. However, these methods can only guarantee finding local optimal solutions. Therefore, there is a need for more efficient methods to be able to find global optimal solutions. On the other hand, derivative-free algorithms do not require explicit calculations of derivatives, and therefore provide better flexibility [8, 9]. Representative algorithms include differential evolution (DE) [10, 11], agent-assisted evolution algorithm (SAEA) [12, 13, 14, 15, 16, 17, 18, 19], particle swarm optimization (PSO) [20], etc. These approaches have been widely employed in numerous optimization projects and have demonstrated excellent global search capabilities. However, this approach takes a large number of simulations, has low computing efficiency, and is difficult to solve for high-dimensional problems, making it unsuitable for usage in this sector. The disadvantage of algorithmic optimization approaches is that they are task-specific, have limited memory, and must be restarted for new tasks. Recent research has attempted to apply RL algorithms to particular challenges in production optimization. Use it, like De Paola and colleagues did. Using the DQN algorithm (De Paola et al., 2020) or Zhang et al. using the SAC algorithm to optimize the production of the water engine during its whole life cycle [21]. Although these studies show a considerable improvement in the ultimate recovery capacity in production optimization dynamic using RL, most RL models are taught and trained for individual reservoirs and hence can only be utilized for that reservoir. When applied to other reservoirs, they often function poorly. This restriction has lately shifted to the use of RL to tackle generalized issues for various cache optimization models, such as Miftakhoff et al. Neden proposed NPV of industrial processes [22]. Based on this, Naseer et al. created a standard reservoir model and trained an RL model to optimize the field development plan (FDP). When applied to an actual reservoir, it transforms into a reservoir model. It is supplied without a scale. As a result, the optimization challenges of scalable field development are resolved [23, 24]. Additionally, Naseer and Dorlofsky created a comprehensive control strategy framework based on deep reinforcement learning (DRL) for closed-loop decision making in subsurface flow situations [25].

Research scope

Oil reservoirs are critical to the global economy since they are the world's largest sources of energy supply. These reservoirs, which hold high quantities of hydrocarbons under the earth's surface, can be complicated, making oil extraction difficult. Injection and production in these reservoirs refer to operations in which fluids such as water or gas are squeezed inside the reservoir to boost pressure, hence allowing more oil to be extracted. However, selecting the right model for injection and manufacturing might be difficult. This is due to the differences in the properties and conditions of various oil reservoirs. Each reservoir has distinct features, such as hydrocarbon content, reservoir pressure and temperature, and reservoir rock properties. As a result, creating an appropriate injection and production model necessitates a thorough grasp of these characteristics as well as sophisticated computations. The current study investigates and develops several patterns in oil reservoirs with the goal of offering an ideal pattern for injection and production. This endeavor will use advanced modeling and simulation to discover the optimal strategies for increasing oil recovery while protecting the environment and the process's economy. This research can significantly contribute to the efficiency and stability of oil activities. The major goal of this research is to evaluate and assess various techniques of development in oil reservoirs in order to provide an appropriate model for injection and production. This issue contains an overview of the current obstacles in the application of conventional procedures, as well as potential advances in the field.

The unknown and confusing parts of this research include establishing the efficacy of different injection methods in reservoirs with varying features, finding factors influencing oil extraction efficiency, and modeling and forecasting reservoir behavior. The circumstances vary. Pressure, temperature, hydrocarbon compounds in the reservoir, reservoir rock features, and the physical and chemical properties of the injected fluids are all relevant factors in this study. The goal of this study is to find new ideas and improve existing procedures for increasing oil production efficiency while preserving environmental requirements and lowering production costs.

Research significant and aim

1. Examination and analysis of current injection processes: Identify and accurately analyze existing injection procedures to determine how they effect oil extraction efficiency.

2. Creation and assessment of sophisticated simulation models: sophisticated simulation models are created and used to estimate reservoir performance under various injection and production situations.

3. Developing and testing novel injection methods, such as CO2 injection or the use of specific chemicals, in order to increase oil extraction efficiency.

4. Environmental impact analysis: a study of the environmental consequences of various injection and production techniques, as well as measures to mitigate negative effects.

5. Using artificial intelligence and data mining: Using modern technologies like artificial intelligence to evaluate data and enhance injection and manufacturing processes.

6. Economic evaluation of injection and production methods: Investigating various economic elements of injection and production processes and proposing cost-cutting options.

7. Creating tailored systems for diverse reservoirs: establishing procedures that may be devised and applied to suit the individual features of each oil reservoir. The ultimate purpose of this study is to increase the effectiveness and efficiency of oil extraction. This entails lowering expenses and minimizing negative environmental impacts. This study seeks to strike a balance between economic efficiency and environmental sustainability in the oil business.

Research objectives and methodologies

1. Review of the relevant literature:
2. Define and create the research model.
3. Data Collection
4. Data Analysis.

5. Test hypotheses and analyze results:

Previous study

Saifaddeen Sallam, Mohammad Munir Ahmad1 and Mohamed Nasr , 2015, The Effect of Water Injection on Oil Well Productivity [26]

According to this study, one of the most effective strategies for enhancing oil output from petroleum reservoirs is water injection. This is owing to the low cost of water and its properties, which help in properly sweeping the trapped oil. The major purpose is to determine how much oil a reservoir can produce on its own, without the use of water injection. As a consequence, the ECLIPSE reservoir simulation tool was utilized to generate an oil reservoir model. In two example experiments, where water was not injected in the first but was added later in the second, this model was used to compare oil output and reservoir pressure. The results of the study showed that if no water was injected, the reservoir model could only yield 3.4% of the reservoir's original oil content of 275,447,700 STB.The case study revealed a significant fall in reservoir pressure, making it insufficient to continue oil production. However, in the second case study, water injection raised average reservoir pressure, resulting in an increase in oil output to 31% of the reservoir's original oil.Water injection is thus an effective strategy for enhancing oil output. when a result, when new methodologies and concepts emerge, it is interesting to investigate further concerns surrounding this topic.

Yu Shi, Yulong Zhang, Xianzhi Song, Qiliang Cui, Zhihong Lei, and Guofeng Song (2023), Injection energy consumption efficiency and production performance of oil shale in-situ extraction [27]

According to this study, oil shale in-situ conversion is a practical and effective extraction method. The primary problem in oil shale in-situ conversion is determining how to recover as much gasoline and oil as feasible while utilizing the least amount of energy. However, it is still unclear how productivity and injection energy utilisation efficiency relate to one another in different operating conditions. This paper uses a computer model of multiphase flow, heat transfer, and chemical reaction to provide a complete examination of the evolution of kerogen pyrolysis with reservoir temperature distribution. The production performance of oil shale in-situ exploitation is investigated with a focus on injection energy efficiency and productivity. The effects of injection energy rate, well shutdown time, reservoir pressure, and well spacing are also investigated. The data show that during kerogen pyrolysis, there is an unnecessary heating region, which significantly reduces energy utilisation efficiency. Although a shut-in method can reduce oil output while improving energy utilization efficiency, it is not a very efficient solution to the wasteful heating problem. enhanced injection temperatures and lower injection flow rates all result in enhanced oil production rates, oil outputs, and energy utilization efficiency at the same energy injection rate. Furthermore, for a higher oil production rate and output, it is recommended to employ a higher reservoir pressure and well spacing of 40-50 m. The findings provide useful advice for fine-tuning operational parameters in relation to oil output and injection energy utilisation efficiency.

