Comparative Study of Different EOR Methods

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Abstract

The Norwegian Continental Shelf (NCS) is facing considerable future challenges regarding reserves' replacement and ultimate field recoveries. This is an ambitious goal considering several of the large fields are on a steep decline. The Norne field which is the base case for this study falls in the same category while most of the recent discoveries are relatively small. Although the current recovery from the reservoir is high considering its subsea development (53%), the need for developing cost efficient enhanced oil recovery (EOR) methods that can improve the sweep efficiency significantly is present. Since it is being produced under water flooding, methods that can improve the water flooding efficiency by chemical additives are of special interest and could probably be implemented with existing facilities and within the relevant timeframe.

Different EOR methods have been studied and understood as a technical part of EiT Norne Village. Chemical flooding, microbial EOR (MEOR) and CO_2 flooding were chosen for Norne Reservoir based upon reservoir temperature, reservoir rock, fluid properties and compositions. These methods were discussed and studied in detail at the same time that an economic evaluation has been done.

A simplified graphical method showed that it would be appropriate to implement CO_2 flooding for both oil recovery and economical reasons. A final recovery factor of 67.2% resulted from this study. However, MEOR was found to be the cheapest and Statoil is also implementing this.

The main challenge in order to realize CO_2 injection in the Norne Reservoir is on CO_2 availability and transport but geological constraints must also be considered. Chemical methods are feasible only if oil prices remain high.

Introduction

The general mechanism of oil recovery is movement of hydrocarbons to production wells due to a pressure difference between the reservoir and the production wells. The recovery of oil reserves is divided into three main categories worldwide[1], figure 1 illustrates these categories:

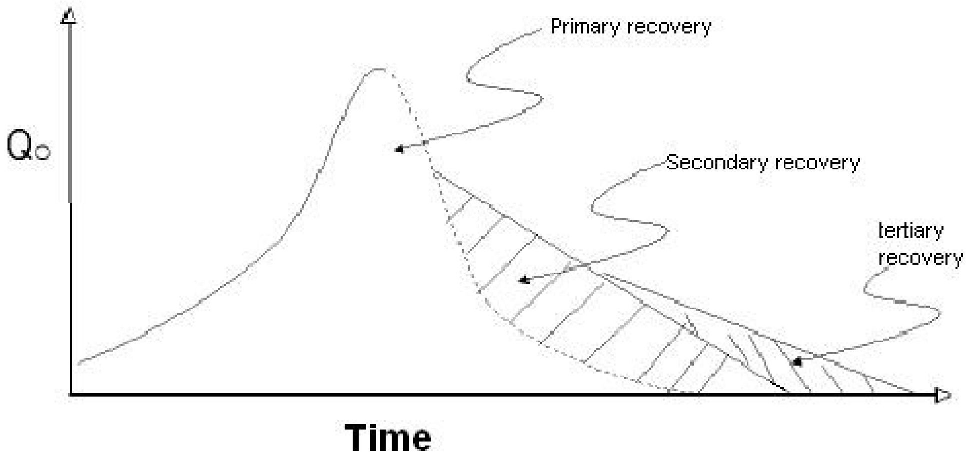


Figure 1: Recovery stages of a hydrocarbon reservoir through time

Primary recovery techniques: This implies the initial production stage, resulted from the displacement energy naturally existing in a reservoir.
Secondary recovery techniques: Normally utilized when the primary production declines. Traditionally these techniques are water flooding, pressure maintenance, and gas injection. The recovery factor can rise up to 50%.
Tertiary recovery techniques: These techniques are referred to the ones used after the implementation of the secondary recovery method. Usually these processes use miscible gases, chemicals, and/or thermal energy to displace additional oil after the secondary recovery process has become uneconomical. The recovery factor may arise up to 12% additionally to the RF obtained with the secondary recovery method.

1. Recovery Stages

As mentioned before, the hydrocarbons from a determined reservoir are recovered through different processes and techniques. The viability of any oil recovery process depends upon following factors:

1. Volumetric displacement efficiency: It is a macroscopic displacement effect which is a function of mobility ratio (M). The efficiency of water-flooding can be improved by lowering of water-oil mobility ratio. Mobility (λ = permeability/fluid viscosity) of a fluid is a quantitative measure of its ability to flow through the channels.

[1] Reservoir recovery techniques. Kleppe, Jon. Kompendium, NTNU, autumn 2009. Trondheim, Norway

$$M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o}$$

Where:

k_{rw} = effective water permeability (mD)

k_{ro} = effective oil permeability (mD)

μ_w & μ_o = viscosities of water and oil respectively (cP)

A mobility ratio greater than one is unfavorable because water is more mobile than oil. Water would finger through the oil zone and, therefore, reduce the oil recovery efficiency. If the mobility ratio is less than unity, the displacement of oil by water occurs more or less in piston-like displacement[2].

Unit displacement efficiency: It is a microscopic displacement phenomenon. With constant oil density, the definition of displacement efficiency for oil becomes:

$$E_D = \frac{\text{Amount of oil displaced}}{\text{Amount of oil contacted by displacing agent}}$$

Fluid, rock and fluid-rock properties also affect E_D.
If the displacing fluid will contact all the oil initially present in reservoir, the volumetric sweep efficiency will be unity.

- Volumetric Sweep Efficiency, E_v

$$E_V = \frac{\text{Volume of oil contacted by displacing fluid}}{\text{Total amount of oil in place}}$$

- E_v can be decomposed into two parts, (areal sweep efficiency) and (vertical sweep efficiency).

$$E_V = E_A \bullet E_I$$

$$E_A = \frac{\text{Area contacted by displacing fluid}}{\text{Total area}} \qquad E_I = \frac{\text{Cross-sectional area contacted by displacing fluid}}{\text{Total cross-sectional area}}$$

[2] Donaldson, E.C., Chilingarian, V.G., Yen, T.F., & Sharma, M.K.; Developments in Petroleum Sciences: Enhanced Oil Recovery; Volume 17B: Processes and Operations; Elsevier B.V.; Amsterdam; 1989; pp (1-9)

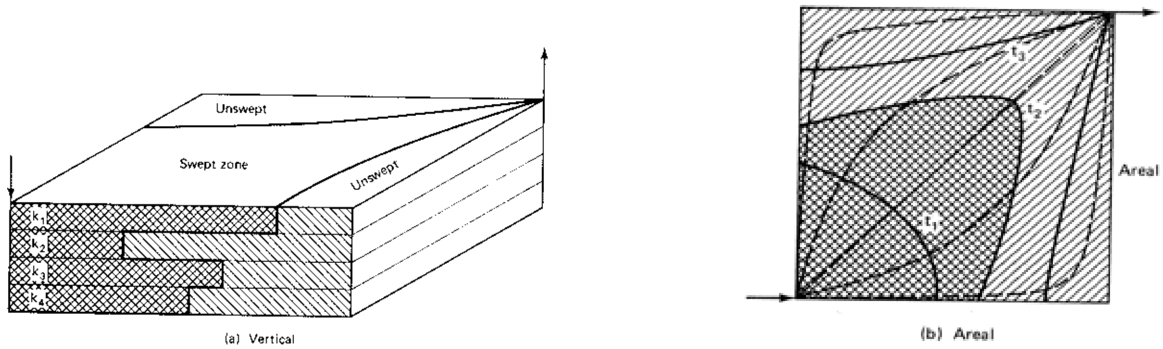


Figure 2: Sweep efficiency schematic [3]

The following chapters will describe the recovery stages presented throughout a reservoir lifetime.

1.1 Primary Recovery

In this recovery process oil is forced out of the petroleum reservoir by existing natural pressure of the trapped fluids in the reservoir. The efficiency of oil displacement is primary oil recovery process depends mainly on existing natural pressure in the reservoir. This pressure originated from various forces:

- Expanding force of natural gas
- Gravitational force
- Buoyancy force of encroaching water
- An expulsion force due to the compaction of poorly consolidated reservoir rocks

Among these forces, expanding force of high-pressure natural gas contributes mainly to oil production. These forces in the reservoir either can act simultaneously or sequentially, depending on the composition and properties of the reservoir.
The gravitational force is more effective in steeply inclined reservoirs, where it facilities the drainage of oil. This force alone may not be effective in moving large amounts of oil into a production well. Another, more effective, force for displacement oil is encroachment of water from the side or bottom of a reservoir. In some fields, edge water encroachment from a side appears to be stationary. The ability of the edge water to encroach depends upon the pressure distribution in the reservoir and the permeability. Compaction of the reservoir as fluids are withdrawn also is a mechanism for movement of oil to production wells. Part of the oil will be expelled due to the decrease in the reservoir volume [2].

1.2 Secondary Recovery

When the reservoir pressure is reduced to a point where it is no longer effective as a stress causing movement of hydrocarbons to the producing wells, water or gas is injected to augment or increase the existing pressure in the reservoir. Conversion of some of the wells into injection wells and subsequent injection of gas or water for pressure maintenance in the reservoir has been designated as secondary oil recovery [2].

When oil production declines because of hydrocarbon production from the formation, the secondary oil recovery process is employed to increase the pressure required to drive the oil to production wells. The purposes of a secondary recovery technique are:

- *Pressure restoration*
- *Pressure maintenance*

The mechanism of secondary oil recovery is similar to that of primary oil recovery except that more than one well bore is involved, and the pressure of the reservoir is augmented or maintained artificially to force oil to the production wells. The process includes the application of a vacuum to a well, the injection of gas or water [2].

2.2.1 Water Injection

In water injection operation, the injected water is discharged in the aquifer through several injection wells surrounding the production well. The injected water creates a bottom water drive on the oil zone pushing the oil upwards. In earlier practices, water injection was done in the later phase of the reservoir life but now it is carried out in the earlier phase so that voidage and gas cap in the reservoir are avoided. Using water injection in earlier phase helps in improving the production as once secondary gas cap is formed the injected water initially tends to compress free gas cap and later on pushes the oil thus the amount of injection water required is much more. The water injection is generally carried out when solution gas drive is present or water drive is weak. Therefore for better economy the water injection is carried out when the reservoir pressure is higher than the saturation pressure.

Water is injected for two reasons:

1) For pressure support of the reservoir (also known as voidage replacement).
2) To sweep or displace the oil from the reservoir, and push it towards an oil production well.

The selection of injection water method depends upon the mobility rate between the displacing fluid (water) and the displaced fluid (oil).

The water injection however, has some disadvantages, some of these disadvantages are:

- Reaction of injected water with the formation water can cause formation damage.
- Corrosion of surface and sub-surface equipment.

As part of water injection it is also common to find the water flooding technique. Water flooding consists of water Water is injected into the reservoir through injection wells. The water drives oil through the reservoir rocks towards the producing wells. For water flooding the most common pattern of injection and production wells is a five-spot configuration as shown in figures 3 and 4 show from different angles, where the water is injected in the central well displacing oil to the four surrounding production wells.

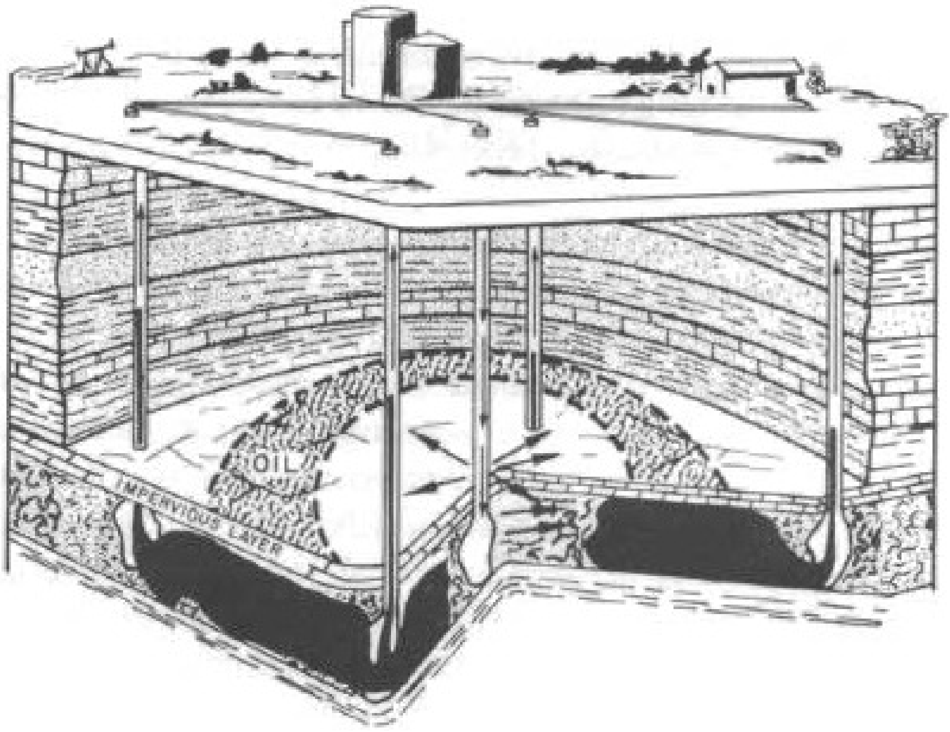


Figure 3: later view from a common water flooding arrangement [2].

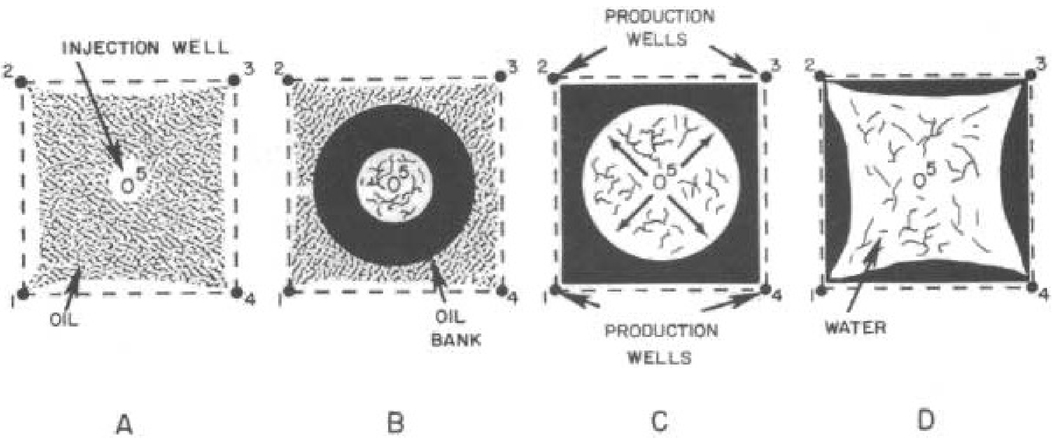


Figure 4: Description from a top view reference of a water flooding process [2].

2.2.2 Gas Injection

It is the oldest of the fluid injection processes. This idea of using a gas for the purpose of maintaining reservoir pressure and restoring oil well productivity was suggested as early as 1864 just a few years after the Drake well was drilled.

The first gas injection projects were designed to increase the immediate productivity and were more related to pressure maintenance rather to enhanced recovery. Recent gas injection applications, however, have been intended to increase the ultimate recovery and can be considered as enhanced recovery projects.

In addition, gas because of its adverse viscosity ratio (higher mobility ratio) is inferior to water in recovering oil. Gas may offer economical advantages. Gas injection may be either a miscible or an immiscible displacement process. The characteristics of the oil and gas plus the temperature and pressure conditions of the injection will determine the type of process involved.

The primary problems with gas injection in carbonate reservoirs are the high mobility of the displacing fluid and the wide variations of permeability. It is required a much greater control over the injection process than the one necessary with water-flooding. In order to evaluate the weep efficiency of the planned gas injection, a short-term pilot gas injection test should be driven. At the same time, this test would provide the necessary data to calculate the required volumes of gas; this in turn, will aid in the design of compressor equipment and estimating the number of injection well which will be required.

In some cases gas injection can increase the ultimate recovery of oil such cases like having carbonate reservoirs. The benefits obtained by the gas injection are dependent upon horizontal and vertical sweep efficiency of the injected gas. The sweep efficiency depends on the type of porosity system present.

2.2.2.1 Identifying a gas injection candidate

Oil fields that have low oil saturation in either primary or secondary gas cap are prime candidates for improved recovery by gas injection into the gas cap. Further shrinkage of oil is reduced by gas injection. Inasmuch as it maintains a relatively high pressure gradient on the oil phase, relative permeability to oil remains high and oil is produced faster and in greater quantity.
In reservoirs having high permeability and high vertical span, gas injection may result in high recovery factors because of gravity segregation. Reservoirs containing volatile oil may have a similar response, thus high oil recovery. ¨

In a few words if the reservoir has a sufficient vertical permeability or relief for gravity segregation to be effective then, gas injection might be a favorable and optimal solution.

2.2.3 Limitations and disadvantages of Primary and Secondary Recovery Processes

- Rapid decrease in reservoir pressure – leads to low oil production rates and oil recovery (5 – 10 % of original oil in place).
- Secondary recovery (water / gas injection) often does not yield a good recovery due to:

- Reservoir heterogeneity
- Unfavorable mobility ratio between oil and water
- Water and gas coning problems
- Low sweep efficiency[3]

When to start EOR?

A common procedure for determining the optimum time to start EOR process after water-flooding depends on:

- Anticipated oil recovery
- Fluid production rates
- Monetary investment
- Costs of water treatment and pumping equipment
- Costs of maintenance and operation of the water installation facilities
- Costs of drilling new injection wells or converting existing production wells into injectors[3].

2.3 Tertiary or Enhanced Oil Recovery Methods (EOR)

Tertiary or enhanced recovery refers to processes in the porous medium that recover oil not produced by the conventional primary and secondary production methods. By EOR is meant to improve the sweep efficiency in the reservoir by use of injectants that can reduce the remaining oil saturation below the level achieved by conventional injection methods. Included in remaining oil defined here are both the oil trapped in the flooded areas by capillary forces (residual oil), and the oil in areas not flooded by the injected fluid (bypassed oil). Examples of injectants are CO_2 or chemicals added to the injected water. In summary, EOR is to reduce the residual oil saturation and to improve the sweep efficiency in all directions[4].

