

2.1 Literature Review

Paterson, L., et al., (1984) found that fingering that occurs when water or a surfactant solution displaces oil in a porous medium in an oil-wet porous medium. It has been shown that the recovery of oil from an underground reservoir increases significantly if the capillary number can be increased beyond the range of 1×10^{-4} to 2×10^{-3} during surfactant flooding.

While Wang Demin, et al., (1997) study of Alkaline/surfactant/polymer (ASP) floods was conducted to increase oil recovery further in Daqing oil field in China, ASP system consisting of surfactant, sodium carbonate alkaline, and a polymer with a molecular weight of 17×10^9 . Surfactant A concentration from 0.05 to 0.6%, polyacrylamide concentration within 1800 mg/L and water salinity from 1000 to 10 000 mg/L. the result of ASP pilot study found that it can enlarge the swept volume, increase the portion of the reservoir put on production and increasing the producing thickness of the pay zone.

Jakobsen, S.R., et al., (1994) discusses the technical and the economical potential for surfactant flooding in North Sea sandstone reservoir UK. The results indicate that optimum economy is achieved when typically less than 50 % of the surfactant flood technical potential. By using simulations and the software was ECLIPSE black oil simulation model they found that surfactant flood can increase and accelerate oil production. But the balance between oil production and surfactant consumption it is utmost importance even marginal over injected can ruin the economy. Maximum net cash flow can be achieved when less than 50% of the technical potential is recovered. In conclusion surfactant flood is not free of risk with respect to expected profit even 20 \$/barrel.

Bragg, J.R., et al., (1983) Successful surfactant pilot test in Loudon Field Illinois (USA) which was completed in October, 1981. The test was conduct on 68 acres (2752 m^2) 5-spot operating in manner that approximated pattern the test was highly successful, recovering 60% of the oil remaining after water flood core was recover from post flood well confirm the low final oil saturation.

After the end of the World War II, the development of EOR has been ongoing, because the operators who owned the reservoirs with declined reserves noticed that there is significant quantities of oil remained unrecovered in their reservoirs after the primary and secondary recovery period. Furthermore interest was put on EOR process

in response to oil embargo of 1973 and the following energy crisis. That high-active period of EOR implementation lasted until the collapse of worldwide oil prices in 1986 (Green et al., 1998).

2.1.1 Overview of EOR history in Sudan

Oil exploration in Sudan was first initiated in 1959 by Italy's Agip oil company in the Red Sea area. Several oil companies followed Agip in the Red Sea Area but none were successful in their exploration efforts after that Chevron suspended its operations in 1984 and entirely ended its 17 year long involvement in Sudan by selling its interests to the Sudanese company Concorp in 1992. Concorp sold these concessions on to the Canadian oil corporation 'State Petroleum' Corporation.

In 1996 it sold 75% of its shares to the China National Petroleum Company (CNPC), Petronas (Malaysia), and Sudapet (Sudan) with which it jointly formed the Greater Nile Petroleum Operating Company (GNPOC). Arakis subsequently sold its 25% share in the GNPOC to the Canadian company Talisman in 1998. GNPOC made considerable discoveries, increasing the amount of proven reserves in Sudan. It also succeeded in the construction of the pipeline from the Heglig and Unity fields to Port Sudan on the Red Sea. In 1999 the pipeline became operational and carried the first Sudanese oil exports to Port Sudan.

There are many reasons to make EOR very attractive in Sudanese oil fields that are because of:

- High amount of oil remaining in reserves.
- High amount of oil remaining in place (STOIIP).
- High water cut.
- Good oil price.
- Low recovery factor after primary and secondary period.
- Availability of technology.

2.2 Enhance Oil Recovery

Enhanced oil recovery became one of the most and common way to increase the oil production rate in all the producing oil and gas fields in the world. There are many reasons behind selecting the tertiary recovery (Enhanced oil recovery) to be used to increase the recovery factor in the oilfields.

Increasing of the knowledge and improving the technology is one of the main reasons to attract and encourage the clients and investors to implement the EOR. In addition to most of the easy oil (green fields) is already produced as well as the production reached the peak already more than 10 years ago. Enhanced oil recovery divided into four groups, see figure 2.1:

- Chemical enhanced oil recovery
- Thermal enhanced oil recovery
- Miscible enhanced oil recovery

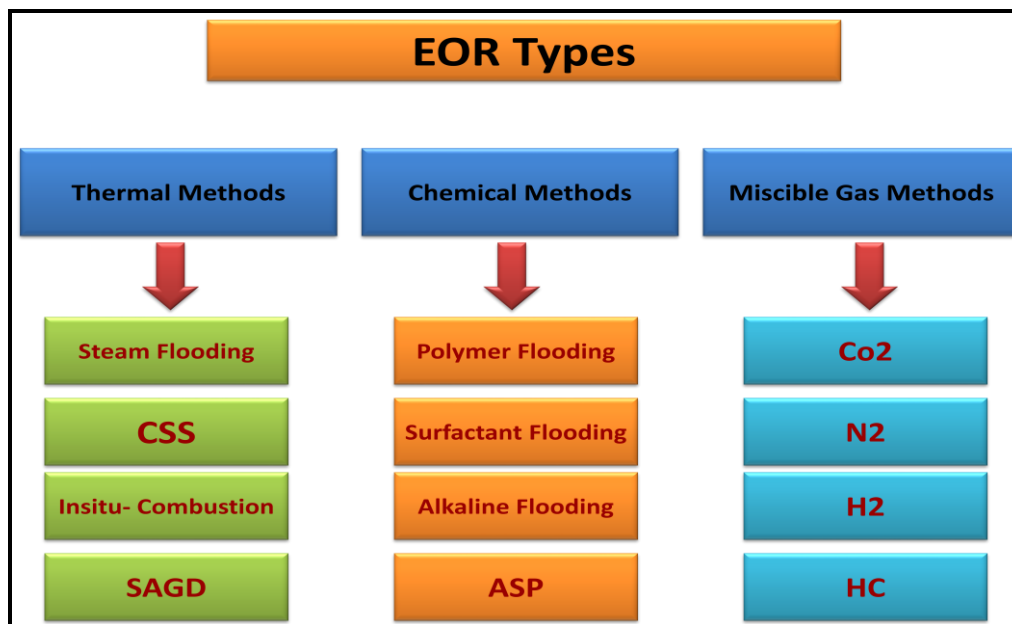


Fig.2.1: EOR Processes (Abdulbasit, 2013)

2.2.1 Chemical Enhanced Oil Recovery

Chemical EOR is a process of injecting of chemical material (usually add to the water) or called (water based) into the reservoir in order to control the mobility ratio by increasing of water viscosity

