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PRODUCTION OPTIMIZATION USING RESERVOIR RECOVERY TECHNIQUES

Samwel Joseph Majani

Petroleum Engineering
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Supervisor: Richard Wilfred Rwechungura, IGP
Co-supervisor: Jon Kleppe, IGP

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Department of Geoscience and Petroleum

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Author: Samwel Joseph Majani

Production Optimization Using Reservoir Recovery Techniques

(Case Study: Norne E-Segment)

Supervisor: R.W. Rwechungura and J. Kleppe

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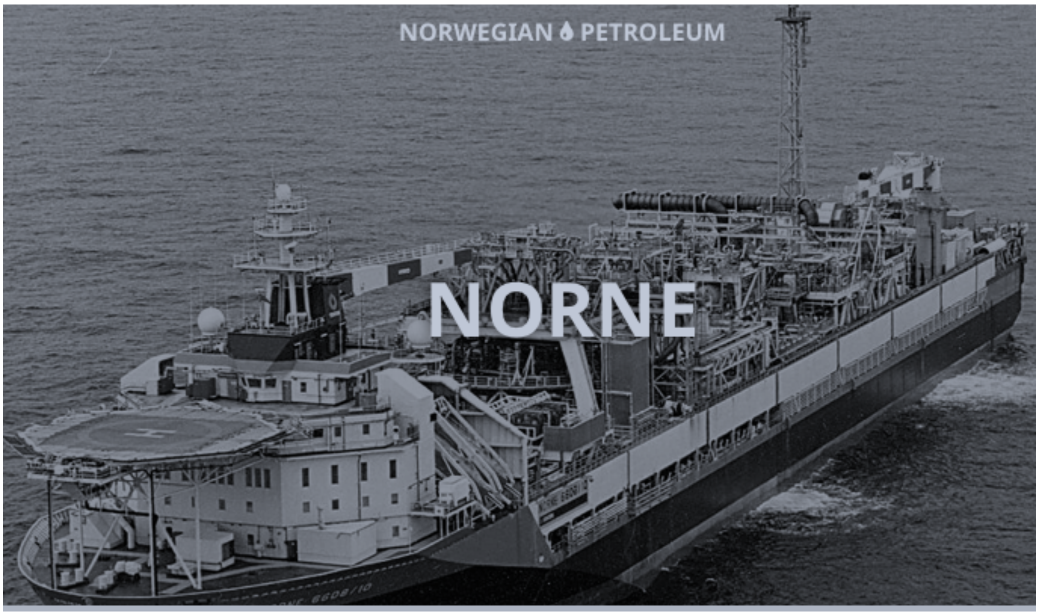
NTNU

Norwegian University of Science and Technology

Faculty of Engineering

Department of Petroleum Geoscience and Applied Geophysics



DISCLAIMER

Most of the information contained in this report is to the best of my knowledge that are accurate and current. No warranties expressed or implied are made by Equinor Energy AS and its Norne License partners (ENI and Petoro) with respect to the information set forth herein.

ABSTRACT

Optimal production is accomplished with the optimum drainage strategy which must lie in any of the primary or secondary or tertiary recovery mechanisms or combined as a result of applying more optimal number of wells in a good location of the reservoir so as to maximize the possible contact with the crude oil system and hence sweeping area which will basically increase recovery while reducing economic costs and maximizing NPV (Net Present Value).

Basically, the given benchmark case model for the Norne field with fined E-Segment and other coarsened segments (C, D and G) from Equinor (formely Statoil) was run in the Eclipse 100 simulator in order to acquire important information and to initiate further simulations.

Some of the information obtained from the model was that, E-segment of the Norne field was producing with 5 wells of which 2 wells (F-1H and F-3H) are injectors and 3 are producers (E-2H, E-3AH and E-3H). On full field basis, Production started from the date of 6th November of 1997 when the field initial conditions were about 166 million Sm^3 for oil in place and 273 bar for pressure to 1st December of 2004 when the field oil in place dropped to about 98 million Sm^3 and the pressure raised to 282 bar with the field oil recovery of about 41.3%.

This implies that both primary (gravity drainage, water drive, gas expansion and rock contraction) and secondary (water flooding and gas injection which ceased in 2005 year) recovery techniques were able to recover only about 41.3% as of 1st December of 2004.

However, Norne E-Segment was the main point of concentration where the benchmark case was predicted to 2035 (5 years more than the time planned by Equinor) in a simulator and other water flooding cases were run aftermath which included; introduction of the new injector G-1H while other producers are open except E-3H, opening all the producers under the presence of the new injector, changing the location of the injector F-3H and opening all producers under the presence of the new injector, changing the location of injector F-1H opening all producers except E-3H under the presence of the new injector G-1H, relocation of both injectors with new producer Z-3H which produced for exactly 3 years from 1st December 2004,introduction of the new producer with the same location of other opened wells except E-3H and finally changing the location of producer E-3AH under the presence of the new producer.

In all cases, Production and injection well placement cases were located manually with the help of floviz of a simulator after identifying grid blocks with high oil saturation from an updated geological model. Even after altering the predicted benchmark case model, there was still some significant amount of oil remaining in the Norne field and some pockets of residual oil saturations in the reservoir especially in the Ile and Tofte formations of the Norne E-Segment and at the date of 1st December of 2025 the full field recovery was about 72%. The residual oil left after water flooding was either from water swept part or area by-passed by water flooding.

The by-passed residual oil has a high interfacial tension with water. The best way for recovering this capillary trapped oil is by flooding the reservoir with chemicals (surfactant (S), polymer (P), alkali-surfactant (AS), surfactant-polymer (SP), or alkaline-surfactant-polymer (ASP)).

The Norne field is producing with the approximately world class recovery factor of 56.5% as of 2015 with primary and secondary (water flooding, and gas injection which ceased in year of 2005) and the current recovery is about 60%. The oil production peaked in 2001 and is now declining. Water flooding alone cannot efficiently recover capillary trapped oil pockets, thus requires enhanced oil recovery techniques. The EOR screening criteria were applied to Norne E- segment in order to come up with the right EOR method that would reduce residual oil saturation to the minimum. Five EOR scenarios such as surfactant flooding, alkaline-surfactant flooding, polymer flooding, surfactant-polymer flooding, and alkaline-surfactant-polymer flooding with different 40 cases were simulated for the Norne E-segment.

The plan was to evaluate the effectiveness of all these flooding methods based on incremental oil production. After this, one of the flooding methods was to be concluded for the Norne E-segment based on expected incremental net present value as an optimum drainage/depletion strategy.

The injection well F-1H and producer E-2H were evaluated as the most promising wells for above cases. A series of trial cases were run with economic consideration to ascertain the injection length, appropriate surfactant quantity and concentration, best injector and producer. Five chemical flooding cases (surfactant (S), polymer (P), alkali-surfactant (AS), surfactant-polymer (SP), or alkaline-surfactant-polymer (ASP)) for every single water flooding case with different combination and concentrations of chemicals (alkali, surfactant and polymer) which made up to 40 cases and were run using Eclipse 100 simulator.

In addition, calculation of expected incremental NPV based on incremental oil production for all cases (40 for chemical flooding and 7 for water flooding); single parameter sensitivity analysis (Spider plot) for low case, base case, and high case at different oil prices, chemicals prices, drilling well costs and discount rate were also performed. It was found that change in oil price has substantial effect on eNPV (expected net present value) compared to other parameters while surfactant price is the least sensitive parameter i.e. very low effect on eNPV for high/low case.

From simulation results and economics analysis, waterflooding was found to be an optimum drainage strategy since it is better than other drainage strategies (scenarios) in terms of expected incremental NPV for the Norne E-segment. However, the **4.24 %** incremental recovery factor by water flooding seems interesting and will have an expected incremental net present value of **+996.542 million USD** and the total expected net present value of **+2.116 billion USD**. It is noted that the additional costs regarding operations and installations were not included in the economics calculation.

DEDICATION

I dedicate this report to my late mother Mwl. Felister Kanoel Rugaimukamu, her presence was very significant for the build-up of my academic excellence and even after she passed away her legacy remained and is still helpful to me up to date. May her continue to rest in peace, Amen.

ACKNOWLEDGEMENTS

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First of all, I am grateful to almighty God for keeping me healthy throughout my studies.
Secondly, I would like to thank NORAD through EnPe Program for this amazing studying opportunity and Equinor Energy AS for financial support thereby creating conducive atmosphere for my studies.

I am also acknowledging Equinor AS (the operator of the Norne field) and its license partners (Eni and Petoro) for the release of Norne data which were so useful for accomplishment of this work.

In any ways, I can't forget those who showed a zeal of contributing to this work either by their technical, professional, social advice or time for which I highly appreciate.

I would like to express my deep thanks to my supervisor Prof. R. W. Rwechungura and Co-supervisors Prof. J. Kleppe from NTNU, Dr. K. Baruti and Mr. M. Richard of University of Dar es salaam together for their readiness to offer help whenever needed.

I would also like to thank Christie, marketing officer of Oil Chem Technology in Houston, Texas for the release of data of chemical prices and other inputs for chemical flooding and economic analysis.
Finally, I thank my family especially my siblings, authors and my fellow colleagues for their countless support.

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CHAPTER 1

1.0: INTRODUCTION

The International Energy Agency (IEA) indicates that the demand of energy will increase in the coming years. Despite the fluctuations in the oil prices in the past few decades, as of 2030, consumption of energy will be 40% extra than the current one and the fossil fuels will be dominant in this increase this is just because the global demand for energy has been steadily growing. Thus, there is a high chance that oil will record high price [1].

This clearly demonstrates the significance of sustaining the production of the major sources of energy, which is specifically true for crude oil as the world's leading energy resource. As time passes, it becomes even more difficult to discover new oil fields; hence, oil companies' main target in any field development is to reach the ultimate recovery while maintaining an economic oil rate.

When it comes to field development several issues must be addressed and the most important one is development plan. The main objective of doing development plan is to enhance production with Ultimate Oil Recovery (UOR) at a possible minimum cost. Reservoir development plans are always implemented by using reservoir simulation whereby a reservoir model is run in accordance with the required goals. [2]

In order to achieve production optimization, several Reservoir Recovery Techniques are being deployed in order to ensure oil recovery from the reservoir at economic sense. These techniques have been discussed in details in literature review. Primarily, natural energy can recover to a maximum of 50% of the original oil in place. This can be explained as, when the reservoir pressure falls below the oil bubble point, dissolved gas in the oil expands and comes out of the solution and flow preferentially towards the production well because it is less viscous than oil depending on the chemistry of gas relative to oil. As a result, oil production and oil recovery factor are lowered. In order to manage this kind of a reservoir, water and/gas injection is usually applied to maintain reservoir pressure above the bubble point for improving oil production [3].

Water flooding is the most applied oil recovery technique with the reason that it is abundant and cheap compared to other fluids. The mobility of water favours recovery of oil and is usually applied to the matured reservoir after the reservoir pressure has dropped below bubble point pressure. However, in order to avoid discontinuity of water and aquifer columns, water injection is applied from the beginning of oil production [2].

Another technique that can be applied to improve oil recovery by pressure maintenance is gas injection. Under gravity influence, the injected gas moves to the top and hence creating a secondary gas cap which pushes oil column towards production well. [4].
Instead of re-injecting into the reservoir at the moment, gas is being exported by pipelines to the market due to the current high demand and price. However, gas injection is more effective than water injection more studies on water-based methods for recovering oil should be opened [5].

After analysing the available and the likely applicable reservoir recovery techniques then economic analysis was followed in order to make sure that the recovery is the most probable and at a minimum cost.

1.1: Problem statement

Norway's Equinor informed that although it was initially scheduled to be shut down during 2014, the ambition is now to extend the life of the life of the Norne field, located in the Norwegian Sea, to 2030. (OGJ Online, Sept. 16, 2013).

Equinor's Norne field was placed on stream in 1997 and the original plan of development anticipated that production would cease in 2014. An effective maintenance program and the addition of several nearby discoveries have kept the field and facilities viable.

Equinor prides itself on the high recovery rates it has been able to realize at its subsea developments. Norne is no different with a world class recovery rate of about 60 % as of 2015 and the operator is now considering boosting that rate beyond 60% and trying other commercial life of the development through 2030. Equinor Energy AS estimates the amount of remaining resources in the area could be as much as much as 300 MMboe which is equivalent to the operator's ongoing Aasta Hansteen development project.

Thus, to improve project economics and company performance, a clear objective should be established in order to optimize the operation cost. Production should be done in an optimal way in order to arrive to this objective.

1.2: *Scope of Work*

This work focused on optimization of oil production by the reservoir recovery techniques using a simulator. Since, recovery techniques are numerous in this work the main emphasis will be on water flooding and chemical flooding after screening.

1.3: Main Objectives

The main objective of this study is to maximize the economic value of the reservoir by maximizing field's oil recovery while keeping the operational cost at a minimum.

1.4: Specific Objectives

In order to accomplish the main objective of this work, the followings were to be achieved;

I. To evaluate the drainage/depletion strategies.

II. To come up with alternative reservoir drainage plans based on secondary recovery (water flooding) mechanism;

   a. *Introducing new wells (infill wells)*
   b. *Deviation of wells*
   c. *Addition of perforations/Recompletion of wells*
   d. *Relocation of wells*
   e. *Changing injector to producer or vice versa*
   f. *Rescheduling the production time*
   g. *Changing the injection rate/production rate/bottom hole pressure or combined*
   h. *Opening and Shutting wells to control production or water cut etc.*

iii. To come up with alternative reservoir drainage plans based on EOR methods (chemical flooding);

   a. *Surfactant*
   b. *Polymer*
   c. *Alkaline-Surfactant*
   d. *Surfactant-Polymer*
   e. *Alkaline-Surfactant-Polyme*r

iv. Performance of economic analysis for the developed reservoir drainage plans.
v. Comparison and determination of the optimum alternative reservoir drainage plans based on the incremental oil production and hence expected incremental Net Present Value.
vi. Performance of Single Parameter Sensitivity Analysis on the best drainage plan.

1.5: *Methodology*

In order to accomplish the proposed objectives, Eclipse simulator is used to run the simulations coupled with S3 GRAF program to read the results of simulations.

The Norne field is modelled in Eclipse 100; a fully implicit, three phase, three-dimensional black oil simulator. Eclipse 100 is a simulator which was used in this work for running simulations coupled with Resin sight complimenting floviz for improving visualization of the model. In summary, the following steps were executed in order to accomplish the task;

I. *The benchmark data file was run and the important information and results were extracted,*
II. *The benchmark model was predicted in the schedule file to 2035 and its data file was loaded and run so as to extract important information and results which were exported to Microsoft Excel,*
III. *The benchmark model was visualized in the floviz to identify the grid blocks with high saturations and high ways from the updated geological model and then placing wells in a good location of the reservoir in order to increase possible contact in the crude oil system for improving sweeping efficiency thus increasing recovery,*
IV. *The schedule file was then edited in order to cope with the new changes, the data file was then loaded and run in a simulator for further results. Steps III and IV were repeated until all the water flooding cases were done,*
V. *Surfactant flooding methods for the given benchmark case and the best water flooding case was run and then production and injection results were extracted in order to select the best injector and producer,*
VI. *Surfactant flooding methods with trial concentrations for the given benchmark case were run for achieving the optimum concentration of the surfactant to be used throughout the chemical flooding simulations,*

VII. *Chemical flooding methods (S, P, AS, SP and ASP) with the best injector for each of the water flooding cases were run to make a total of 47 cases,*

VIII. *Finally, Microsoft Excel was used for data analysis.*

CHAPTER 2

2.0: THE NORNE FIELD

2.1: *General Information*

The Norne Field was discovered in December 1991.The Horst block is approximately 9 km by 3 km. It is an oil field located 200 km from coastline and about 80 km north of the Heidrun field in the Norwegian Sea. The water depth at the field's area is 380 meters. The field is situated in the blocks 6608/10 and 6508/1 in the Southern part of the Nordland II area. Its location, relative to the nearby fields is shown in Figure 1.

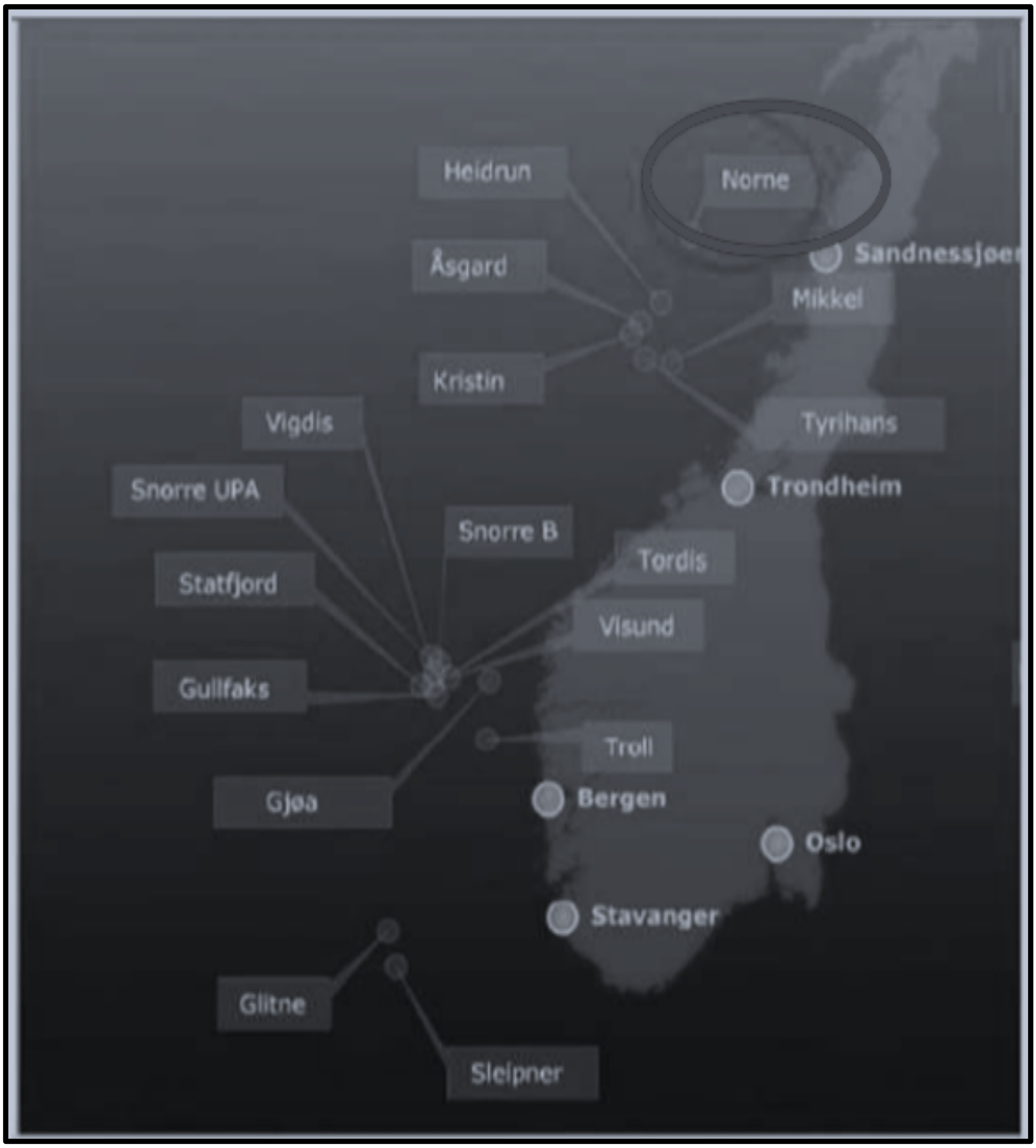


Figure 1: Location of Norne Field Relative to other Fields [6].

The Norne Field is currently owned by a partnership of Petoro AS (54%), Equinor Energy AS (39.1%) and Eni Norge AS (10%). Equinor Energy AS is the main operator.