Aminu Yau Kaita, Oghenerume Ogolo, Xingru Wu, Isah Mohammed, and Emmanuel Akaninyene Akpan, 2020. Investigation of the effect of injection settings on the performance of miscible sour gas injection for increased oil recovery. [28]

According to this study, sour gas reserves have received criticism for potential environmental issues and concerns. As a result, new methods for dealing with or appropriately disposing of the resulting sour gasses are needed. Many strategies for processing and utilizing sour gas have been created over time via research and experience. These include reinjecting sour gas for miscible flooding, better oil recovery in depleted or producing light oil reservoirs, and solid sulfur storage. The goal of this paper is to investigate how injection parameters influence how effectively sour gas injection works to boost oil recovery. Using empirical correlations, the minimum miscibility pressure (MMP) is identified as the important parameter controlling phase behavior while designing a miscible gas flooding project. The efficacy of miscible sour gas injection for enhanced oil recovery was investigated in relation to injection parameters such as minimum miscibility pressure, acid gas concentration, injection pressure, and injection rate using a compositional simulator. The results showed that the amount of methane in the process had a substantial influence on its MMP. Furthermore, as gas viscosity rises owing to increased acid gas concentration, the process's MMP decreases. This extends the plateau time, leading to late gas breakthrough, and enhances process recovery overall.

Oil Extraction Efficiency

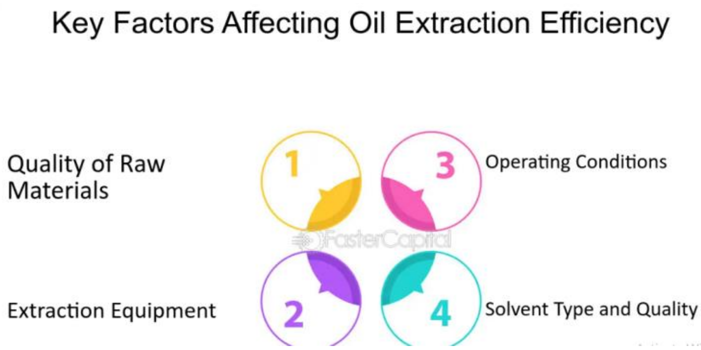
Understanding the Oil Recovery Process

The process of recovering oil is complex, requiring a full understanding of the reservoir's geology, fluid flow parameters, and rock properties. Various recovery strategies can be used depending on the reservoir's qualities and cost constraints. This section will explain the oil recovery process, the various recovery strategies, and the elements that influence its success.

1. Primary Recovery Method: This approach obtains oil by using the reservoir's intrinsic energy. Typically, a well is drilled, and the oil is allowed to rise to the surface. However, only a small part of the oil in the reservoir—usually between 5% and 20%—can be retrieved using this method.
2. Secondary Recovery strategy: This strategy involves putting gas or water into the reservoir to increase pressure and urge the oil towards the well. As a result, the recovery rate might increase by 20% to 40%.
3. Tertiary Recovery Process: To mobilize the leftover oil, chemicals, steam, or other ingredients are pumped into the reservoir. As a result, the healing rate may increase to 30-60%.
4. Elements Recovery efficiency is influenced by a variety of variables, including reservoir permeability, oil viscosity, recovery technology, injection rate, and well spacing. For example, if the reservoir has restricted permeability, a new recovery approach would be necessary, perhaps leading to a poor recovery rate.[29]

5. Improved techniques for oil recovery Using a variety of enhanced oil recovery techniques can increase the recovery process's efficiency. For example, steam infusion can reduce the oil's viscosity, allowing for easier extraction. While gas injection can increase reservoir pressure, chemical injection can break up the oil and drive it towards the well. Overall, the oil recovery process is complex and requires a detailed understanding of the reservoir's features as well as the various recovery processes. It is possible to increase the recovery rate and enhance process efficiency by combining better oil recovery techniques with the suitable recovery method.

Key Factors Affecting Oil Extraction Efficiency



EOR

Enhanced oil recovery (EOR) techniques are used to increase oil output and extraction efficiency. EOR techniques have lately gained popularity because they allow for the recovery of a greater proportion of oil from reservoirs that are no longer producing oil using conventional methods. Although EOR processes are frequently more expensive and complex than traditional approaches, the benefits in terms of increased output and recovery rates justify the additional costs .[30]
EOR techniques can take many different shapes, each with its own set of advantages and disadvantages. Some of the most often used EOR approaches are:
1. Gas Injection: One of the most used EOR procedures is gas injection. To increase pressure and drive the oil to the surface, gas—usually carbon dioxide or nitrogen—is pumped into the reservoir. This approach is best suited to reservoirs with high permeability.[31]
2. Chemical Injection: Chemical injection alters the oil's properties by introducing chemicals that reduce its viscosity. This simplifies the procedure of withdrawing oil from the reservoir. Polymers and surfactants are the most common compounds used for this purpose.
3. Thermal Recovery: Thermal recovery refers to the use of heat to reduce the viscosity of oil and allow extraction. This approach is extremely effective in thick oil reservoirs. The two types of thermal recovery procedures are in-situ combustion and steam injection.
4.Microbial EOR: Microbial EOR employs microorganisms to alter the reservoir's properties and aid oil extraction. This approach is well-suited to reservoirs with high water saturation..

Data collection

Enhanced Oil Recovery

Because mature fields produce the vast bulk of global oil output, boosting oil recovery from older reservoirs is a significant priority for oil firms and governments. Furthermore, discovering alternatives to the reserves provided by discoveries has significantly reduced during the last decades [32].

As a result, improving oil recovery rates in older fields for both main and secondary products will be important to meeting future energy demand. Malaysia seeks to maximize the impact of its indigenous oil reserves on overall supply [33,34]. The primary objective is to enhance the performance of the country's existing oil fields by utilizing EOR techniques in technologically advanced ways to reach resources that were previously unreachable due to geological

difficulties or high prices. EOR is primarily concerned with the oil's mobility throughout the drilling process. This is accomplished by injecting fluids into the reservoir, resulting in 30-50 percent of the original Oil in Place (OOIP), as compared to 20-40 percent eliminated during primary or secondary recovery operations [35–36]. EOR production is divided into three stages: primary, secondary, and tertiary recovery. Primary recovery involves bringing oil to the surface through natural or artificial sources. Secondary recovery, on the other hand, entails injecting water and gas at high temperatures and pressures (HTHP) to raise and transport the oil to the surface. Several scholars, including the US Department of Energy, have claimed that production can recover up to 65% of the trapped oil in the reservoir, using primary and secondary methods. Furthermore, increase oil output by using a tertiary recovery method, which may remove up to 75% of the trapped oil from the well but is more expensive in heavy oil fields with low permeability and uneven fault lines [37–38].
EOR distinguishes itself from secondary recovery technologies by altering the actual properties of hydrocarbons to guarantee acceptable fluid mobility. Figure 1 is a schematic depiction of the EOR mechanism. In this case, EOR techniques restore the damaged formation while boosting oil displacement in the reservoir. In addition, secondary recovery methods include water flooding, steam injection, and (CO2) gas injection.