There are FOUR common types of chemical EOR methods (figure 2.2) namely:

- Polymer Flooding.
- Surfactant Flooding.
- Alkaline Flooding.
- Alkaline-Surfactant-Polymer (ASP) Flooding

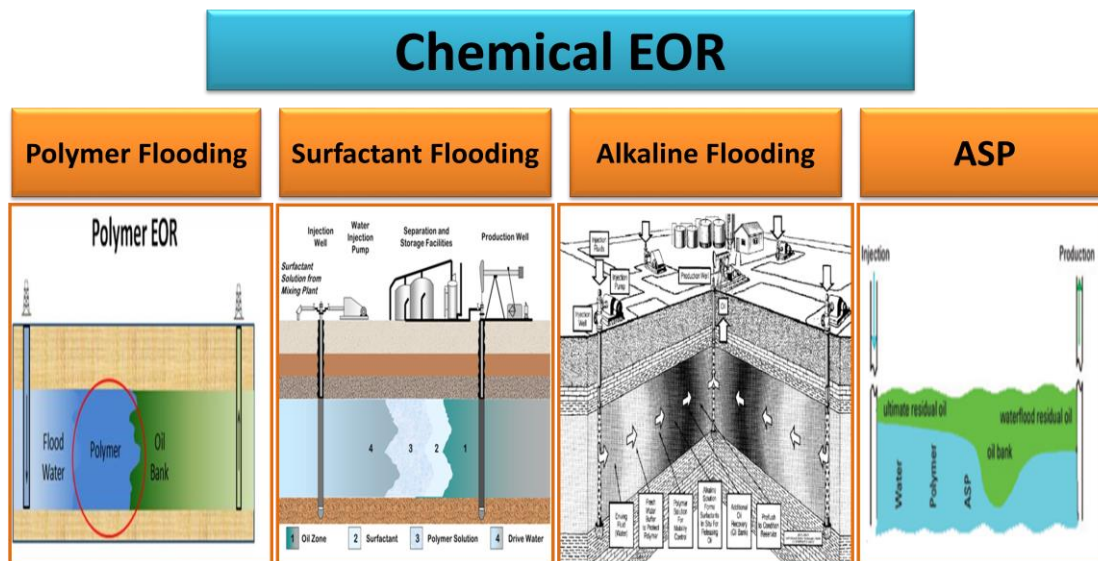


Fig. 2.2: Chemical EOR (Abdulbasit, 2013)

2.2.1.1 Polymer Flooding

Injecting of chemical materials into the reservoir (polymer) in order to stop or reduce water production by increasing its viscosity and therefor reduce the mobility ratio and enhance oil production. The description of the process is to inject polymer into the formation, followed by water injection for the purpose of sweep efficiency where it acts like a piston, polymer has the ability to create oil bank to increase oil recovery, see figure 2.3.

Polymer injection to control mobility ratio, water injection to improve the sweep efficiency.

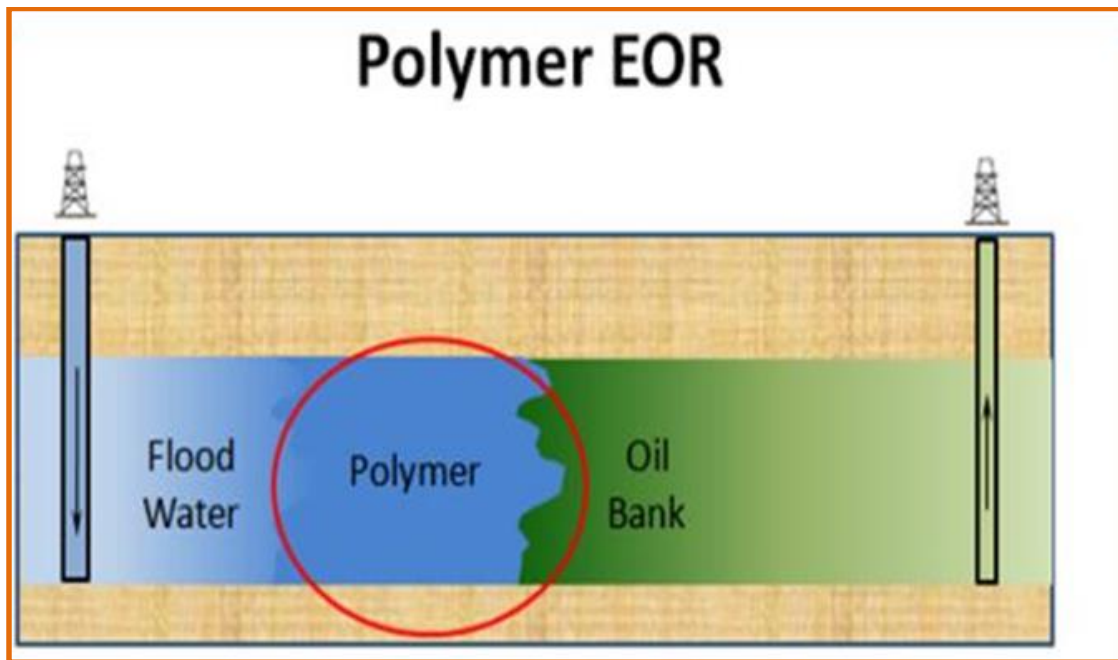


Fig.2.3: The Process of Polymer Flooding (Abdulbasit, 2013)

If water is only injected and due to reservoir heterogeneity, the swept area will be less, but by adding polymer the mobility is controlled, see figure 2.4.

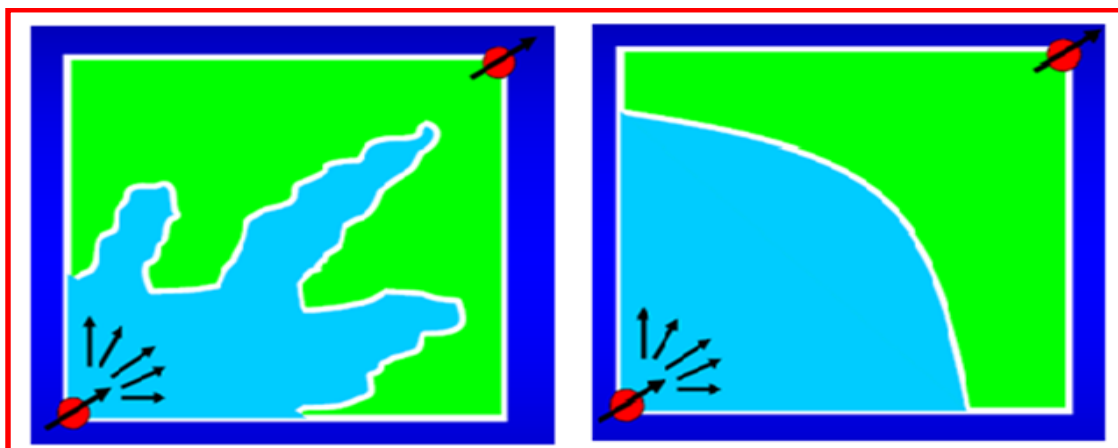


Fig.2.4: Effect of the Polymer in Enhance the Sweep Efficiency (Abdulbasit, 2013)