The oil recovered by both primary and secondary processes ranges from 20 to 50 % depending upon oil and reservoir properties. The goal of enhanced oil recovery processes is to recover at least a part of the remaining oil-in-place. These methods change the reservoir fluid properties. The objective of EOR is to increase the pressure difference between the reservoir and production wells, or to increase the mobility of the oil by reduction of the oil viscosity or decrease of the interfacial tension between the displacing fluids and oil. There are several EOR processes that are considered to be promising:

- Chemical processes
- Thermal processes
- Miscible displacement processes[2]

[3] Prof. Ole Torsæter, Kompendiu, NTNU, Trondheim, Norway.
[4] Technology Strategy for Enhanced Recovery; OG21

These processes are the overall of the EOR techniques, as shown in figure 5 there are more EOR methods than secondary recovery techniques.

2.3.1 Chemical processes

The chemical processes refer to those processes in which additional non-natural components are added to the fluids in order to stimulate the mobility between the both the displacing and displaced fluid. These are water based EOR methods. Chemical flooding processes can be divided into three main categories:

- Surfactant flooding
- Polymer flooding
- Caustic flooding

In chemical flooding, a combination of Alkaline-Surfactant-Polymer (ASP) is injected into the reservoir. The polymer is used to improve the sweep efficiency of the invading fluid by changing the mobility ratio between the invading fluids vs. the displaced fluid. The surfactant is present to change the wet-ability of the formation rock if necessary and to reduce the interfacial tension[5]. Caustic injected into the petroleum reservoir reacts chemically with the fatty acids present in the petroleum derivatives and form in-situ sodium salts of fatty acids. The formation of these surfactants results in ultra-low interfacial tension. The chemical flooding processes have been schematically illustrated in the following figure.

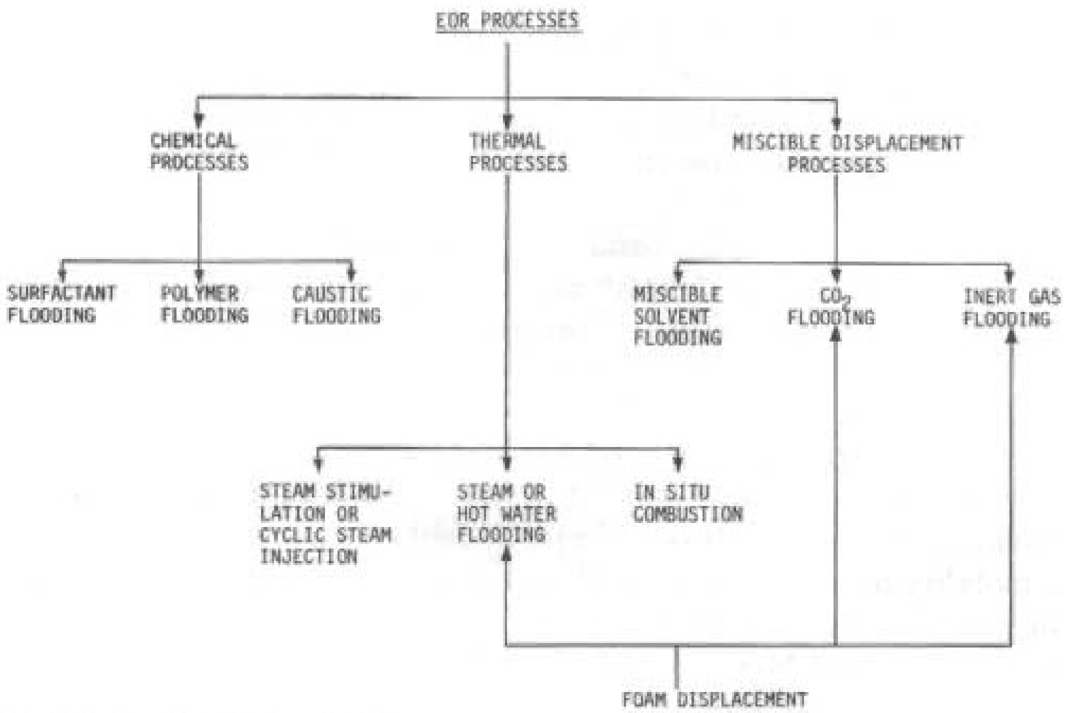


Figure 5: Classification of the different EOR methods[2].

[5] Enhanced Oil Recovery (EOR) Chemicals and Formulations; Akzo Nobel Surface Chemistry; 2006; pp (1-6).

This chapter will give a brief description of some of the EOR processes mentioned before.

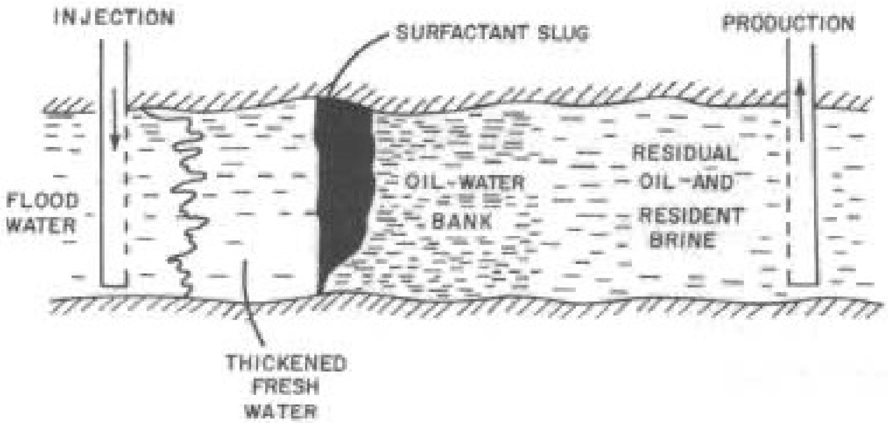


Figure 6: chemical flooding process description[7].

In regardless of the Norwegian Continental Shelf have water injection or water alternating gas (WAG) injection as main drainage mechanism, EOR methods that can further enhance the recovery by chemical additives in the injection water need to be addressed.

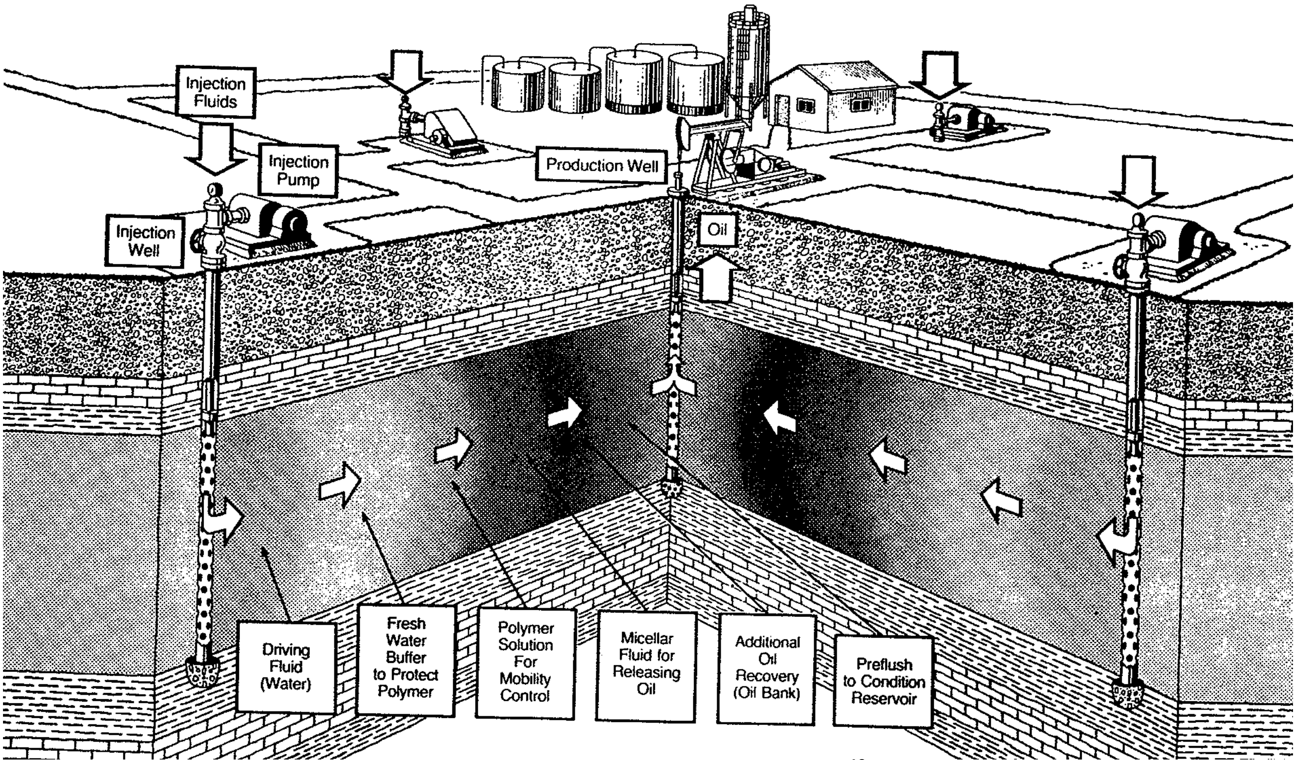


Figure 7: Surfactant/Polymer flooding process[10]

The amount of trapped oil remaining after water-flooding is considered the single most important factor in the economics of EOR. Residual oil drops, once isolated, remain trapped by capillary forces. As long as the boundary conditions provided by the solid and contact angle permit curvatures of the oil drop to adjust locally to the imposed pressure gradient, the oil remains trapped. Droplet mobilizes when pressure gradient will be sufficient, a draining process (oil displacing water) occurs at the leading end of the drop and imbibitions (water displacing oil) take place at the trailing end[6]. The residual saturation of a displacing phase can be correlated by means of grouping viscous forces (differential pressure), surface forces (interfacial tension) and capillary flow to form a dimensionless Capillary Number.

$$N_C = \frac{*\Delta P}{L}$$

Where ΔP/L is the pressure gradient along the capillary and σ is the interfacial tension[5].
In order to allow passage of the crude oil meniscus through the porous channels of the reservoir, the meniscus shape must be changed. Its configuration is deformed by the pressure gradient. Decreasing the interfacial tension between the crude oil and the driving liquid (water) reduces the differential pressure required to distort the drop configuration and allow the drop to move through the pore channels [5].

Wetting is the ability of oil drop to maintain contact with a solid surface of reservoir rock due to adhesive forces. The degree of wetting (wet-ability) is determined by a force balance between adhesive and cohesive forces. Cohesive forces within the oil droplet cause the drop to ball up and avoid contact with the surface. The contact angle (θ) between drop and solid surface is shown in the figure below. The contact angle is determined by the resultant between adhesive and cohesive forces. The tendency of a drop to spread out over a flat, solid surface increases as the contact angle decreases. Thus, the contact angle provides an inverse measure of wet-ability[8].
Although contact angles are almost universally accepted as a basic measure of wet-ability, their application to reservoir systems is limited as measurements of contact angle are not made directly on reservoir rock surfaces. The mineralogical complexity of reservoir rocks could cause wet-ability to vary from place to place[7].

Figure 8: Contact angle between rock surface and oil drop [D]

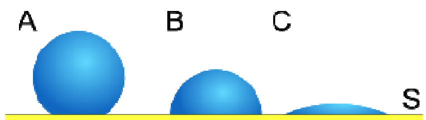


Figure 9: Wetting of different fluids. A shows a fluid with very little wetting, while C shows a fluid with more wetting. A has a large contact angle, and C has a small contact angle [E]

[6] Donaldson, E.C., Chilingarian, V.G. & Yen, T.F.; Developments in Petroleum Sciences: Enhanced Oil Recovery; Volume 17A: Fundamentals and Analyses; Elsevier B.V.; Amsterdam; 1989; pp (54-59)
[7] http://www.statoil.com/en/OurOperations/TradingProducts/CrudeOil/Crudeoilassays/Pages/Norne.aspx

Contact angle	Degree of wetting	Strength of:	
		Solid/Liquid interactions	Liquid/Liquid interactions
$\theta = 0$	Perfect wetting	strong	weak
$0 < \theta < 90°$	high wet-ability	strong	strong
		weak	weak
$90° \leq \theta < 180°$	low wet-ability	weak	strong
$\theta = 180°$	perfectly non-wetting	weak	strong

Table 1: Wetting and contact angle [8]

Some of the chemical processes will be described.

2.3.1.1 Surfactant Flooding

The aim of surfactant flooding is to recover the capillary-trapped residual oil after waterflooding. By means of surfactant solutions, the residual oil can be mobilized through a strong reduction in the interfacial tensions between oil and water.

Some of the larger field tests (90 to 400 acres) have been technical successful, recovering 25 to 30% of the residual oil with a volume ratio of 9 to 27 Sm^3 of oil per ton surfactant[8]. In spite of this, the process seemed to be far from economical. For the North Sea this method seems to be very optimistic. By the possibility to inject the surfactant before the reservoir is completely waterflooding, it is likely to improve the process economy by earlier production of the extra oil, restricting us to a time window for the application of surfactant flooding.

After the surfactant solution has been injected, the trapped oil droplets or ganglions are mobilized due to a reduction in interfacial tension between oil and water. The coalescence of these drops leads to a local increase in oil saturation. Behind the oil bank, the surfactant now prevents the mobilized oil from being retrapped. The ultimate residual oil saturation will therefore be determined by the interfacial tension between oil and surfactant solution behind the oil bank.

Norne Reservoir is a mixed wet reservoir. One of the key oil recovery problems in oil-wet reservoirs is overcoming the surface tension forces that tend to bind the oil to the rock. In water wet-reservoirs surface tension forces act to create bubbles of oil, which can block pore passages as bubbles resist movement in the increased surface area associated with squeezing through the passages. These surface tension forces are the primary reason why reservoirs

[8] "Recent Advances in Improved Oil Recovey Methods for North Sea Sandstone Reserviors". Kleppe, Jon, Skjæveland, Svein. Norwegian Petroleum Directorate, Stavanger, 1992.

become increasingly impermeable to oil, relative to water, as the water saturation increases [5].

By designing and selecting a series of specialty surfactants to lower the interfacial tension to the range of 10^{-3} dynes/cm, a recovery of 10-20 % of the original oil in place, when not producible by other technologies, is technically and economically feasible by surfactant-flooding EOR [5].

A typical surfactant molecule consists of two parts: a non-polar lypophile and a polar hydrophile. Depending on their polar moieties, surfactants can be classified into four main groups:

1. *Anionics:* These surfactants are the most used in oil recovery since they are soluble in aqueous phase; efficiently reduce IFT, relatively resistant to retention, stable and not very expensive.
2. *Cationics*: These have little use due to the high adsorption by the anionic surfaces of interstitial clays.
3. *Non-ionic:* These are mainly used as co-surfactants
4. *Amphoterics:* These have not been used in oil recovery.
5. *Petroleum and Alkyl/Aryl sulfonates*
6. *Salt-Tolerant surfactants*
7. *Surfactant mixtures/cosurfactants*

When an anionic surfactant is dissolved in an aqueous phase, molecules of the surfactant start to dissociate into a cation and an anionic monomer. Due to dual nature of surfactant molecule, it tends to accumulate at the interface with lypophilic (hydrophobic) ‘‘tails’’ placed in the oil phase and hydrophilic ‘‘heads’’ in the aqueous phase. The increased concentration of the surfactant at the interface results in dramatic reduction of IFT between the phases. For EOR always prefer to use low salinity water for injection because increasing salinity causes reduction in electrical double layer so reduction in IFT will be low and hence more difficult to recover oil [6].

The Norne Reservoir is a mixed wet reservoir. One of the key oil recovery problems in oil-wet reservoirs is overcoming the surface tension forces that tend to bind the oil to the rock. In water wet-reservoirs surface tension forces act to create bubbles of oil, which can block pore passages as bubbles resist movement in the increased surface area associated with squeezing through the passages. These surface tension forces are the primary reason why reservoirs become increasingly impermeable to oil, relative to water, as the water saturation increases [5].

The interfacial tension is generally in a range of 20-30 dynes/cm and by designing and selecting a series of specialty surfactants to lower the interfacial tension to the range of 10^{-4} dynes/cm, a recovery of 10-20 % of the original oil in place, when not producible by other technologies, is technically and economically feasible by surfactant-flooding EOR method [5].

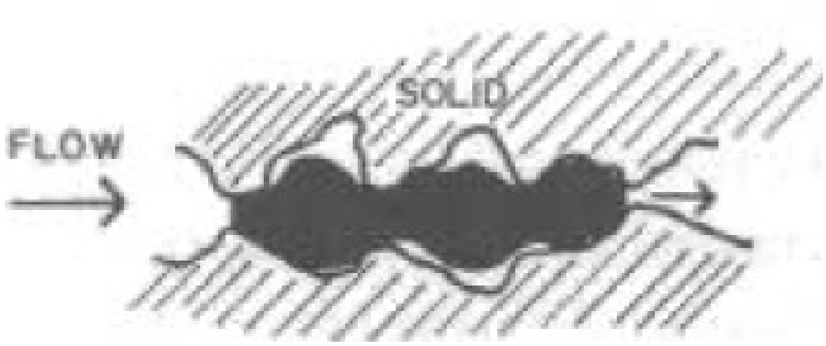


Figure 10: Schematic diagram of the role of IFT in surfactant flooding. For the movement of oil through narrow neck of pores a very low oil/water interfacial tension is desirable (0.001 dynes/cm) [5].