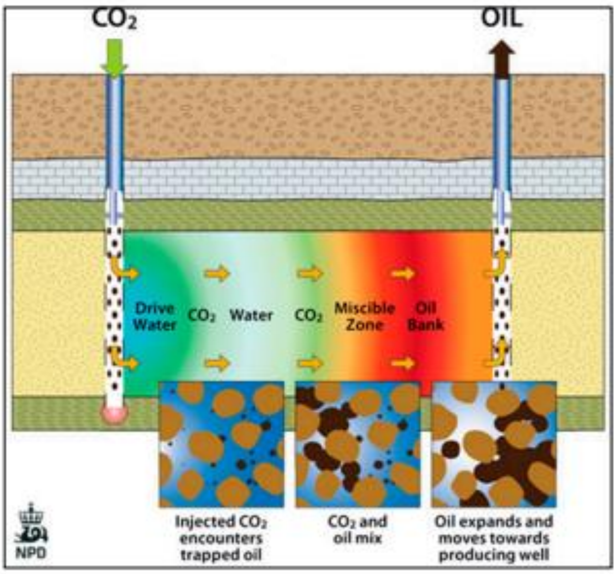


Figure 1. EOR illustration for carbon dioxide and water used in flushing residual oil from the reservoir [39].

Gas injection is a tertiary recovery technique that includes injecting natural gas, CO2, or nitrogen into a reservoir. During this process, the gasses dissolve in the oil, decreasing its viscosity and improving fluid flow. While the chemical injection process aids in the removal of trapped oil within the reservoir, this technique introduces long-chained molecules known as polymers into the reservoir to improve the effectiveness of water flooding or the efficiency of surfactants, resulting in a reduction of interfacial tension and an increase in oil flow. Finally, thermal recovery is the process of pumping steam into the reservoir to lower the viscosity of the oil and increase the fluid viscosity for oil displacements, which involves injecting steam into the reservoir environment to improve its capacity to flow.

Table 1 highlights the literature review on enhanced oil recovery technologies from previous studies. Despite claims that EOR procedures have been widely used in sandstone formations [40], sandstone reservoirs hold the greatest potential for implementing EOR research because to the technologies involved, which have been tested in pilot and commercial phases. Furthermore, there are several fields where multiple EOR technologies have been successfully examined on a pilot scale, indicating the technical applicability of different EOR methods in the same field, such as Buracica and Carmópolis (Brazil), and Karazhanbas.

(Kazakhstan).

Table 1. The details of the enhanced oil recovery mechanism from the previous research

Authors	Method	EOR Factor influenced	Result/finding	Parameters Value
Ibrahim Khan et al. (2017) [41]	Nano flooding	Physiochemical properties.	Temperature, pressure, time, and pH value can play important role in controlling the shape and morphology of nanoparticles materials	10^{-4} to 10^{-2} mN/m
Baoliang Peng et al.,2017 [42]	Nano flooding	Wettability alteration, Reduction of interfacial tension, Controllable viscosity, and Disjoint pressure for oil displacement.	Salinity, temperature, and pH value, Surface modification of nanomaterial, intrinsic properties; electrical, magnetic, rheological, and thermal Potential mechanism of nanofluid flooding are explained.	10^{-3} to 10^{-2} mN/m
Goshtasp Cheraghian et al., 2016 [43]	Nano Chemical flooding	Reduction IFT, emulsion formation, wettability alteration, Capillary forces	Nanotechnology has the potential to have a positive effect on the chemical EOR process.	10^{-3} to 10^{-2} mN/m
Hon Chung Lau et al,2017 [44]	Chemical EOR	Rock wettability alteration, oil-water IFT reduction, Oil viscosity, and injection fluid viscosity	Six applications of nanoparticles are considered, and it is discovered that reservoir imaging, Drilling, tight reservoir applications and EOR ranked higher and have the highest potential impact.	10^{-5} to 10^{-3} mN/m

Miscible Gas Injection Method

EOR using the miscible gas injection method is widely used for light oil recovery and is considered one of the most successful EOR technologies. The injected gases are classified into four types: hydrocarbon gases, nitrogen gas (N2), carbon dioxide gas (CO2), and flue gases. In a miscible condition, two phases can be combined in any proportion [45]. To achieve a miscible condition between injected gas and reservoir oil, the gas is injected above the

Minimum Miscible Pressure (MMP). Consider CO2 gas as an example: when pressure increases, CO2 gas density increases, lowering the density difference between CO2 gas and reservoir oil [46]. This lowers the IFT between CO2 gas and crude oil, rendering them miscible. The MMP of CO2 gas and crude oil are affected by reservoir temperature, oil concentration, and injected gas purity. For example, a low-temperature reservoir with light oils will have a lower MMP between CO2 gas and reservoir oil. The impact of impurities, on the other hand, depends on the kind of impurity components; adding H2S would reduce the MMP, while adding N2 would increase the MMP between CO2 gas and reservoir oil [47–48]. To ensure that the oil may become miscible with nitrogen without damaging the producing deposit, the reservoir must be at least 5,000 feet deep and capable of withstanding injection pressures exceeding 5,000 psi. Nitrogen gas (N2) is a suitable option for flooding such reservoirs since it can be produced locally at a lower cost and is non-corrosive due to its inert properties. Cryogenic processes take N2 from the air, providing a limitless supply. When injected into the reservoir, N2 forms a miscible front by vaporizing some of the lighter oil components [49].

As the gas exits the injection wells, it comes into contact with new oil and vaporizes more components, enriching it even further. This process continues until the leading edge of the gas front is so enriched that it dissolves in the reservoir oil, resulting in a single fluid combination. The constant infusion of nitrogen pushes the miscible front into the reservoir, displacing oil to the producing wells. To boost sweep efficiency and oil recovery, water slugs are alternately injected with N2. The created reservoir fluids, which include natural gas liquids and injected nitrogen, may be separated on the surface [50]. Carbon dioxide (CO2) is commonly used to enhance oil recovery (EOR) in sandstone reservoirs. CO2 is injected into the reservoir to displace the oil and direct it to the producing well. This strategy is known as CO2 flooding or CO2-EOR. The technique entails pumping CO2 into the reservoir at a pressure and temperature suitable for the reservoir's geological and fluid characteristics. The CO2 dissolves in the oil, reducing viscosity and allowing it to flow more easily. This improves the amount of oil that can be extracted from the reservoir [51].

CO2-EOR is seen as a more environmentally friendly method of producing oil since it recycles CO2 that would otherwise be discharged into the atmosphere, such as from power plants or industrial activity. The collected CO2 is stored underground in the reservoir, reducing greenhouse gas emissions. However, there are significant barriers to CO2-EOR in sandstone reservoirs. One of the most difficult challenges is keeping the injected CO2 inside the reservoir and out of the surrounding rock formations. This demands close monitoring and supervision of the injection procedure. Another issue is the cost of collecting and compressing CO2 for injection. This may be expensive, especially in smaller oil fields. However, as CO2 collecting and storage technology develops and the need for EOR rises, the cost is likely to fall.