Condition to be applied: Polymer flooding applied when Water-Oil Ratio (WOR) < 10 , this reason is important due to polymer is used where water production is high but before WOR becomes excessively high. Clays are undesirable due to adsorption

of the polymer. Aquifer strength has to be either weak or moderate because polymer flooding is affected by strong aquifer and the oil viscosity should be low.

2.2.1.2 Surfactant Flooding

Surface-active agents, or surfactants, are chemical substances that adsorb on or concentrate at a surface or fluid/fluid interface when present at low concentrations in a system (Rosen, 1978). The importance of the surfactant that they decrease the interfacial tension (IFT) between oil and water.

Commonly, surfactant consists of hydrocarbon portion (nonpolar) and a polar, or ionic, portion. Figure 2.5 shows a simplified schematic of the molecule. The hydrocarbon portion is often called the “tail” which can be either a straight chain or branched chain. The ionic portion is called the “head” of the molecule.

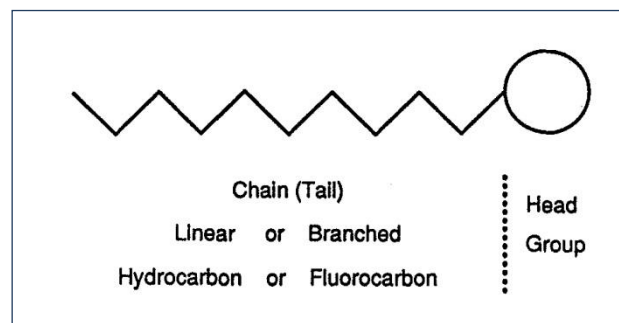


Fig.2.5: Schematic of Surface-Active Molecule (Ottewill, 1984)

Classification and Structure of Surfactant

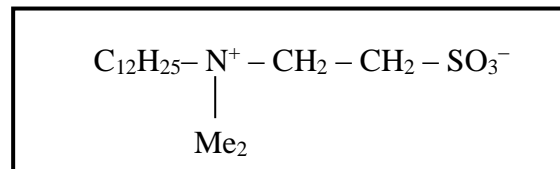
Surfactants may be classified according to the ionic nature of the head group as anionic, cationic, nonionic and zwitterionic. Examples of these types as follow (Ottewill, 1984):

Anionic: sodium dodecyl sulfate ($C_{12}H_{25}SO_4^-Na^+$). In aqueous solution, the molecule ionizes, and thus the surfactant has a negative charge. This surfactant is classified as anionic because of the negative charge on its head group.

Cationic: dodecyl-trimethyl-ammonium bromide ($C_{12}H_{25}N^+Me_3Br^-$). In aqueous solution, ionization occurs and the surfactant head group has a positive charge and is cationic.

Nonionic: dodecyl-hexa-oxy-ethylene glycol mono-ether ($C_{12}H_{25}[OCH_2CH_2]_6OH$). In this particular molecule, which does not ionize, the head group is larger than the tail group.

Zwitterionic: 3-dimethyl-dodecyl-amine propane sulfonate. This surfactant has two groups of opposite charge.



Anionic and nonionic's are the main surfactants used in EOR processes. Anionic surfactants have good surfactant properties they are relatively stable, exhibit relatively low adsorption on reservoir rock, and can be manufactured economically; thus they are the most widely used. In the other hand, nonionic's have been used primarily as co surfactants to improve the behavior of surfactant systems.

Mechanism: Firstly the surfactant is injected into the formation targeting the surface between oil-water to break the attractive forces between them (IFT) by producing soaps at the contact reducing residual oil saturation in addition to wettability change from oil wet to water wet, then a polymer is injected behind the surfactant in order to enhance the sweep efficiency and control the mobility as well as to stabilize the flow pattern, then a drive water is pumped down to sweep this mixture into the producing well, see figure 2.6.

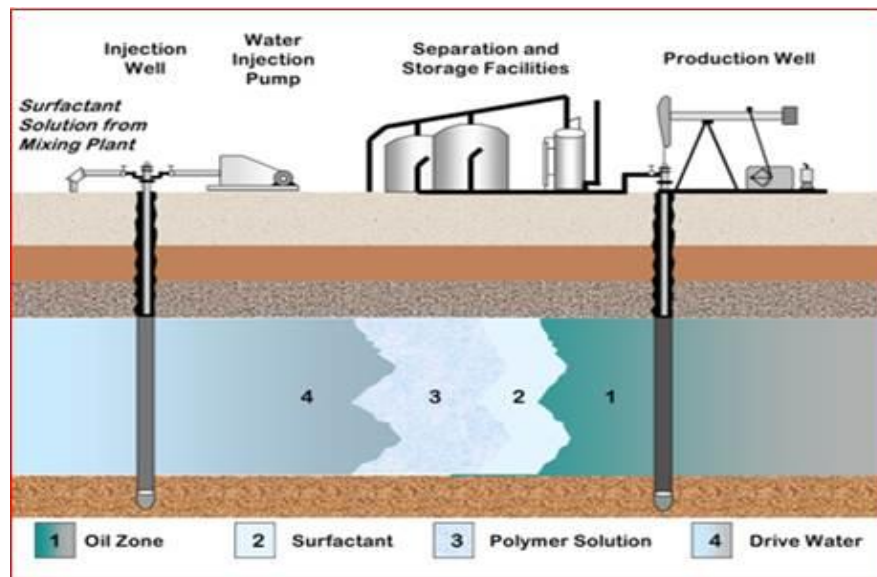


Fig.2.6: Surfactant Flooding Mechanism (Abdulbasit, 2013)

2.2.2 Thermal Recovery Process

Thermal recovery process rely on the use of the thermal energy in some form both to increase reservoir temperature thereby reducing oil viscosity and to displace oil to producing wells. Three processes have evolved over the past 30 years to the point of commercial application. These are cyclic steam stimulation, steam drive, and forward in-situ combustion (figure 2.7).