The success of surfactant flooding EOR depends on different factors:

- Formulations
- Cost of surfactants
- Availability of chemicals
- Environmental impacts
- Oil price

All of these factors are critical due to the high volumes usually required to flood one field. Therefore, in order to minimize the transportation costs, it is critical to have plants, big enough to accommodate the capacity needed to satisfy the demand in close proximity to the field being flooded and that the cost of the chemicals be low enough to make the sizable initial investment in chemicals profitable in the long terms [5].

2.3.1.1.1 Working mechanism of surfactant molecule to reduce IFT

When an anionic surfactant is dissolved in an aqueous phase, molecules of the surfactant start to dissociate into a cation and an anionic monomer. Due to dual nature of surfactant molecule, it tends to accumulate at the interface with lypophilic (hydrophobic) ‘‘tails’’ placed in the oil phase and hydrophilic ‘‘heads’’ in the aqueous phase. The increased concentration of the surfactant at the interface results in dramatic reduction of IFT between the phases. For EOR always prefer to use low salinity water for injection because increasing salinity causes reduction in electrical double layer so reduction in IFT will be low and hence more difficult to recover oil [6].

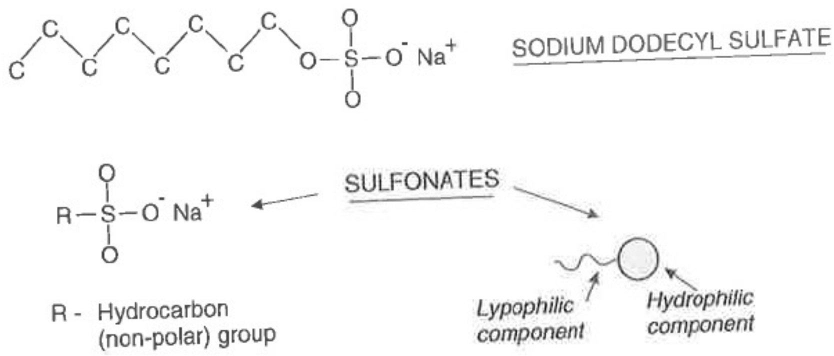


Figure 11: Schematic structure of surfactant molecule [6].

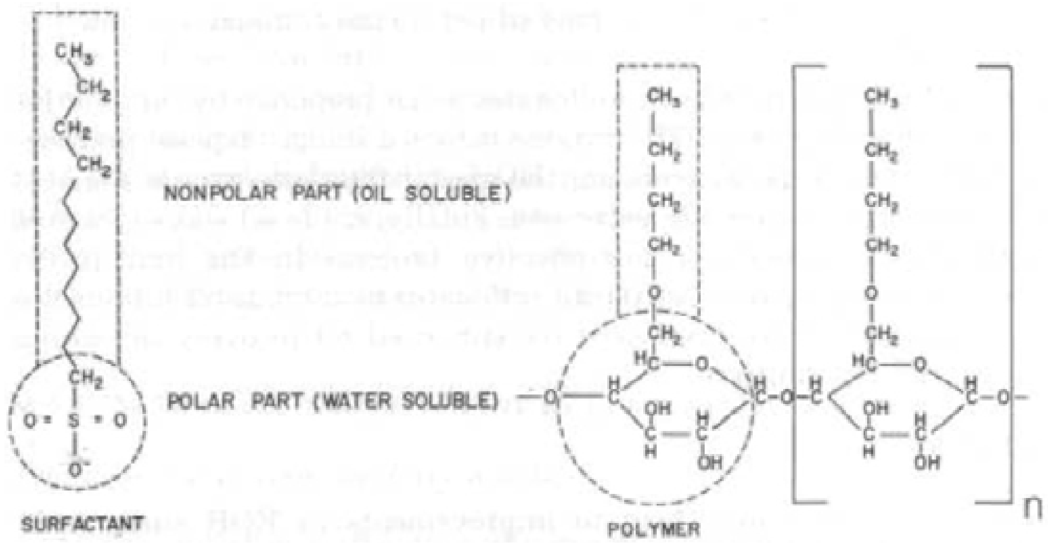


Figure 12: The structure of surface active molecules. The broken lines illustrate the separation of polar and non-polar parts of the molecules [6].

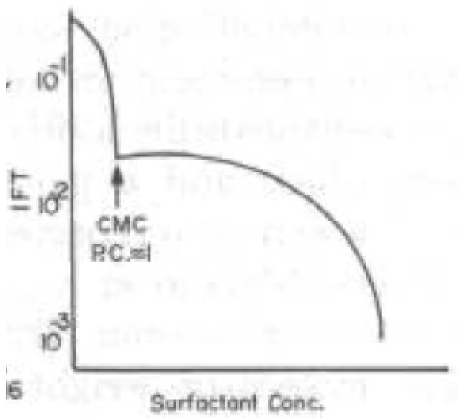


Figure 13: Effect of alkyle benzene sulphonate on IFT [6].

The magnitude and nature of interfacial charge and surface charge on minerals and clays present in the reservoir rocks in the oil-displacement can contribute significantly to the design of surfactant formulations for optimum performance under given reservoir conditions. The sign and magnitude of the charge will influence the adsorption of the surfactant on minerals and clays of the reservoir [7].

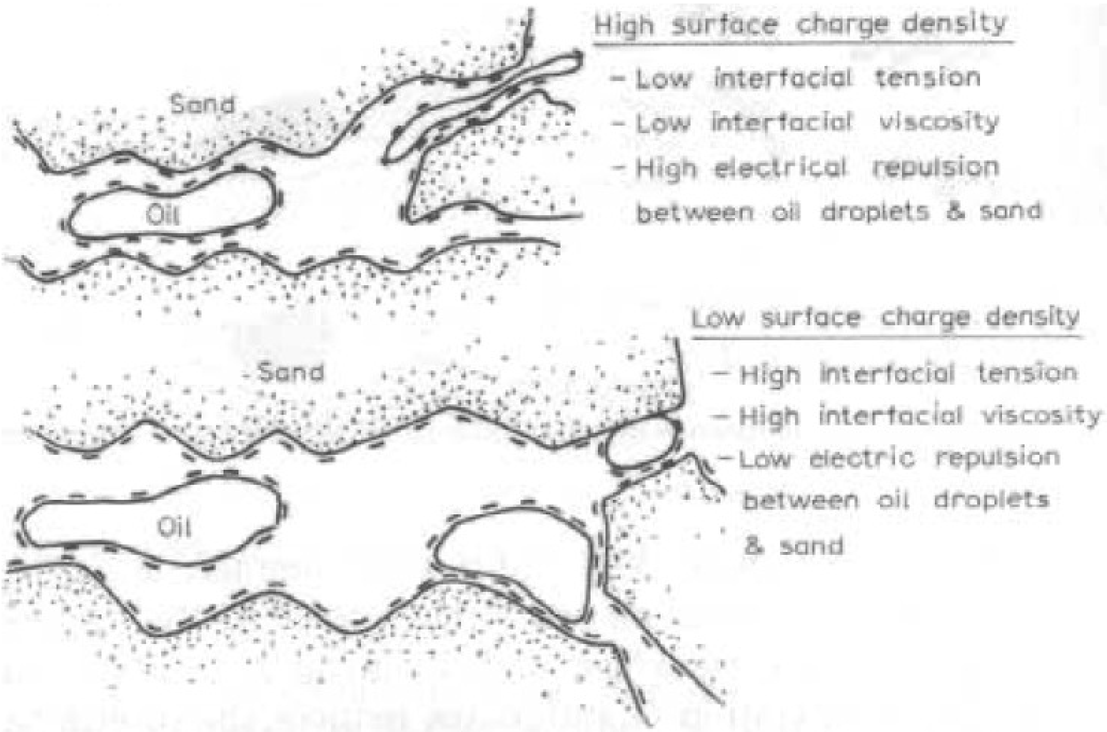


Figure 14: Displaced oil droplets must be coalesce and form a continuous oil slug for efficient oil recovery for which a very low interfacial viscosity (IFV) is required [7].

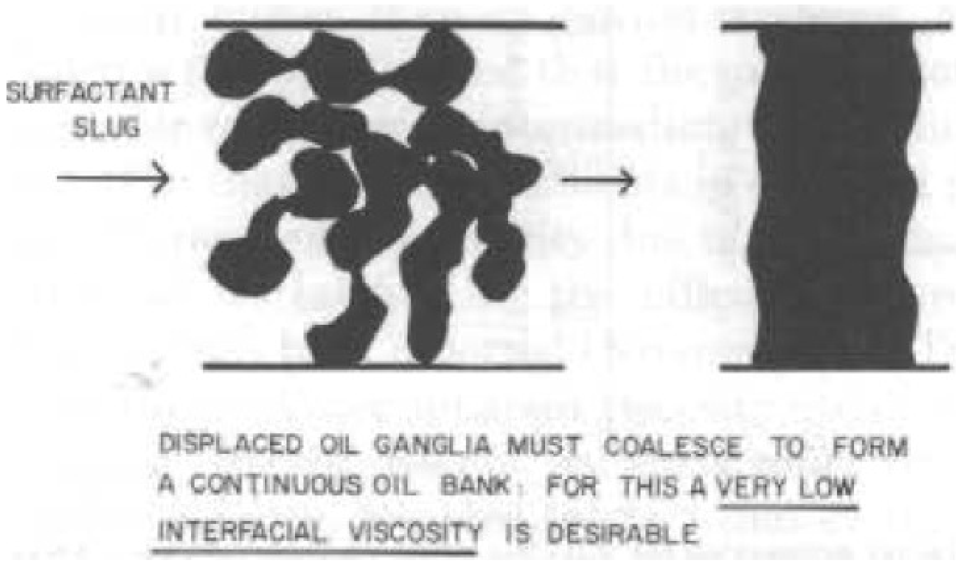


Figure 15: Schematic diagram of the role of the interfacial viscosity in the oil recovery [7].

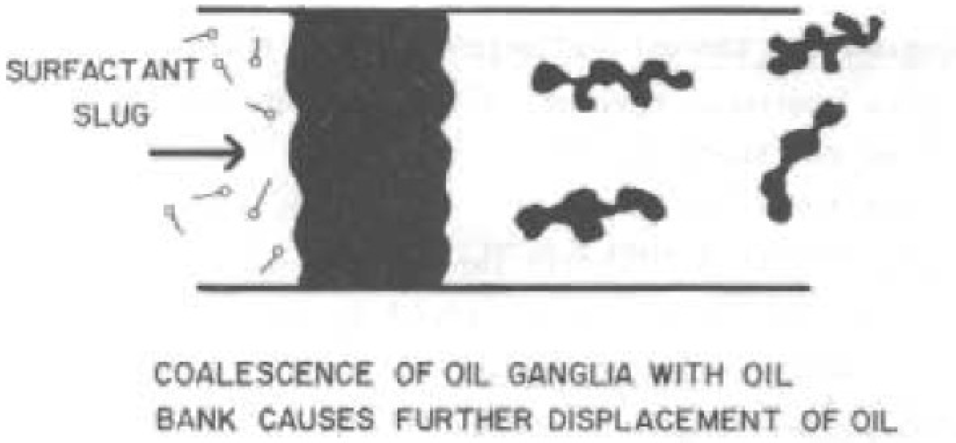


Figure 16: Schematic diagram of the role of coalescence of oil droplets in oil displacement process [7].

Polar constituents (asphaltenes and resins) in crude oil play an important role in determining the reservoir wettability due to their adsorption onto the rock surface. The oil-wetting surfaces lead to poor oil displacement, whereas the water-wetting surfaces lead to efficient oil displacement for surfactant flooding. The proper choice of surfactant can selectively alter the rock wetting from oil to water (brine) and can create favorable conditions for efficient oil displacement. Also the use of additives (salt, acid or base) to alter the rock wettability is a promising approach for EOR. Sodium hydroxide (NaOH) can effectively change rock surfaces from oil-wet to water-wet [14].

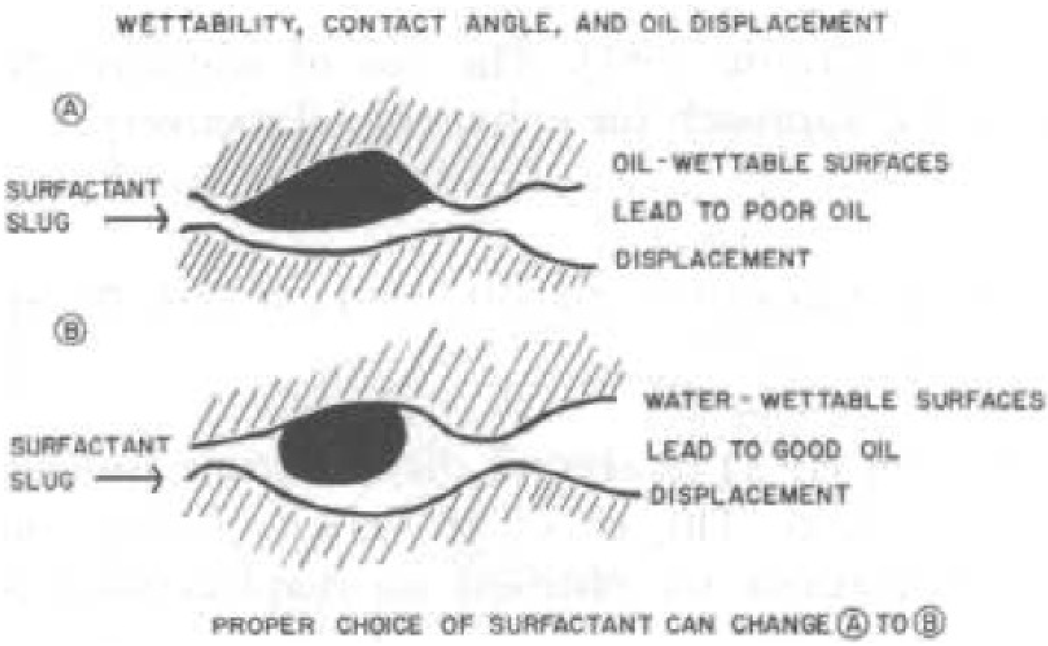


Figure 17: Schematic diagram of role of wettability and contact angle on oil displacement [7].

Effect of Surfactant concentration on IFT: IFT decreases with increasing surfactant concentration and at a critical concentration the IFT approaches its minimum value. Beyond this critical concentration, the IFT increases with an increase in surfactant concentration.

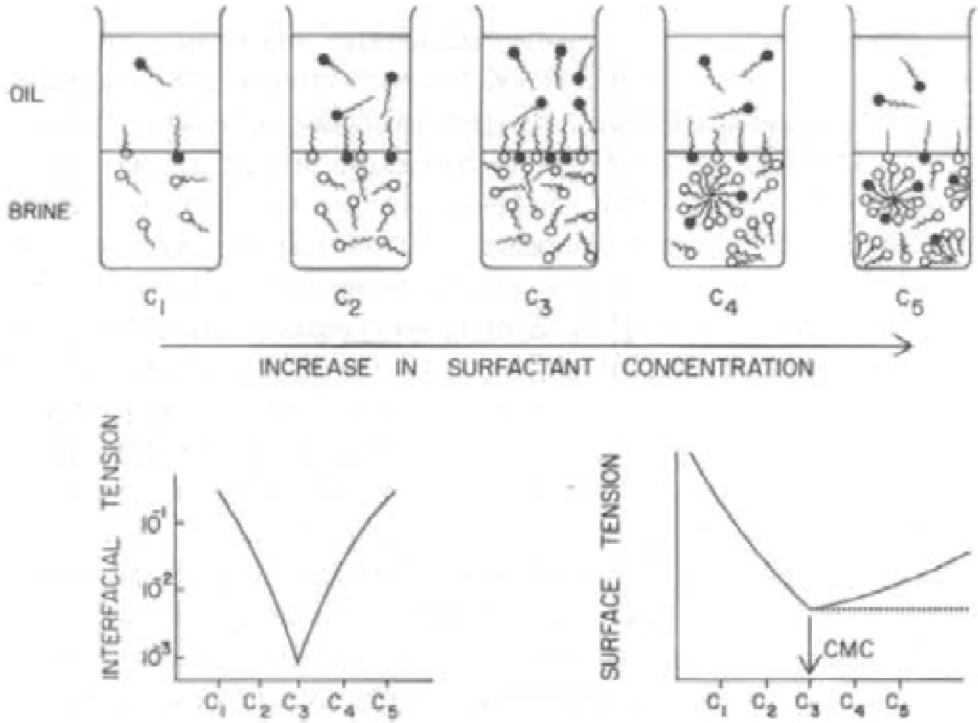


Figure 18: The proposed molecular mechanism for the effect of surfactant concentration on interfacial and surface tension [7].

Effect of salinity: A specific surfactant concentration and salinity is required for the formation of ultra-low IFT. As the salt concentration varies in aqueous phase, the partition coefficient of the surfactant between oil and water is altered which seems to be responsible for achieving ultra-low IFT. The surfactant concentration in the oil phase increases with increasing salt concentration in the aqueous phase and vice versa. Select optimal salinity in such a way that surfactant concentration is highest at the oil-water interface which produces the lowest IFT. The partition coefficient at optimal salinity was found to be unity [7].