CO2-EOR in sandstone reservoirs is a promising method for improving oil recovery while lowering greenhouse gas emissions [52]. CO2 gas injection significantly increased the oil recovery factor from 7% to 23% of OOIP. Furthermore, employing CO2 as the injection gas may help in CO2 sequestration, resulting in a reduction of greenhouse gasses in the environment [53]. CO2 gas often has a bigger one-phase zone than N2 gas or dry gas; the larger the one-phase region, the greater the miscibility. CO2 gas has a lower miscibility pressure (about 1200-1500 psi) than N2 gas and dry gas, which have higher miscibility pressures (around 3000 psi or more). Lower miscibility pressure allows the gas to mix with the reservoir oil at lower pressure, resulting in a lower cost. However, the use of CO_2 gas as an injection gas must be managed cautiously since it is slightly acidic and can cause corrosion of surface facilities.

Miscible CO_2 gas injection involves injecting CO_2 gas into a reservoir, where it interacts chemically and physically with the existing hydrocarbon fluid. These interactions function as processes for oil recovery. The mechanisms include expansion of oil volume, decrease in oil and water density, decrease in oil viscosity, lowering of IFT between the crude oil and reservoir rock, which slows the flow of oil through the pores in the reservoir, and vaporization and extraction of trapped crude oil [55-54].

CO_2 gas is extremely soluble in oil, causing it to expand and reducing its density and viscosity. Furthermore, because CO_2 gas is soluble in water, injection may help to reduce the density of water left in the reservoir after previous floods. As a result, the oil and water density becomes essentially equivalent, leading to a decrease in gravity segregation effect, less override flow, and a fingering phenomenon that is less prone to occur [56]. Although miscible gas injection has many benefits, it does have certain limitations and downsides. Gas mobility influences miscible gas injection, which is a single-phase operation. As a result, miscible gas injection requires a considerable depth to assure miscibility. Furthermore, the formation thickness may affect the efficiency of miscible gas injection. Gravity override effects can occur in especially dense formations, resulting in poor sweeping performance [57].

Aside from that, there are various issues in the operation of miscible gas injection, which include transportation concerns, gas-induced corrosion of equipment and tubes, and the separation and recycling of the miscible gas [58].

Thermal method

According to the study papers, thermal EOR techniques are incredibly essential and widely available across the world. Over the last several decades, various aquatic methods of dealing with water and its wastes have gained popularity. Hot fluid injection is one of the most used thermal EOR methods. This hot fluid injection may be divided into three types: cyclic steam stimulation (CSS), in-situ combustion (ISC), hot water steam flooding, and steam aided gravity drainage (SAGD). Other thermal EOR systems include non-aqueous methods that deliver thermal energy to reservoirs without injecting water or its derivatives [60-59].

Hot fluid injection is an EOR technology that uses hot fluid in an oil reservoir to promote the flow of oil for extraction. Thermal energy (in the form of heat) enters the reservoir via a mix of convection and conduction processes [61]. This thermal energy aids in reducing the high viscosity and thermal expansion of the reservoir's crude oil. In thermal EOR technology, injecting steam is the most prevalent and cost-effective way. Steam injection uses three techniques: CSS (also known as the huff-and-puff technique), steam flooding, and SAGD.

Figure 2 shows the steam-assisted process structure. Steam flooding, in addition to sweeping, circulates steam into injection wells to lower oil viscosity. However, despite its greater effectiveness, this technique demands more effort than the CSS.

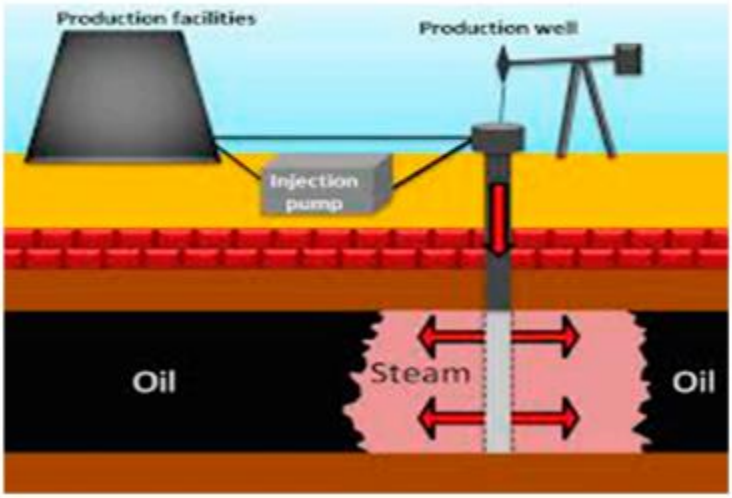


Figure 2. Shows the steam assisted EOR method during the thermal EOR.

Chemical method

EOR normally uses two strategies to achieve its aim of oil recovery. The first phase is to increase the quantity of energy in the reservoir, followed by creating an environment conducive to hydrocarbon displacement. These techniques include increasing capillary number, decreasing capillary forces, lowering IFT, decreasing oil viscosity, and increasing water viscosity [62]. Chemical methods to EOR use the process of creating advantageous circumstances by increasing water viscosity, increasing permeability to oil, and decreasing permeability to water [63].

It does this by including chemicals into the injected water; in essence, chemical procedures are a variation on secondary oil recovery in which water is injected [64]. However, instead of clean water, chemicals are employed to improve oil recovery rates. Chemical techniques use three types of chemicals: alkalis (also known as polymers and surfactants), foam, and nanofluids. In the 1980s, typical chemical treatments, notably polymer flooding, were frequently used on sandstone reservoirs. Since the 1990s, the technique has diminished internationally, with the exception of China, due to market volatility and the lower cost of alternative chemical additives [65].

Alkali is the most often used chemical EOR, notably for polymer floods. (e.g., xanthan gum, carboxymethylcellulose, and hydroxyethyl cellulose) They help with oil recovery through three mechanisms: mobility control, viscoelastic polymer molecules, and reduced disproportionate permeability. Mobility control employs a metric known as the mobility ratio, which describes the ratio of water mobility to oil mobility. When the mobility ratio surpasses one, it means that the water injected is more mobile than the oil; this impacts the injected water and prevents it from breaking through the oil zone and dislodging the oil.

To ensure that the mobility ratio is less than one, polymers are added to the water to enhance the injectant's viscosity and allow for improved sweep efficiency. Some reservoirs are heterogeneous, with different permeabilities throughout. This permits water to move to higher

permeability locations, making it harder for primary and secondary operations to extract oil from lower permeability spaces. Polymer flooding will restrict water flow in some regions of the reservoir, decreasing relative water permeability while maintaining oil permeability constant. This method may route water to replace oil in lower permeability zones, while high permeability areas are "blocked off" by polymer flooding using the relative permeability modification technique. Polymer molecules stretch and contract when flowing across porous surfaces, resulting in elastic viscosity, which improves sweep efficiency. Urbissinova and Veerabhadrappa's study suggests that high elastic polymers may result in greater resistance to flow via porous media or higher viscosity [66,67].
This technique has certain limitations: electrostatic and weak intermolecular interactions between the polymer and the rock surface may cause retention. Retention occurs in a lower viscosity than anticipated, which reduces oil recovery.