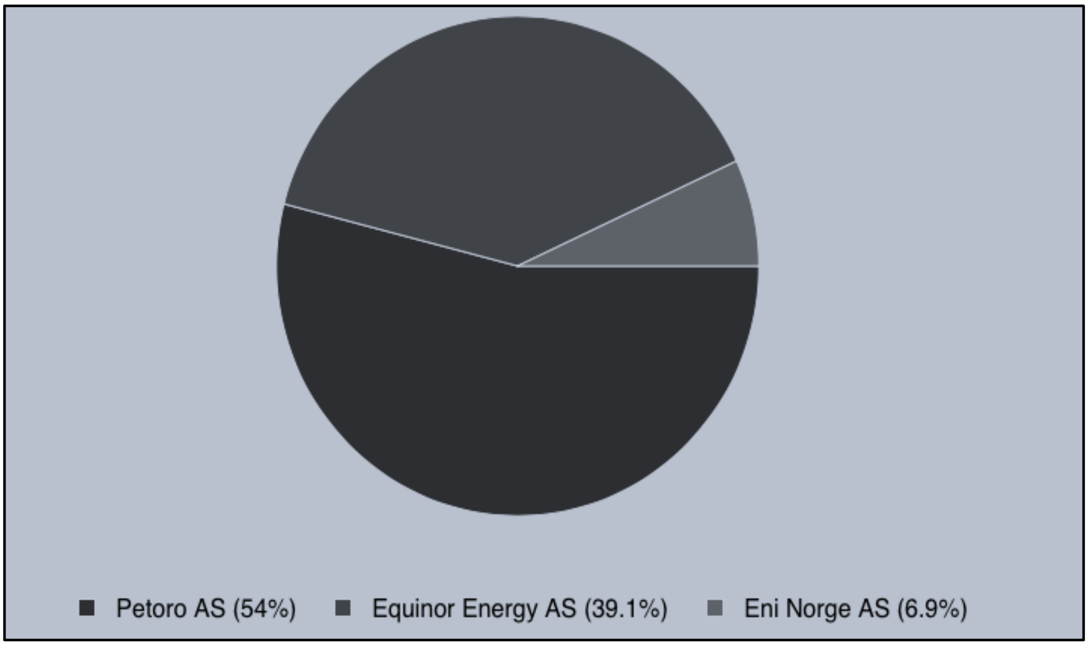


Figure 2: Share distribution among the companies [6]

well 6608/1 O-2 first penetrated at the Norne reservoir in December 1991. Appraisal well 6608/1 O-3 was drilled in 1993 and proved the field.

2.2: *Geology of the Field*

The Norne reservoir rock is comprised of Jurassic sandstones, mainly dominated by fine-grained and well to very well sorted sub-arkosic arenites. The sandstones are buried at deep depth of 2500 m to 2700m affected by diagenesis process which reduces the reservoir quality by mechanical compaction. Even though, most of the sandstones are of good quality and the porosity is in the range of 25% to 30% and permeability is in the range of 20-2500 mD [7].

The Norne Main Structure is relative flat with generally a gas filled Garn Formation and the gas oil contact in the vicinity of the Not formation clay stone. The northern flank dips towards north-northwest with an oil leg in the Garn Formation (Figure 2). Gas-oil (GOC) and oil-water (OWC) contacts in the different formations and segments are listed in Table 1. The Hydrocarbon were found in the rocks of Lower and Middle Jurassic age [7].

Table 1: GOC and OWC in the different formations and segments in the Norne [8]

Formation	C-Segment		D-Segment		E-Segment		G-Segment	
	OWC	GOC	OWC	GOC	OWC	GOC	OWC	GOC
Garn	2692	2582	2692	2582	2618	2582	2585	No gas cap
Ile	2693	2585	2693	2585	2693	2585	Water filled	Water filled
Tofte	2693	2585	2693	2585	2693	2585	Water filled	Water filled
Tilje	2693	2585	2693	2585	2693	2585	Water filled	Water filled

Acquired reservoir pressure data from the development wells indicate that the Not formation is sealing and there is no reservoir communication across the Not Formation during production.

Reservoir pressure is close to hydrostatic, with a formation pressure of 273 bar and a temperature of 98f^{o}C at a reference depth of 2,639m below MSL. The reservoir quality is generally good with 100-2,500 md horizontal permeability. The oil/water reserves in-place are estimated at one billion barrels (160 million m^3) of oil and 29 billion m^3 of free and associated gas. Reservoir simulations and risk analysis suggest that the most likely estimate for recoverable reserves is 450 million barrels of oil and 15 billion m^3 of gas of recovery rate of roughly 45%.

Hydrocarbons in the Norne Field are located in Lower–Middle Jurassic Sandstones with an oil zone of 110 m thick with an overlying gas cap make up the hydrocarbon column. The reservoir is a flat structure with the crest about 2,525 m below mean sea level (MSL*)*.

2.2.1: Stratigraphy and Sedimentology

The Norne reservoir is classified into two major groups, the FANGST which consists of the Ile, Garn and Not formations and the rest is BÅT which includes ROR, Tilje, Åre and Tofte formations. These formations are further subdivided into sub formations as shown in Figure 3. The Ile and Tofte altogether contains 80% of the proven oil in which 36% is for Ile and 44% for Tofte. These are generally most important formations because they contain many sweet spots.

2.2.1.1: Tofte formation

The Tofte formation was deposited during late Toarcian on the top of the unconformity and is approximately 50 m thick sandstone. As can be seen in Figure 2, the formation is divided into three reservoir zones; Tofte 1,2 and 3 where Tofte 1 consists of medium to coarse grained sandstone with variable but generally very good reservoir properties. In the middle, Tofte 2 is composed of muddy and fine grained sandstone unit and the top represents Tofte 3 which is very fine to fine grained sandstone. The Tofte formation is subdivided into seven parts (layer 12 to 18) in the reservoir model.

2.2.1.2: Ile formation

The Ile formation was deposited during the Aalenian and is 32-40 m thick sandstone. As shown in Figure 2, the formation is subdivided into three zones; Ile 1, Ile 2 and Ile 3 where Ile 1 and Ile 2 and ROR are separated by a cemented calcareous layer as depicted in Figure 2. These calcareous layers are probably the result of minor flooding events in generally regressive period, which might form barrier to vertical fluid flow and is therefore important in the reservoir modelling. The Ile formation is subdivided into seven parts (layer 5 to 11) in the reservoir model as shown in Figure 3.

2.3: *Reservoir communication*

There are restrictions to vertical and lateral flow in the Norne Field Reservoir which contains both faults and stratigraphic barriers/layers. In order to have a better understanding of the reservoir communication and drainage pattern during production, vertical transmissibility multipliers and fault transmissibility multiplier have been implemented in the reservoir simulation.

2.4: *Faults*

Since the Norne field is situated on a horst, a number of faults are expected. A horst is the raised fault block bounded by normal faults or graben. Figure 4 shows the fluid contact and faults in the reservoir.

In order to describe the faults in the reservoir model, the fault planes are divided into sections which follow the reservoir zonation. Each sub-area of the fault planes has been given transmissibility multipliers. The transmissibility multipliers are functions of fault rock permeability, the matrix permeability, fault zone width and dimensions of the grid blocks.

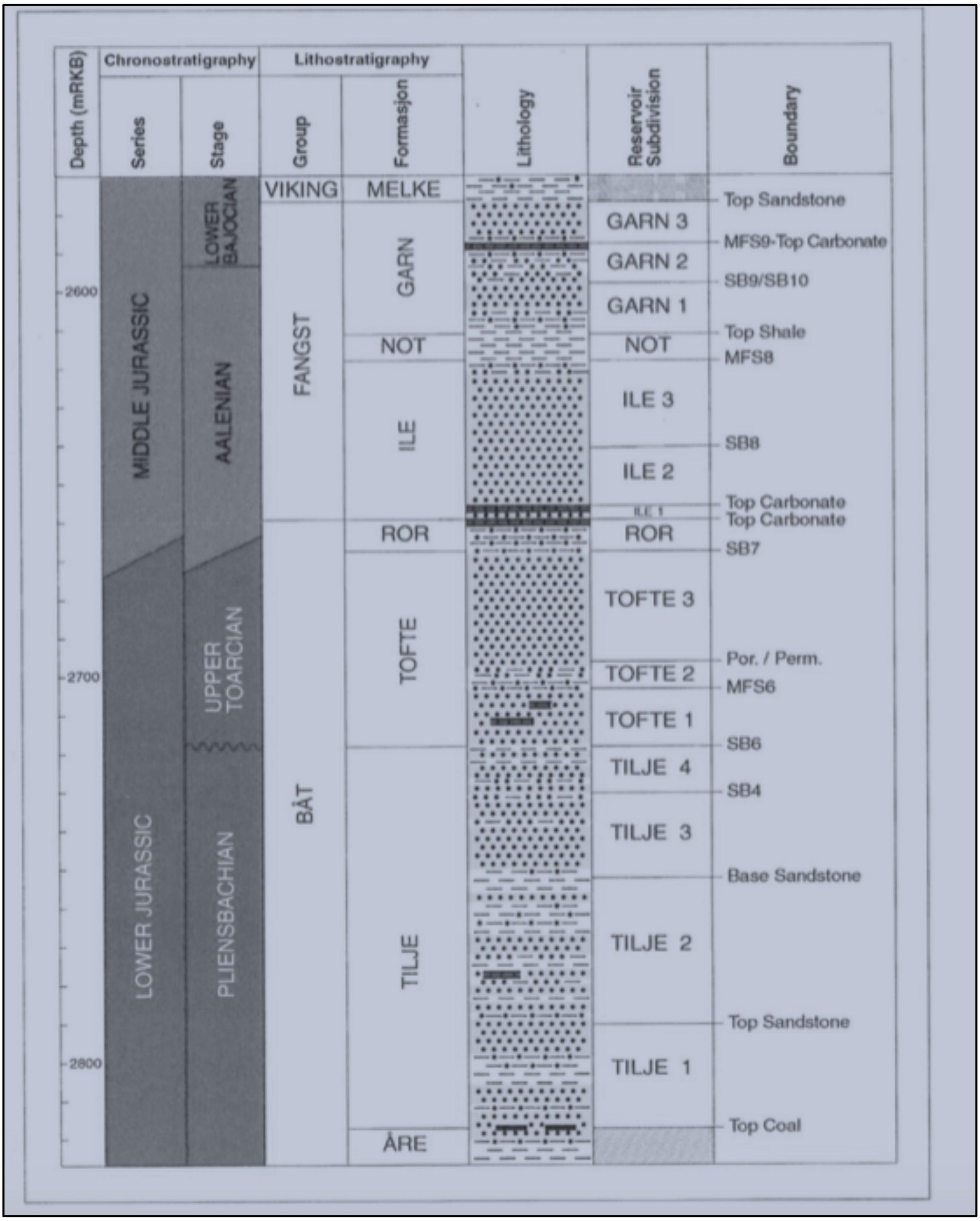


Figure 3: Stratigraphic sub-division of the Norne reservoir [7].

2.4: *Faults*

Since the Norne field is situated on a horst, a number of faults are expected. A horst is the raised fault block bounded by normal faults or graben. Figure 5 shows the fluid contact and faults in the reservoir.

In order to describe the faults in the reservoir model, the fault planes are divided into sections which follow the reservoir zonation. Each sub-area of the fault planes has been given transmissibility multipliers. The transmissibility multipliers are functions of fault rock permeability, the matrix permeability, fault zone width and dimensions of the grid blocks.

2.5: Stratigraphic barriers

Stratigraphic barriers have been identified and their lateral extent and thickness variation have been assessed using core and logs. The intervals which are believed to be continuous within the Norne Field, restricting the vertical fluid flow:

- Garn 3/Garn 2-carbonate cemented layer at top Garn 2
- Not Formation- claystone formation
- Ile2/Ile1-carbonate cemented layers at base Ile 2
- Ile3/Ile2-carbonate cementations and increased clay content at base Ile 3
- Tofte 2/Tofte 1-significant grain size contrast
- Ile 1/Tofte 4-carbonate cemented layers at top Tofte 4
- Tilje 3/Tilje 2-claystone formation [9].

The plan view of the faults is shown by Figure 4 taken from the Eclipse 100.

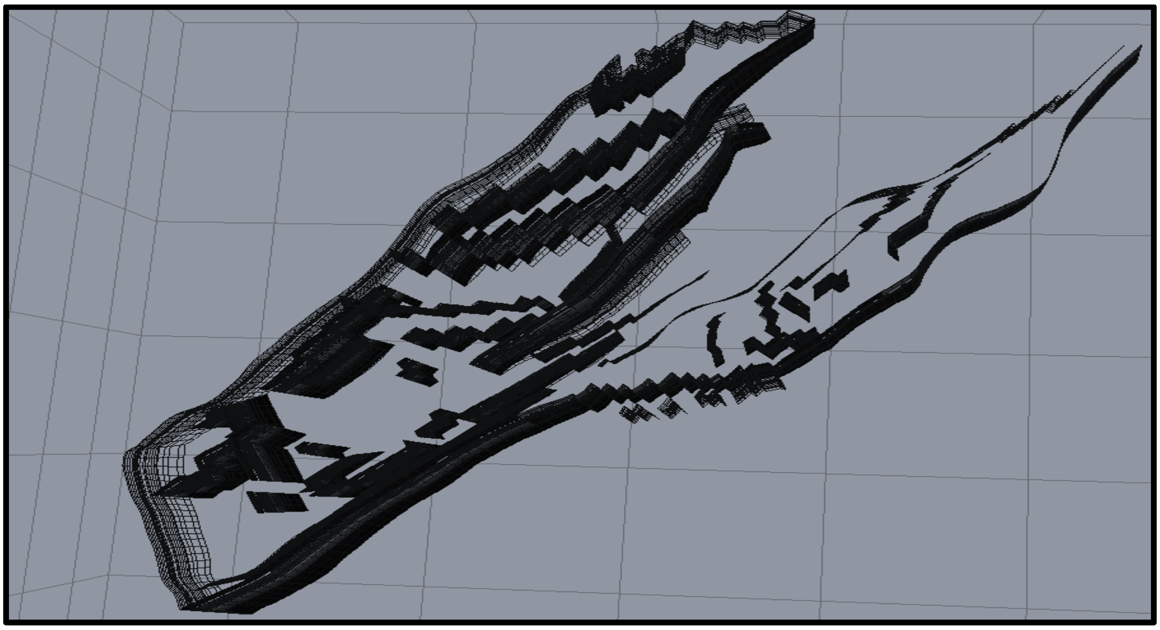


Figure 4: Distribution of faults in Norne field as seen in a simulator.

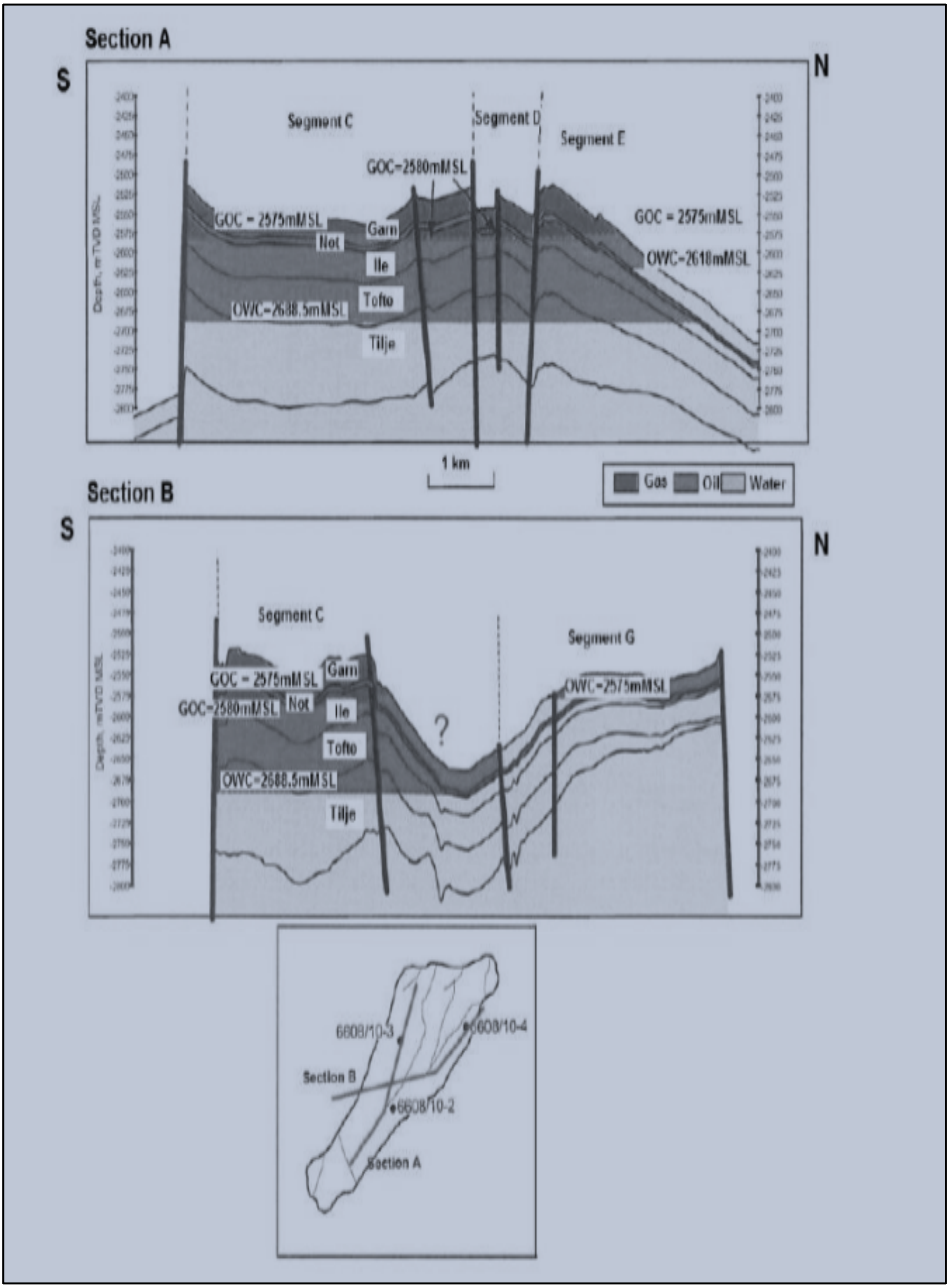


Figure 5:Structural cross section through the Norne Field with fluid contacts and fault [7]

2.6: *Development*

The main goal of developing the Norne field was to obtain an economic optimum production profile. In 2006, the focus was to optimize the value creation by

- Explore the potential in the license
- Safe and cost effective drainage of proven reserves
- Prove new reserves at optimal timing to utilize existing infrastructure
- Adjust capacities for cost effectiveness
- Improve drainage strategy with low cost infill wells as multilateral/MLT and through tubing drilled wells (TTRD and TTML)
- Increase reservoir pressure in the Ile formation and the Norne G-segment

Development drilling began in August 1996 and oil production started November 6th 1997. Sea depth in the area is about 380 m. The field has been developed with a production and storage vessel which is operated from Harstad in Norway by Equinor Energy AS and its partners (Eni and Petoro).

Norne consists of two separate oil compartments; Norne Main Structure (Norne C-, D- and E-segment, discovered in 1991), which contains 97% of the oil in place, and the North-East Segment (Norne G-segment).