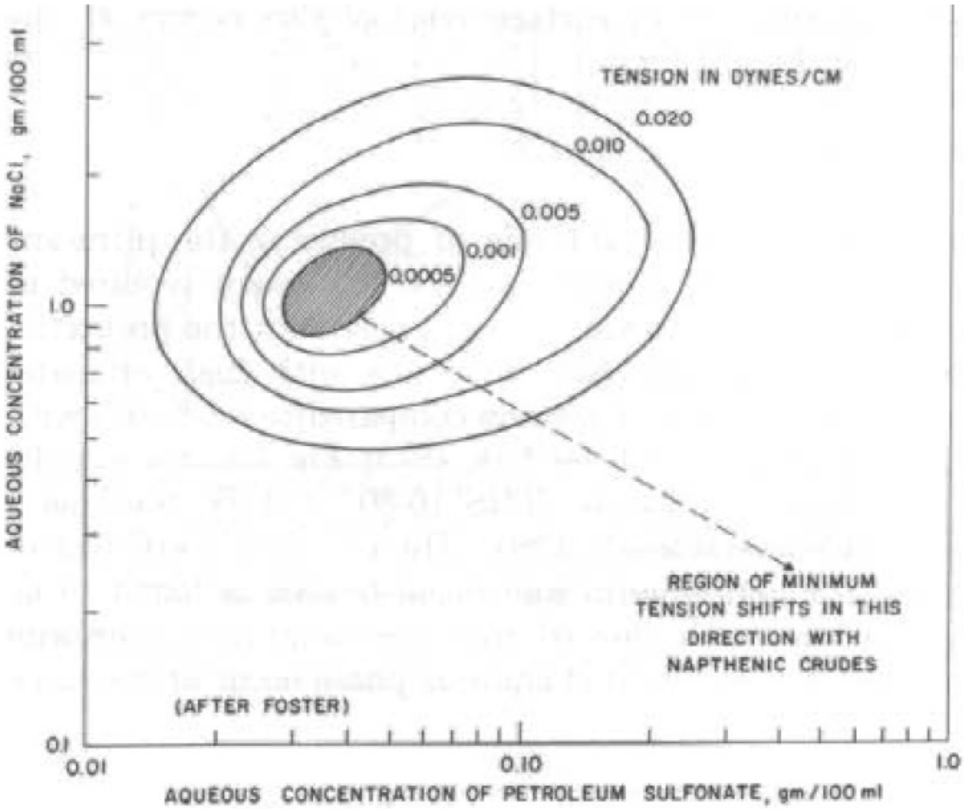


Figure 19: IFT map for petroleum sulphonate-NaCl-water system against intermediate paraffinic crude [7].

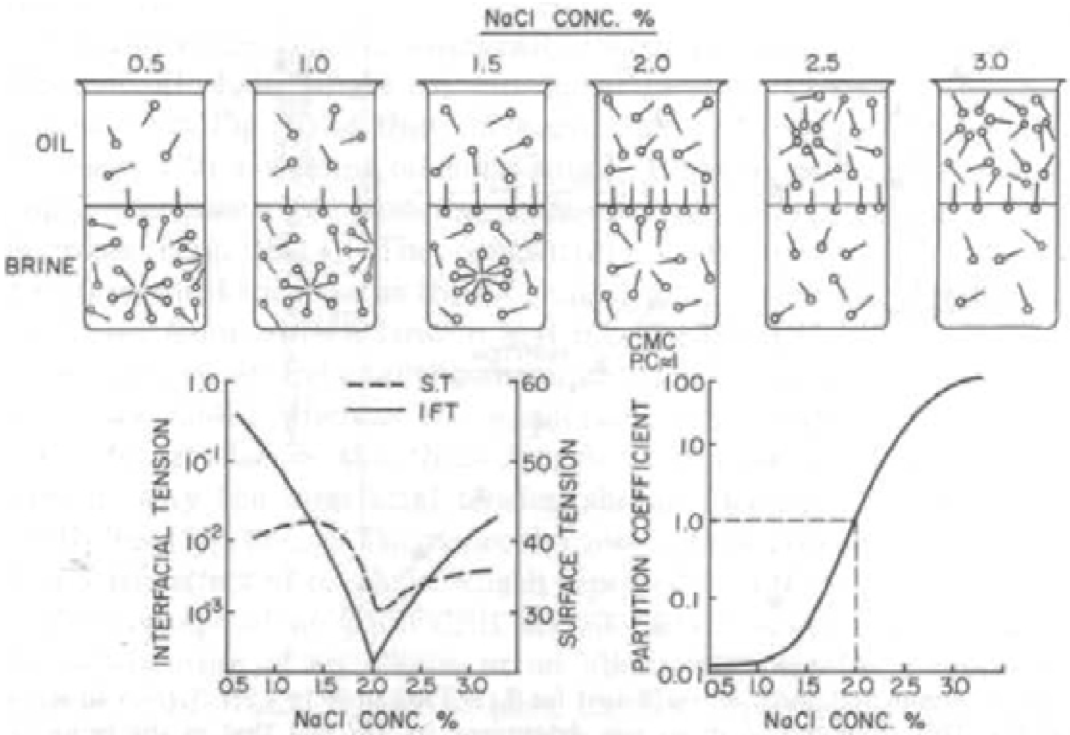


Figure 20: The molecular mechanism for effect of salt concentration on IFT and surface tension [7].

Mobility Control: For an efficient oil displacement by surfactant flooding, the mobility-controlling polymer should be less mobile than the surfactant slug and oil bank. Loss of mobility control in the fluid sequence causes fingering which, in turn, reduces oil displacement efficiency. Mobility control is one of the most important considerations in designing a surfactant polymer formulation. Many polymers such as polyacrylamides and polysaccharides have been used as effective mobility control agents [7].

2.3.1.2 Polymer Flooding

Polymers are used to achieve favorable mobility ratios during water or surfactant flooding. It is therefore essential that the viscosity of the polymer solution is not reduced during the flooding period, which for North Sea reservoirs can be several years. Temperature can affect polymer viscosity both with respect to the change in state of energy and temperature dependant chemical breakdown of the polymer chain. Te high viscosity of the polymer solution may reduce the injectivity dramatically and lead to low injection rates. The polymer injection is high dependant on the temperature. The long-term, temperature dependency stability of the polymer has been studied for the promising polymers xanthan and scleroglucan at unfavorable conditions, which may be present in real field cases, the xanthan viscosity decay-time constant, τ, as defined by,

$$\overset{*}{\boldsymbol{P}} = \exp\left(\frac{-\boldsymbol{t}}{}\right)$$

It can be in the order of days. At optimum conditions, however, the decay-time constant can be in the order of years, illustrating the level of uncertainty in predicting polymer viscosity. Generally surfactant flooding is used in combination of polymer flooding which results in:

- Increase in the viscosity of water
- Reduction in relative permeability to water

As a result of those alterations, mobility ratio M is also reduced leading to more favorable conditions for oil recovery. In reservoirs with high mobility ratio, results in the improvement of the volumetric sweep efficiency [6].

Polymer flooding will be favorable in reservoirs where oil viscosity is high, or in reservoirs that are heterogeneous, with the oil bearing layers at different perm abilities. Polymers have been extensively used in field applications in order to reach the following goals:

- To improve mobility ratio and thus, to reach more favorable conditions for oil displacement
- To reduce effective permeability to the displacing fluid in highly permeable zones or to plug those zones
- To improve the infectivity profile of the injecting wells and to improve the production performance of producers by plugging off high conductivity zones in the vicinity of a well [6].

Polymer molecules can be retained by reservoir rock by means of

- Adsorption on surface of pores
- Mechanical entrapping in pores

- Precipitation, i.e. local accumulation of polymer molecules [6]
-

North Sea reservoir conditions put strong restrictions on the use of polymers:

- High injection rates
- High temperatures
- Large inter-well distances (which means that polymer must be stable over a long time at high temperatures)
- The use of sea water with high salinity [6].

2.3.1.2.1 Miceller-polymer flooding technology

In order to prevent/reduce adsorption of expensive surfactants and to increase their technological effect the following technology for secondary / tertiary oil recovery is conventionally used:

1) Pre-flush is used to form the best conditions for the effective reduction of IFT.
2) Surfactant slug injection to recover residual oil.
3) Polymer slug injection in order to improve sweep efficiency
4) Taper: Injection of polymer slug with a gradual decreasing concentration of the polymer from maximum at the front to zero at the back in order to mitigate the effect of adverse mobility ratio between the taper and chase water.
5) Chase water is used to move the miceller-polymer composition deep into the reservoir [6].

2.3.1.3 Microbial EOR Methods (MEOR)

The function of MEOR is same as that of chemical flooding except that in most cases chemicals produce in-situ (in reservoir) by microbes. MEOR processes generally consist of the injection of a microbial population with some form of nutrient (molasses, corn syrup etc.). Carbon source will either be sugar or crude oil. Other nutrients are shown in following figure-122.
The microorganisms feed on nutrients and produce a number of byproducts:

1) CO_2 and other gases Essential nutrients
2) Surfactants and/or polymers
3) Alcohols
4) Certain acids [6]

Presence of these products in-situ leads to:

- Reduction of IFT (surfactants, alcohols, acids)
- Selective plugging of the most permeable zones
- Reduction of oil viscosity [6]

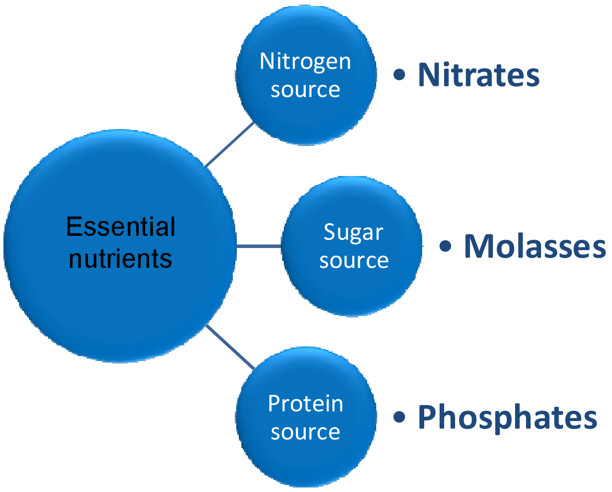


Figure 21: Essential nutrients for microbes to grow [6, 12].

As a result, part of the immobilized oil can be remobilized, and zones upswept earlier can be involved in oil displacement.

There are two ways of using microbial processes:

1) Microbial production of desired product at the surface and the subsequent injection into a reservoir;
2) Direct injection of microorganism into a reservoir and in-situ generation of desirable product.

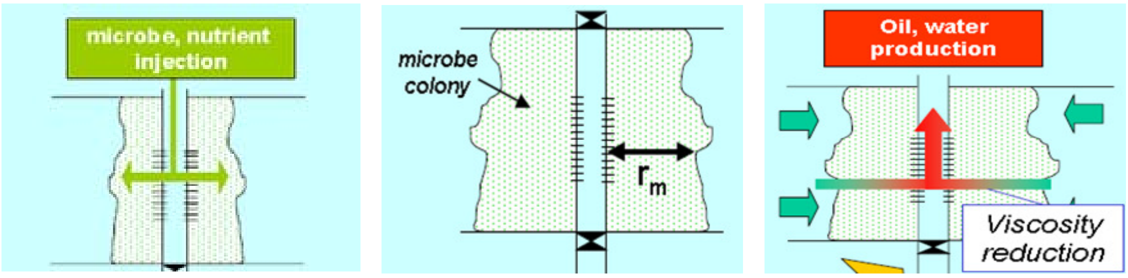
Bioproduct	Effect
Acids	Modification of reservoir rock
	Improvement of porosity and permeability
	Reaction with calcareous rocks and CO_2 production
Biomass	Selective or nonselective plugging
	Emulsification through adherence to hydrocarbons
	Modification of solid surfaces
	Degradation and alteration of oil
	Reduction of oil viscosity and oil pour point
	Desulfurization of oil
Gases (CO_2, CH_4, H_2)	Reservoir repressurization
	Oil swelling
	Viscosity reduction
	Increase of permeability due to solubilization of carbonate rocks by CO_2
Solvents	Dissolving of oil
Surface-active agents	Lowering of interfacial tension
	Emulsification
Polymers	Mobility control
	Selective or non-selective plugging

Table 2: Microbial substances and their contribution to EOR [16].

MEOR is usually restricted to the second approach because of the possible side effects [16]. Water, nutrients and microbes injected by any of two ways:

1) Huff and puff method
2) Microbial flooding

In huff and puff method water, nutrients and microbes injected and then well shut-in and give time to microbes to grow. During their growth, they use nutrients and produce waste. The waste will be surfactant, polymer, alcohols and CO_2. Then production can be started [16].



Well shut-in Production

Figure 22: Huff and Puff MEOR [17].

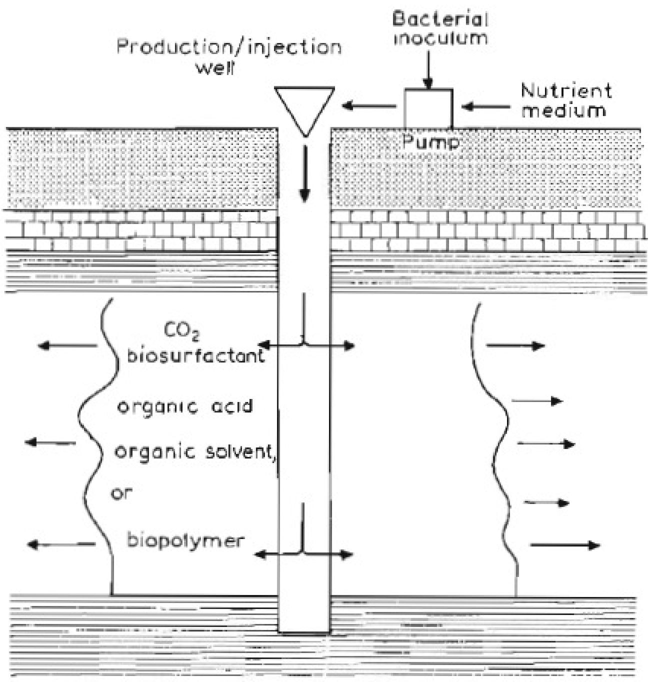


Figure 23: Schematic showing the migration of cells and the synthesis of metabolic products around the wellbore following inoculation and closing of injection well. This corresponds to the huff stage of huff and puff process [16].

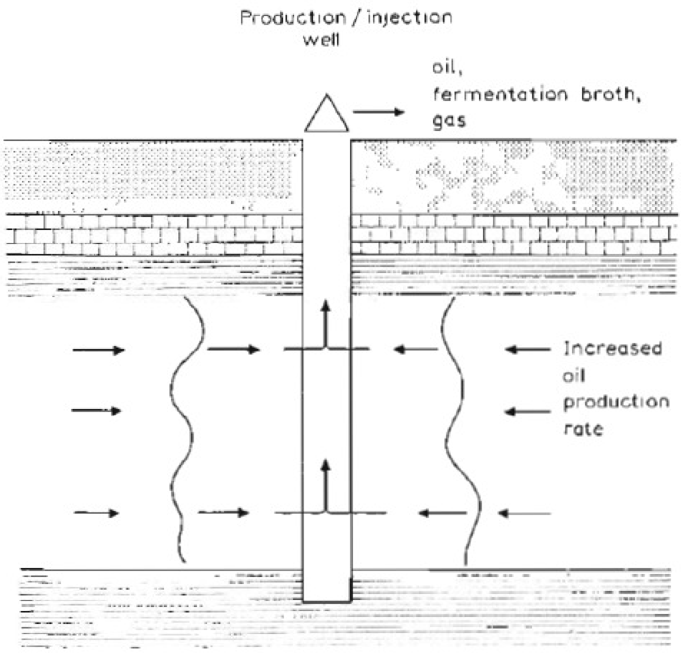


Figure 24: Schematic showing the production of oil at the end of the incubation period, when the well is reopened. This corresponds to the puff stage of huff and puff process [16].

Microbial flooding works as shown in figure 25:

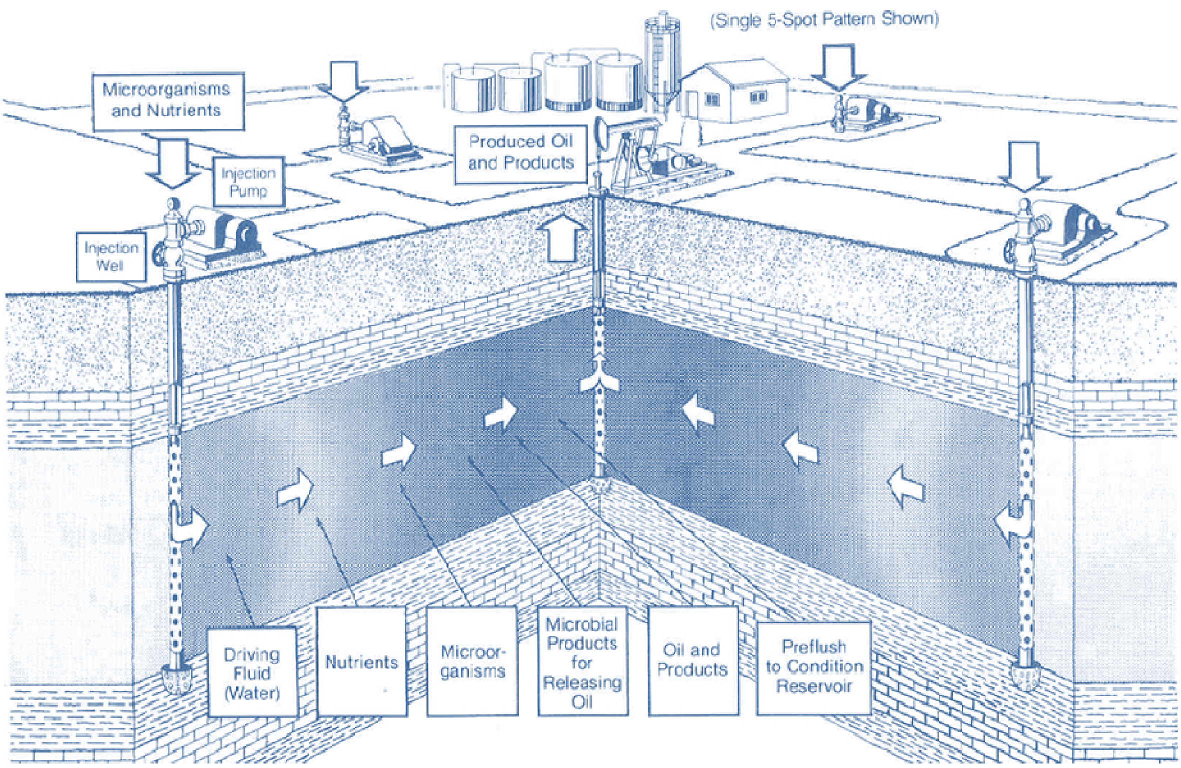


Figure 25: Microbial flooding process [16].