Foam flooding is another chemical technique to EOR. This technique was developed to solve gas injection restrictions such as gravity override and viscous fingering. Thus, foam gas trapped within a thin liquid layer called lamellae resulted in a continuous liquid phase separated by a gas. Foam flooding controls two mechanisms that increase oil recovery efficiency. The first approach includes increasing the injectant's viscosity to improve the mobility ratio, comparable to polymer flooding. Second, gas bubbles can form in a porous media, increasing the permeability of the reservoir's undisturbed areas. Foam flooding is a gas-injected method; however, substances like protein and surfactant have replaced traditional CO_2 and nitrogen foams, resulting in more stable foams with longer half-lives.

Foam flooding has various drawbacks, including a reliance on foam lamellae renewal for effective propagation, lamellae stability when utilizing surfactants in contact with crude oil, and lamellae loss due to coalescence. More recent breakthroughs in EOR have incorporated the use of nanotechnology, namely nanofluid flooding. Nanofluids are fluids that contain a base fluid, such as water or oil, as well as minute solid particles. The solid particles are typically less than 100 nanometers in size, thus the name "nanofluids." These small particles, which are frequently made up of metals, metal oxides, or carbon-based compounds, can improve the thermal and mechanical properties of the base fluids. The addition of nanoparticles to the base fluid improves its thermal conductivity, allowing it to transmit heat more efficiently. This feature makes nanofluids ideal for applications such as electronics cooling, heat exchangers, and solar thermal collectors.

Nanofluids have been investigated for possible use in Enhanced Oil Recovery (EOR) because to their unique thermal and rheological properties. Nanofluids can be used in EOR to improve sweep efficiency, minimize interfacial tension, and maximize oil recovery.
One of the key advantages of nanofluids is their ability to alter the viscosity of a fluid. The viscosity of the nanofluid can be increased or decreased by adding nanoparticles, depending on the kind and concentration used. This property is particularly essential in EOR, where a higher viscosity fluid can help displace oil from the porous media. Nanofluids can also improve the thermal properties of the fluid. Adding high thermal conductivity nanoparticles to the fluid can increase its overall thermal conductivity, lowering the amount of energy required to heat the fluid during EOR operations. Furthermore, nanoparticles can help to reduce the interfacial tension between the fluid and the reservoir rock, allowing the fluid to flow more freely through the reservoir and increasing oil recovery. This impact occurs because

nanoparticles have a huge surface area and can permeate the rock surface, changing its wettability.

Data analysis

Porosity

One of the most critical factors impacting the EOR process is porosity. Porosity may be used to assess the actual quantity of oil and gas in a reservoir. It is defined as the proportion of the total rock volume V that is not filled by solid materials, and may be stated as follows:

$Porosity = \Phi = v_p/v_b$ = pore volume/ total pulk volume

Pores in reservoir rock must be large enough to hold oil and gas for production. However, porosity does not reveal the pore's size, distribution, or connectedness. It is inadequate to explain the oil recovery factor; the rocks must be permeable, with well-connected pores that allow oil and gas to move through the reservoir. If the rock has low permeability, the oil that has accumulated within it may be impossible to be extracted because it cannot flow into the drilling wells rapidly enough. As a result, rocks with the same porosity might have quite diverse physical properties. The pores inside the mortar texture may be split largely into three categories (Figure 3): (1) Effective porosity: This type of pore indicates the mortar's open porosity. The pores are connected, allowing water to pass through the texture. This type of porosity is regarded as the most significant contributor to mortar permeability. (2) The second type is dead-end pores, which increase the mortar's total porosity. However, it increases permeability. Saturation levels alter the content of these pores. (3), The last kind is closed porosity. This type of porosity does not contribute to the overall porosity of the mortar, hence its content will remain isolated.

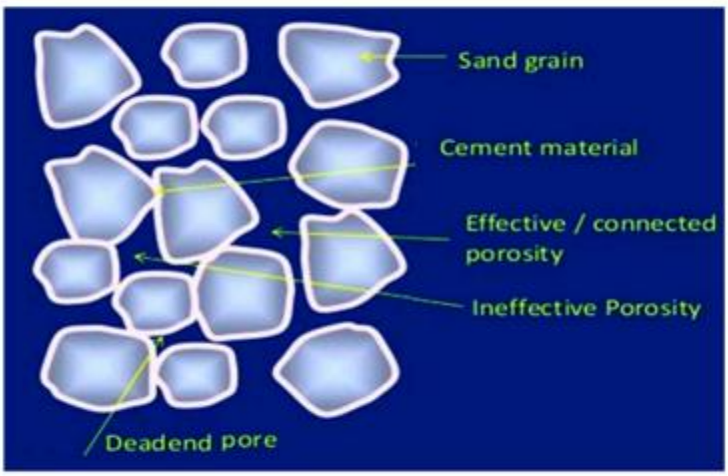


Figure 3. types of porosity present in the reservoir condition.

Permeability

Permeability describes how easily a fluid flows through rock. Permeability is one of the most important aspects to investigate in petroleum production research. The hydraulic gradient, or the head loss per unit length between any two points, has a direct impact on the velocity of water flowing through a soil mass. Permeability is the characteristic of soil that allows water to flow freely through its voids. Permeability is defined quantitatively as the velocity of water moving across a hydraulic gradient. Permeability is measured in the same units as velocity, namely cm/s or m/day. Understanding soil permeability is crucial for developing wells and hydraulic systems [68,69].

Grain size is one of several factors that influence permeability. Permeability is proportional to the square of the effective diameter of particles (D10). K= C(D10) 2 2 where K represents permeability, C is a constant value, and D is particle diameter or grain size. Several factors can impact permeability in reservoir sandstone, including particle size and sorting. Sandstone's permeability is mostly determined by the size and arrangement of its grains. Sandstones that are coarsely grained and well-sorted are more permeable than those that are finely grained and poorly sorted. Porosity: The sandstone's connected pore space may impact permeability. The higher the porosity, the more interconnected the pore space and the larger the permeability. Cementation: The presence of mineral cement between the grains can limit the size of the pore space, reducing permeability. Saturation: The presence of fluids, such as water or hydrocarbons, can increase or decrease permeability, depending on their kind and amount. Over time, the weight of the underlying sediment can compact the sandstone, reducing its porosity and permeability. Diagenesis: Chemical or physical changes in the sandstone during burial and lithification might impact its porosity and permeability.

Fractures: Fractures can significantly improve the permeability of a sandstone reservoir by forming new routes for fluid transport. Permeability is also influenced by the characteristics of pore fluids, which are fluids that live in the gaps between pores in rock or soil. Permeability is directly related to the unit weight of the pore fluid, and inversely proportionate to its viscosity [70]. The next factor is temperature: As pore fluid viscosity decreases with increasing temperature, permeability rises. Aside from that, permeability is controlled by adsorbed water that surrounds each soil grain. Figure 4 shows oil trapped in the reservoir owing to impermeability. The water adsorbed on the soil grain was unable to move freely, reducing the effective pore space and permeability. Furthermore, trapped air and organic pollutants would reduce flow and permeability. The level of soil saturation may also influence permeability, with fully saturated soil being more saturated than partially saturated soil. Finally, the shape of particles affects permeability. Soil with a higher specific surface area will be less permeable.