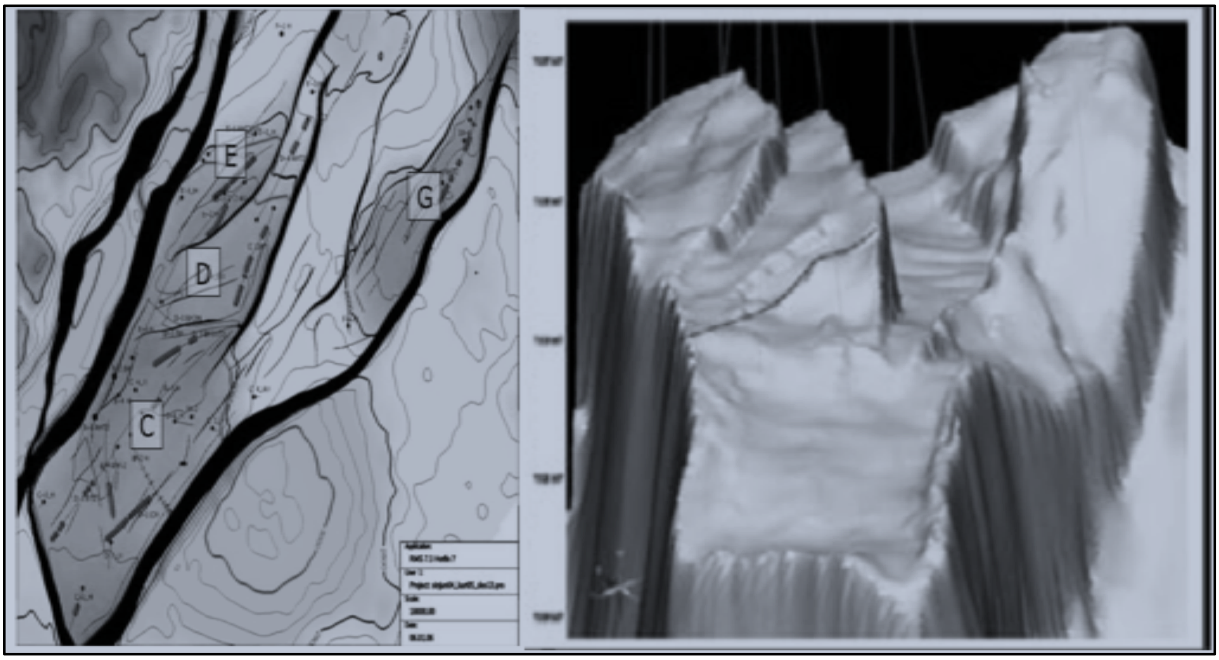


Figure 6: The Norne Field segments[7]

Total Hydrocarbon column (based on well 6608/10-2) is 135 m which contains 110 m oil and 25 m gas. Approximately 80% of oil is located at Ile and Tofte formation and gas in the Garn formation. The Norne Field is being developed with a floating production and storage vessel. The vessel is connected to six subsea wellhead templates named B, C, D, E and K, as seen in Figure. Template K has 4 slots available; 3 production and 1 for injection or production.

The Norne Field was discovered with well 6608/10-2 in 1991. Well 6608/10-3 confirmed the result of hydrocarbons in the discovery well, while well 6608/10-4 encountered oil in the North-East segment. Development drilling started with well 6608/10-D-1 H in August 1996 *[8]*. The well stream is carried by flexible risers to the vessel, which rotates around cylindrical turret anchored to the sea floor. The vessel has storage tanks for stabilized oil and a processing plant is located on the deck of the ship.

2.7: *Production*

Approximately 0.532 million Sm^3 of oil was produced from I1 well slots in March 2010. Water is injected in 8 wells. The Norne Field has produced 83.2 million Sm^3 of oil in total per March 2010 (NPD, 2010).

Figures 4, 5 and 6 illustrate the gross production of oil, gas and water per month from April 2009 until March 2010. The graphs show that the production of oil and gas gradually decrease while water production increases [9].

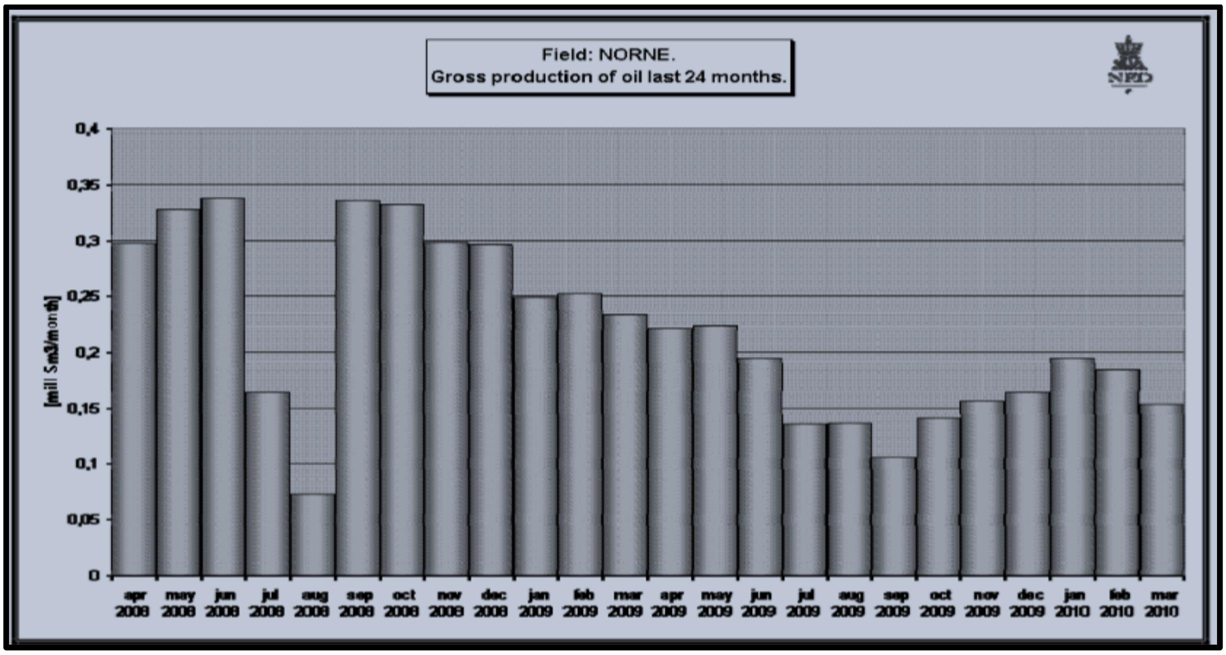


Figure 7: Gross production of oil, April 2009 – March 2010 [6]

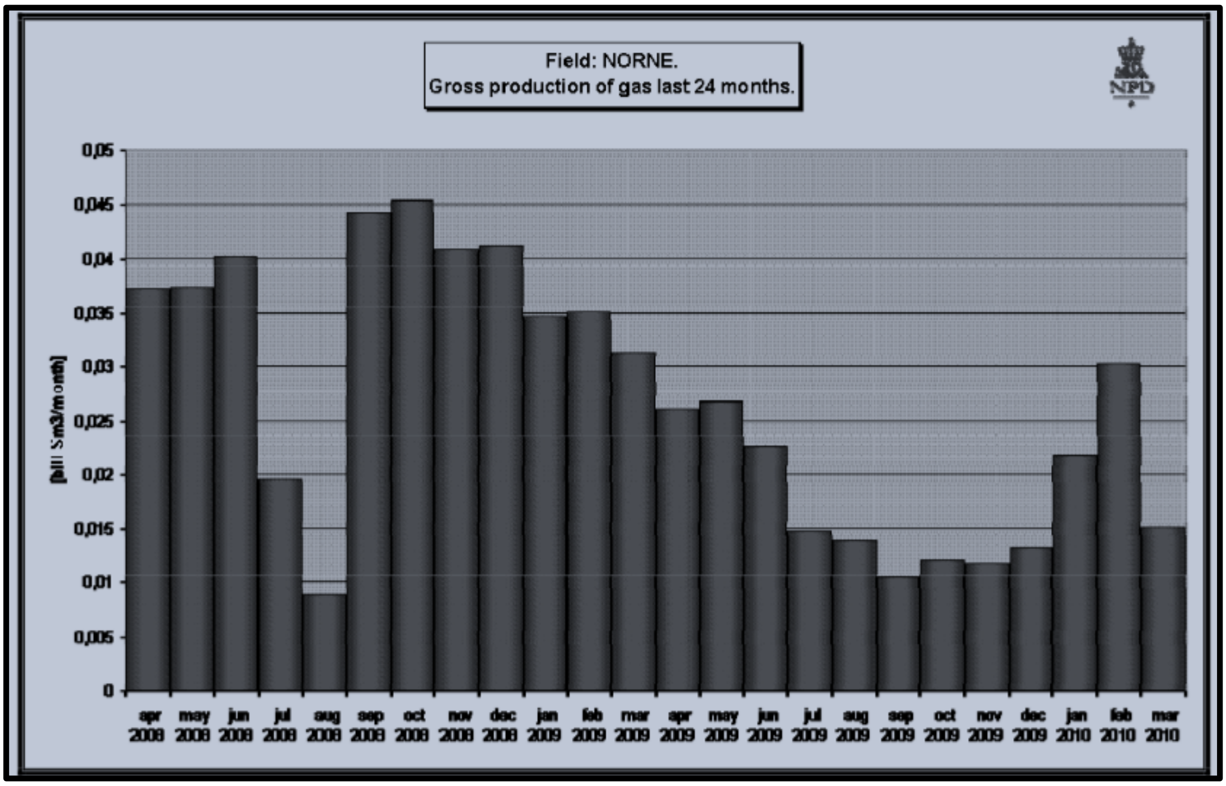


Figure 8: Gross production of gas, April 2009 - March 2010 [6]

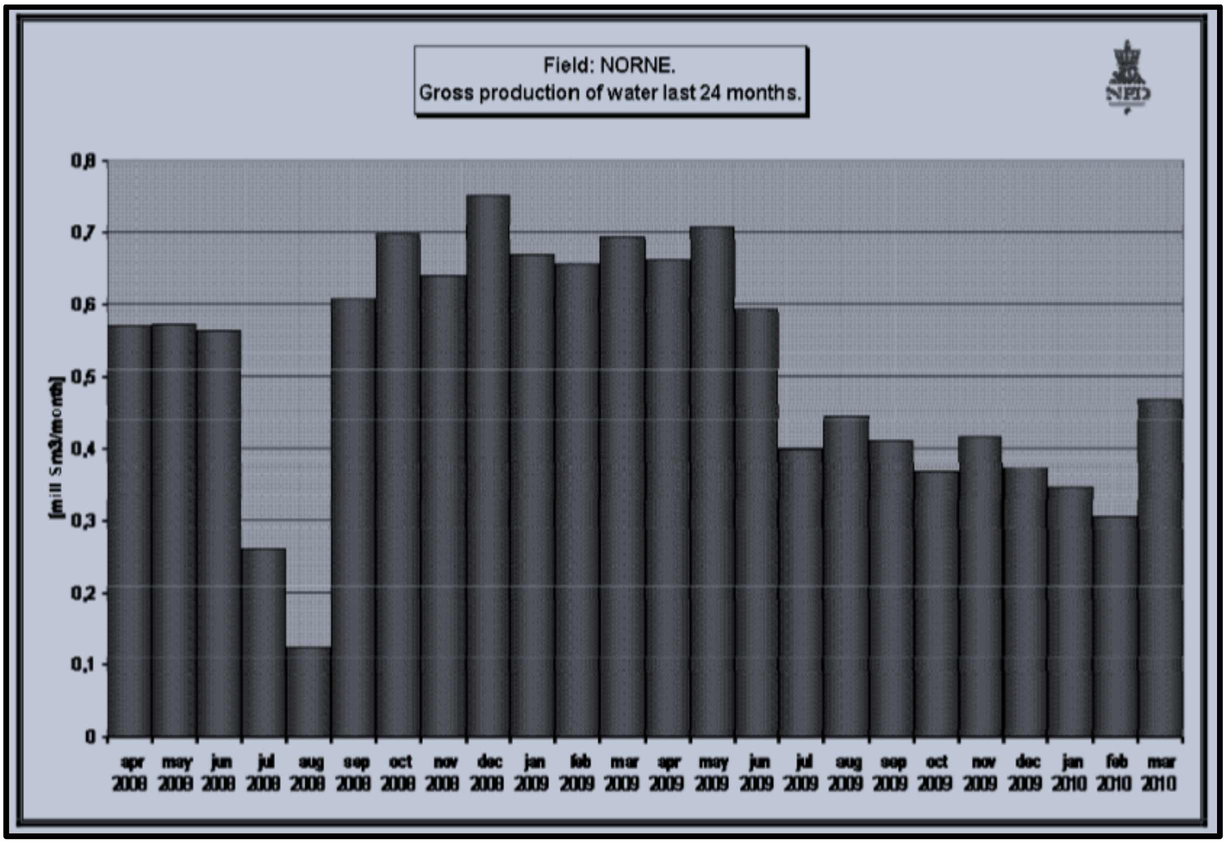


Figure 9: Gross production of water, April 2009 - March 2010 [6]

Totally 50 wells have been drilled in the field which contains 33 producers (16 active wells, 2010) and 7 observation wells. Table 2 illustrates the active development wells in this Field. The development of Norne Field starting from discovery to production is described in Steffe [10].

Further, development of horizontal wells and methods to control gas lift are described in Selle et al. (2008), [11] and Huseby et al. (2005) in 2005 describe the use of natural geochemical tracers to improve reservoir simulation models, using Norne Field data. Koalewski et al. (2006) reports an experimental study for testing the possibility of using microbial improved oil recovery in the Norne Field.

2.8: *Production and Storage*

The production and storage vessel is a turret-moored monohull, which is equipped with production, storage and offloading facilities. Based on the Tentech 850 S design, it will weathervane around a turret attached to the seabed by a 12-point mooring system.

Processing facilities and power units are installed on deck, while oil will be stored in tanks in the hull before they are loaded into shuttle tankers through an offloading system located aft. The processing and utility systems will be fabricated as skid-mounted units by various suppliers, mainly in Norway.

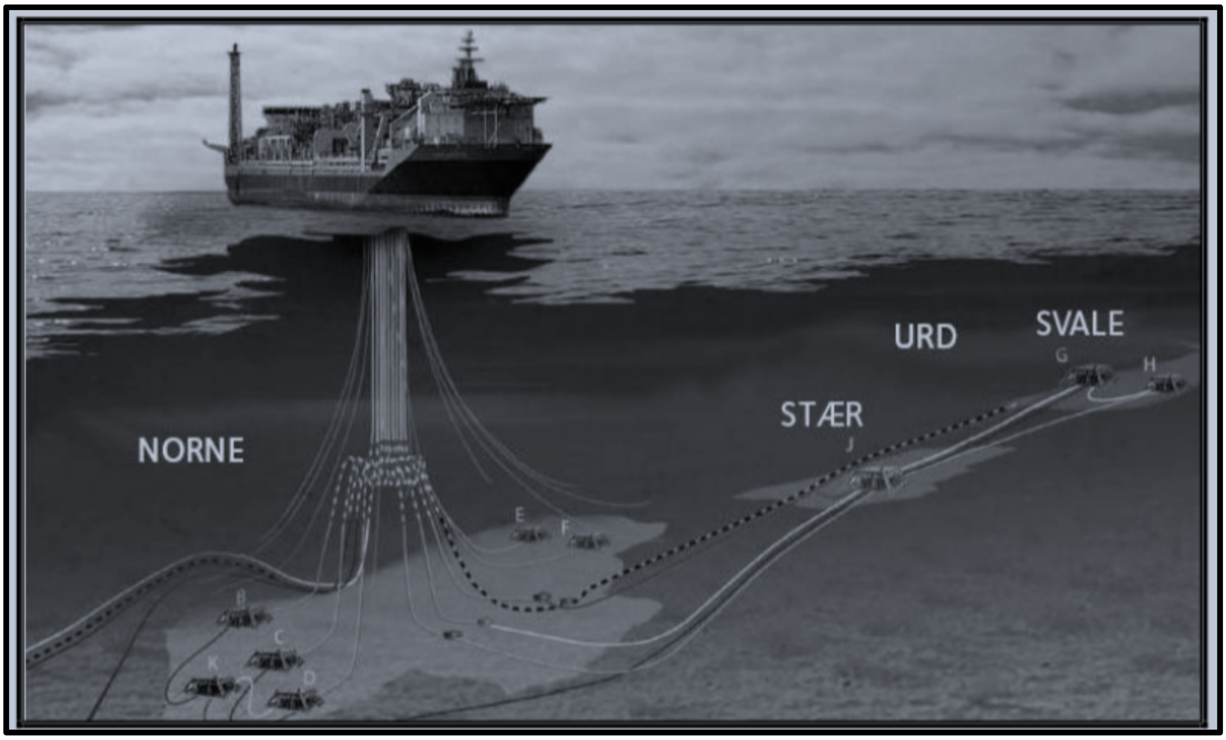


Figure 10: Development of the Norne Field[7]

Topside production systems and equipment are due to be placed on a deck 3.5 m above the ship's cargo deck so as to provide the air gap required for safety reasons. These installations comprise oil separation and produced water treatment, gas separation and compression, power generation, water injection, export metering, chemical injection and a heating and cooling medium [12].

2.9: *Main Processing System*

The well stream will be transferred via the swivel mounted in the turret to the inlet separator, operating at 15-20 bar. Oil from this separator is stabilized in a second separation unit, operated at 1.5-2 bar, before it is transferred via a coalesce to a storage tank. Gas from the second-stage separator is compressed in two stages, then mixed with gas from the inlet separator. All the gas is then compressed in three stages to 280 bar, for its reinjection into the reservoir [12]

Figure 11: Floating Production and Storage Offloading [7]

2.10: *Reservoir drainage strategy*

Initially, the drainage strategy was to maintain the reservoir pressure by re-injection of produced gas into the gas cap and oil is produced with water injection in the water zone as drive mechanism. During the first year of production it was experienced that the Not shale is sealing over the Norne Main Structure, so this non-communication between the Garn and Ile formations made the plan to be revised in such a way that gas was then injected in the water zone and the lower part of the oil zone with proper monitoring to prevent early breakthrough and increase GOR. The water injection was started in July 1998 and is being injected in the Tilje formation (water zone). Gas injection ceased in 2005 and all gas was planned to be exported. In order to avoid rapid pressure depletion in the gas cap, gas will be injected for an extended period of time.

Deaerating of the injection water has been eliminated, since the presence of oxygen in the injected seawater will also be reinjected into the reservoir.