2.3.1.3.1 Limitations of MEOR

Within the most important limitations are:

1) Increasing salinity absorbs water from the microbe and negatively affects its growth.
2) Permeability, temperature, pressure, salinity and pH affect the selection of microbes.
3) Study of bacteria metabolism, and relation to subsurface environment, need great effort.
4) Microbes Produce H_2S and SO_2 ccausing bio-corrosion of the equipment, and contamination of ground water.

But on the other hand microbes produce organic chemicals less harmful than synthetic chemicals used by EOR methods [17].

2.3.1.3.2 Economics of MEOR

- Microbes and nutrients are relatively cheap materials.
- Cost is independent of oil prices.
- Implementation needs minor modifications to field facilities.
- Economically attractive for marginal producing wells.
- The total cost of incremental oil production from MEOR is only 2 – 3 $/bbl [17].

2.3.1.4 Issues related with chemical processes

- *Use of chemicals in the injection water will raise the question of environmental impacts. Throughout the R&D efforts as well as preparing for field implementation such impacts need to be thoroughly evaluated and as much as possible avoided [4].*
- *Cost reductions in the way of cost-effective chemicals will be needed to utilize the potential of such EOR methods and it is also very important to predict the amount of the surfactant required for successful flooding [4].*
- *Large quantities of surfactants needed for large offshore field applications might be a constraint [4, 6]*
- *Adsorption of surfactants on reservoir rock is another important consideration in surfactant flooding formulations. It is well known that high equivalent molecular weight surfactants which are responsible for most IFT reduction are adsorbed preferentially on the rock surface than lower molecular weight surfactants. Hence this loss decreases the surfactant slug ability to displace residual oil. To reduce the adsorption, the classical solution is either to add sacrificial agents into the formulations, or pre-flood the reservoir with sacrificial agents [5]. Adsorption also causes the surfactants retention. Usually this effect is extremely negative, but in case of the oil wet reservoir, adsorption gives positive effect by changing the wettability preference of the rock [6].*
- *Salinity and hardness of brine are the most important factors affecting the ability of surfactants to reduce IFT [6].*

2.3.2 Miscible displacement methods

These processes are defined as the processes where the effectiveness of the displacement results primarily from miscibility between the oil in place and the injected fluid. Displacement fluids, such as hydrocarbon solvents, CO_2, flue gas, and nitrogen, are considered. Miscibility plays a role in surfactant processes, but is not primary recovery mechanism for these processes.

In an immiscible displacement process, such as a waterflood, the microscopic displacement efficiency, E_D, is generally much less than unity. Part of the crude oil in the places contacted by the displacing fluid is trapped as isolated drops, stringers, or pendular rings, depending on the wettability. When this condition is reached, relative permeability to oil is reduced essentially to zero and continued simply flows around the trapped oil. This limitation to oil recovery may be overcome by the application of miscible displacement processes in which the displacing fluid is miscible with the displaced fluid at the conditions existing at the displacing-fluid/displaced-fluid interface. Interfacial tension (IFT) is eliminated. If the two fluids do not mix in all proportions to form a single phase, the process is called immiscible.

In practice, solvents that are miscible with crude oil are more expensive than water or dry gas, and thus an injected solvent slug must be relatively small for economical reasons. For this situation, the primary (solvent) slug may be followed by a larger volume of a less expensive fluid, such as water or a lean gas.

Various gases and liquids are suitable for use as miscible displacement agents in either FCM or MCM processes. These include low-molecular-weight hydrocarbons, mixtures of hydrocarbons, CO_2, nitrogen, or mixtures of these. The particular application will depend on the reservoir pressure, temperature, and compositions of the crude oil and the injected fluid.

2.3.2.1 CO_2 Flooding

The CO_2 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. It is particularly effective in reservoirs deeper than 2,000 ft., where CO_2 will be in a supercritical state, with API oil gravity greater than 22–25º and 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. Carbon dioxide flooding works on the premise that by injecting CO_2 into the reservoir, the viscosity of any hydrocarbon will be reduced and hence will be easier to sweep to the production well.

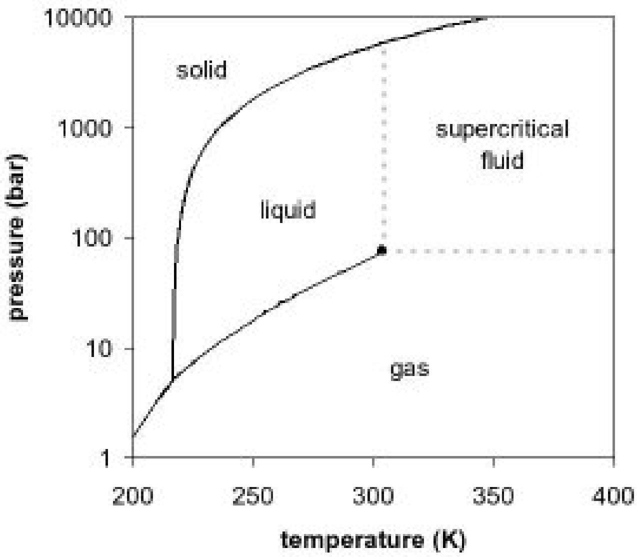


Figure 26: Carbon dioxide pressure-temperature phase diagram.

If a well has been produced before and has been designated suitable for CO_2 flooding, the first thing to do is to restore the pressure within the reservoir to one suitable for production. This is done by injecting water (with the production well shut off) which will restore pressure within the reservoir to a suitable pressure for CO_2 flooding. Once the reservoir is at this pressure, the next step is to inject the CO_2 into the same injection wells used to restore pressure. The CO_2 gas is forced into the reservoir and is required to come into contact with the oil. This creates this miscible zone that can be moved easier to the production well. Normally the CO_2 injection is alternated with more water injection and the water acts to sweep the oil towards the production zone. The Weyburn oil field in Canada is a famous example where this method is applied in financially interesting conditions.

CO_2 flooding is the second most common tertiary recovery technique and is use in facilities around the world. In the scope of global warming, it is an available method to curb CO_2 emissions.

For CO_2, it is possible to make recovery predictions. The following data should be chosen:

- Injection pressure
- Injection slug size
- Continuous CO_2.
- Injection or alternate injection of water
- Well pattern
- Zonal isolation

In a gravity-stable flood, the CO_2 is injected above the oil zone. Drive gas is then injected above the slug. In this case some additional design factors are:

1) Critical rate for stale displacement

2) Initial placement of CO_2
3) Estimation of coning into the producing wells.

The critical rate, u_c, in ft/day may be calculated from the equation:

$$u_c = \frac{0.0439(\ _o - \ _c)\sin}{\frac{\ _o}{k_o} - \frac{\ _c}{k_c}}$$

Where the densities are given in lb/ft^3, the viscosities in cP, and the permeabilities in darcies, and alpha is the angle, relative to horizontal.

Pressure transient data should be obtained and analyzed to determine directional permeability and barriers to flow. Analysis of a previous waterflood is critical to the success of a CO_2 flood. Production history matching with a reservoir simulator will be of enormous aid in guiding performance prediction using CO_2.
CO_2 is mainly injected into gas reservoirs for enhanced gas recovery. The main benefit of CO_2 injection is pressure support to prevent subsidence and water intrusion. Enhanced gas recovery can be via both displacement and repressurisation of the remaining natural gas. In general, an incremental gas recovery of 8% can be achieved by CO_2 injection. The profitability of any CO_2 project is sensitive to gas price, cost of CO2, original gas composition in the reservoir, and further processing of the produced gas.

2.3.2.2 Inert Gas Flooding

The ever-rising cost and limited supply of natural gas prompted operators to search out for a substitute for injection. Promising substitutes that received the most attention were:

- Pure nitrogen gas (inert)
- Inert gas mixture that is predominantly nitrogen.
-

The injection of nitrogen can enhance the recovery of oil or gas by one or more of the following mechanisms:

1) Pressure maintenance
2) Immiscible displacement
3) Miscible displacement (depending on the conditions of pressure and temperature). Nitrogen miscibility requires high pressure (deep reservoirs) and light oils.

The primary advantage of inert gas is its availability and low cost. Other advantages include:,

- Prevention of oil encroachment into the gas cap when gas cap is present.
- Higher recoveries compared to water drive in reservoirs having low permeability
- Residual inert gas at abandonment rather than saleable natural gas.
- Reliability of the supply.

2.3.3 Thermal Processes

When petroleum reservoirs contains a low-gravity (less than 20^{o} API), high-viscosity oil and have a high porosity, secondary recovery methods are not effective for displacement of oil. For such reservoirs, thermal processes are most effective. The injection of steam reduces the oil viscosity which causes an increase in the oil mobility. Depending on the way in which the heat is generated in the reservoir, the thermal processes can be divided into two categories:

- In-situ combustion
- Steam injection

2.3.3.1 Steam Injection

Steam is injected in the reservoir either continuously or in cycles. Continuous steam injection involves both injection and production wells, whereas cyclic injection involves one well only which serves as both injection and production well. Steam floods are easier to control than in-situ combustion. For the same pattern size, the response time is 25-50% lower than the response time for additional production by in-situ combustion. The steam injection process works as shown in figures 10 and 11.

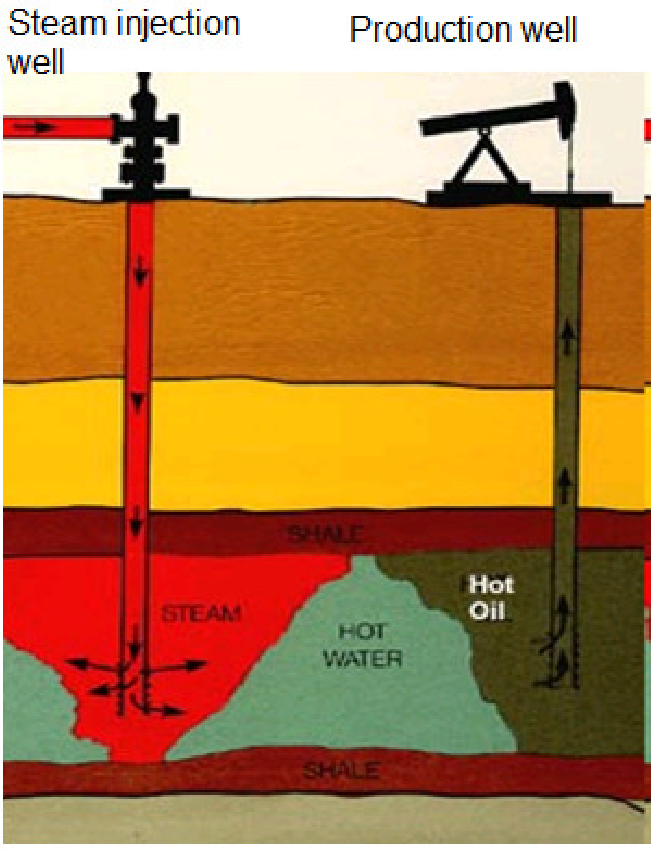


Figure 27: Usual steam injection process [3].

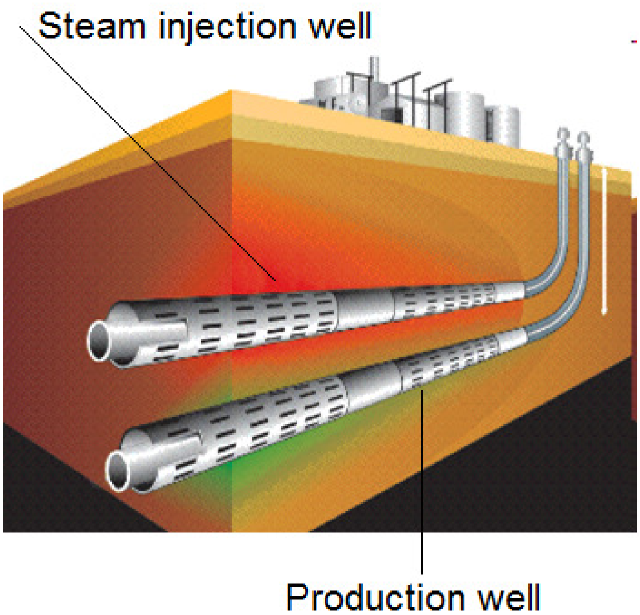


Figure 28: Steam insisted gravity drainage [3]

2.3.3.2 In Situ Combustion

For In situ combustion there are two methods:

- Wet combustion – water added to air to carry more heat forward to oil zone
- Dry combustion – Only air is used for ignition

Dry Combustion: The crude oil near the well bore is ignited using chemicals, down-hole electric heaters or down-hole gas burners. After completing ignition in the vicinity of the wellbore, continuous air injection promotes movement in the burning zone toward the producing wells. Propagation of a continuous burning zone results in almost complete removal of all reservoir liquids and leaves behind hot, clean rock, which heats the injected air before it reaches the burning zone.

Wet Combustion: In this in-situ combustion process, a large amount of heat is left behind in the swept formation as waste heat. The heat utilization and efficiency of the process can be improved by water injection. In this process, water is injected with the air. Superheated steam forms in an evaporation front and travel travels behind the combustion front. The important advantage of this process is that the amount of residual oil left to be burned as fuel by the burning front is considerably decreased, which in turn displaces more oil and less air is required to burn a unit volume of oil in the reservoir [10].

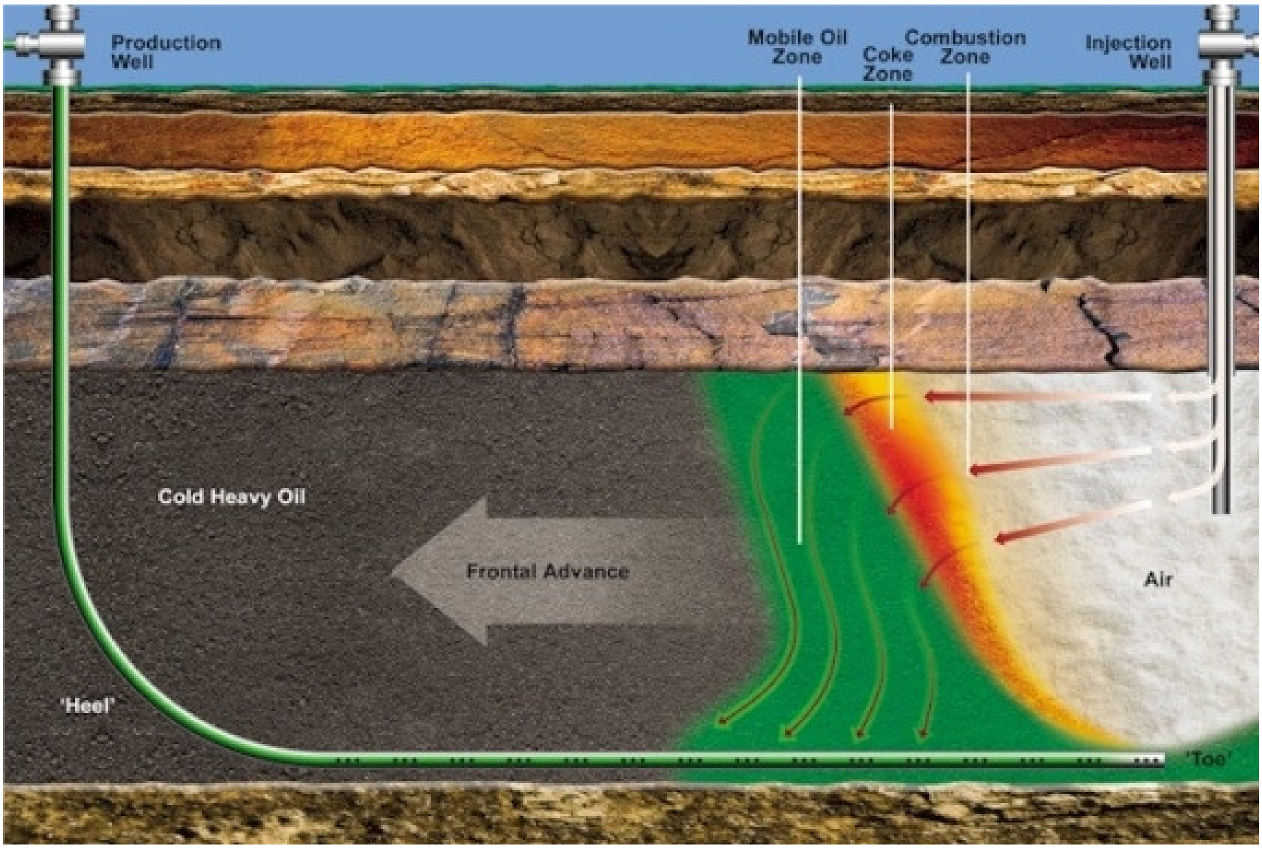


Figure 29: In situ combustion process [C].

2. The Project

2.1 Background

The potential for enhanced recovery by advanced injection techniques has been known for many decades, but unstable economic climate and the complex nature of the reservoir processes often involved in enhanced recovery have hindered implementation of many projects. Due to improved drilling methods, better production technologies, improved reservoir knowledge, and higher oil prices, these methods are more attractive today [4].