The motivation for developing thermal recovery was existence of major reservoir all over the world that were known to contain billions of barrels of heavy oil and tar sand that couldn't be produced with conventional techniques.

Thermal recovery processes are the most advance EOR processes and of contribute significant amount of oil to daily production most thermal oil production is result of cyclic steam injection and steam drive. In 1993 worldwide production from cyclic steam and steam drive was more than 700,000 B/D state by Don W. Green and G Paul Willhite, 1998.

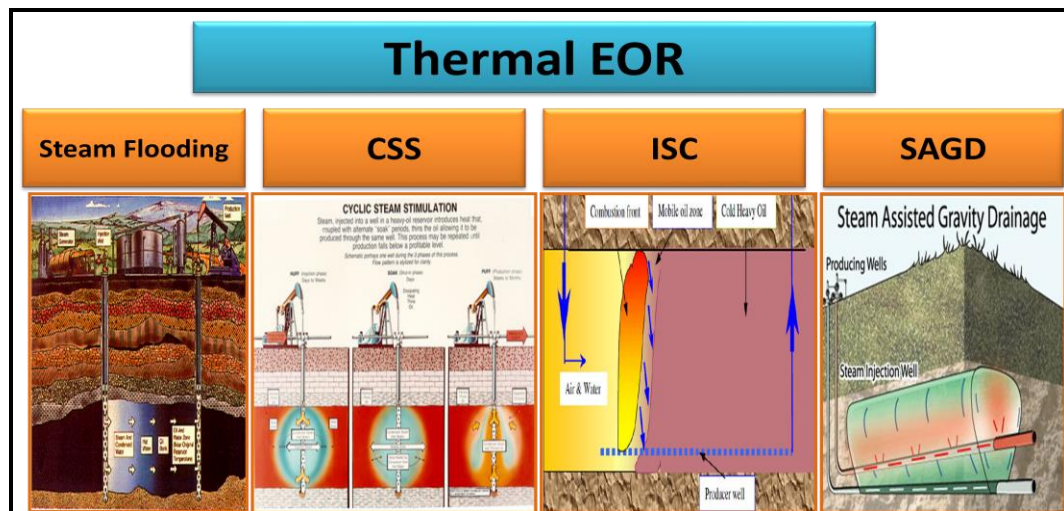


Fig. 2.7: Thermal EOR (Abdulbasit, 2013)

2.2.2.1 Heat losses during steam injection

Steam for cyclic steam and steam drive processes is usually supplied by steam generators that produced 80% quality steam at the steam generators outlet and part of the steam is use to produce electricity steam is distribute to different wells through series of insulated lines, see figure 2.8.

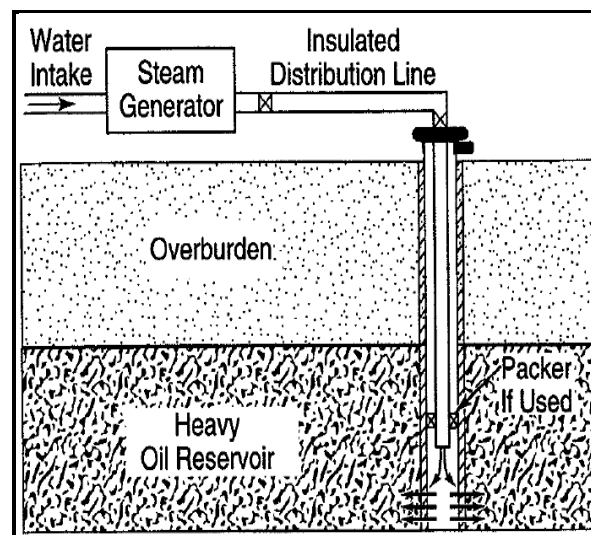


Fig.2.8: Steam Flow in Cyclic and Steam Drive Project (Green and Willhite, 1998)

2.2.2.2 Steam injection

Steam injection is the thermal process which supplies the heat needed to increase reservoir temperature and the energy to displace oil. Steam is the heat carrier agent

provided by the steam generator. Continuous steam injection is called steam drive. Steam drive uses a pattern flood with injector and producers.

2.2.2.3 Cyclic steam stimulation

Cyclic steam injection is a method of stimulating well production to obtain higher oil rates. Used in a single well operation, injecting steam and then producing oil from the same well. Steam injection is called cyclic steam injection, steam soak, or "Huff-n-Puff", see figure 2.9.

It used only when the productive formation is thick, and/or the reservoir is dipped with good permeability along the strata. Most steam injection operations have been applied to heavy crude oil reservoirs with densities between 12 and 18 °API and viscosities between 600 to 6000 cp in reservoir conditions (Carcoana, 1992).

The main objectives were to increase oil production by reducing oil viscosity and to increase oil recovery by steam displacement.

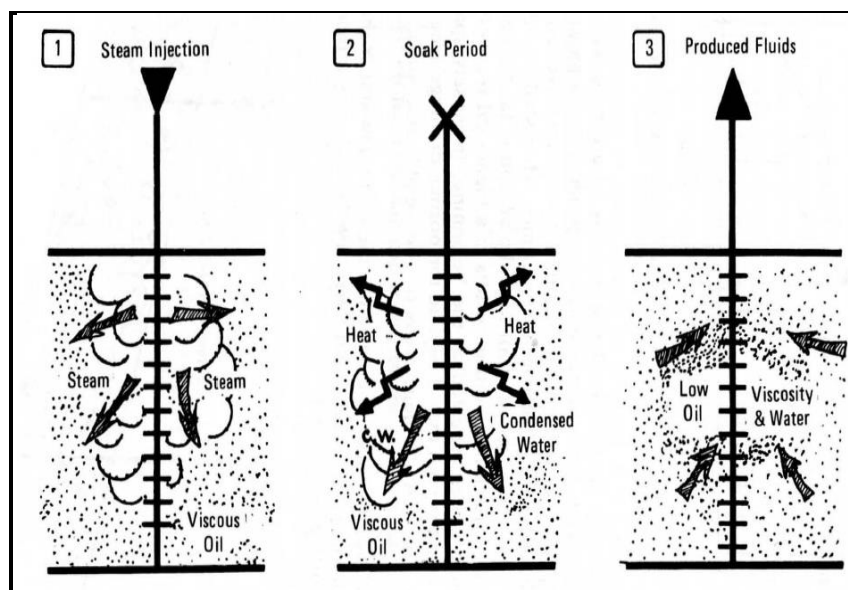


Fig.2.9: Three Periods of Cyclic Steam Stimulation (Carcoana, 1992)

2.2.2.4 In-situ combustion

In the porous rock of an oil reservoir, the oil can be ignited around the wellbore by means of an igniter or by a spontaneous reaction of the oil to the air injected into the formation. A burning front is built up, and the combustion is sustained by continuous

injection of air or oxygen enriched air. A small portion of the oil in place is burned furnishing heat to the rock and its fluids, the heat generated is used to:

- Reduces the viscosity of the oil, increasing its mobility.
- Increases sweep efficiency and reduce oil saturation.
- Vaporizes some of the liquids in the formation generating steam and hot gases.
- Produces miscible fluids by condensation of the light components of the vaporized oil.