Together, with the reduced use of chemicals owing to the elimination of deaeration, this solution will help to safeguard the environment. Injecting raw seawater, together with the produced water, has simplified the water-injection system, but has also required the extensive use of high-quality materials. [12]

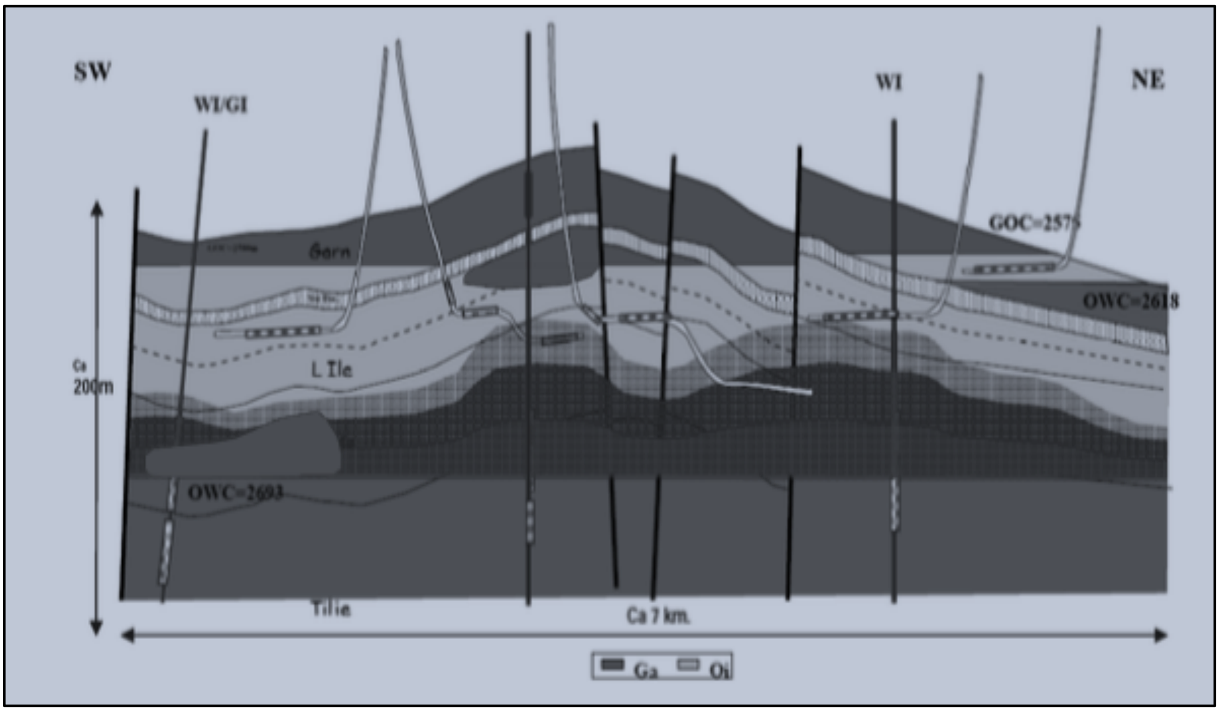


Figure 12: NE-SW Running structural cross section through the Norne Field with initial fluid contacts and current drainage strategy [7]

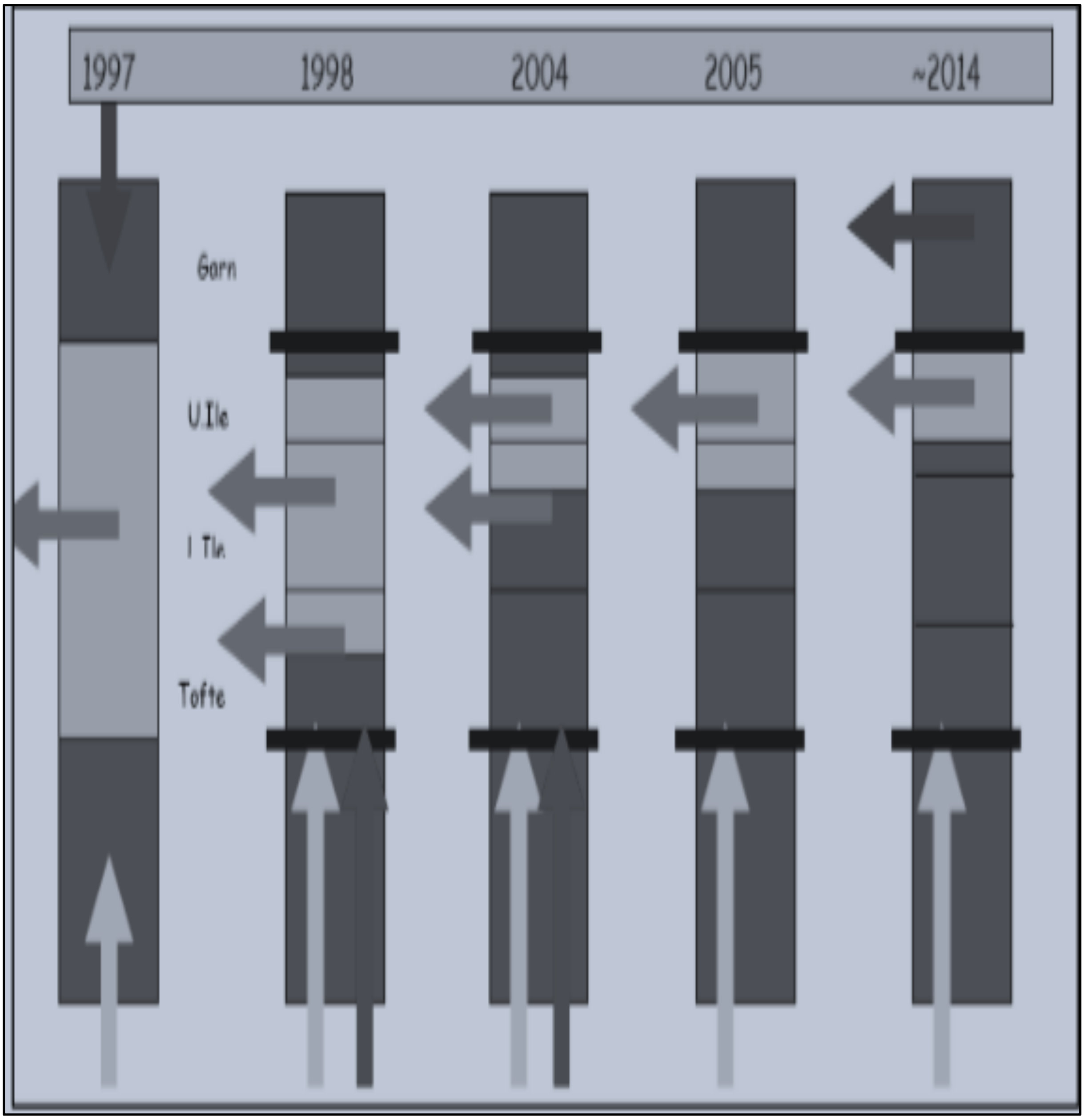


Figure 13: The drainage strategy for the Norne field from the pre-start to 2004 [7]

2.11: *Subsea system*

Subsea production facilities will comprise five well templates-three for production, one for water injection and one for combined gas and water injection. Each template has four slots and the capacity to tie in additional satellite wells.

Flexible flowlines and risers are specified. A multifunctional umbilical will be used to control and monitor the subsea system, to distribute chemicals and hydraulic fluid, as well as to supply power. The templates are being installed in northern and southern groups, placed about 4000m apart. Water depth varies between 370-390 m. One production and one water injection will make up the northern group.

Table 2: Active development of wells in the Norne Fields [6]

6608/10-B-1 BH	2006	2634-P	PRODUCTION	OIL
6608/10-B-2 H	1997	1239-P	PRODUCTION	OIL
6608/10-B-3 H	1999	1590-P	PRODUCTION	OIL
6608/10-B-4 DH	2004	2423-P	PRODUCTION	OIL
6608/10-C-1 H	1998	1422-P	INJECTION	WATER
6608/10-C-2 H	1998	1501-P	INJECTION	WATER
6608/10-C-3 H	1999	1570-P	INJECTION	WATER
6608/10-C-4 AH	2004	2342-P	INJECTION	WATER
6608/10-D-1 CH	2003	2335-P	PRODUCTION	OIL
6608/10-D-2 H	1998	1249-P	PRODUCTION	OIL
6608/10-D-3 BY2H	2005	2580-P2	PRODUCTION	OIL
6608/10-D-3 BY1H	2005	2580-P1	PRODUCTION	OIL
6608/10-D-4 AH	2003	2218-P	PRODUCTION	OIL
6608/10-E-1 H	1999	1591-P	PRODUCTION	OIL
6608/10-E-2 CH	2008	2915-P	PRODUCTION	OIL
6608/10-E-3 CH	2005	2551-P	PRODUCTION	OIL
6608/10-E-4 AH	2000	1727-P	PRODUCTION	OIL
6608/10-F-1 H	1999	1584-P	INJECTION	WATER
6608/10-F-2 H	1999	1638-P	INJECTION	WATER
6608/10-F-3 H	2000	1669-P	INJECTION	WATER
6608/10-F-4 AH	2007	2898-P	INJECTION	WATER
6608/10-K-1 H	2006	2772-P	PRODUCTION	OIL
6608/10-K-3 H	2006	2743-P	PRODUCTION	OIL
6608/10-K-4 H	2007	2830-P	PRODUCTION	OIL

These installations are tied back to the production ship by two nine-inch water-injection line and one control and service umbilical. The southern group comprises two production templates, a combined water-/gas – injection line and two control and service umbilical. The templates in each group are positioned so that the rig can enter all the slots without the need of anchoring.

2.12: *Seismic Survey and Reservoir Monitoring*

Seismic survey plays an important role in decision making and reservoir simulation for the Norne Field [13, 14]. Time lapse seismic surveys are performed and used for history matching purposes and reservoir monitoring and characterization at large reservoirs.

Techniques and methods related to these surveys can be found in different geophysics books. In terms of recovery factor, most of the subsurface oil fields in North Sea are able to achieve

50% recovery factor, but the Norne field is reported to be the sub-sea developed field with the highest oil recovery of around 60% [14].
The initial work on preparation for a benchmark case based on real data was done by [9].

2.13: Location of wells in Norne reservoir

During the development phase of the reservoir, it was taken into account that the best drainage strategy is the one that ensures high amount of petroleum recovery. The wells of the Norne field were designed based on the following principles;

- *Location of the gas injectors at the structural heights of the reservoir,*
- *Location of the water injectors at the flanks of the reservoir,*
- *Location of the oil producers between gas and water injectors for delaying gas and water breakthrough.*

As for water injection strategy, water injectors were arranged in areal distribution so as to maintain a steady rise of water level and hence a good areal sweep. Furthermore, the vertical communication in the reservoir is restricted by the cemented layers of which the only way to overcome it was to convert the drainage strategy from vertical to flank sweep. The objective was obtained by locating the water injectors towards the flanks. Moreover, water injectors are completed in the Tilje 3 up to Ile 3 formation. Finally, the locations are optimized according to gas and water breakthrough times by the use of reservoir simulation studies.

2.14: *The reservoir model*

Eclipse 100 from Schlumberger is one of the leading reservoir simulators in oil industry. It is a batch program as the user creates text file with a set of keywords that must be located in a particular section and gives a complete description of a reservoir. The Norne Field Simulation Model has a start-up time of 06th November, 1997.The dimensions are 46 × 112 × 22 in metric system, five phases are activated in the simulation (gas, oil, water, dissolved oil and vapour gas). The grid consists of 113344 cells, where 44927 are active cells and rest are inactive. The model is physically divided into two sections by a shale layer with a name NOT formations. The upper and lower sections consist of 3 and 18 layers respectively.

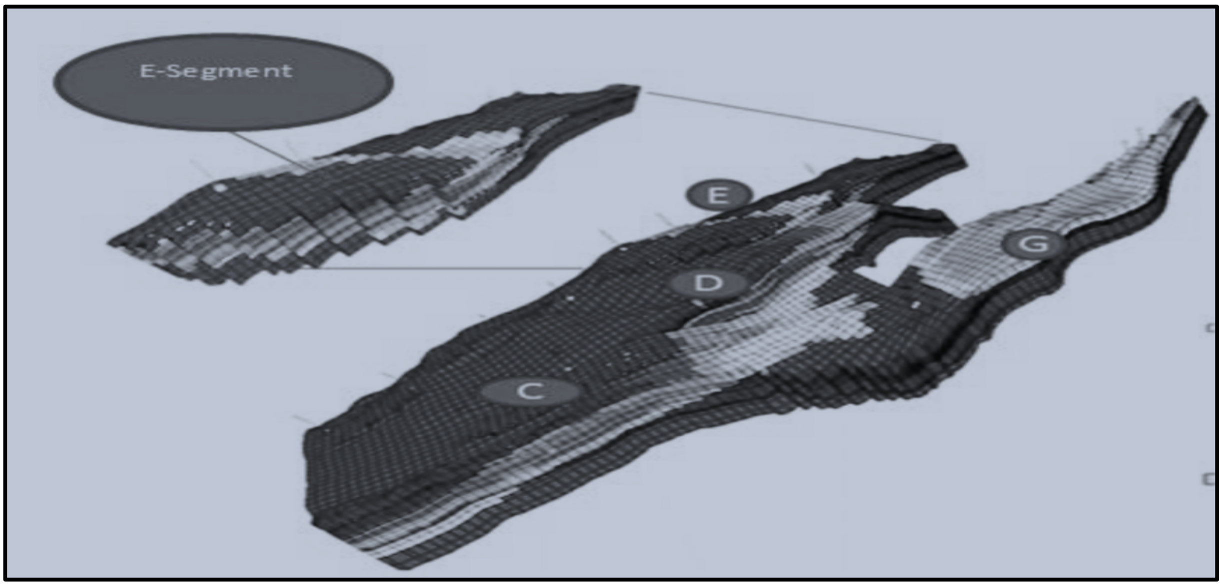


Figure 14: Norne field model, fine grids (E-Segment) and coarse grids (C, D and G Segments)

Reservoir properties are assigned to every cell then they are modified according to specific segments, wells and layers. Net-to-gross, porosity and permeability appear to have a layer-dependent structure. The defined permeability in X direction is copied to Y direction and Z direction. However, permeability in Z direction is reduced using multipliers according to a specific layer which implies that permeability in X and Y direction are the same while permeability in Z differs. Specified transmissibilities are modified further in the edit section to honour the changes in a reservoir structure made by drilling through the faults and the layers. Areas near the wells are set with increased transmissibility multipliers. For Norne field, the value has a range of 0.00075 to 20. Only Transmissibility multipliers for two faults are bigger than 1 which means there was an increased flow through these faults. The initial reservoir properties of Norne field has shown in the Table 5.

The reservoir can be subdivided into regions if there is a need to set different local properties for the field. There are 4 flux regions for each geological layer: Garn, Ile, Tofte, Tilje-top and Tilje-bottom. Thus, there are 20 regions in total in Norne field. There are transmissibility multipliers specified between each pair of neighbouring regions.

CHAPTER 3

3.0: NORNE E-SEGMENT

3.1: Introduction to E-segment of Norne field

E-segment was used in this work as a case study and is a part of the Norne field which has a total of 4 segments (C, D, E and G). This segment is separated from the rest of the field with the hypothetical constant flux boundary which implies that the fluid flowing into and out of the E-segment is equal. Thus, any change in the rest part of the reservoir theoretically has no effect on any parameter inside the E-segment. The given reservoir model shows that E-segment consists of 3 producers and 2 injectors as of 2004 shown in Figure 15 and Table 4.

The location by grid cells of E-Segment is shown by Table 3.

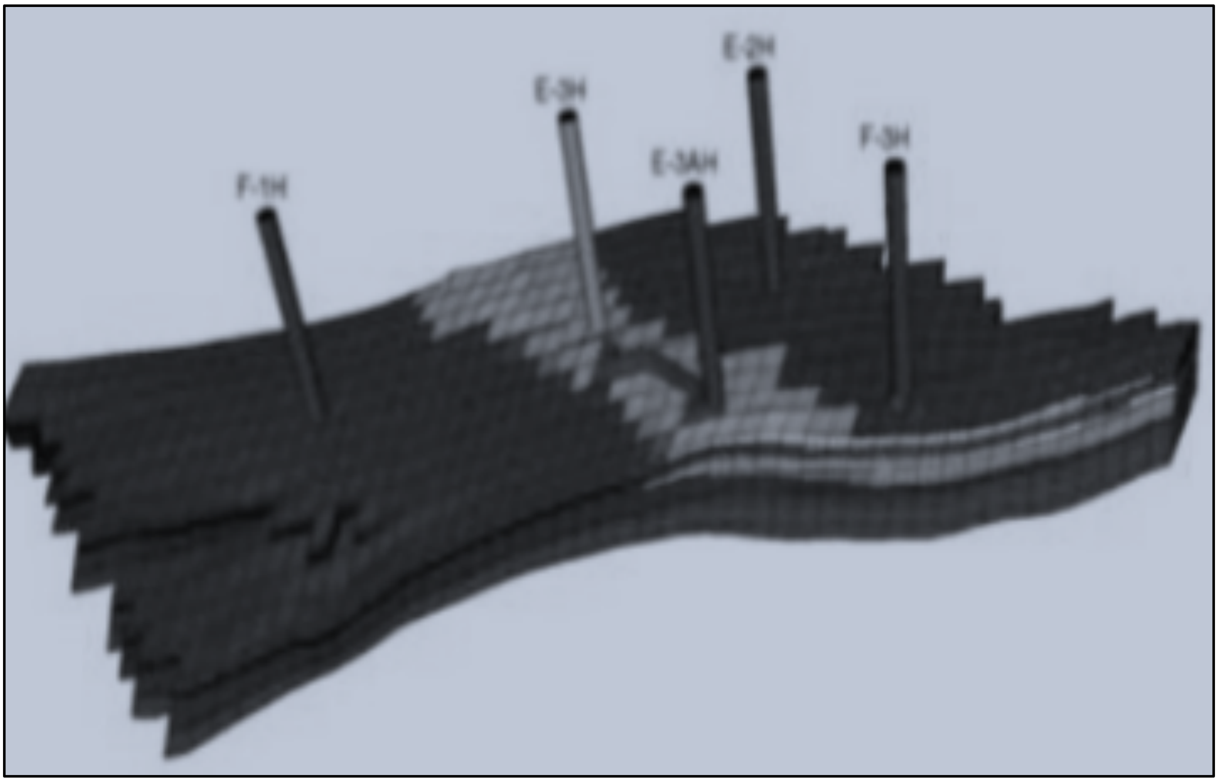


Figure 15: Localizations of wells in E-Segment

Table 3: E-Segment by Grid Cells Position.

I_1	I_2	J_1	J_2	K_1	K_2
6	*6*	*45*	*88*	*1*	*22*
7	*7*	*45*	*90*	*1*	*22*
8	*8*	*47*	*91*	*1*	*22*
9	*9*	*49*	*92*	*1*	*22*
10	*10*	*54*	*94*	*1*	*22*
11	*11*	*55*	*94*	*1*	*22*
12	*12*	*57*	*96*	*1*	*22*
13	*13*	*60*	*97*	*1*	*22*
14	*14*	*62*	*99*	*1*	*22*
15	*15*	*65*	*100*	*1*	*22*
16	*16*	*70*	*100*	*1*	*22*

Table 4: Status of wells in E-Segment

WELL NAME	TYPE OF WELL	CONTENT	STATUS
E-2H	Horizontal	Oil Production	Active
E-3H	Vertical	Oil Production	Shut
E-3AH	Vertical	Oil Production	Active
F-1H	Vertical	Water Injection	Active
F-3H	Vertical	Water Injection	Active

From Table 4, pressure maintenance is achieved by water injection and currently, two production wells are still active and another well has been plugged due to high water cut.

The key formations in this segment are Ile and Tofte which altogether contain 80% of the oil present in the Norne field and Table 6 indicates other formations penetrated by wells.

Table 5: The Norne Field Properties

Property	**Value**
Initial pressure	273 bar at 2639 m TVD
Reservoir temperature	98 ^{O}C
Oil density	859.5 Kg/m^3 API = 32.7
Gas density	0.854 Kg/m^3
Water density	1033 Kg/m^3
Oil formation volume factor	1.32
Gas formation volume factor	0.0047
Rock wettability	Mixed
Pore compressibility	4.84×10^{-5} 1/bar at 273 bar.

Table 6:Formations Penetrated by the Wells in E-Segment

Formation	Fluid available
Garn	Gas
Ile	Oil
Not	Oil (Hindered communication between Garn and Ile due to sealing)
Tofte	Oil
Tilje	Oil/water

3.2: The reservoir Fluid Properties

Figure 16 indicates how reservoir fluid properties varies with pressure during production. The fluid properties are gas formation volume factor (Bg), gas oil ration (GOR), oil formation volume factor (Bo) and viscosity.