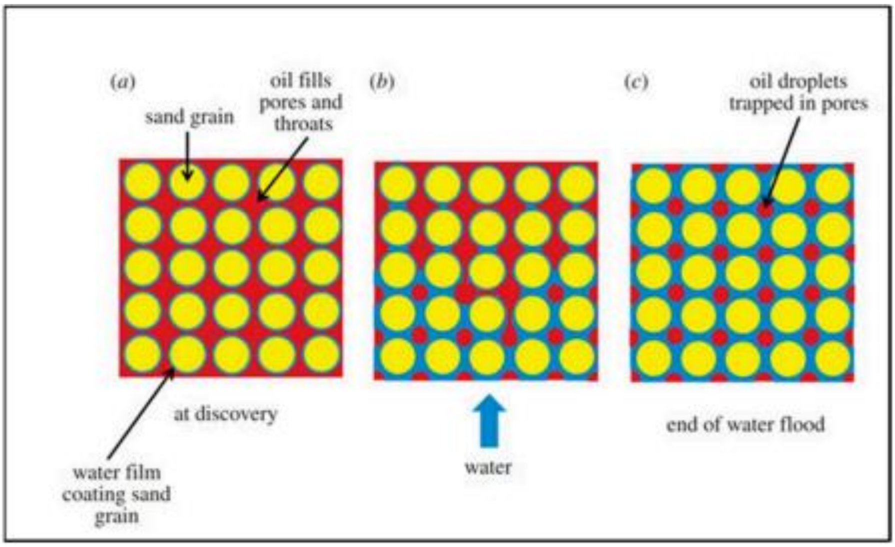


Figure 4 Illustration of trapped oil in wet rock: (a) Sand grain coated with a thin water covering, and holes filled with oil. (b) advances in water flooding deepens the water films. (c) water film and oil loss [70].

Table 2. Criteria of permeability for EOR methods.

EOR Method	Permeability, md
Steam	> 200
In situ	> 200
Alkaline	> 20
Surfactant	> 20
Polymer	> 20
CO_2	Any range
HP gas	Not a critical factor

Darcy's law can be used to determine permeability. Henry Darcy, a French hydrology engineer, created this law in 1856 to study how water moves through sand filters [71]. Using the experiment, we determined the volumetric flow rate of water via a sand filter and got the following equation [72,73]:

$q = k \Delta P / \mu L$

Where μ is the dynamic viscosity of the fluid, k is the permeability of the porous medium, and L length in the flow direction.

Darcy discovered that the volumetric flow rate of water through a sand filter is a function of the size of the porous medium and the difference in hydraulic head [74].

Reservoir Pressure

Another component influencing the EOR process is reservoir pressure. It denotes the pressure of the fluid in the reservoir. Reservoir pressure is useful for performing volumetric calculations. Bottom-hole pressure measuring equipment are used to determine the pressure of fluids inside reservoir pores. Because reservoir pressure varies when oil and gas are produced, it should be represented as measured at a certain instant [75]. There are three types of pressure distribution in the reservoir during fluid flow: steady-state flow, pseudo-steady-state flow, and transient flow.

Temperature

The reservoir temperature may also have an impact on the EOR process. Temperature influences not just oil transportation, but also the wettability of reservoir rock. Higher temperatures allow the rock surface to transition from oil-wet (OW) to more water-wet (WW), which aids in oil recovery. Furthermore, the influence of pressure on permeability decreases with increasing temperature, especially at lower pressures. This is because, when the temperature increases, the rock matrix and fluids in rock pores expand, counteracting the rock's compression.

Viscosity

Viscosity, or a fluid's internal resistance to flow, can also have an impact on the EOR process. This parameter is necessary for any computation involving fluid flow. Viscosity is impacted by several factors, including oil composition, temperature, dissolved gas concentration, and pressure. Furthermore, oil composition may be characterized in terms of API gravity; when crude oil API gravity decreases, viscosity increases. Viscosity increases approximately linearly with pressure and temperature [76]. Fluid viscosity varies with temperature, pressure, and composition; it is well understood that viscosity in the gaseous state is significantly lower than in the liquid state [77]. Momentum is primarily transmitted via intermolecular contacts between densely packed molecules in the liquid phase, whereas momentum is transferred by collisions of freely moving molecules in the gas phase [78]. Eynas Muhamad Majeed and Tariq Mohammed Naife 2020 tested several additives to lower the viscosity of heavy crude oil. It is well acknowledged that heavy oil's high viscosity has a substantial influence on both upstream and downstream oil recovery procedures. Furthermore, by using different additives, the viscosity of the heavy was reduced to a maximum of 3.78 cSt at 750C and 26 API at 250C [79]. Another study, undertaken by Sherif Fakher and Abdulmohsin Imqam in 2018, looked at the reduction of heavy oil hydrocarbons using a chemical solvent. Four new formulations were devised with remarkable stability in difficult reservoir conditions and good solubility in crude oil to significantly reduce heavy oil viscosity, thereby enhancing production from these reservoirs and permitting the shipment of these heavy oils [80].

Wettability Alteration

Wettability is defined as a solid surface's preference for a certain type of fluid in the presence of other non-miscible fluids [81]. The wettability of the rock surface influences the location of the reservoir's rock fluid flow distribution [82–83]. Petro physical properties of the reservoir, such as relative permeability and capillary pressure, are crucial considerations since they have a significant influence on oil recovery. Reservoir oil wettability is usually classified as WW, OW, or mixed wet conditions [[84,85]. The contact angle, spontaneous imbibition, zeta potential, and surface imaging studies may all be used to determine the reservoir rock's properties. Most reservoir wettability research uses a contact angle to characterize the point at which the oil-water interface contacts with the rock surface [86]. The wettability of a rock's surface changes from oil to water, reducing the viscous force of thermodynamics. As a result, it raises the reservoir's oil permeability. However, most research findings indicate that oil recovery is simpler in water-wet reservoirs than in OW reservoirs [87]. In the oil industry, wettability refers to a solid surface's preference for one fluid in the presence of another immiscible fluid [88].

Wettability is a key factor that influences fluid placement and distribution inside the reservoir. Given that oil reservoirs are generally made up of oil and saline water, they can be classed as oil wet, water wet, or intermediate wet. Reservoir water (also known as connate brine) is considered a wetting fluid (or reservoir rock is viewed as wet) when the angle of contact between water and rock is between 0 and 900 degrees Celsius. When the angle of contact is between 90 and 1800C, oil functions as a wetting fluid (or the reservoir rock becomes oil wet).

The spreading and adhesion interfacial phenomena of the fluid-rock contact, also known as wettability change, have a substantial impact on multi-phase flow and, hence, recovery efficacy in petroleum reservoirs. Wetability (Table 3) is one of the most critical factors controlling reservoir fluid flow into porous media, and it has a considerable influence on both the liquid and gas phases' relative permeability values, as well as recovery [89-90]. Inadequate liquid for drilling and production would have a significant influence on reservoir wettability, potentially causing damage and decreased output in terms of recovery factors [91,92]. In this situation, most governments have explored other ways to increase oil output by adopting nanotechnology EOR processes [93].