2.2.3 Miscible Fluid Displacement

Miscible oil displacement is the displacement of oil by fluids which mixed in all proportions without the presence of an interface, all mixtures remaining single phase.

The fluid mainly used in miscible displacement is hydrocarbon fluids, alcohol were recommended as miscible agents also natural gas, flue gas, and nitrogen at high pressure. There are four common miscible gas injections in EOR (Figure 2.10):

- Carbon Dioxide (CO₂) Injection.
- Nitrogen (N₂) Injection.
- Hydrocarbon (HC) Injection.
- Hydrogen (H₂) Injection.

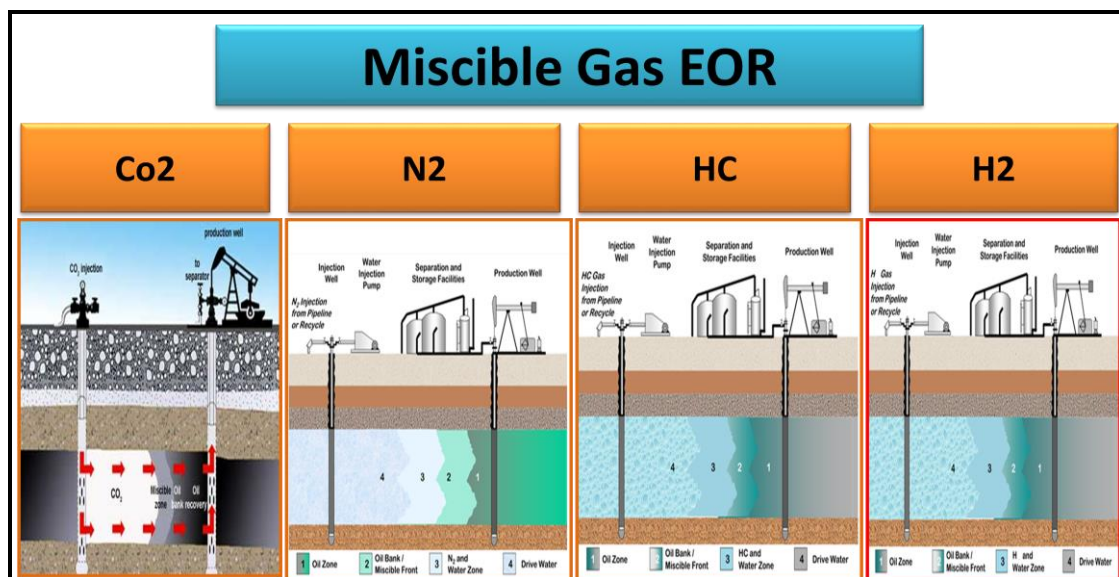


Fig.2.10: Miscible Gas EOR (Abdulbasit, 2013).

2.2.3.1 Carbon Dioxide injection (CO₂)

The CO₂ flooding method has been implemented commercially since 1985 to date. It is a process whereby carbon dioxide is injected into an oil reservoir in order to increase output when extracting oil when a reservoir's pressure is depleted through primary and secondary production, carbon dioxide flooding can be an ideal tertiary recovery method. MMP for carbon dioxide has to be less than the current reservoir pressure, if not, water injection has to take place. It is the injection of carbon dioxide in to the reservoir with high pressure which is at least equal to MMP. The objective is to achieve miscibility between oil and injected CO₂ to reduce oil density (viscosity) and enhance the displacement efficiency as well as increasing the recovery factor. CO₂ source is the most important factor, either it is being produced and re-injected or transferred from another location using storages or pipelines, see figure 2.11.

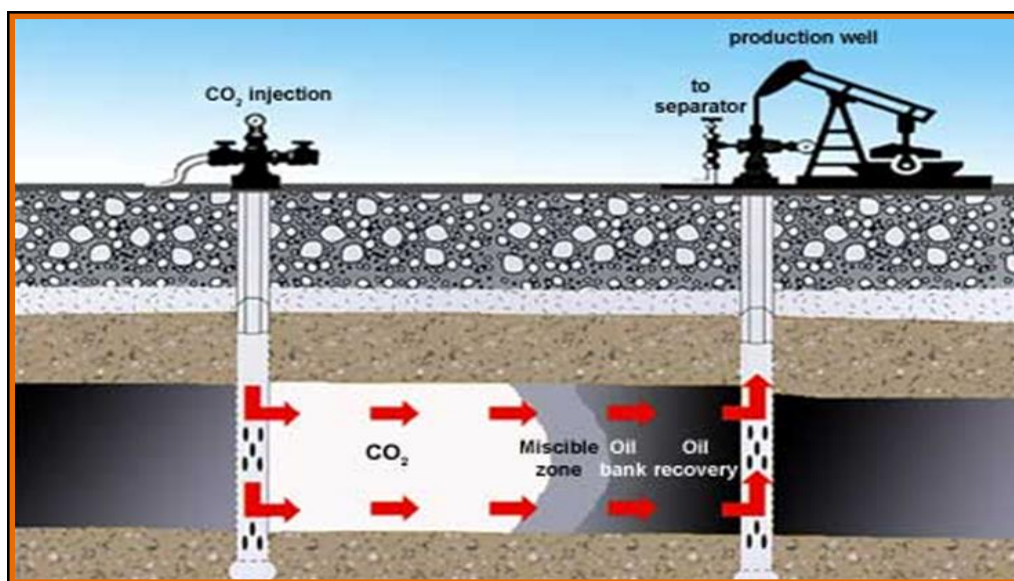


Fig. 2.11: The Process of CO₂ Injection (Abdulbasit, 2013)

CO₂ has to be injected continuously to sustain the injectivity and improve the displacement efficiency. CO₂ is the most common gas which can be used in WAG mode resulting in high recovery factor and improvement in the displacement efficiency.

Advantages: The greatest difference compared to other gases is that CO₂ can extract heavier components up to C₃₀, also the solubility of CO₂ in hydrocarbon oil causes the oil to swell lit reduces oil (density) viscosity, it can vaporize and extract portions of

the oil, reduces S_{or} (remaining oil volume) and it reduces the surface tension between oil and water and result in a more effective displacement.