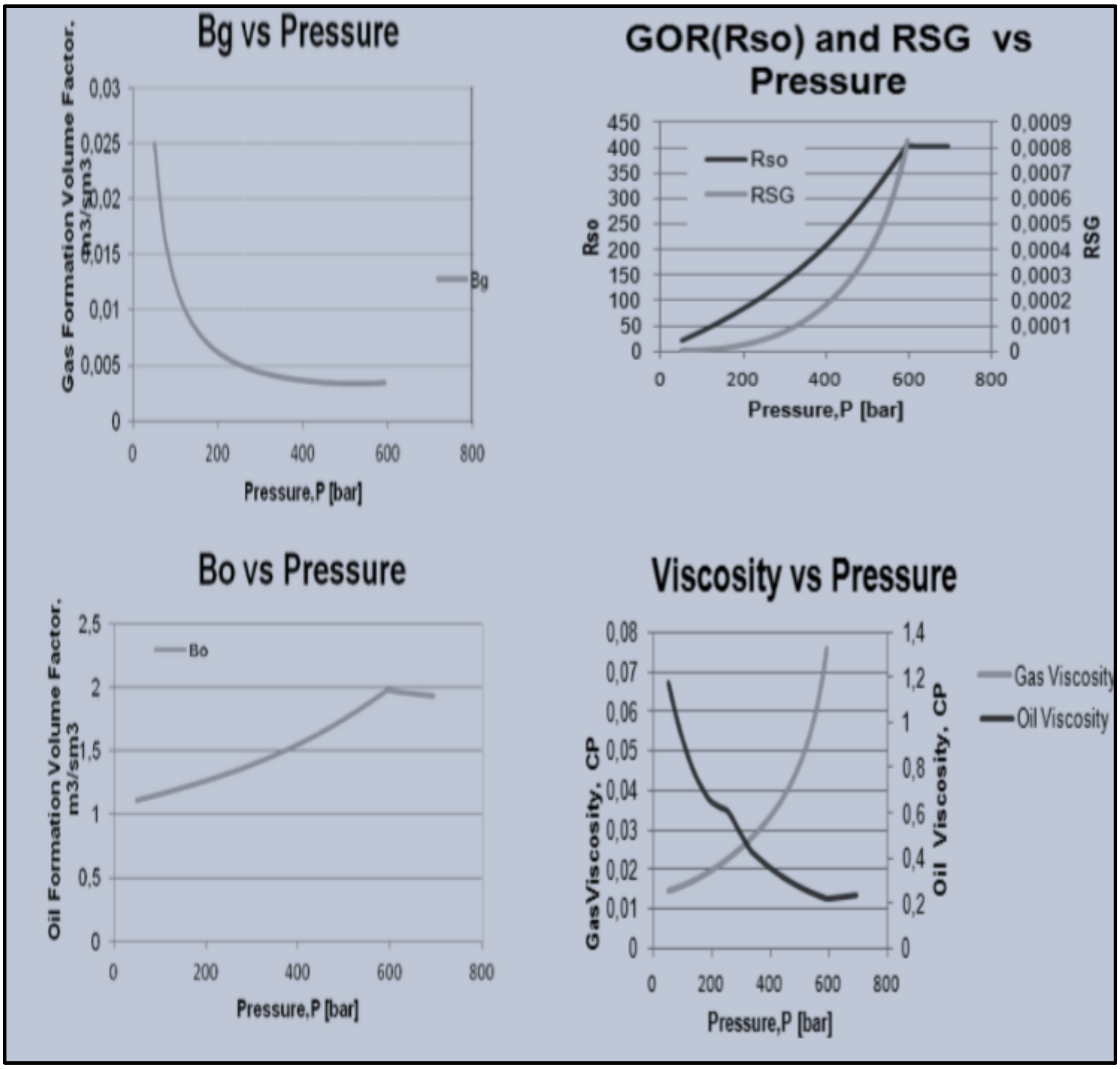


Figure 16: Variations of Fluid Properties of Norne Field with Pressure [6]

3.3: The reservoir pressure profile

The initial reservoir pressure of Norne field was 273 bars which declines with oil and gas production due to the injection of gas into the Garn formation as well as injection of water into the Tilje formation. As there was no communication between Garn and Ile formation, the injection of gas had to discontinue. Later on, gas was injected into the Tilje formation. The bubble point pressure for the Norne Main Structure is 251 bars while for the Norne-G Segment are 216 bars. The pressure profile for the Norne field is shown in Figure 17. The plot of Formation volume factor and reservoir pressure profile shows that the Norne reservoir is still in the under saturated region due to the fact the reservoir pressure is above the bubble point pressure.

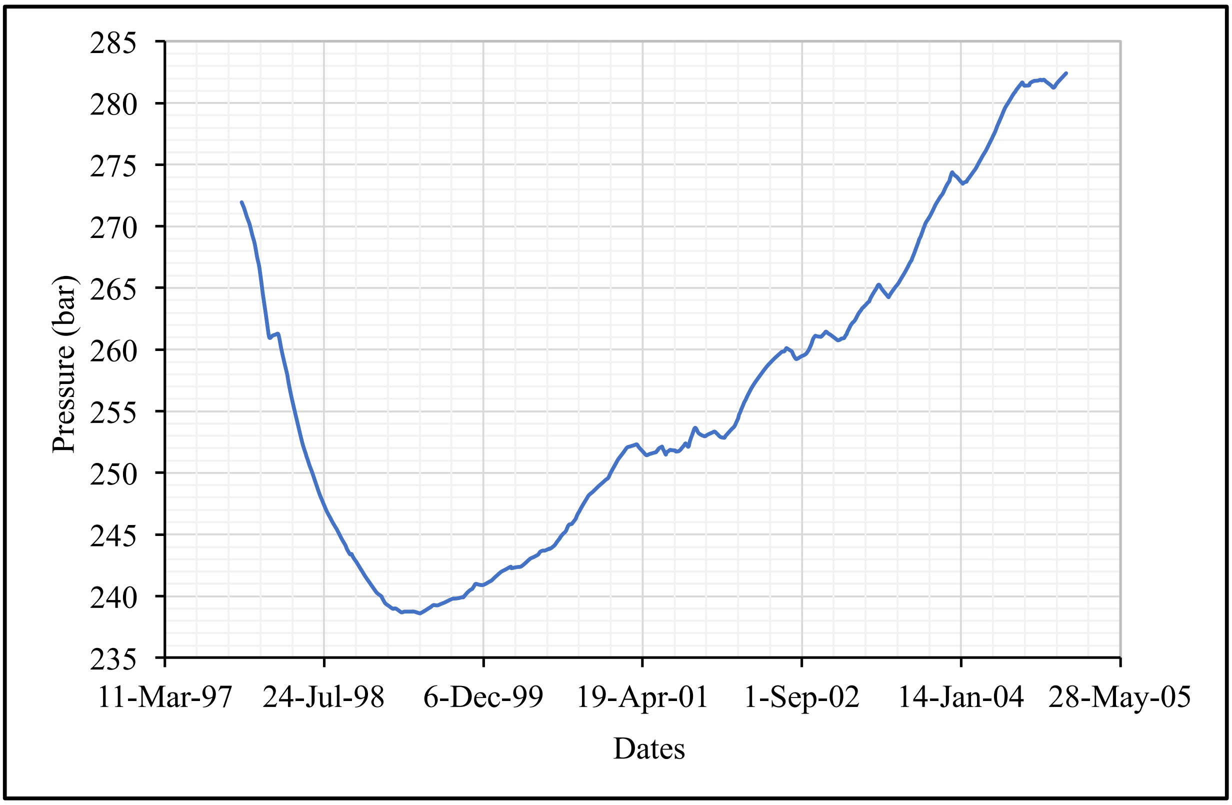


Figure 17: Reservoir Pressure for the Norne Field

3.4: Waterflooding Potentiality at the Norne E-Segment from the Benchmark Model

Since most of the oil in Norne E-segment is located in the Ile and Tofte formation, therefore these two formations are chosen as the target area for waterflooding. Figures 18 shows the oil saturations in from top all the way to the bottom of both Ile and Tofte layer in 1997 through 2004. Ile and Tofte formations are represented by layers 5–18 in the Eclipse model and oil have been produced from 1997 to 2004. In some areas, the oil saturation is still high, as can be seen from the different layers. This indicates that the best target area for further production of oil and gas from the reservoir by waterflooding is between layers 5–12 of the Ile formation. Here the oil saturation is higher than further down in the reservoir, and a lower water cut will be achievable.

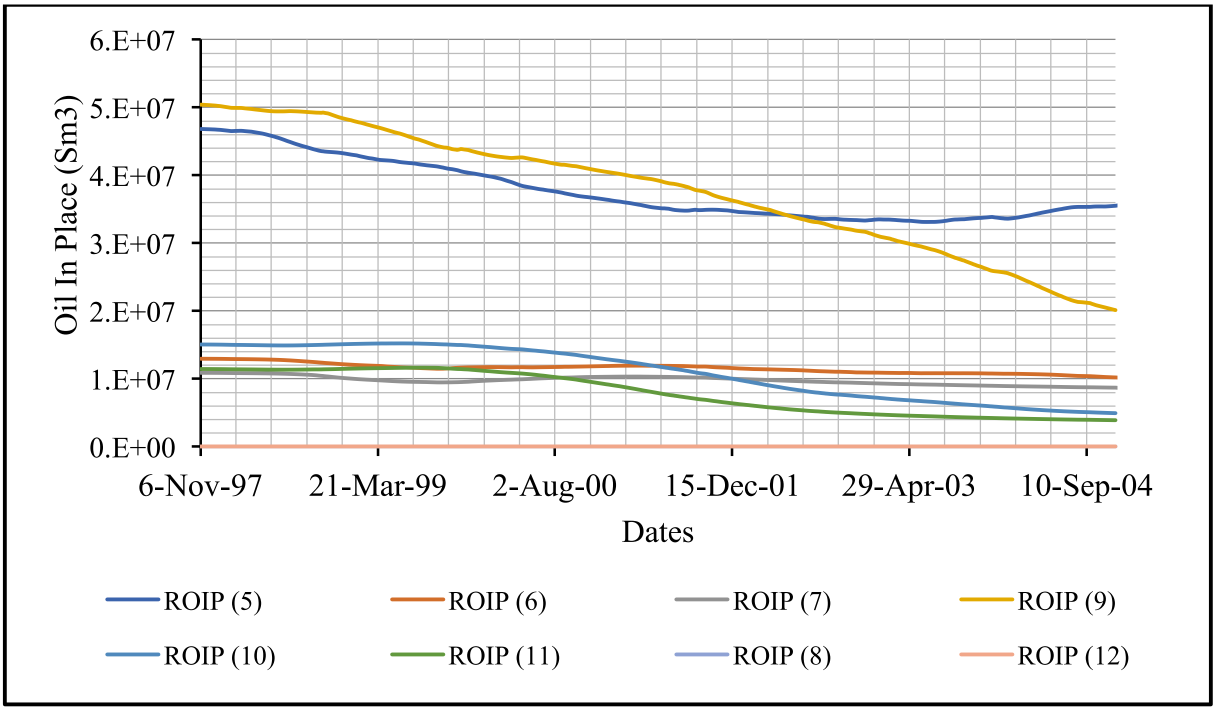


Figure 18: Variation of oil in place for layers (5-12) of E-Segment

Furthermore, the reservoir pressure curve is very sharp as Figure 17 indicates it increases with time due to addition of energy from water and gas re-injection. This implies that injection was still working out and might have recovered more than 41.3% % if production time was to be prolonged as shown in the graph in Figure 19. Figure 19 shows that as of 2004, more 41% of oil had been recovered and in the prolonged production time the field oil in place might go below 98 million Sm^3.

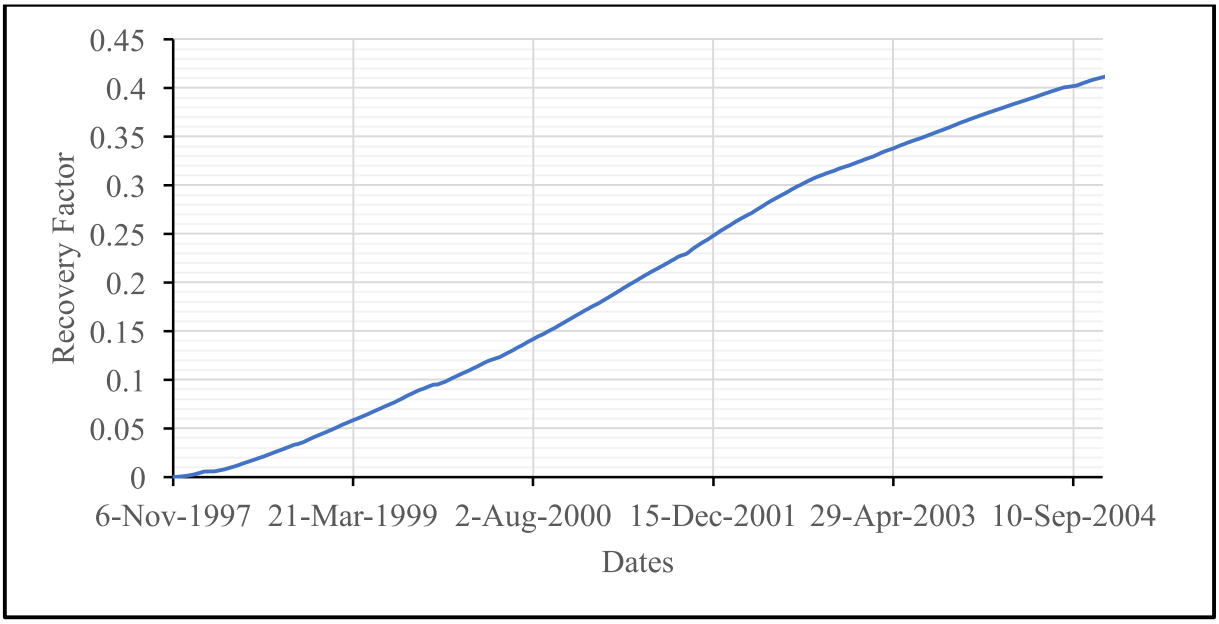


Figure 19: Recovery Factor for the Norne Field

The top of Ile formation (Layer 5) still had about 75 % of oil in place left, which means that the recovery factor was just around 25 % and there still was a lot of producible oil left which is shown in Figures 18.

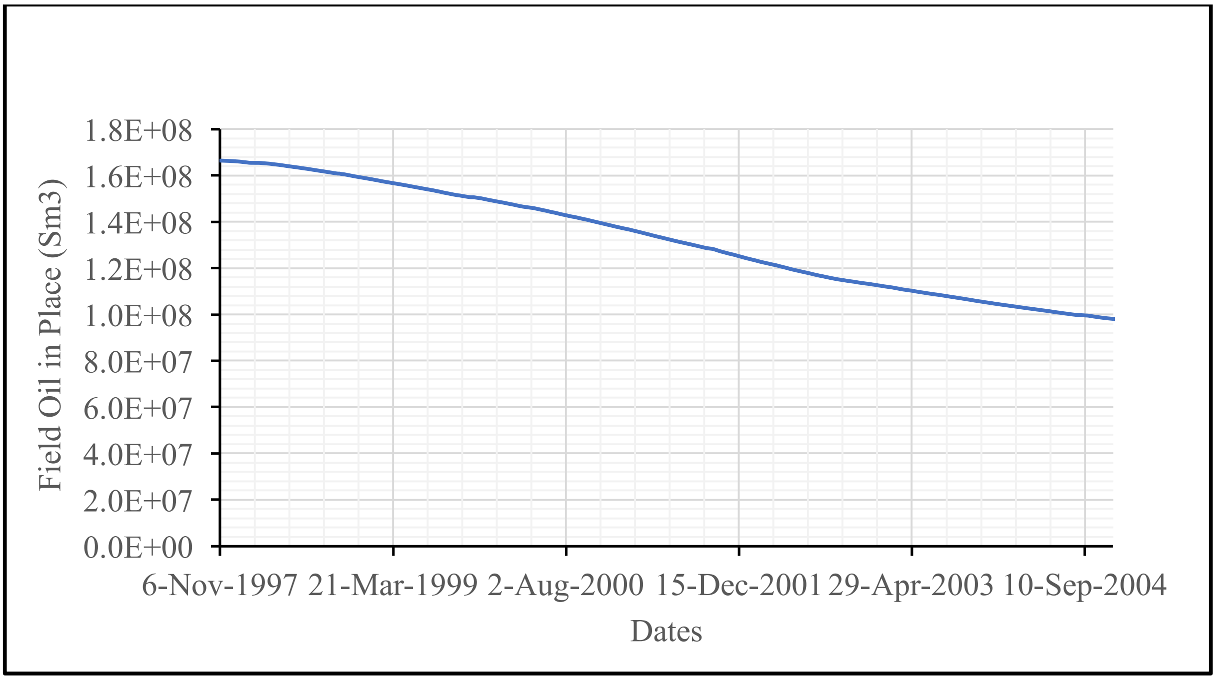


Figure 20: Field Oil in Place for the Norne Field

From all the observations which are not limited to the ones explained above but also viewing saturations in E-segment, it was concluded that there is still more oil to be further recovered.

CHAPTER 4

4.0: OVERVIEW OF PRODUCTION OPTIMIZATION USING RESERVOIR RECOVERY TECHINIQUES

4.1: *Introduction to production optimization*

Researches on optimization of oil reservoirs using reservoir recovery techniques have been conducted by different scholars. However, there are three major topics dealt when it comes to optimization of oil reservoirs; optimal well placement, history matching and production optimization. History matching is outside the scope of this work although it will be briefed as a comment on this subject. [15]

Production optimization is essentially ''Production control'' where production of oil, gas and perhaps water is minimized, maximized or targeted. For instance, we can easily maximize or target the production and/or gas while minimizing water cut (WC) or run oil production and gas-oil ratio (GOR) to set point to maintain reservoir energy.

There are several alternative production objectives because each well and field are quite different, a flexible means of controlling production is provided. In short production optimization gives more than merely maximizing production but a set point on production. The solution enables to target or minimize other calculated results such as GOR or WC.
The optimization can be done on individual wells or simultaneously the entire platform. With experience 5-20% production gains over hand optimizing due to being real time and eventually ultimate recovery may be enhanced. [16]

4.2: *Oil and gas recovery and production*

Oil and gas are naturally occurring hydrocarbons at depth beneath the Earth's surface. These hydrocarbons are stored in a special underground structure called reservoir. Reservoirs are porous and permeable with the ability of storing and transmitting fluids usually a sandstone.

Apart from the reservoir there is a special structure surrounding the reservoir namely as a Trap which is impermeable rock and can sometimes be water formation preventing hydrocarbons from escaping to nearby structures (Trapping mechanism) due to high clay content which leads to poor permeability usually a shale. Some of the trapping mechanisms are shown in Figure 22 through 26 Reservoirs are classified based on initial pressure conditions as explained by [17] as gas condensate or gas and oil reservoir.

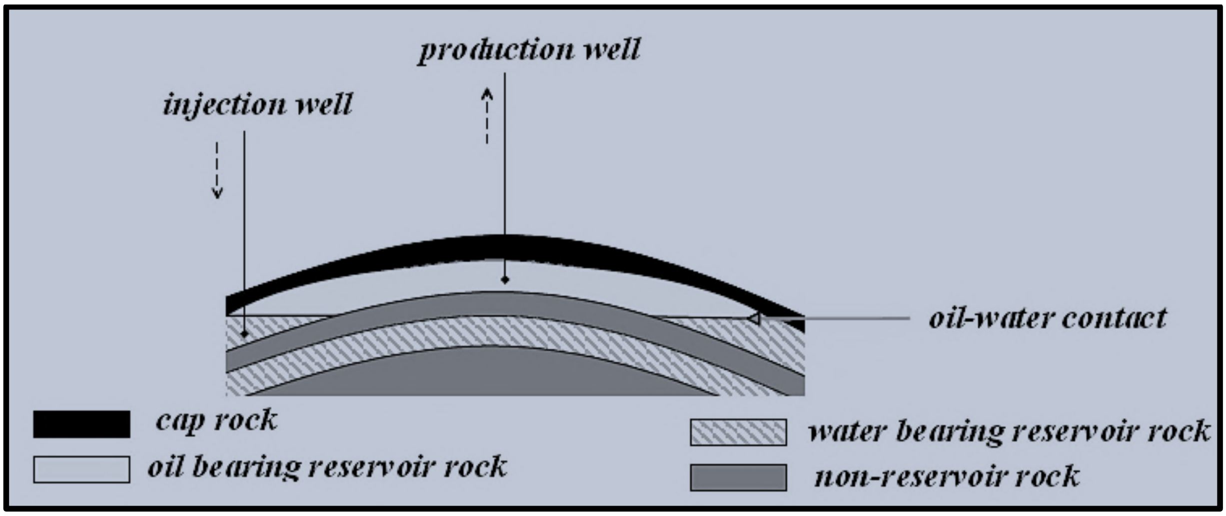


Figure 21: Oil Reservoir Cross-Section [18].

Structural

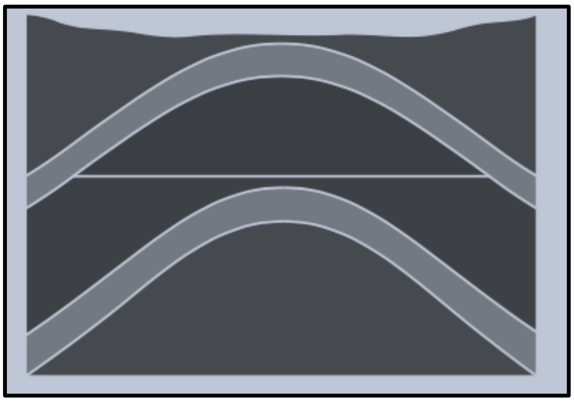


Figure 22: Anticline [19].