The Norwegian Continental Shelf (NCS) is facing considerable future challenges with regards to depleting reserves replacement and ultimate field recoveries. The overall new target for oil recovery, set by the NPD, is to increase the oil reserves by 800 million Sm^3 of oil (five billion barrels) by 2015. Enhanced Oil Recovery (EOR) methods will have to play a key role in achieving this target [4].

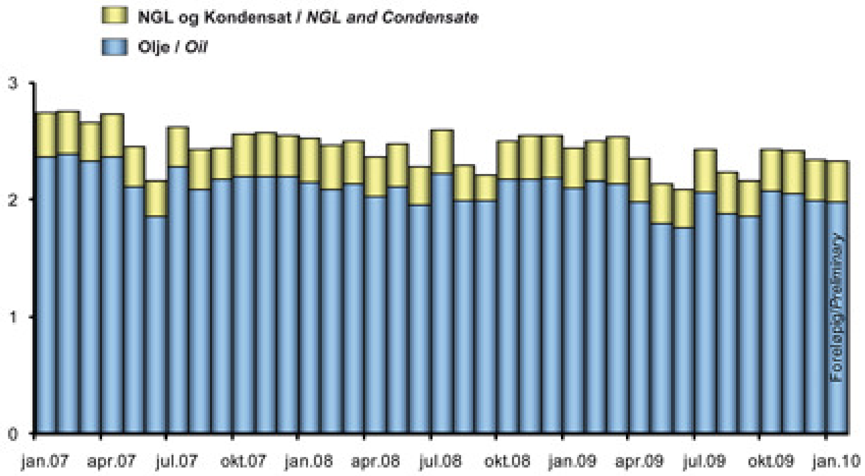


Figure 30: Production of oil, NGL and condensate on the NCS 2007-2010 in million barrels per day [A]

The average recovery factor for the fields on the NCS will be 46% of the original oil in place under existing development plans. The recovery estimate is substantially higher than predictions some years ago, especially for many of the larger fields as can be seen in figure 15. This increase is a result of significant implementation of among others field optimisations, better reservoir characterization, gas- and WAG injection, and improved drilling and well technology. However, as the recovery factor increases, the potential for enhanced recovery is correspondingly reduced, and the remaining oil target will necessarily in the future be more challenging to recover economically through enhanced recovery methods [4].

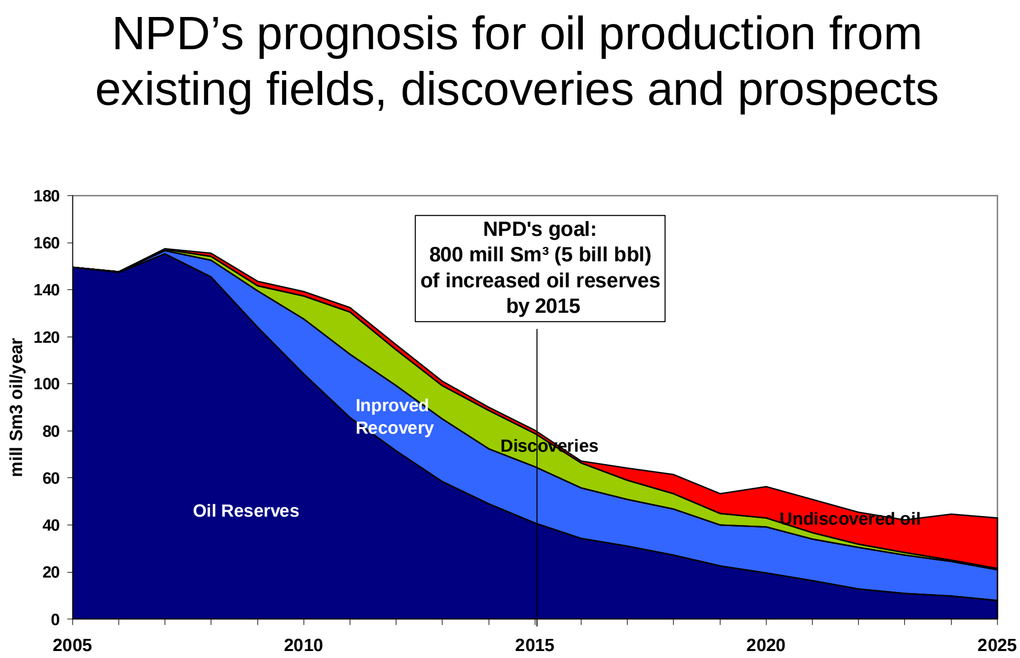


Figure 31: Future potential for increased reserves for Norwegian Continental Shelf [4]

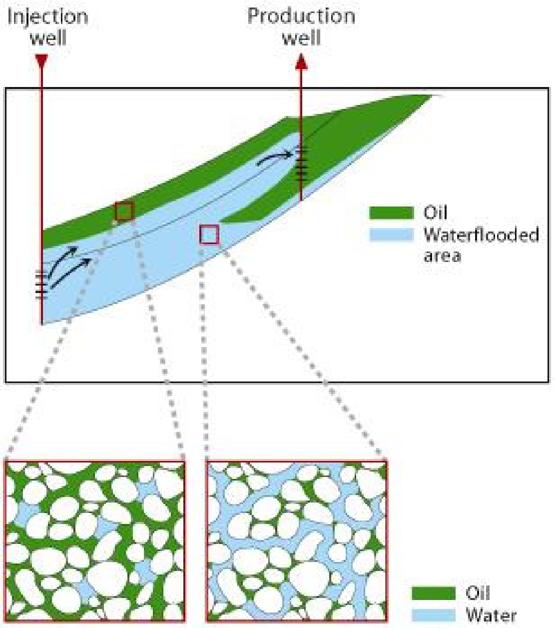


Figure 32: Section through a reservoir showing an example of the distribution of oil and water following water flooding, and the distribution of the liquids at the pore level. [B]

The success of an enhanced recovery project depends:

- Upon the mechanism by which the injected fluid displaces the oil (displacement efficiency).
- On the volume of reservoir which the injected fluid contacts (conformance or sweep efficiency).

Thermal processes have been used extensively for the displacement of heavy oils, whereas chemical and miscible displacement processes have been employed for the recovery of light oils. Among the various processes for oil recovery, thermal processes have least uncertainty, and offer a promising approach for about 70% of the world's enhanced oil recovery production. At present, surfactant flooding is the most complex and, therefore, has the highest degree of uncertainty. If the surfactant formulation for oil recovery is properly designed and if the flow of the formulation is properly controlled in the reservoir, it has a high potential for achieving maximum oil recovery [2].

2.2 Analysis of the E-segment.

As part of the study, the reservoir and fluid properties were analyzed as shown in table 2, in order to get familiarized with the case and by using the literature to decide how to perform the selection of a suitable EOR for it.

Norne Reservoir and Fluid characteristics			
Crude characteristics		**Reservoir characteristics**	
API gravity	32.7^o	**Sandstone**	
Specific gravity	0.8619	**Porosity**	25-30%
Sulpher	0.21 mass %	**Permeability**	50-3000 mD
Pour point	9 C^o	**Initial reservoir Pressure**	273 bar
Viscosity	14.06 cSt	**Initial reservoir temperature**	98 C^o
GOR	111 Sm^3/Sm^3		

Table 3: Norne Reservoir and Crude data [6]

Later, simulations were run on Eclipse to analyze the Norne's E-segment in order to estimate and review the actual status of the reservoir. Different cases were run in order to make a more profound judgment.

- Opening all the injection wells.
- Closing all injection wells
- Closing the injection well F-1H.
- Closing the injection well F-3H.

Throughout the analysis, great differences between the chosen scenarios were observed. Mostly in terms of oil production rates, gas production rates and gas-oil relationships.

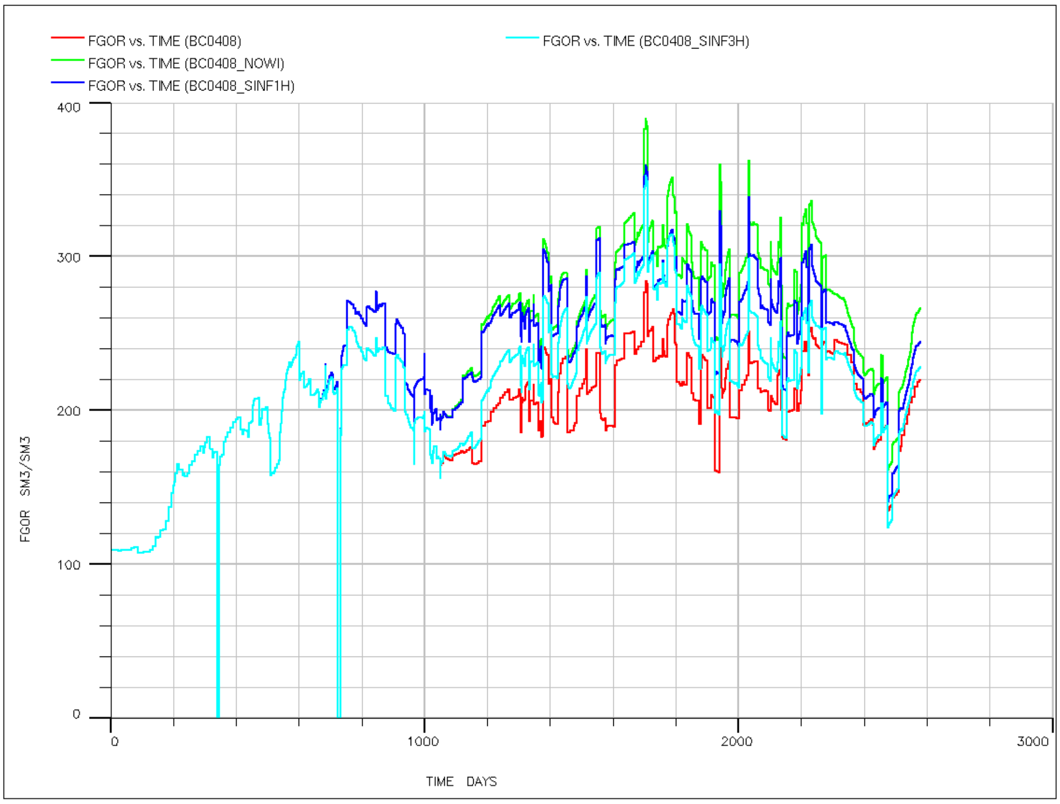


Figure 33: Gas-Oil relationship for the E-segment.

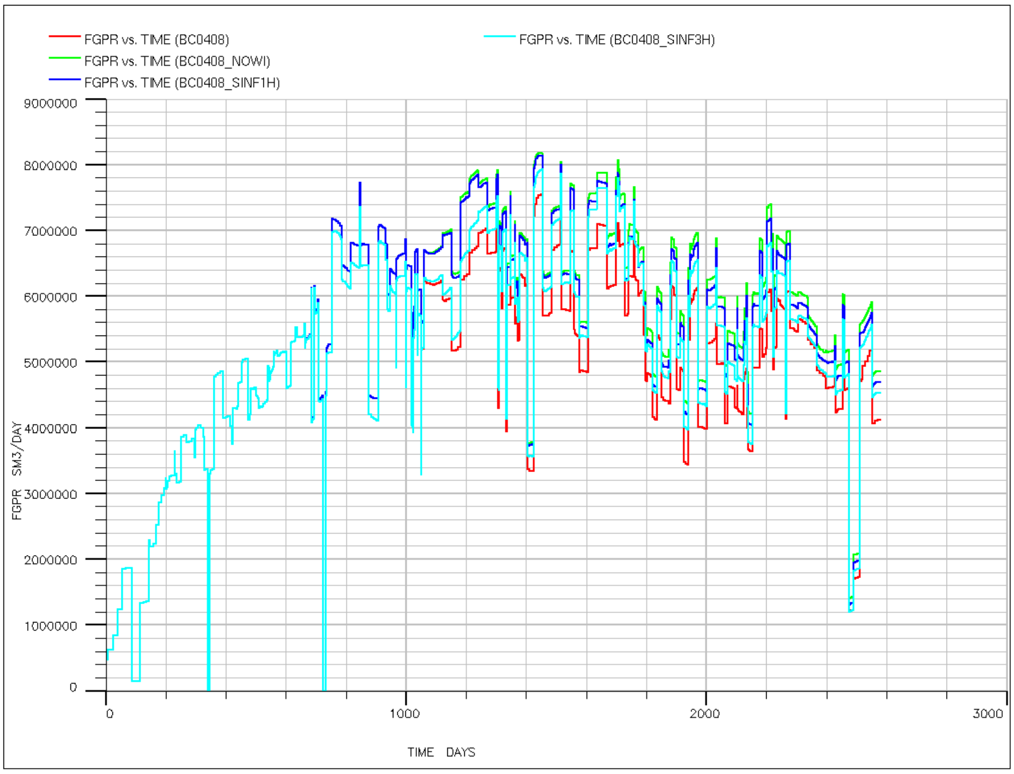


Figure 34: Field Gas Production Rate for the E-segment.

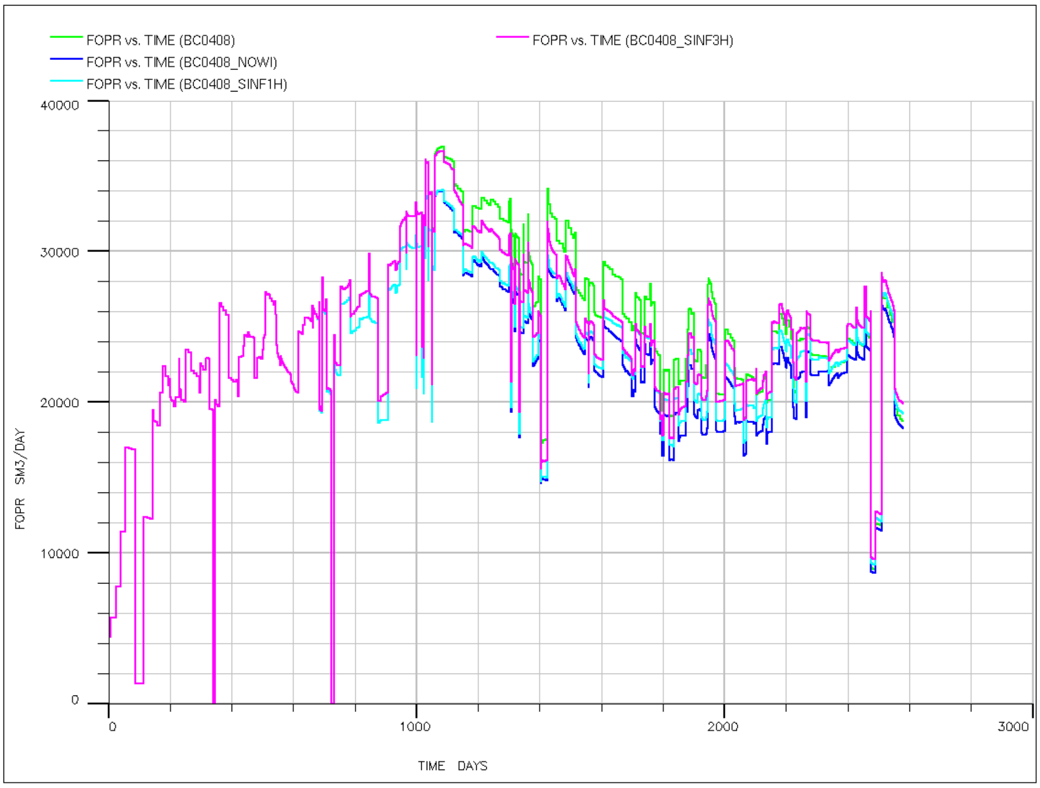


Figure 35: Field Oil Production Rate for the E-segment.

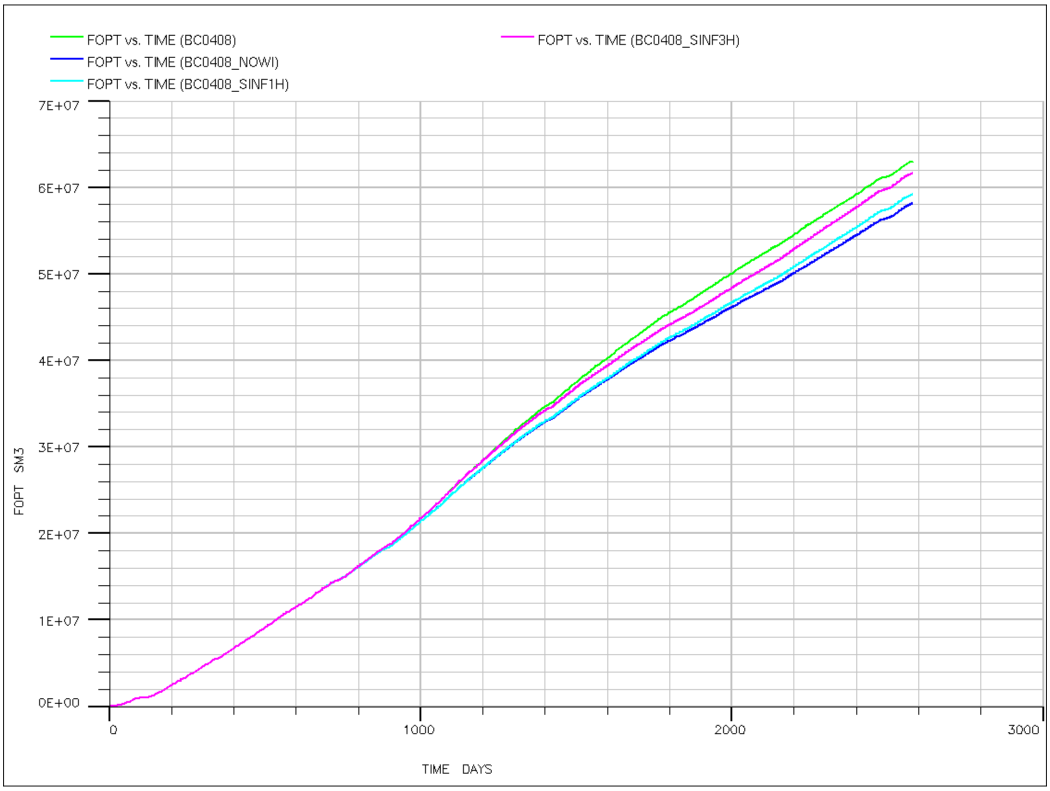


Figure 36: Field Oil Production Total for the E-segment.