Disadvantages: This method has many disadvantages they are high mobility of the CO_2 , the relative low density and viscosity of CO_2 compared to reservoir oil are responsible for viscous fingering, availability of CO_2 , and corrosion and erosion due to CO_2 is being produce.

Conditions to be applied: The best condition for CO_2 to be applied for reservoirs deeper than 2,000 ft, API gravity >25 oil remaining oil saturations greater than 20%. It should also be noted that Carbon dioxide flooding is not affected by the lithology of the reservoir area but simply by the reservoir characteristics, oil viscosity with maximum 10 cp and high current reservoir pressure otherwise water injection has to take place (MMP).

2.2.3.2 Nitrogen Injection (N_2)

Injecting large volumes of nitrogen and sometimes alternating with water, it's preferred with light oils (to reduce the problems due to different in mobility ratio) and at very high pressure to perform miscibility. Nitrogen is injected usually with MMP to achieve miscibility with oil, MMP for nitrogen is very high and it needs either water injection before the implementation or high current reservoir pressure. Nitrogen flooding enhances production by vaporizing the lighter components of the crude oil and generating miscibility if the pressure is high enough, see figure 2.12.

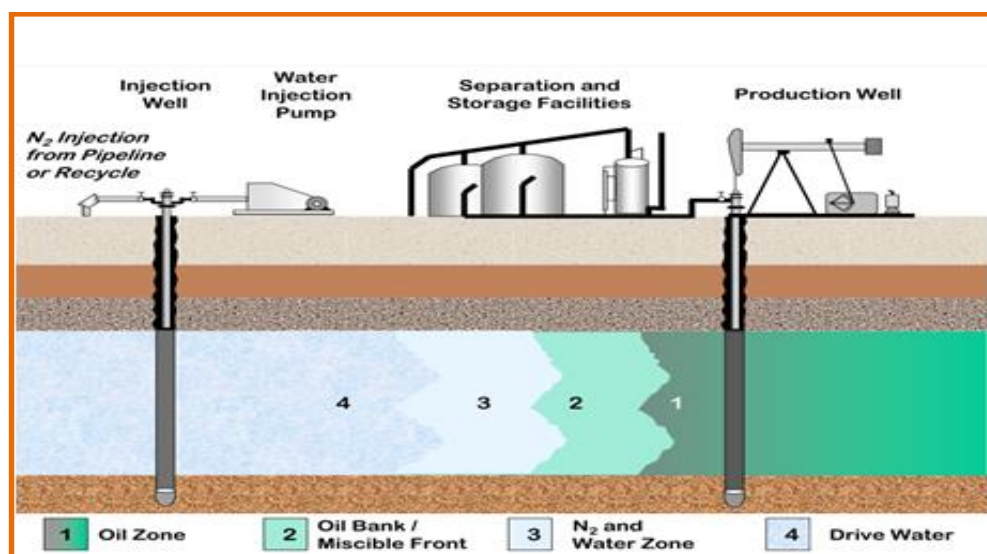


Fig.2.12: Process of Nitrogen Injection (Abdulbasit, 2013)

Advantages: It reduces oil viscosity, it can vaporize and extract portions of the oil, reduces S_{or} (remaining oil volume) also has low cost compared with CO_2 and hydrocarbon, and Increases oil recovery and oil production.

Disadvantages: Disadvantage represent in dip reservoir problem and its effect on gravity, difference between mobility's cause viscous fingering which results in poor vertical and horizontal sweep efficiency and nitrogen has a very high MMP compared to the other gas injection methods.

Conditions to be applied: Condition at which N_2 applied when we have light oil with API >34 , Low oil viscosity 5 cp, Deeper reservoir depth is preferred more than 6000 ft and also N_2 must be available, High current oil saturation and High reservoir pressure (MMP).

2.2.3.3 Hydrocarbon injection (HC)

Hydrocarbon miscible flooding recover oil by generating miscibility if the pressure is high enough, enhancing the oil movement ability by increasing the oil volume (swelling). Injection of light oil components into the reservoir with very high pressure to achieve miscibility and produce oil by vaporizing the heavy oil components, see figure 2.13.

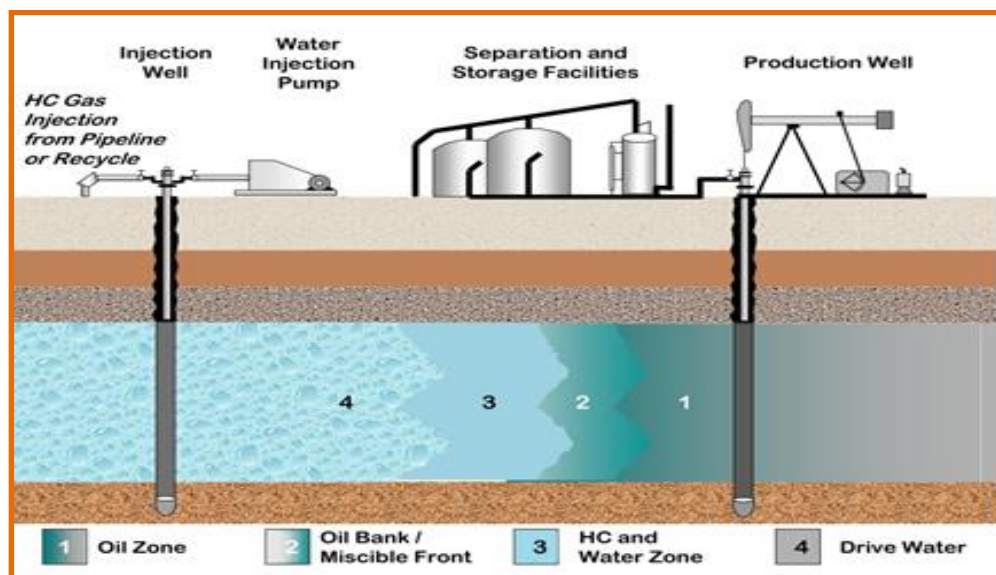


Fig.2.13: Hydrocarbon Injection Process (Abdulbasit, 2013)

Advantages: Reduction of oil (density) viscosity, vaporizing the heavy oil components wettability change reduction of S_{or} and there for increasing of oil recovery factor and oil production.

Disadvantages: High mobility of the lighter components being injected into the reservoir resulting in gas fingering. High cost compared to other gas injection methods, less effectiveness method compared to other gas injection types, and Injected hydrocarbon can be trapped in the reservoir and it has high MMP.