Table 3. The effect of nanoparticles on wettability alteration.

Properties	Condition	Nanofluid & Variables	Substrate	Result
Hydrophilic, 14 nm, Spherical		Based Fluid: DW. NPs conc. (0.1-5 wt.%)	Glass	The surface was completely altered to water wet (0o) at 5wt% NF conc.
Hydrophobic, 10nm, Spherical		NPs conc. = 0.5-4wt%, NaCl = 0-20 wt%,	Calcite	SiO2 altered θ from 120o to 45o at 2wt% optimum conc. This was altered further to 40o at 30000 ppm salinity.
Hydrophobic, 5nm, Spherical		Based Fluid = DW, Size = 5 & 25nm, Temp. = 23&50oC	Calcite	Size has no effect. θ decreased with higher temp
Spherical, 35nm	T= 70ºC, P = 600psi	Based Fluid = DW, NPs conc. = 5wt% Salinity = 3-12wt%	Calcite	SiO2 NPs reduced the θ below 90º up until 8wt% salinity.
Hydrophilic, 15nm	T<30ºC	Based Fluid = DI NPs conc= 0.1wt% Surfactant conc. = 0.14wt%.	Calcite	SiO2 NPs with and without surfactant altered wettability to strong water wet by 9.87% and 6.15% respectively.
15nm	N.A	NF=H2O+NPs+ SF(AOT, 11.25mM)+SA(NaCl+Na2 SO4+CaCl2+ MgSO4·7H2O).	Sandstone	Increase in NPs conc. does not magnify W.A. Highest W.A. was achieved with 0.1wt% conc. of NPs at 0.3wt% salinity.
Spherical,15nm	Room	NF = H2O+NPs+SA(NaCl)	Calcite	W.A. reduces with an increase in NP conc. (73.72% changes). The reduction was further enhanced in the presence of NaCl

Hydrophilic (40nm) and surface modified (6nm) SiO2, Spherical.	Room	NF= H2O +NPs+ SA (NaCl+CaCl2+KCL+MgSO4+MgCl2, 73050 ppm).	Sandstone	Adhesion forces reduce up until 0.5wt% NPs conc. Treated NPs outperformed unmodified ones due to increased interfacial activity,
Silane treated SiO_2 (15nm)	Room	NF = Propanol+NPs.		θ reduces with increase in conc.

Capillary pressure effect

Capillary force is acknowledged as a significant influence in fluid flow through porous media. The wetting phase tends to move to the pore wall, reducing the pore cross-section. As a result, the wetting phase's adsorption on the surface of porous medium reduces fluid flow. Capillary pressure, as specified (P_c):

$P_c = 2\sigma \cos\theta / r_c$

Where σ is surface tension, σ is contact angle, and rc is capillary radius. As more wetting phase is adsorbed on the rock surface, rc decreases, resulting in higher capillary pressures. Seismic waves can generate mechanical Vibro-energy on the pore surface, decreasing liquid film adsorption to the pore wall and, as a result, increasing the capillary radius (rc) (dropping capillary pressure). Surface tension (σ) can potentially affect PC performance. Other studies demonstrated, based on experimental data, that Vibro-energy can reduce the oil/water surface tension due to agitation and fluid temperature increase, resulting in a drop in Pc [187]. When using vibration, Kouznetsov et al. [188] suggest that vibration can lower the interfacial tension between oil and water by two orders of magnitude. Kuznetsov et al. [94].The equation for acoustic capillary pressure was developed with the assumption that the vibration acceleration is constant (14% of the maximum amplitude):

$$P_{ac} = \int_0^z \omega^2 A_{\rho\omega} \frac{1-\Delta}{1+2\Delta} dz$$

Where ω is the wave frequency, A is the maximum offset amplitude, $\rho\omega$ is the wetting phase density, $\Delta = \rho^{nw}/\rho w$ is the nonwetting phase to wetting phase ratio, and z is the linear coordinate. The equation describing the relationship between wetness and non-wetting phase pressure is:

$$P_{nw.0} - P_{w.0} + \int_0^z \omega^2 A_{\rho\omega} \frac{1-\Delta}{1+2\Delta} dz = \sigma j(S_\omega) \cos\theta \sqrt{\frac{\theta}{K}}$$

Where $P_{nw.0}$ is the capillary pressure for the nonwetting phase without vibration; $P_{w.0}$ is the capillary pressure for the wetting phase without vibration; θ is the contact angle; (S_w) is the leverets J function; and θ is the porosity.

The relative permeability effect.

During the oil recovery process, the water and oil phases are mixed; particularly at the conclusion of oilfield development, the oil phase is dispersed into the water phase, resulting in a discontinuous flow condition for the oil phase. At low oil saturation, the oil phase segregates into tiny, discrete droplets. The relative permeability curve is crucial for reservoir oil production because it shows the oil saturation threshold (Sor), below which the oil becomes immobile. Nikolaevsky [95] observed that seismic waves might increase the relative permeability of the oil phase, resulting in lower mobility than Sor. Vibro-energy can produce quasi- or periodic motions by altering the flow direction of the oil or water phase on a regular basis.

Surface vibration and periodic motions can limit fluid adhesion to the solid phase. The fluid coating formed on the pore surface is broken down, allowing more fluid to pass through the narrow pore throats. In comparison, oil molecules are much bigger than water molecules. As a result, although water molecules can pass through even the smallest pores, oil molecules fail to do so because of their huge molecular size. When pore size rises, oil molecules may flow through these open holes, affecting the relative permeability of the oil phase more than the water phase. Both high and low power frequency waves can damage the fluid coating, reducing the sealing portion of the pore throat. The viscosity of crude oil lowered by the ultrasonic wave may exceed 20%. Some research have proposed that the influence of ultrasonic waves on oil viscosity may be categorized into three phase [96]. The oil viscosity increases over time due to the dissolution of suspended particles, which can increase internal friction within the oil components; in Stage II, the oil viscosity decreases due to the thermal effect and disintegration of crude oil's large components; and in Stage III, the oil viscosity increases due to the integration of broken chain asphaltene particles into long chain flocs.

Interfacial tension

Interfacial tension (IFT) is the Gibbs free surface energy that acts on two distinct immiscible liquids [195], such as oil and connate brine in EOR. IFT is so critical that it is now used as a standard characterization measure in chemical EOR to determine fluid flow and distribution throughout the formation. The IFT is inversely proportional to a dimensionless quantity known as the Capillary number (N_{ca}) which is theoretically defined and usually employed with the recovery factor. The smaller the IFT, the higher the N_{ca} and recoverability.

$$N_{ca} = \frac{Viscous\ forces}{Capillary\ forces} = \frac{v\mu}{\sigma cos\theta}$$

v indicates velocity, μ dynamic viscosity, σ interfacial tension, and θ contact angle. A very high capillary number is required to achieve a significant reduction in residual oil situation. To reach this aim, the IFT should be decreased to as low as 10-3 mN/m [97–98].

The pendant drop technique is most widely employed to assess IFT between oil and nanofluids. During the IFT experiment, the oil droplet is released into the nanofluid from the outer end of a capillary needle at a constant pressure and temperature level. The IFT value is then obtained by accurately estimating the shape of the oil droplet with a high-end precision camera system and analytical software.