Stratigraphy

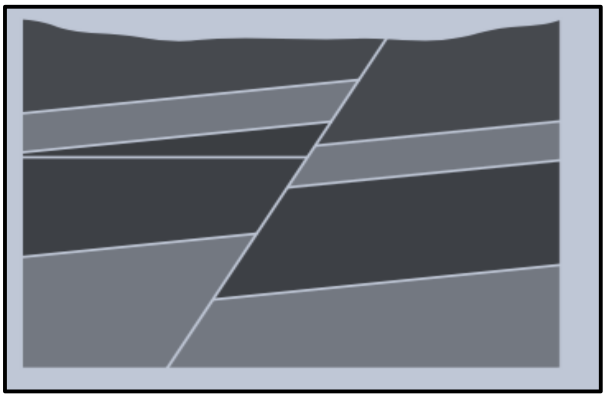


Figure 23: Trap at an unconformity [19].

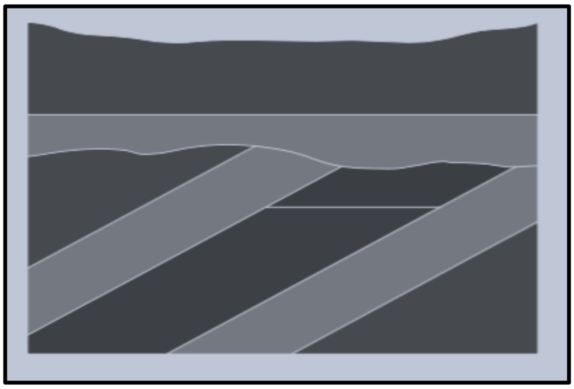


Figure 24: Fault [19]

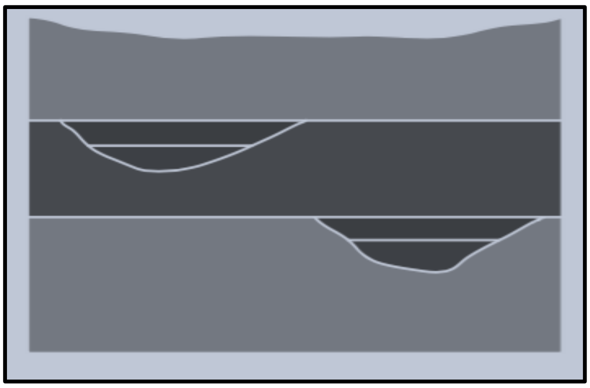


Figure 25: Buried sand channels [19]

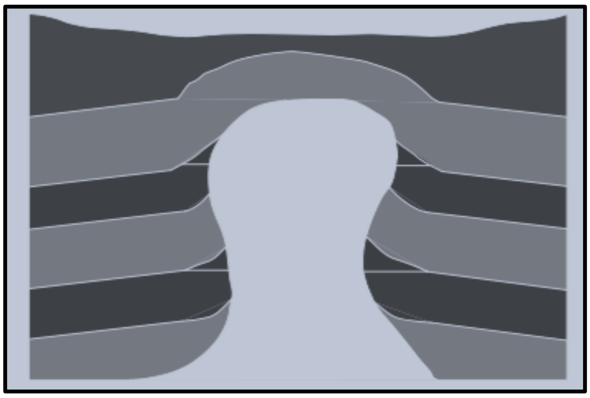


Figure 26: Salt tectonics/ dome [19].

Wells are drilled to intersect the hydrocarbon bearing zone(s) in order to produce oil and gas. There is a need of natural source of energy to allow fluid to move into the well and also pressure difference between the bottom hole and the surface where fluids are produced to.
There are three forces that govern the fluid flow in a reservoir which are viscous, gravity and capillary forces. Thus, the fluid moves into the well and get produced at the surface by virtue of its hydrostatic pressure. For a newly developed field, there is very high pressure which supports production for a certain period of time (primary production phase).

As the time goes and production continues, the available pressure decreases resulting into the decline in production and it reaches a point where production faces severe hindrance. In order to boost the reservoir pressure due to depletion, fluids are injected into the reservoir to maintain target production capacity.

This kind of production is called the secondary production phase and the most common is water flooding which is also the part of this work. However, amount of water production increases with time until a point where the process is considered to be uneconomical. A third production phase should now be employed and this is called tertiary production phase and most of the time it is called EOR for which chemical flooding is the part of this work.

This kind of recovery process is the most expensive, complex technically than the secondary recovery process because the more sophisticated fluids are injected into the reservoir. These include steam, surfactants, cheap hydrocarbon gases and polymers and so on. There is another method which is in situ combustion where air is burnt in the reservoir in order to drive production.

Gas production from gas reservoir is relatively easier compared to oil due to the fact that gas is highly compressible and easier to move. Pressure decline is also not so serious and single phase usually exists throughout production time. Water flooding is one of the cheapest means of enhancing production as explained by [20].

In order to develop a huge field, we have to overcome challenges and the main goal is to reach the highest ultimate oil recovery (UOR) by finding the best locations for new producers and injectors by identifying the grid blocks with high oil saturations.

There are several recovery techniques for developing the field and few are discussed in this project in order to maximize UOR and hence optimizing production.

Actually, several methods are used to develop fields, but none of them is comprehensive enough. Location of a new well should be considered and then its effect on the ultimate production should be investigated in order to develop a field and this method is called infill drilling combined with streamline simulation. [21].

A visualization of the Norne E-segment shows high residual oil saturation in some layers after water flooding and this has justification for the tertiary recovery and may be considered later in future work.

4.3: *Types of wells*

The type of well affects its performance. Production or injection wells can be vertical, horizontal or deviated wells. Due to technological and economic constraints, vertical wells were preferred. However, the advancement in drilling technology and the need to reduce cost of drilling many vertical wells to hit the reservoir, horizontal wells and deviated wells are now becoming popular in the petroleum industry [22]

Conventional Wells are the most common types of wells. These kinds of wells are easier and cheaper to be drilled.

Drilling conventional Wells is so advantageous because of the following factors namely;

- *They cover small contact area with the reservoir by limiting the well productivity and*
- *They are not good candidates for optimization because of insufficient installed instrumentation and control gadgets.* [23].

The disadvantages of the conventional wells are overcome by the Non-Conventional Wells (NCW) which are horizontal, highly deviated or multilateral wells and they are also referred to as advanced wells. The following are the advantages of using NCWs namely;

- *They are more cost effective than conventional wells because drilling a single NCW is equivalent to drilling many CWs.*
- *They cover more drainage area and therefore exploit the reservoir more efficiently.*

The only disadvantages of these kinds of wells is that they don't provide a great chance of controlling.

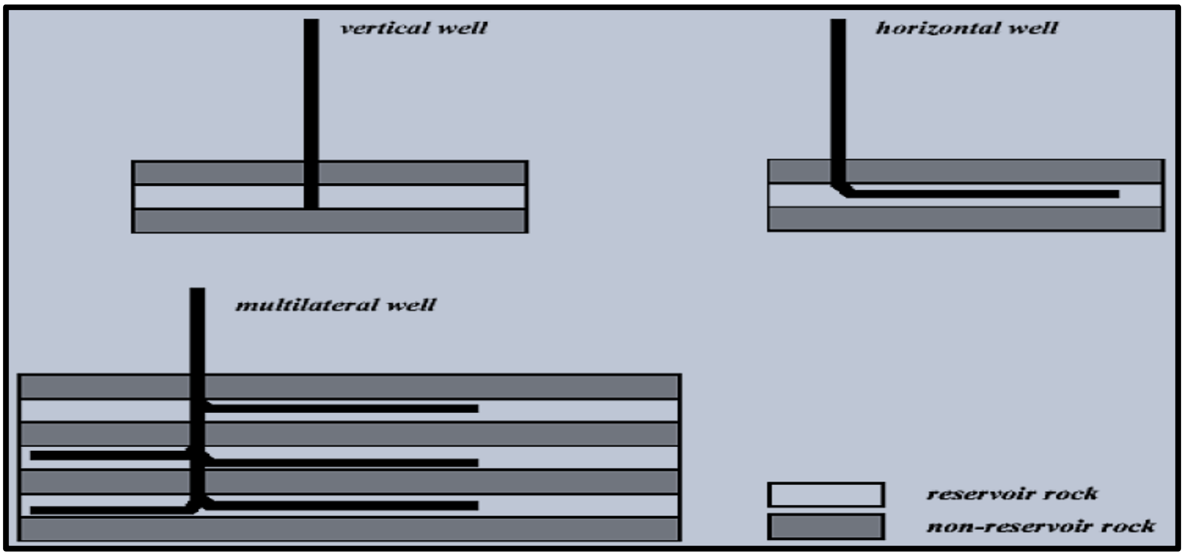


Figure 27: Types of wells [23]

Oil or gas production system primarily consist of the reservoir, well, flowlines, separator, pumps and transportation lines. The reservoir as explained earlier serves as a store for the hydrocarbon fluids. The well is a flow path for the movement of the fluids from bottom hole to the surface and also is a means of control.

The fluids move from the well to separator in flow lines. Water and/ or gas are separated from oil in the separator. The oil and gas are sent to storage tanks or sales points through transportation lines.

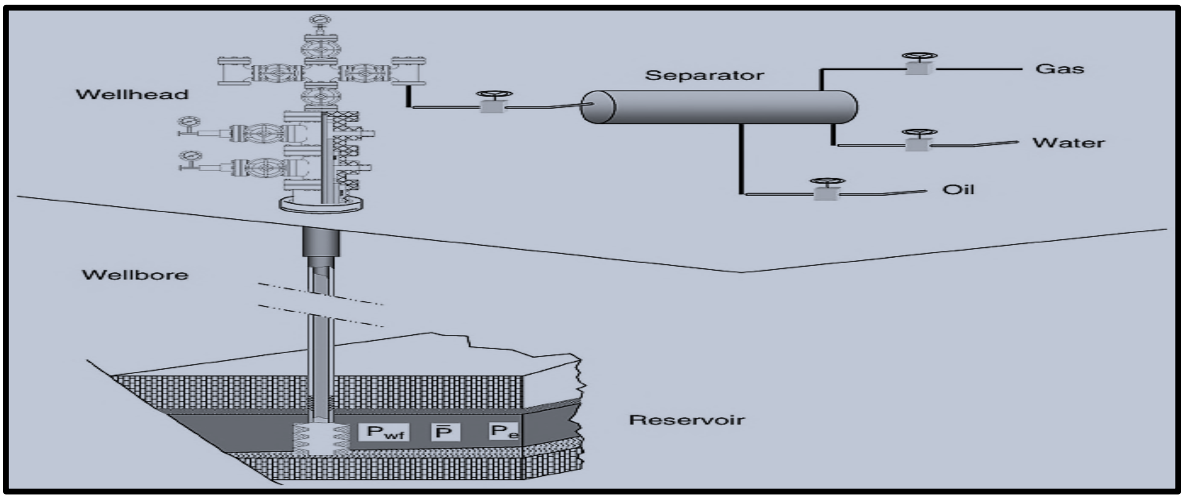


Figure 28: Petroleum Production System [17]

4.4: Well placement

Well placement is a part of development plans and well performance depends upon the location. Deciding wrong location of the well results in financial loss and recovery. [24]. Optimum well placement may be achieved by using simulators by analysing complex interactions of parameters affecting reservoir development decisions like reservoir and fluid properties, well surface networks and economic factors [25]. Optimal well placement has something to do with the oil recovery for a given oil production technique. Economically, well spacing should be small in order to get access to large area of the reservoir so as to attain highest recovery factor and hence highest NPV.

When it comes to mature field, well spacing has to be managed in order to avoid collisions with the other wells and hence the recommended 'Oriented Separation Factor' greater than 1.5 is required. [24]. As far as topography is concerned, wells can be spaced uniformly or no-uniform relative to each other. In fields already having primary production, some production wells can be converted into injectors and in other cases new injection wells may be required. Generally, injection well placement has to be well-matched with the production wells taking advantage of known reservoir structures [26].

4.5: Overview of reservoir recovery techniques

This is the fundamental of this work and addresses the physics of petroleum reservoirs and computational methods for planning of recovery of oil and gas from such reservoirs. The analysis of internal and external energy sources for reservoir production, and analysis of their influence on recovery of oil and gas from various types of petroleum reservoirs and fluid systems.

4.5.1: *Fundamentals of fluid flow in a porous media*

Porous materials are encountered literally everywhere in everyday life, in technology and in nature. With the exception of metals, some dense rocks, and some plastics, virtually all solid and semi-solid materials are 'porous' to varying degrees. A material or structure must have these two properties in order to qualify as a porous medium

1. *It must contain spaces, so-called voids or pores, free of solids, embedded in the solid or semi-solid matrix. The pores usually contain some fluid, such as air, water, oil or a mixture of different fluids.*
2. *It must be permeable to a variety of fluids, i.e., fluids should be able to penetrate through one face of a sample of material and emerge on the other side.*

There are many examples where porous media play important roles in technology and, conversely, many different technologies that depend on porous media. Among the most important technologies that depend on the properties of porous media are:

1. *Hydrology, which relates to water movement in earth and sand structures, such as water flow to wells from water-bearing formations.*
2. *Petroleum engineering which is mainly concerned with petroleum and natural gas exploration and production.*

In this work, as a petroleum engineer, the main concern is to know the quantities of fluid content within the rocks, transmissibility of fluids through the rocks, and other related properties. These properties depend on the rock, and frequently upon the distribution of character of the fluid occurring within the rock. Knowledge of the physical properties of the rock and the existing interaction between hydrocarbon system (gas, oil and water) and the formation is essential in understanding and evaluating the performance of a given reservoir.

Rock properties are determined by performing laboratory analysis on cores from reservoir to be evaluated. The cores are removed from the reservoir environment through the well during the drilling operations. There are primarily two main categories of core analysis tests that are performed on core samples regarding physical properties of reservoir rocks. These are:

Routine core analysis tests

- *Porosity*
- *Permeability*
- *Saturation*

Special core analysis tests

- *Capillary pressure*

- *Relative permeability*
- *Wettability*
- *Surface and Interfacial Tension*
- *Electrical Conductivity*
- *Pore size distribution*

These properties constitute a set of fundamental parameters by which the rock can be quantitatively described. They are essential for reservoir engineering calculations as they directly affect both the quantity and the distribution of hydrocarbons and, when combined with fluid properties, control the flow of the existing phases (i.e., gas, oil, and water) within the reservoir.

4.5.2: Immiscible displacement

Buckley-Leverett Theory

One of the simplest and most widely used methods of estimating the advance of a fluid displacement front in an immiscible displacement process is the Buckley-Leverett method.

The Buckley-Leverett theory (1942) estimates the rate at which an injected water bank moves through a porous medium. The approach uses the fractional flow theory and is based on the following assumptions:

- *Diffuse flow conditions*
- *Displacing and displaced are Incompressible fluids*
- *Flow is linear and horizontal*
- *Fluids are immiscible*
- *Gravity and capillary effects are negligible*

In many rocks, there is a transition zone between the water and the oil zones. In the true water zone, the water saturation is essentially 100. In the oil zone, there is usually present connate water, which is essentially immobile. Only water will be produced from a well completed in the true water zone, and only will be produced from the true oil zone. In the transition zone both oil and water will be produced, and at each point the fraction of the flowrate that is water will depend on the oil and water saturation at that point. Generally, the frontal advance theory is an application of the law of conservation of mass. Flow through a small volume element with length Δx and cross-sectional area 'A' can be expressed in terms of total flow rate q as:

$qt = qo + qw$ ……………………………………………………………… *(Equation 1)*

$qw = qt \times fw$ .... *(Equation 2)*

$$qo = qt \times fo = qt \times (1 - fw) \text{.........................} \textit{(Equation 3)}$$

Where q denotes volumetric flow rate at reservoir conditions and the sub-scripts (o, w, t) refer to oil, water, and total rate, respectively and fw and fo are fractional flow to water and oil (or water cut and oil cut) respectively:

$$qw = \frac{krwkA}{\mu w}\frac{dp}{dx} \ldots\ldots\ldots\ldots\ldots \textit{(Equation 4)}$$

$$qo = \frac{krokA}{\mu o}\frac{dp}{dx} \ldots\ldots\ldots\ldots\ldots \textit{(Equation 5)}$$

$$f_w = \frac{q_w}{q_o + q_w} = \frac{\frac{k_{rw}A}{\mu_w}\frac{dp}{dx}}{\frac{k_{ro}A}{\mu_o}\frac{dp}{dx} + \frac{k_{rw}A}{\mu_w}\frac{dp}{dx}} \ldots\ldots\ldots \textit{(Equation 6)}$$

$$f_w = \frac{\frac{k_{rw}}{\mu_w}}{\frac{k_{ro}}{\mu_o} + \frac{k_{rw}}{\mu_w}} = \frac{1}{1 + \frac{k_{ro}\mu_w}{k_{rw}\mu_o}} \ldots\ldots\ldots \textit{(Equation 7)}$$

ko/kw is a function of saturation. So, for constant viscosity fw is just a function of saturation.

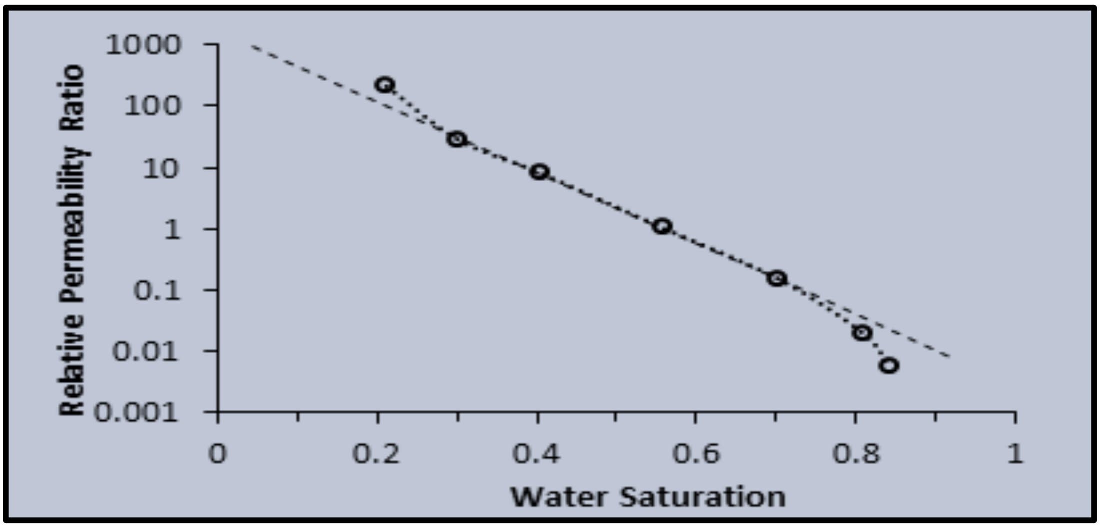


Figure 29: Semi log Plot of Relative Permeability Ratio Versus Water [17]

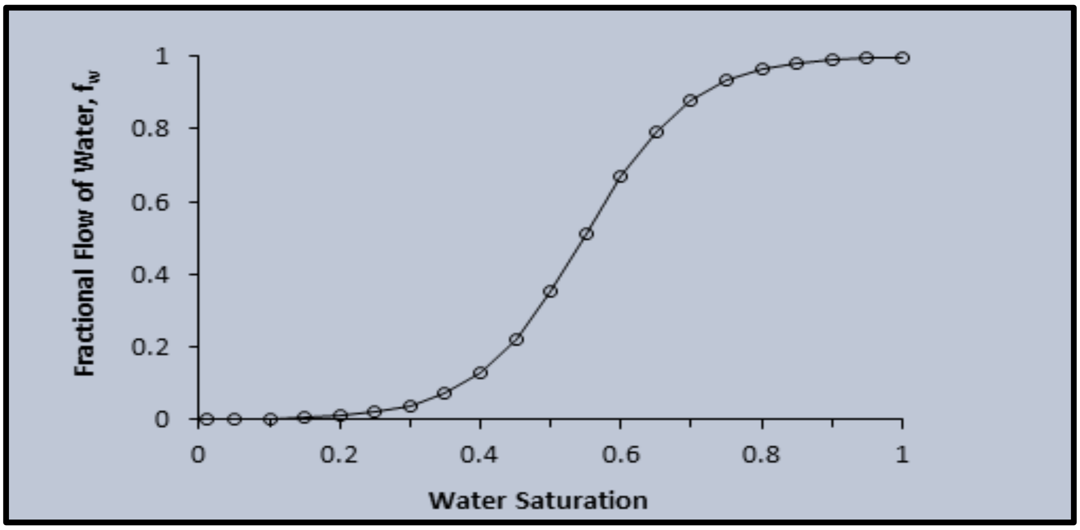


Figure 30: Fractional Flow Curve [17]

4.5.3: Miscible displacement

In an immiscible displacement process, such as water flooding, the microscopic displacement efficiency is generally much less than unity. Part of the crude oil in places contacted by the displacing fluid is trapped as isolated drops, stringers, or pendula rings, depending on the wettability. At this condition, relative permeability to oil would be almost zero and no more oil will be produced by continuing displacing fluid injection. In this situation, capillary pressure prevents the oil drops to move and pass through constrictions in the pore passages.