Conditions to be applied: Applied when light oil with API >23 with low viscosity with less than 5 cp. Deeper reservoir is preferred and also high current oil saturation. And high current reservoir pressure to achieve MMP availability of hydrocarbon gas in the field.

2.2.3.4 Hydrogen Injection (H_2)

Hydrogen miscible flooding recover oil by generating miscibility if the pressure is high enough, enhancing the oil movement ability by increasing the oil volume (swelling). Injection of H_2 into the reservoir with very high pressure to achieve miscibility and produce oil by vaporizing the heavy oil components. It is very unique process, it has been done but failed, see figure 2.14.

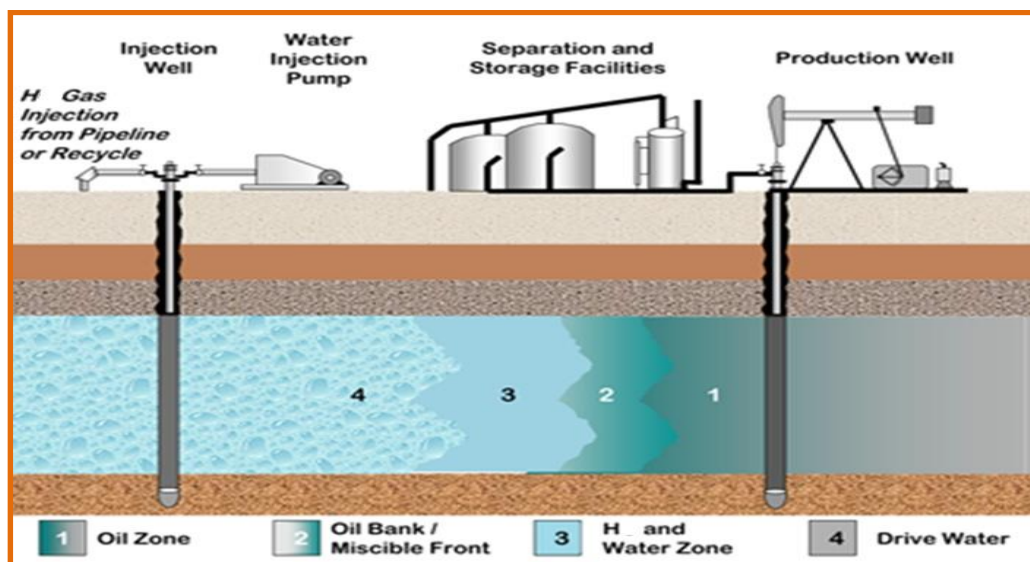


Fig.2.14: Hydrogen Injection Process (Abdulbasit, 2013).

Advantages: Reduction of oil (density) viscosity vaporizing the heavy oil components, wettability change, reduction of S_{or} and therefor increasing of oil recovery factor and oil production.

Disadvantages: Difficult to be controlled and has high MMP.

Conditions to be applied: Applied at light oil with API >23 and low oil viscosity with less than 3 cp. Deeper reservoir is preferred, high current oil saturation and high current reservoir pressure to achieve MMP.

2.3 Factors Affecting the Displacement Efficiency

There are many factors affecting the displacement efficiency. Examples as follow:

2.3.1 Mobility Ratio

The mobility ratio concept described by Aurel Carcoana (1992) is defined as the ratio of mobility of the displacing phase to the mobility of the displaced phase.

The water is the displacing fluid and its mobility is defined as the following:

$$\lambda_w = k_w/\mu_w \dots \dots \dots \text{Eq. (2.1)}$$

Where k_w is the effective permeability of the rock to water in the water swept zone of the reservoir and μ_w the water viscosity and the oil is the displaced phase. The oil mobility is defined as the following:

$$\lambda_o = k_o/\mu_o \dots \dots \dots \text{Eq. (2.2)}$$

The mobility ratio (**M**) will be the mobility of water divided by the mobility of the oil (equation 2.3):

$$M = \frac{\lambda_w}{\lambda_o} = \frac{k_w \mu_o}{k_o \mu_w} \dots \dots \dots \text{Eq. (2.3)}$$

It is obvious that when the mobility ratio is greater than unity, since μ_w is less than μ_o , water flows at a higher velocity through the path of least resistance and breaks through into producing wells, so it is an unfavorable value and we always tend to reduce the mobility ratio number.

2.3.2 Capillary pressure

The capillary forces in a petroleum reservoir are the result of the combined effect of the surface and interfacial tensions of the rock and fluids, the pore size and geometry, and the wetting characteristics of the system (Ahmed, 2006).

The pressure exists between the two fluids, which depends upon the curvature of the interface separating the fluids. We call this pressure difference the *Capillary pressure* and it is referred to by P_c .

Denoting the pressure in the wetting fluid by P_w and that in the nonwetting fluid by P_{nw} , the capillary pressure can be expressed by (equation 2.4):

Capillary pressure = (pressure of the nonwetting phase) – (pressure of
The wetting phase)

$$P_C = P_{NW} - P_W \dots\dots\dots \text{Eq. (2.4)}$$

2.3.3 Water Fingering and Tonguing

In thick, dipping formations containing heavy viscous oil, water tends to advance as a “tongue” at the bottom of the pay zone. Similarly, displacement of oil with a gas will result in the gas attempting to overrun the oil due to gravity differences unless stopped by a shale barrier within the formation or by a low overall effective vertical permeability.

2.3.4 Displacement and sweep efficiency

To analyze and evaluate recovery efficiency obtainable by gas displacement operation in term of three efficient factor areal sweep, vertical sweep and displacement efficiency (Teknica, 2001). The product of the three efficiencies determines the volumetric efficiency (equation 2.5):

$$R = E_{AS} E_{VS} E_D \dots \dots \dots \text{Eq. (2.5)}$$

R = recovery

E_{AS} = areal sweep efficiency

E_{VS} = vertical sweep efficiency

E_D = displacement efficiency

Areal sweep efficiency: Is the fracture of the pattern area invaded by displacing fluid and it affected by the following variable: pattern geometry, mobility ratio, and areal heterogeneity.

Vertical sweep efficiency: Vertical sweep efficiency is affected by vertical permeability stratification and by gravity. Permeability variation has bad affect on vertical sweep efficiency.