Fluid Displacement Efficiency

Fluid displacement efficiency is the rate at which one fluid displaces another in a reservoir during oil production. In other words, it defines how much oil may be recovered from a reservoir by injecting a displacing fluid (like water or gas) into it. Several factors influence fluid displacement efficiency, including reservoir rock and fluid properties, injection rate and pressure, and fluid mobility ratios. A high fluid displacement efficiency suggests that a significant amount of oil in the reservoir may be retrieved by injecting a displacing fluid. In contrast, poor efficiency suggests that there is still a significant amount of oil in the reservoir. Optimizing fluid displacement efficiency is an important consideration in the design and management of oil production processes because it may have a significant impact on recoverable oil and project costs. Displacement efficiency is a crucial factor influencing oil recovery from the reservoir zone [99].

In the reservoir system, rock pore characteristics, fluid properties, and fluid interaction with pore walls, often known as wettability, are all significant. A reservoir rock has larger gaps (pores) that are linked to smaller spaces or restrictions (throats). However, larger pores may be linked to larger throats, and smaller pores to smaller throats. That is, pore and throat sizes can be arranged in a correlated rather than random or disordered manner. To determine the fluid's performance in a constrained clastic rock reservoir, some key parameters were addressed throughout the experimental process. This comprises the pore throat morphology, as well as the physical interaction between the reservoir's fluid and pore walls. (Figure 5) [100].

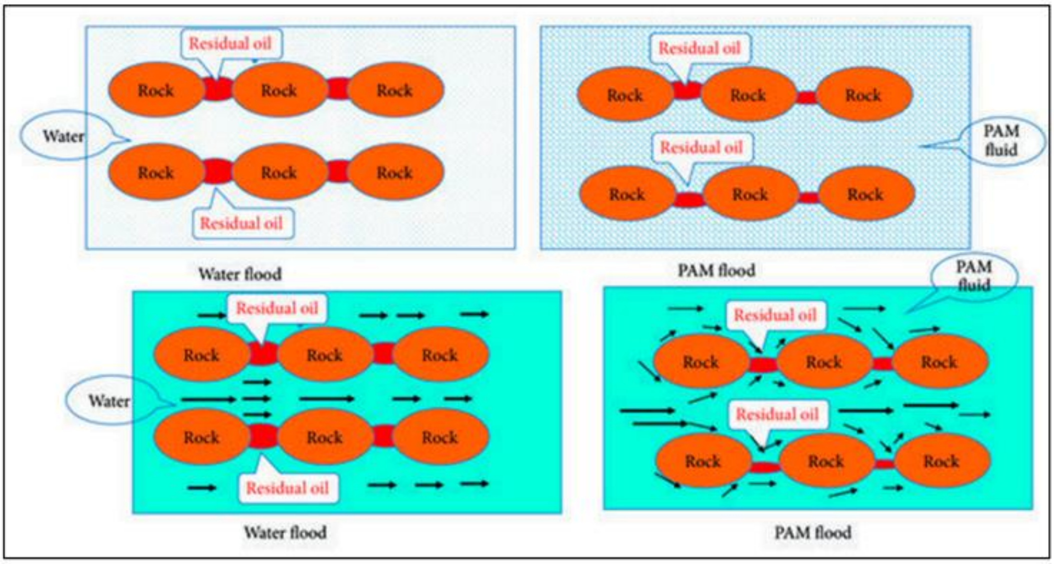


Figure 5. The fluid displacement efficiency in the porous medium.

Nonetheless, pore-throat morphology varies greatly in tight clastic rock reservoirs, and fluid flow must be closely monitored [101]. As a result, throats are measured in diameter, whereas pores are measured in diameter and volume. These two characteristics are the key elements that influence reservoir fluids. Pores demonstrate a rock's capacity to contain fluids; nevertheless, in rocks with throats far smaller than pores, the throats have the biggest effect on fluid flow. In multiphase fluid flow, the size and frequency distribution of the pore and throat affect fluid flow.

2. Discussion

The majority of the power for oil displacement during the water injection development phase comes from the driving pressure differential, capillary force, and gravity. Capillary forces in the matrix are primarily responsible for spontaneous penetration and oil drainage while creating a constant water injection. This phenomenon, however, is only visible when the reservoir is moist, and it is distinguished by high speed but low efficiency. Sandstone reservoir wettability can be increased by modifying the parameters of injected water (for example, low-salinity treatment and carbonization). The poor efficiency of spontaneous imbibition and oil drainage is mostly due to the large pore-throat ratio and oil-water viscosity ratio.

Water drive and gravity are the main components of a fracture system, and the type of water injection used has a significant impact on oil recovery. According to the research, unstable water injection is an effective approach for increasing the recovery of cracked carbonate deposits. The residual oil can be effectively collected by changing the direction of the flow field and raising the spreading coefficient. Crude oil viscosity and channeling production are two limiting criteria for sandstone resource exploitation. Steam injection and thermal recovery are commonly employed to lower the viscosity of crude oil. The use of a surfactant reduces the oil-water interfacial tension, improving washing efficiency. Polymer injection has the capacity to raise the sweep coefficient, so blocking the channel. Foam and particle-based plugging agents increase plugging capacity.

Deep plugging can be accomplished by transporting particle plugging agents in foam. Sandstone reservoirs are created under harsh circumstances. Steam injection and thermal recovery are routinely used to reduce crude oil viscosity. The application of a surfactant lowers the oil-water interfacial tension, increasing washing efficiency. Polymer injection has the ability to increase the sweep coefficient, thereby clogging the channel. Foam-type and particle-based plugging agents enhance plugging performance. Deep plugging can be achieved by carrying particle plugging agents in foam. Sandstone reservoirs are created under extreme conditions. To avoid damage to the wellbore and reservoir, use the appropriate type and concentration of acid and pump it at a safe rate. Furthermore, it is necessary to assess the environmental effect of these methods.

Acidizing and fracturing, if not done correctly, can contaminate groundwater and release hazardous chemicals into the environment. As a result, it is vital to employ appropriate procedures that promote safety and environmental preservation. The use of suitable acidizing and fracturing techniques can help to protect reservoirs while also maximizing output in a safe and responsible manner. Furthermore, new injection media, intelligent optimization, and other backup technologies should be created as soon as possible. Production control should be employed throughout the development of natural energy drives to prevent premature channeling. In the early stages of water and gas injection development, injection and production well patterns should be determined based on the reservoir unit's kind, connectivity, and spatial position in order to optimize water and gas injection control and oil production while lowering residual reserves. In the middle and late stages of water and gas injection development, it is necessary to improve oil well control based on the main control factors and the distribution characteristics of the remaining oil, as well as to disrupt (reform) the flow field with measures such as gravity drainage, spontaneous infiltration, and drainage. Chemical enhanced oil recovery (C-EOR) technology development should not be overlooked; these technologies have the potential to partially replace water injection and gas injection while enhancing oil output from carbonate reservoirs. Finally, a flexible and perfect development plan and technical system should be built in conjunction with cutting-edge technology like as artificial intelligence to accomplish cost-effective carbonate reservoir development and accelerate the global petroleum industry's progress.

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