The limitation to oil recovery may be overcome by application of miscible displacement processes in which the displacing fluid is miscible with the displaced fluid at the condition existing at the interface between the displaced and displacing two fluids that mix together in all proportions within a single fluid phase are miscible. If the two fluids do not mix in all proportions to form a single phase, the process will be immiscible [27]. Most practical miscible agents exhibit only partial miscibility toward the crude oil itself, so some times 'solvent flooding' term is used instead of 'miscible flooding'. It should be mentioned that there is difference between 'miscibility' and 'solubility'. In contrast to the 'miscibility', 'solubility' is defined as the ability of a limited amount of one substance to mix with another substance to form a single homogeneous phase while miscibility is defined as the ability of two or more substances to form a single homogeneous phase when mixed in all proportions.

The physics of miscible and immiscible displacements are significantly different. Therefore, different factors dominate these displacements at the pore level, and different phenomena are considered in modelling them.

In immiscible displacements in porous media an interface separates the fluids. One fluid is never completely displaced by another, immiscible fluid. After the displacement has reached a steady state there will be irreducible or residual saturations. Typical oil residual in displacement by water (So_{rw}) can be 25-40% of the original oil in place (OOIP). In a capillary system, such as a porous medium, the interfacial tensions associated with the immiscible fluid interfaces play an important role in determining fluid distributions within the porous medium, as covered under the subject of capillarity. The displacement front in an immiscible displacement will be sharper at higher flow rates, or when capillary forces are neglected, On the other hand, in a miscible displacement, no interface exists between miscible fluids of different composition. In the absence of fluid/fluid interfaces, capillary forces are absent. Steady state is reached when one fluid has completely displaced the other fluid; the concept of irreducible or residual saturations does not apply. This means that by using miscible displacement process we could achieve very high 'pore scale' recovery efficiencies. Once the solvent front has moved through a volume of the porous medium containing the original oil, little to no residual oil is left behind.

Miscible displacement can be used as a secondary recovery process just after primary recovery of the oil or as tertiary recovery method at the end of water injection process.

The main oil recovery mechanisms during miscible flood are extraction, dissolution, vaporization, solubilization, condensation, or other phase behaviour change involving the crude oil, viscosity reduction, oil swelling and solution gas drive, but the primary mechanism must be extraction [28].

However, solvents that are miscible with crude oil are more expensive than water or dry gas, so instead continues solvent injection a slug of the solvent (such as Liquefied Petroleum Gas, with a size of approximately 5% of reservoir pore volume is injected that is followed by a larger volume of a less expensive fluid (chase fluid), such as water or lean or flue gas

In order to have efficient displacement of the primary (solvent) slug, ideally this secondary slug should be miscible with the primary (solvent) slug. To improve the overall sweep efficiency by Liquefied Petroleum Gas process, the hydrocarbon slug is displaced by altering the chase gas with water slug and finally with continuous gas injection.

Mobility ratio effect on displacement of oil

The basic mechanics of oil displacement by water can be understood by considering the mobilities of the separate fluids [29].The mobility of any fluid is defined as:

$$\lambda = \frac{kkr}{\mu} \dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots\dots \ (Equation\ 8)$$

Where, k is absolute permeability and k_r is relative permeability.

The manner in which water displaces oil is illustrated in Figure 31 for both an ideal and non-ideal linear horizontal waterflood

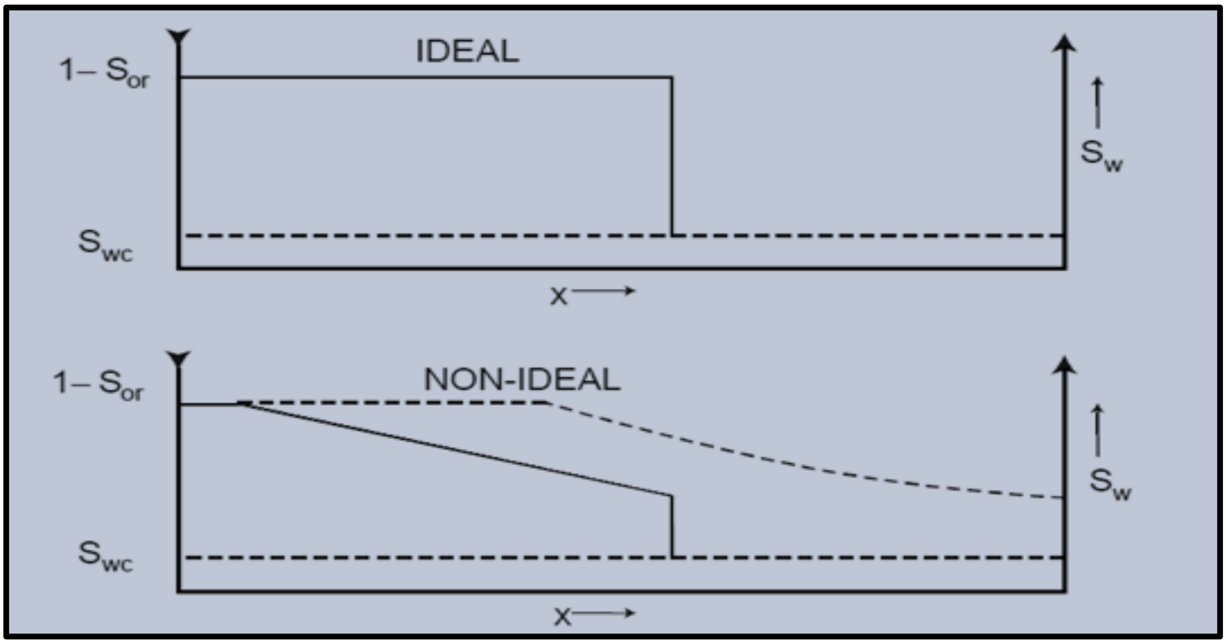


Figure 31: Water saturation distribution as a function of distance between injection and production wells for (a) Ideal or Piston –like Displacement (b) Non-ideal Displacement [30]

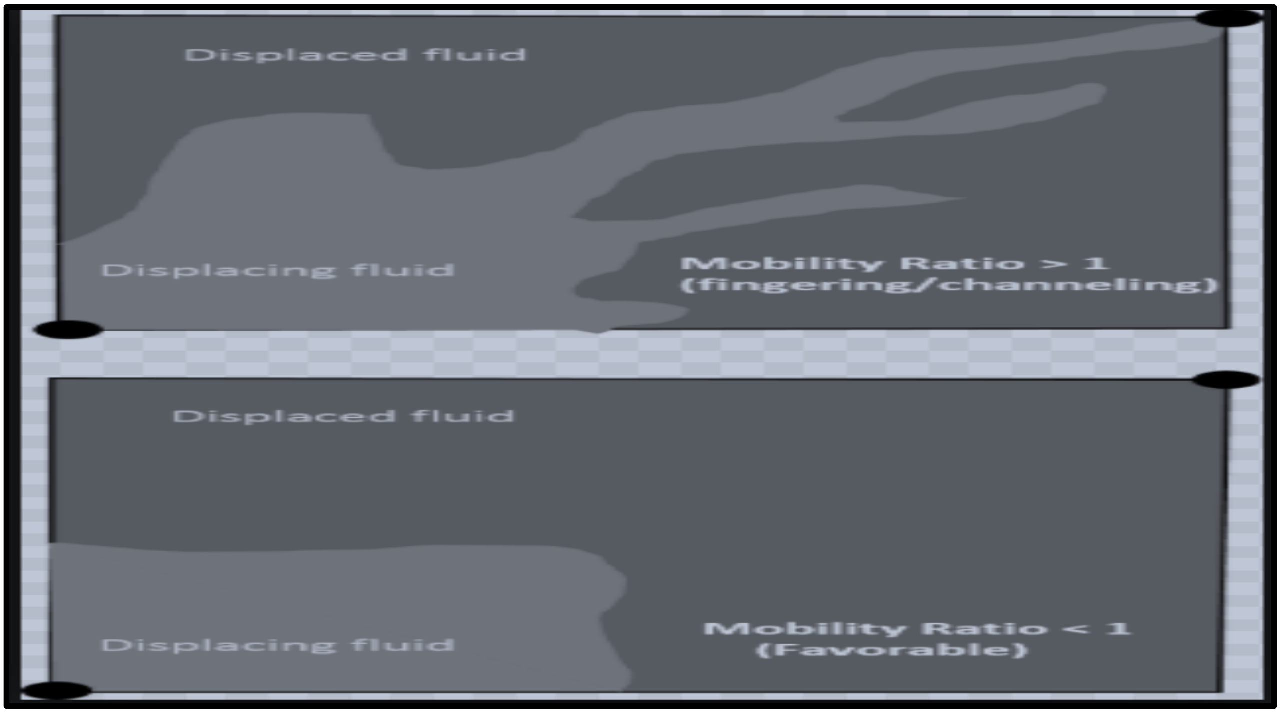


Figure 32:A schematic demonstrating improvement in displacement efficiency at lower mobility ratio [27]

In the ideal case, there is a sharp interface between the oil and water. Ahead of this oil is flowing in the presence of connate water.

$(relative\ mobility = \frac{(kro)\ at\ Sw=Swc}{\mu o} = \frac{k\prime ro}{\mu o})$……………………………………..*(Equation 9)*

while behind the interface water alone is flowing in the presence of residual oil

$(relative\ mobility = \frac{(krw)\ at\ Sw=1-Sor}{\mu w} = \frac{k\prime rw}{\mu w}$ ………………………………… *(Equation 10)*

This favourable type of displacement will only occur if the ratio $M = \frac{\frac{k\prime rw}{\mu w}}{\frac{k\prime ro}{\mu o}} \leq 1$

Where, M is known as the end point mobility ratio and, since both k'_{ro} and k'_{rw} are the end point relative permeability, is a constant.

If M ≤1 it means that, under an imposed pressure differential, the oil is capable of travelling with a velocity equal to, or greater than, that of water. Since it is the water which is pushing the oil, there is therefore, no tendency for the oil to be by-passed which results in the sharp interface between the fluids. The displacement in Figure 31(a) is, for obvious reasons, called 'Piston-like displacement' and its picture is also shown in Figure 32. Its most attractive feature is that the total amount of oil that can be recovered from a linear reservoir block will be obtained by the injection of the same volume of water. This is called the movable oil volume where:

$1(MOV) = PV(1 - Sor - Scw)$………………………………………………………..*(Equation 11)*

The non-ideal displacement depicted in Figure 31(b), which unfortunately is more common in nature, occurs when M>1. In this case, the water is capable of travelling faster than the oil and, as the water pushes the oil through the reservoir, the latter will be by-passed. Water tongues or fingers develop leading to the unfavourable water saturation profile.

Ahead of water front oil is again flowing in the presence of connate water. This is followed, in many cases, by a water flood front, or shock front, in which there is a discontinuity in the water saturation. There is then a gradual transition between the shock front saturation and the maximum saturation Sw = 1- Sor. The dashed line in Figure 31(b) depicts the saturation distribution at the breakthrough time. In contrast to the piston-like displacement, not all of the movable oil will have been recovered at this time. As more water is injected, the plane of maximum water saturation (Sw = 1-Sor) will move slowly through the reservoir until it reaches the producing well at which time the movable oil volume has been recovered.

Unfortunately, typical cases it may take five or six MOV's of injected water to displace the one MOV of oil. At a constant rate of water injection, the fact that much more water must be injected, in the unfavourable case, protracts the time scale attached to the oil recovery and this is economically unfavourable. In addition, pockets of by-passed oil are created which may never be recovered.

An even more significant parameter for characterizing the stability of Buckley Leverett displacement is the shock front mobility ratio, Ms, defined as:

$$Ms = \frac{\frac{(Kro) at\ Swf}{\mu o} + \frac{(Krw) at\ Swf}{\mu w}}{\frac{k'ro}{\mu o}} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(Equation\ 12)$$

From the equation above, the relative permeabilities in the numerator are evaluated for the shock front water saturation, S_{wf}. [31] has shown using theoretical argument backed by experiment, that Buckley-Leverett displacement can be regarded as stable for the less restrictive condition that Ms < 1. If this condition is not satisfied there will be severe viscous channelling of water through the oil and breakthrough will occur even earlier than predicted using the Welge technique.

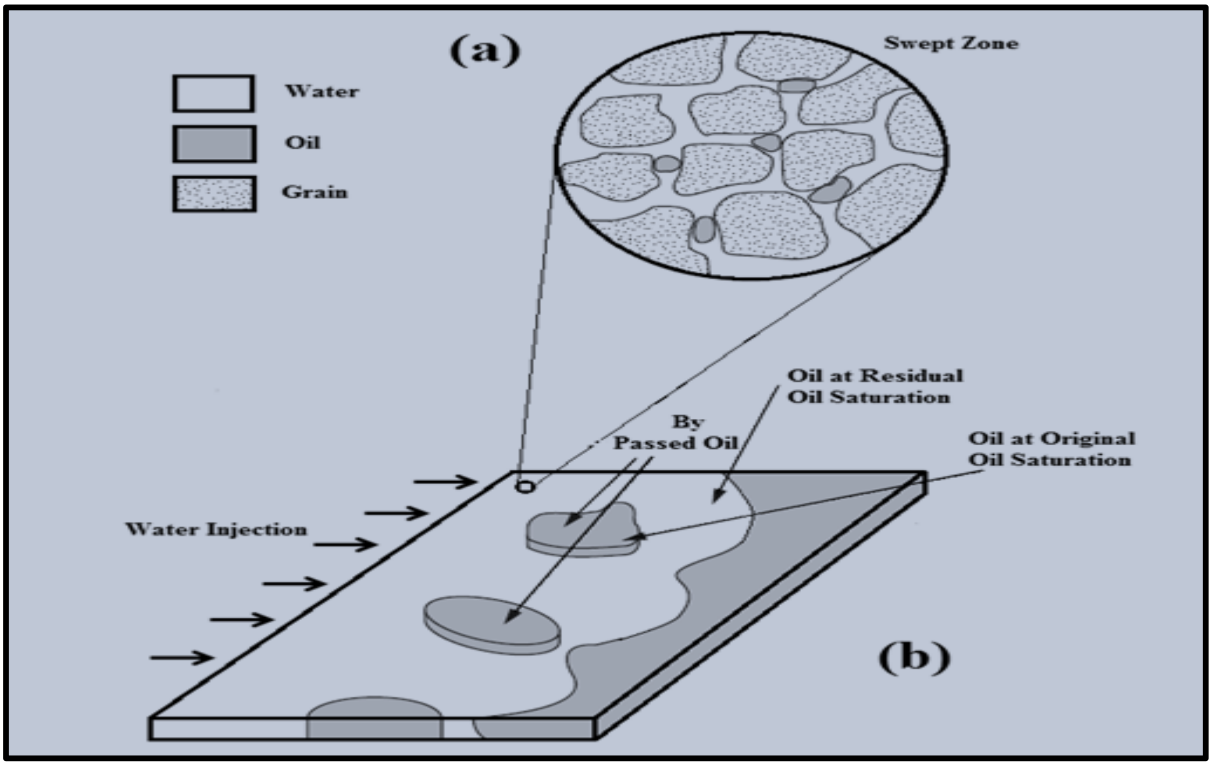


Figure 33: (a) Microscopic displacement (b) Residual remaining after a Waterflood [20]

4.6: Classification of Recovery mechanisms

Recovery of hydrocarbons from an oil reservoirs is commonly recognized to occur in several stages which are primary, secondary, tertiary recovery as shown in Figure 34 through 36.

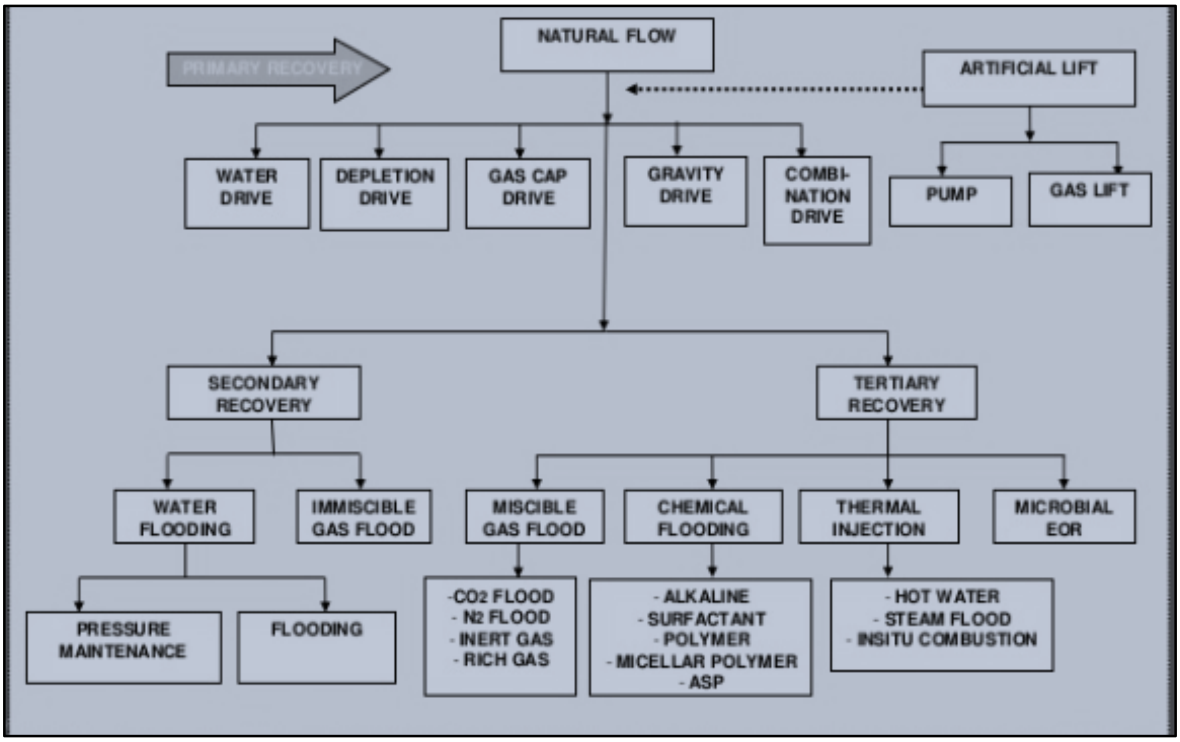


Figure 34: The Hierarchy of Recovery Mechanisms *[29]*

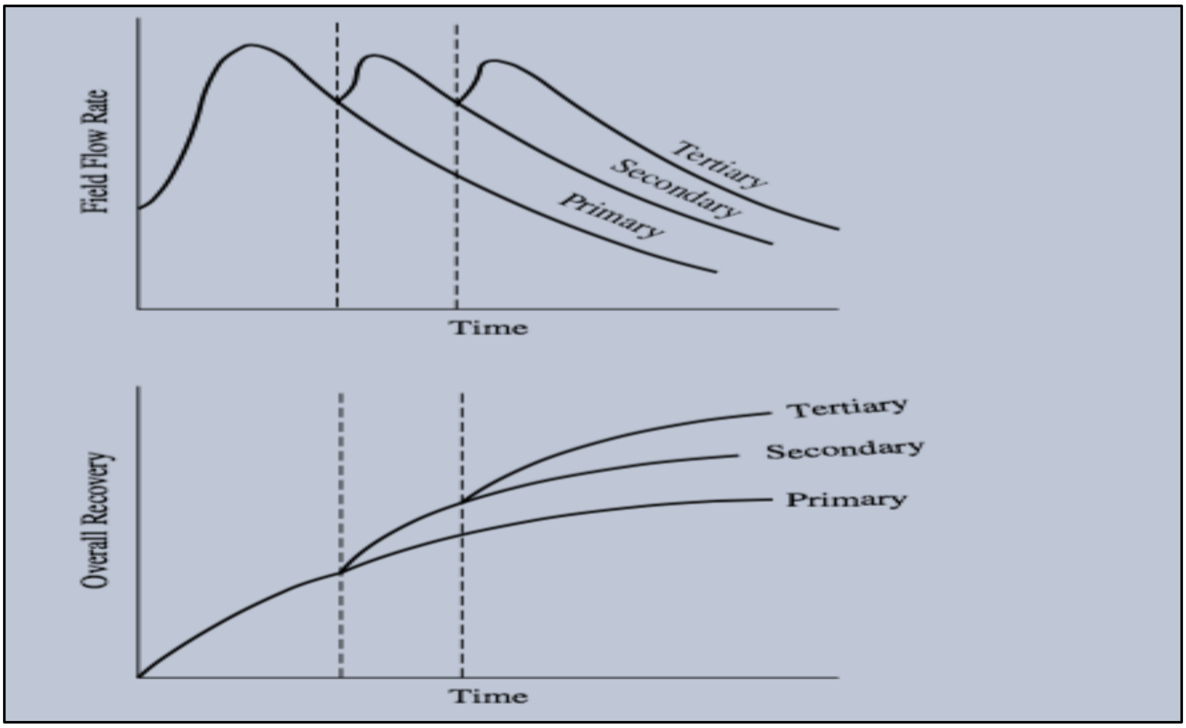


Figure 35: Oil Recovery Category *[32]*.