Displacement efficiency: Whatever we do we can't obtain 100 percent displacement for the following factors:

1. Trapped oil by mobile water saturation
2. Bypassing because of the reservoir heterogeneity
3. Precipitation of heavy end

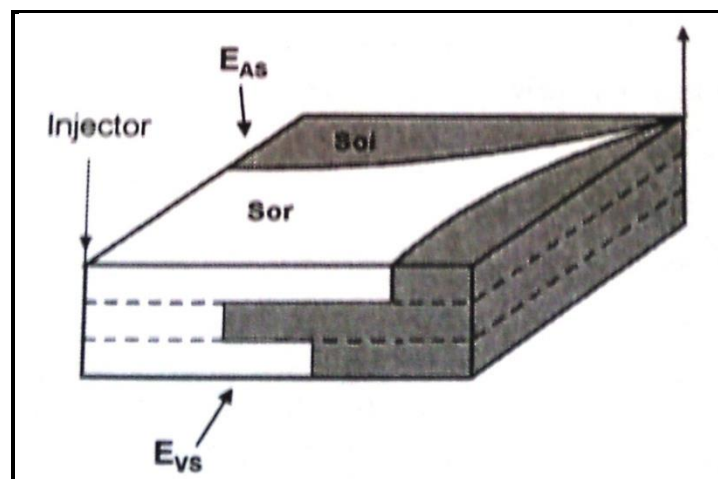


Fig.2.15: Vertical and Areal Sweep Efficiency (Carcoana, 1992)

2.4 Economics

Any project must be economically evaluated. The project may be successful from the technical side, but its real value measured in term of income and expenses.

The incremental ultimate recovery is calculated for each economic scenario and the most profitable one is to be chosen. The estimated incremental ultimate recovery from EOR is subjected to major uncertainty because of the unknown reservoir characteristics.

The most key factors of prospective EOR project returns are high uncertain and they are: investment cost, operating cost, process effectiveness, oil price, taxation, and Environmental factor.

2.5 Screening Criteria

It is a procedure to select one of the EOR methods to be applied in the field to obtain good outcomes. Suitable method for each type of reservoirs is illustrated in the following figures (figure 2.16 and figure 2.17). This method depends on number of parameters such as:

- Reservoir Type
- Reservoir Depth
- Reservoir Pressure
- Reservoir Temperature
- Water Aquifer Strength
- Clay Volume
- Net Pay
- Reservoir Permeability, and others

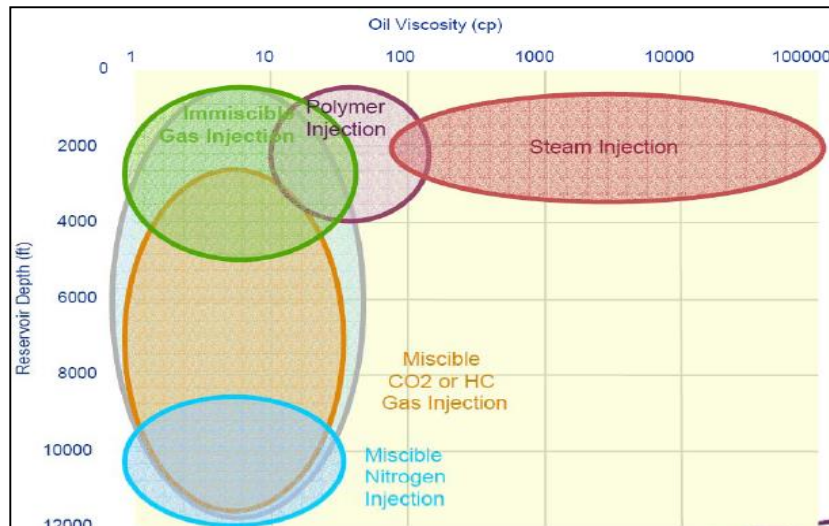


Fig.2.16: Methods of EOR According to Viscosity and Pressure (Abdulbasit, 2013).

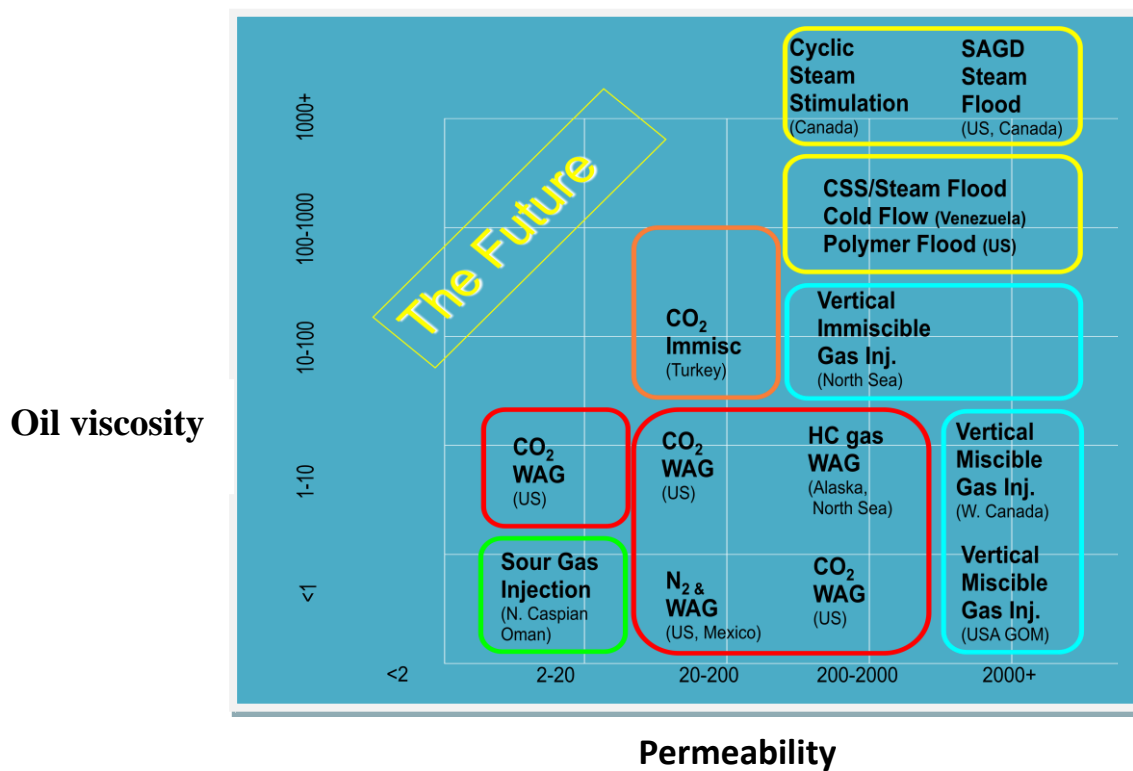


Fig.2.17: Method of EOR According to Viscosity and Permeability (Abdulbasit, 2013).