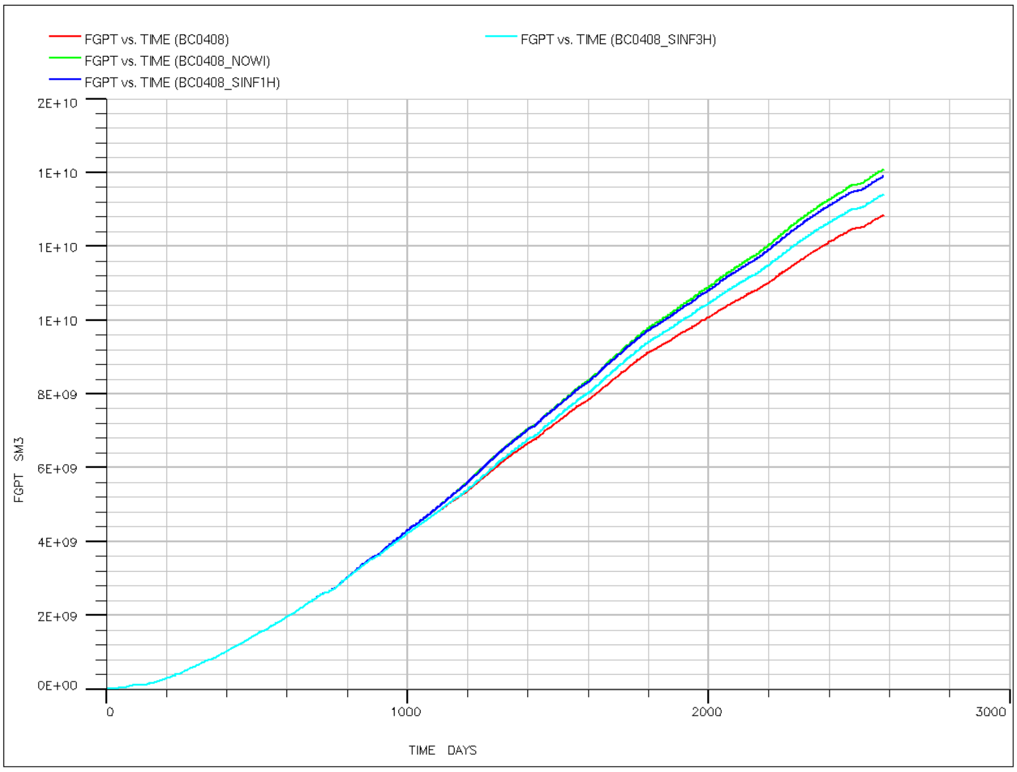


Figure 37: Field Gas Production Total

In the figures it is possible to observe the differences between the production rates of the different scenarios. The most important facts to point out within the analysis are:

- The Oil production rate at the end of the simulation (year 2010) is higher for the case in which the injection wells were shut down than when all injectors are on. This helped for the EOR selection and its extrapolation in order to obtain the desire results for the project which will be discussed ni the following chapters. The fact that the field oil rates matched at the end of the simulation in regardless of water injection or not, paved the way to a base case for EOR flooding. Although the Total oil production is much higher when injecting than when not injecting.
- There is higher gas production rate and gas total production when water injection is avoided than when it is used, as shown in figures 38, 41 and 42.
- Thus, the Gas-Oil relationship is 20% higher when injection is avoided.
- As shown in figures 37, 38 and 39, It was found out that when shutting down F-3H the oil recovery was 10% higher than when shutting injector F-1H.

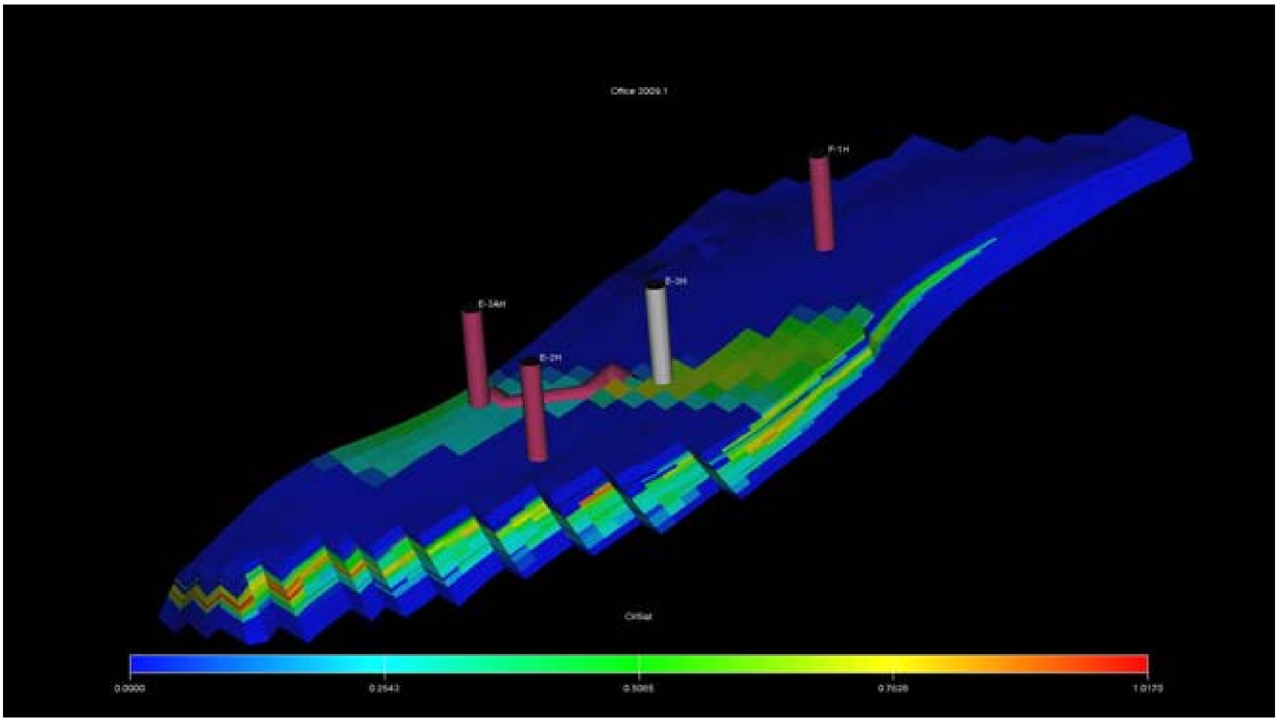


Figure 38: Oil production total when shutting down injector F-3H.

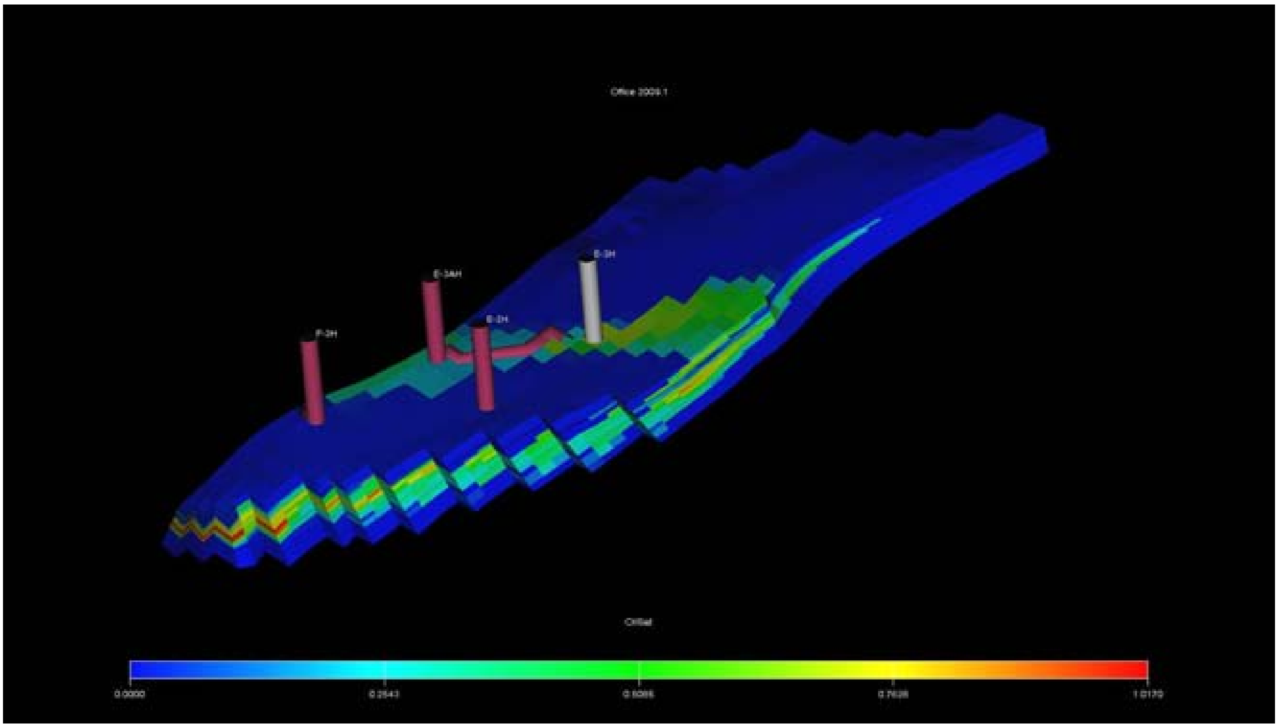


Figure 39: Oil production total when shutting down injector F-1H.

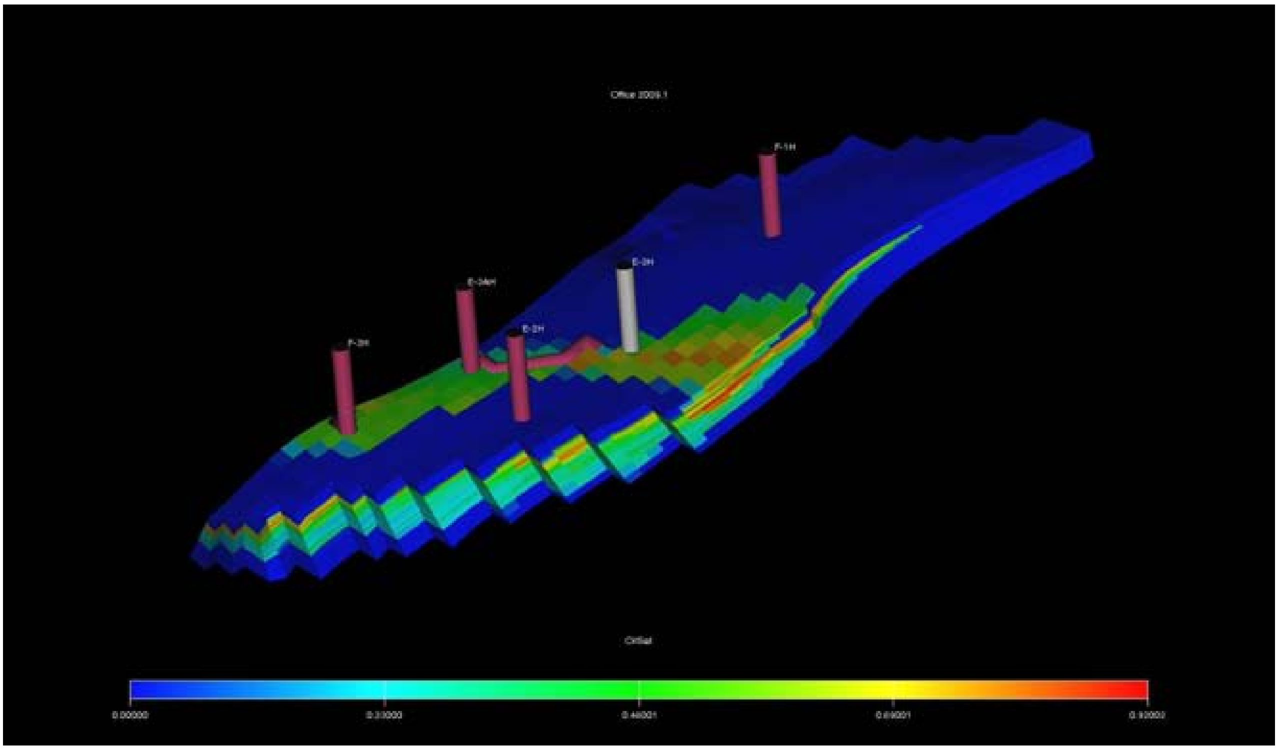


Figure 40: Oil production total when using all injectors.

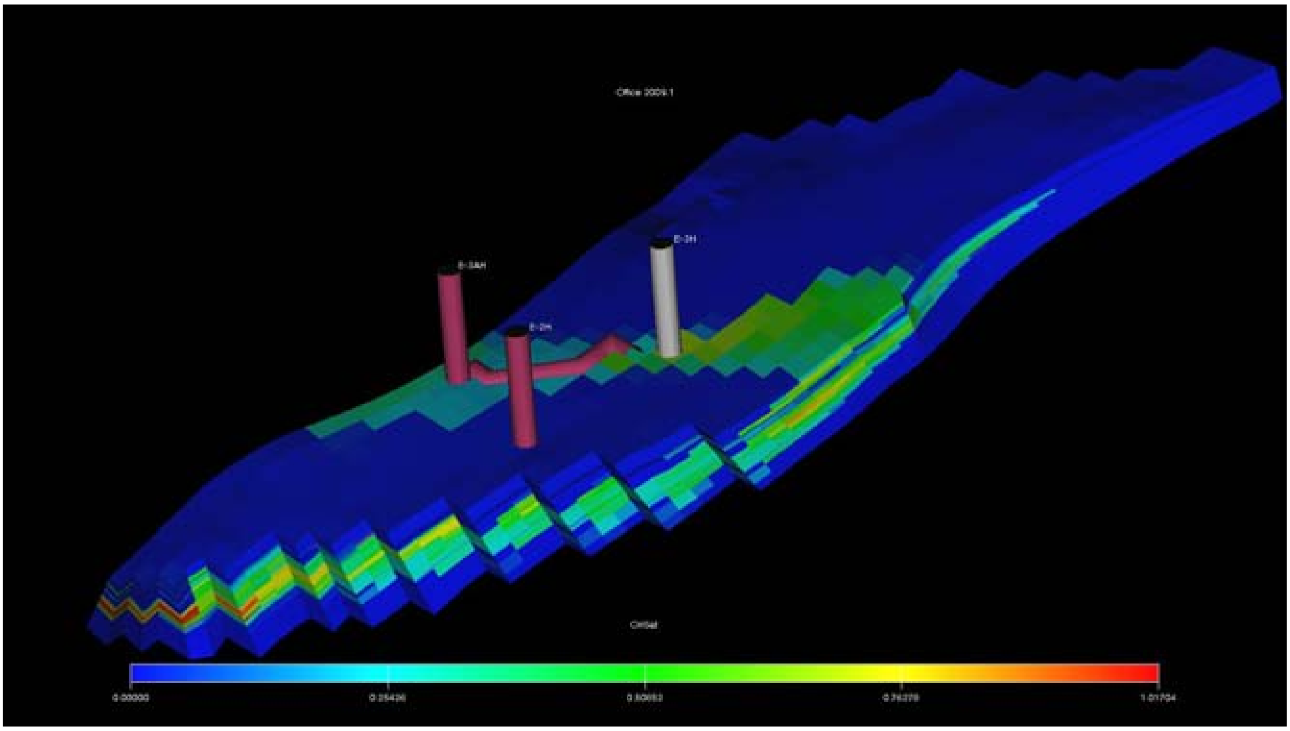


Figure 41: Oil production total when shutting down all injectors.

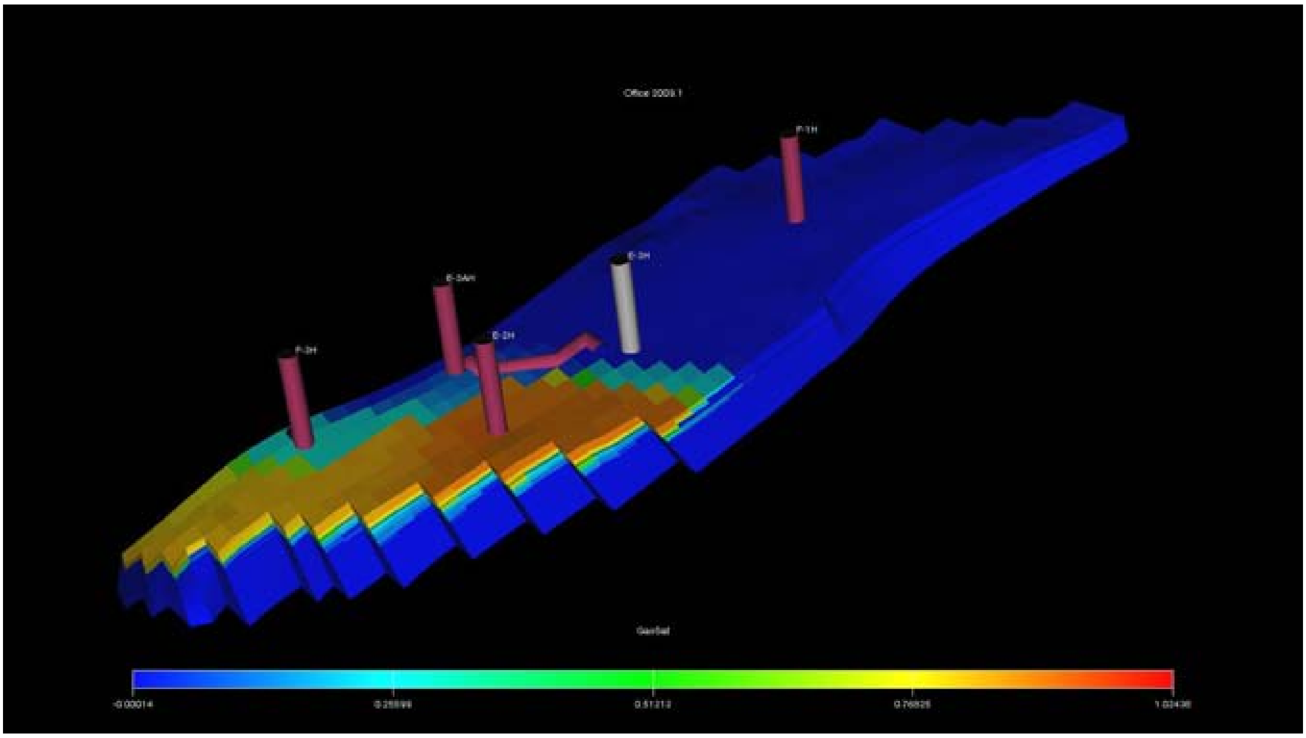


Figure 42: Gas Production Total when using injection wells F-1H and F-3H.

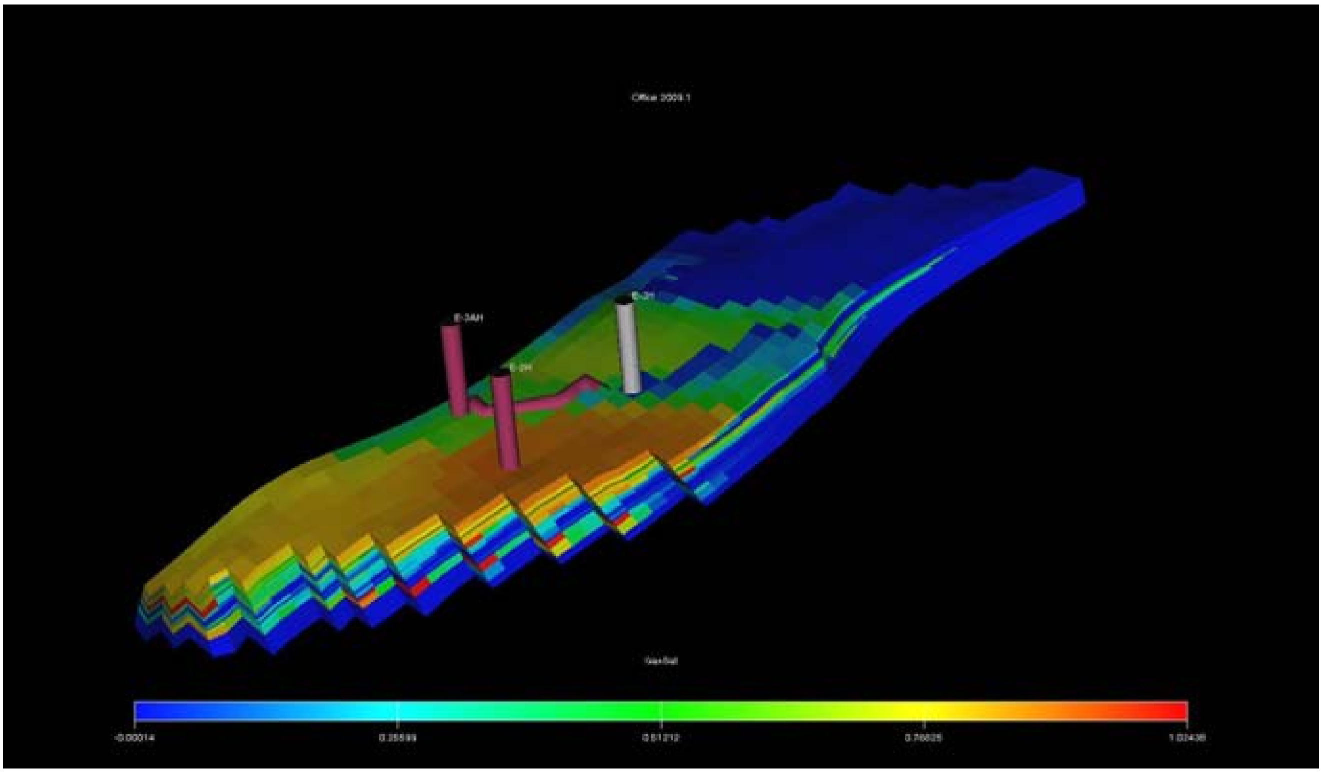


Figure 43: Gas Production Total when shutting down the both injectors.

2.3 Creating the model

As the simulations on ECLIPSE turned more complicated than previously thought, a simple graphical model created out from the information found in the literature was used in order to select a proper EOR method for our case.
Some of the relevant information found in literature which was used is shown in table 3.

	Oil Properties			Reservoir Characteristics					
EOR Method	Gravity°API	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)									
Nitrogen (& Flue Gas)	>35↗48↗[1]	<0.4↘0.2↘	High % of C_1-C_7	>40↗75↗	Sandstone or Carbonate	Thin unless dipping	N.C.[2]	>6,000	N.C.
Hydrocarbon	>23↗41↗	<3↘0.5↘	High % of C_2-C_7	>30↗80↗	Sandstone or Carbonate	Thin unless dipping	N.C.	>4,000	N.C.
Carbon Dioxide	>22↗36↗	<10↘1.5↘	High % of C_5-C_{12}	>20↗55↗	Sandstone or Carbonate	(Wide range)	N.C.	>2,500	N.C.
Chemical									
Micellar/-Polymer, Alkaline/-Polymer (ASP), and Alkaline Flooding	>20↗35↗	<35↘13↘	Light, intermediate. Some organic acids for alkaline floods	>35↗53↗	Sandstone preferred	N.C.	>10↗450↗	<9,000↘3,250	<200↘80
Polymer Flooding	>15-<40	<150,>10	N.C.	>70↗80↗	Sandstone preferred	N.C.	>10[3]↗800↗	<9,000	<200↘140
Thermal									
Combustion	>10↗16→?	<5,000→1,200	Some asphaltic components	>50↗72↗	High porosity sand/ sandstone	>10	>50[4]	<11,500↘3,500	>100↗135
Steam	>8-13.5→?	<200,000↘4,700	N.C.	>40↗66↗	High porosity sand/ sandstone	>20	>200[5]	<4,500↘1,500	N.C.

1. Underlined values represent the approximate mean or average for current field projects. ↗ indicates higher value of parameter is better.
2. N.C. = not critical.
3. >5 md from some carbonate reservoirs.
4. Transmissibility >20 md ft/cp.
5. Transmissibility >50 md ft/cp.

Table 4: Summary of screening criteria for EOR [10]

Analyzing the options given before and the reservoir information we can tell that:

- CO_2 miscible process is limited to reservoir with sufficient depth to obtain the miscibility pressure and/or mobility problems.
- The main challenge with CO_2 now is on gas availability and transport.
- Steam-drive has reservoir depth limitations because of heat losses and the steam temperature obtainable.
- Surfactant/polymer processes are generally limited because of salinity and temperature and the associated difficulty of designing stable surfactant/polymer systems. [10]

2.3.1 Selection of an EOR method

The criteria for selection of a particular EOR process are complex because of the large number of petro-physical, chemical, geologic, environmental and fluid properties (density & viscosity which are dependent on temperature) that must be considered for each individual case. [2]
Nevertheless the graphical model utilized for this case as shown in figures 45 and 46 which altogether gives a simplified method for the proper selection of an EOR method not just for our case but for other reservoirs as well, including an economical overview of each method.

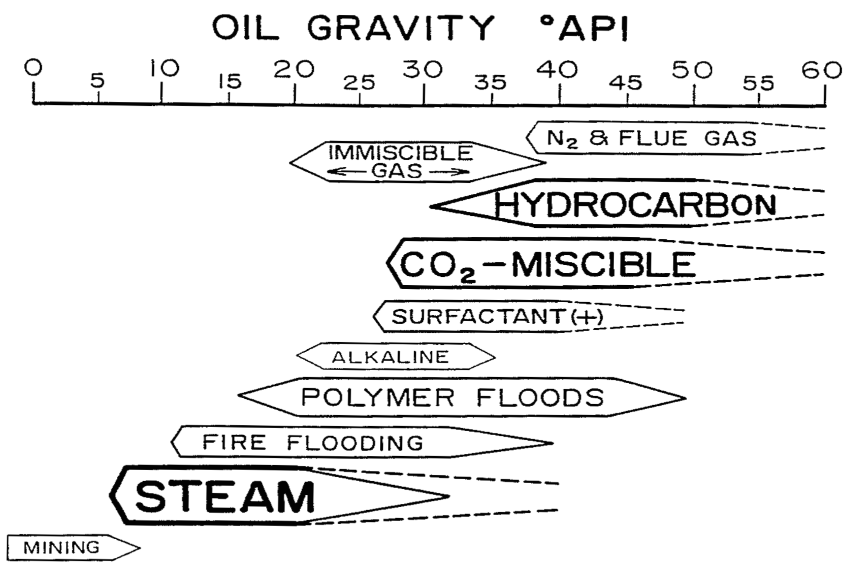


Figure 44: Optimal density range for various the proper selections of EOR Methods [11]

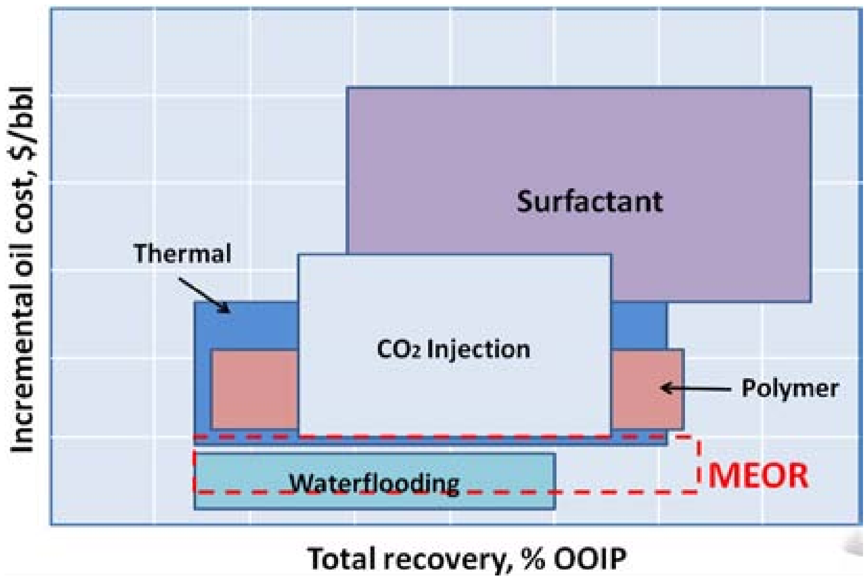


Figure 45: Cost comparison for the different EOR methods [E].

Thereafter, it was decided to choose two EOR methods that were close enough to compare with each other both technically and economically. The methods selected were:

1) CO_2 injection
2) Surfactant flooding

From literacy and from the information given from the EiT village[9] a simple but profound analysis on both technical and economical features was driven. The following chapter shows the results obtained from the latter.

2.4 Results

As mentioned on the previous chapter, the analysis was done by showing three different scenarios (three different methods). By assuming the continuous injection of water in the upcoming years – until 2019 – without any chemical addition it was possible to calculate the different scenarios for both CO_2 and surfactant flooding.

Table 3 and figure 46 summarize the production results obtained from extrapolating the information thrown by ECLIPSE and making the proper assumption regarding each method according to literature.

Year	Water injection (Sm^3/day)	Surfactant flooding (Sm^3/day)	CO_2 Flooding (Sm^3/day)
2010	19000	22420	20900
2011	18250	21535	20075
2012	16800	19824	18480
2013	16500	19470	18150
2014	15000	17700	16500
2015	15100	17818	16610
2016	14300	16874	15730
2017	13900	16402	15290
2018	13500	15930	14850

[9] Norne excel spreadsheet for economical evaluation.

2019	12100	14278	13310

Table 5: Oil recovery results and comparison by using the different EOR methods. Extrapolating the data from ECLIPSE and using literature.

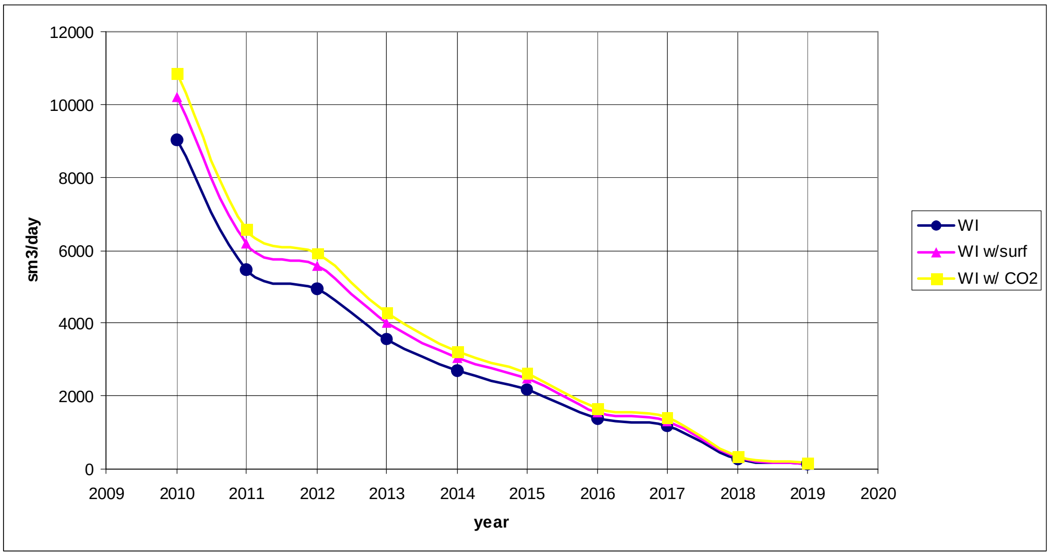


Figure 46: Oil production rates according to the EOR method selected and compared with simple water injection.

For the economical evaluation part, the excel spreadsheet given by the land's leader was utilized [12]. According to the economical simulation and the information given for the project (including the estimated future rates), the results –according to each method- were:

Method	NPV MMNOK	
	Before Tax	After Tax
Water injection	98 685	25 658
Surfactant flooding	115 277	29 958
CO_2 flooding	107 570	27 957

Table 6: Net Present Values obtained from the analysis of the EOR methods applied according to the excel spreadsheet.

The assumed costs for utility, equipment and operations were obtained from other EiT villages[10]. Finally an oil recovery overview was driven and it is shown in table 6. Based on the fact that the original oil in place recoverable is 95 000 000 sm^3[11]

[10] Gullfaks Village 2010. Gullfaks Sør Omega Project, some cost data and economic assumptions.
[11] Statoil field development report Norne 2004

Method	To year	Cumulative oil production (sm^3/day)	% of total recovery
Water injection	2010	50 350 000	53%
Water injection	2019	61 610 000	64.8%
Water injection w/surfactants	2019	63 073 800	66.3%
CO_2 flooding	2019	63 862 000	67.2%

Table 7: Prognosis and percentage of reservoir recovery by the different EOR methods.

The results show that for both economical and oil recovery reasons, CO_2 flooding should be applied in this reservoir.

3. Conclusions

At the end of this project it was concluded that:

- Since the temperature of the Norne reservoir is high and oil is light so thermal methods cannot be applicable to Norne reservoir or at least, they are not suggested.
- Chemical and polymer flooding can be used as seen in the field case. However, nearly 90% of the surfactants injected are believed to be retarded by the formation when passing through the reservoir rock. Thus, only a small amount is lowering the interfacial tension between the oil and water. It is therefore extremely important to be able to quantify the amount of surfactant needed for a successful chemical flooding. High cost of surfactants and their retention impose high risk and uncertainty to their implementation and make them less attractive economically.
- Microbial EOR can also be implemented and it is more viable economically according to the information obtained and elaborated.
- CO_2 injection can also be used and gives a higher oil recovery at a lower cost than surfactant flooding.
- Most of the EOR methods are time-dependent function. Some of the methods (surfactants and polymer flooding, thermal methods) require considerable investments; however the response in the extra oil production is usually delayed 5-10 years. This means that in order to be economical an EOR method has to recover most of the extra oil within the time schedule for conventional recovery. Otherwise the project will be uneconomical due to extra operational costs and higher risk of realization.
- Hydrocarbon and inert gas injection methods can not be applied since it is not a field with light oil. Although hydrocarbon injection can be applied as well to medium light oils such as in this case.
- Due to the lack of time and of technical knowledge it was not possible to elaborate a more precise model based on ECLIPE simulations. Therefore it is highly suggested that a more profound study should be run in the future in order to demonstrate the feasibility of the selection driven by this study.
- The comprehension of the technical and economical knowledge regarding EOR methods has been achieved successfully for the entire group. It was demonstrated that by simplicity and basic comprehension it was possible to select proper methods and disregard the improper ones without doing a deeper study.

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