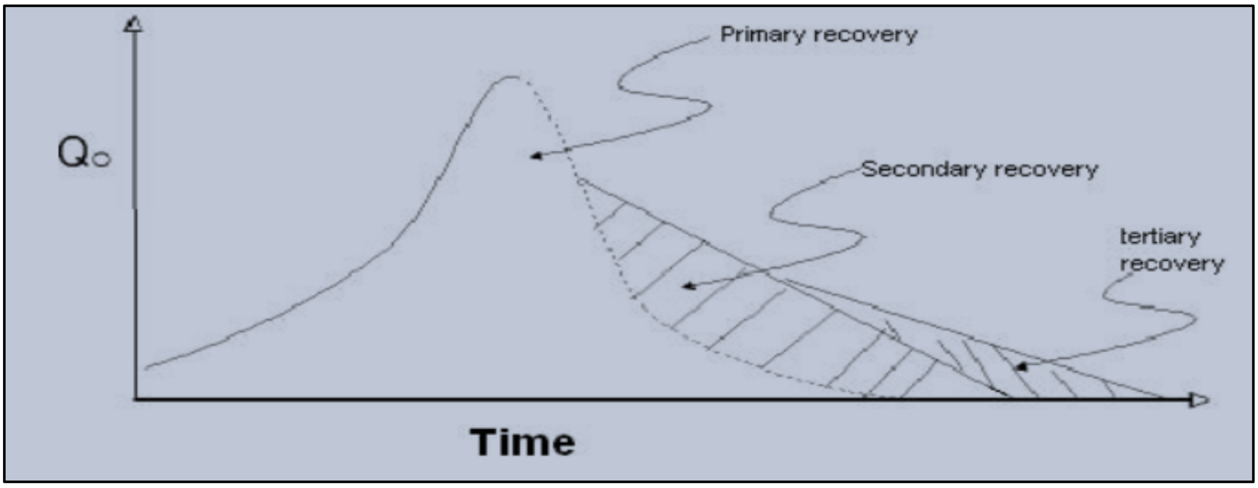


Figure 36: Cumulative Oil Production Category *[32]*

4.6.1: Primary drive mechanisms

The natural sources of energy that enable oil and gas to flow from the reservoir to the surface are called primary drive mechanisms.

The categories of these mechanisms include;

1. Rock compression (minimal)
2. Solution gas (depletion) drive
3. Gas cap drive
4. Water drive
5. Gravity drainage
6. Combination or mixed drive

If these mechanisms appear in the reservoir system as combined are referred to as combination drive. [17].

Table from AAPT wiki http://wiki.aapg.org/Drive_mechanisms_and_recovery

Drive Mechanism	Energy source	Recovery % OOIP
Solution gas drive Evolved gas Gas expansion	Evolved solution gas and expansion	20-30 18-25 2-5
Gas Cap drive	Gas cap expansion	20-40
Water drive Bottom Edge	Aquifer expansion	20-60 20-40 35-60
Gravity drainage	Gravity	50-70

The above-mentioned drive mechanisms will actually indicate the requirement and extent to which water flooding is required in a particular filed. In real sense, when primary drive mechanism fails to deliver sufficient energy to produce fluids from reservoir some additional energy will be required in order to overcome such shortage of energy. Primary recovery methods are described by Figure 37 through 40.

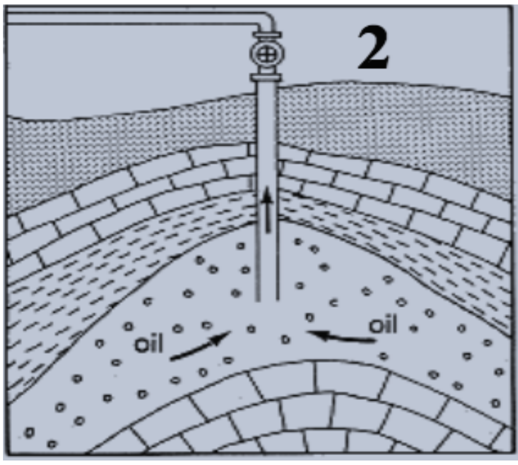


Figure 37: Solution Gas Drive [32]

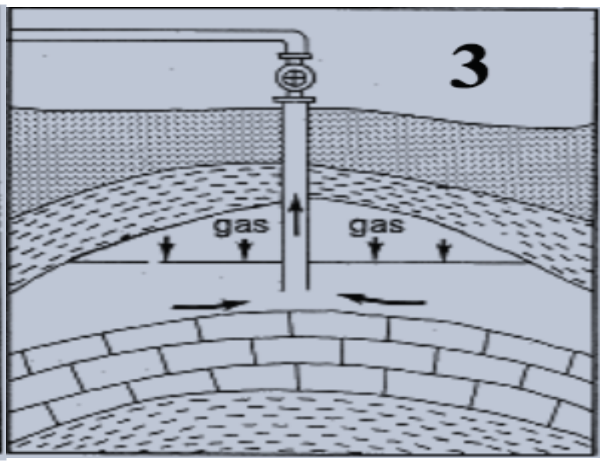


Figure 38: Gas Cap Drive [32]

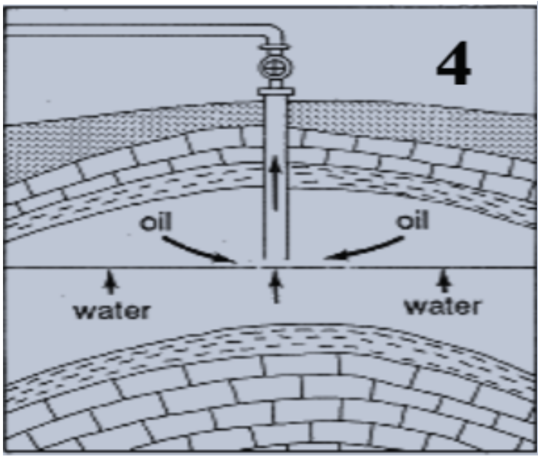


Figure 39: Water drive [32]

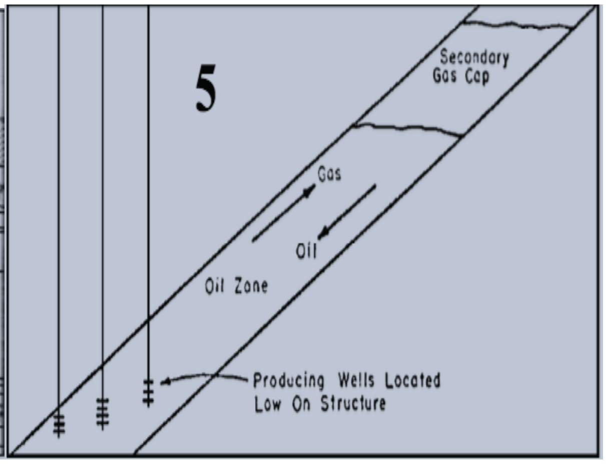


Figure 40: Gravity drainage [32]

Thus, a reservoir with a very strong aquifer or good gravity drainage will normally not require additional energy (Water flooding) since because they have sufficient energy to get oil into the surface. On the other hand, reservoirs with weak aquifer, depletion drive, small gas cap or inefficient water drive are good candidates for water flooding [33].

4.6.2: Secondary drive mechanisms

4.6.2:1: Overview of Waterflooding Mechanism

General Principles and Challenges

Waterflooding is the processing of injecting water through an injection well into the reservoir for pressure maintenance as well as for displacing and producing incremental oil after (or sometimes before) the economic production limit has been reached and producing to the well. Basically, this is the secondary recovery system and has been in use for more than past 100 years but gained popularity in 1950's. It is one of the simplest and perhaps economical means of oil recovery [20].

The key factors that drove water flooding's development and increasing use were.

- *Water is inexpensive*
- *Water generally is readily available in large quantities from nearby streams, rivers, or oceans, or from wells drilled into shallower or deeper subsurface aquifers.*
- *Water injection effectively made production wells that were near the water-injection wells flow or be pumped at higher rates because of increased reservoir pressure* [34].

Rationale for waterflooding

The principal reason for waterflooding an oil reservoir is to increase the oil-production rate and, ultimately, the oil recovery. This is accomplished by ''voidage replacement''-injection of water to increase the reservoir pressure to its initial level and maintain it near that pressure. Actually, water displaces oil from the pore spaces, but the efficiency of such displacement depends on many factors of which oil viscosity and rock characteristics are among them.

Voidage replacement has been also used to mitigate additional surface subsidence in oil fields such as Wilmington (California, US) and Ekofisk (North Sea. In Wilmington oil field's reservoirs, the high porosity of the unconsolidated sandstones and in the Ekofisk oil field, the chalk reservoir rock had compacted significantly when the reservoir pressure was drawn down during primary production.

SPE has published three significant and in-depth books that addresses waterflooding technology over the past 40 years and which are written by Willhite [35], Craig [36] and Rose et al [37].

In water flooding, water is injected into one or more injection wells while the oil is produced from surrounding producing wells spaced according to the desired patterns [34]. There are many different waterflood patterns used in the industry, the common of which are illustrated in Figure 43.

There are two main purposes for which water is injected into a reservoir [33]

- *To increase oil recovery into semi depleted and depleted reservoir and*
- *To maintain pressure into these kinds of reservoir and hence to sustain production rates.*

Factors to be considered when doing water flooding

According to [32], prior to water injection the following reservoir properties have to be understood;

I. *Lithology and Rock properties*

According to [32], the type of the rock and its formation properties has an effect on the water flooding process and these properties are porosity, permeability, clay content and net pay thickness. Due to heterogeneity of the reservoir, reservoir rock influences fluid flow process. The injected fluid flows through highly permeable areas leaving impermeable areas un-swept [38]

II. *Fluid properties*

The fluid properties determine the suitability and efficiency of water flooding significantly. These properties are mainly fluid viscosity and density at reservoir conditions. Oil viscosity determines mobility ratio and it is very important in controlling the sweep efficiency [32]. The effect is as shown in Figure 15. The fluid with low viscosity has high mobility regardless of its low permeability, and vice versa(http://petrowiki.org/Waterflooding).

III. *Reservoir Depth*

The depth of reservoir affects technical and economic parts of water flooding. This is due to the fact that maximum water injection pressure increases with depth and cost of taking oil from deeper wells limits the maximum water cut that can be accepted. Eventually, reduces the ultimate recovery factor and increase project operating cost. However, shallow reservoirs require low water injection pressure as it has to be less than fracture pressure to avoid pressure parting [32].

IV. *Reservoir Geometry*

Areal geometry of reservoir dictates the location of injection wells and for the case of offshore field, it determines the location and number of platforms to be used. It also determines the means to be used in producing a reservoir through water injection [32].

Waterflooding is the dominant means of production among secondary recovery methods which lead to present high production rates [39]. The factors which popularize when it comes to secondary production /recovery phase as discussed by [39] are namely;

- *The availability of water*
- *Mobility of water in the oil bearing formation*
- *Ease of injection and*
- *Displacement efficiency possessed by water.*

In ideal sense, the injected water sweeps oil from the point of injection towards the production well which get produced to the surface. In real sense, this is not so easily due to heterogeneity of reservoir which means that the properties of reservoir vary spatially in such a way that the degree of variability depends on depositional environments as well as the factors which led to reservoir formation which include dolomitizing, compaction, solution and cementation. The properties with high heterogeneity includes porosity, permeability, saturation, thickness, fractures and faults and rock facies [32].

Obviously, the injected water will flow through the easiest paths with low resistance and hence high permeability zones and through conductive fractures, finally it bypasses pools of oil and get its way into the production wells. This process reduces the efficiency of sweeping and finally the ultimate recovery.

However, in offshore fields, waterflooding is applied from the beginning in order to get rid of the risk that the oil and aquifer column may not be continuous as shown in Figure 20 where they are separated by the sealing fault. The occurrence of such segregation may not be detected by appraisal development since data at that period are collected under static condition [2].

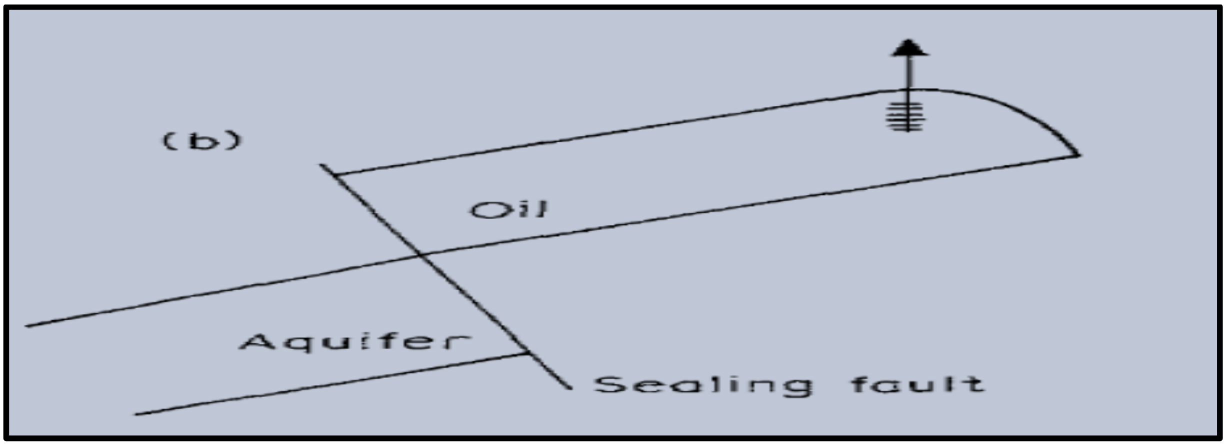


Figure 41: Aquifer-oil column separated by the sealing fault [30]

Water will also be produced and the amount of water produced increases with time until uneconomical point reaches, a point where the cost of injection and treatment of produced water outweighs the realizable oil sales. Unfortunately, Due to poor sweep efficiency only about one-third of the original oil in place is recovered even with water flooding.

The remedies to poor sweep efficiency are mentioned below; [40]

- *Mechanical isolation*
- *Squeeze cementing and*
- *Use of polymeric materials*

There is another alternative which now receives great attention in the Petroleum Industry and this is the installation of both smart injection and production wells [30].

A smart well is an unconventional well with multi-segment completion. Each segment is equipped with inflow control valves (ICVs) so that the flow can be controlled independently. The well has features which are able to delay or avoid early water breakthrough. [41]

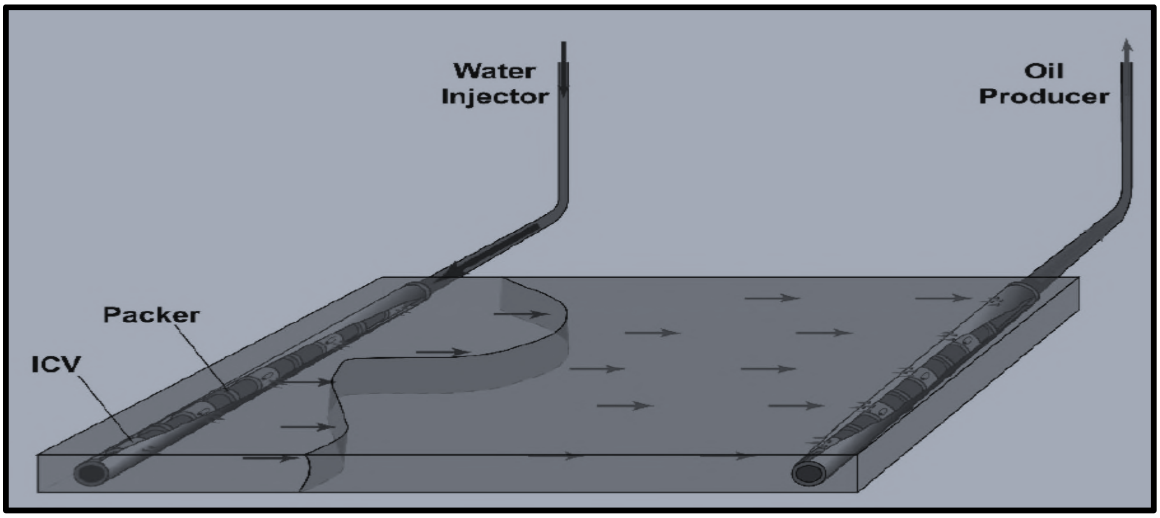


Figure 42: Heterogeneous reservoir with two smart wells[18]

Design and Mechanism of Waterflooding

Several critical factors have to be considered in order to design Water flooding [33] namely;

- *Reservoir geological understanding*
- *Reservoir and fluid properties*
- *Water flooding patterns and*
- *Well spacing*

The following discussion is based on the above mentioned critical factors;

Reservoir geological understanding

This is required in order to understand the reservoir rock so as to evaluate a field waterflooding project. In the beginning, the understanding should be based on knowing the depositional environment at the pore and reservoir levels and possibly also several levels in between. Then, structures, shale layers, faults and other flow barriers must be determined to understand the interconnectivities among the various parts of the reservoir, particularly the injector/producer connectivity.

Finally, the water/oil/rock characteristics need to be understood because they control wettability, residual oil saturation to waterflooding, and the oil relative permeability at higher water saturations. Upon these needs, there is a need of a development geologist on the waterflood-evaluation team.

All oil reservoirs in the way the rocks are formed are heterogeneous in nature. The primary geological in waterflooding evaluation is to determine the nature and degree of heterogeneities that exist in a particular oil field.

Reservoir heterogeneities can take forms, including

- *Interbedded hydrocarbon-bearing layers that have significantly different rock qualities-sandstones or carbonates.*
- *Shale, anhydrite, or other impermeable layers that partly or completely separate the porous and permeable reservoir layers.*
- *Varying continuity, interconnection, and areal extent of porous and permeable layers throughout the reservoir.*
- *Fracture trends that developed because of regional tectonic stresses on the rock and the effects of burial and uplift of the particular rock layer.*
- *Directional permeability trends that are caused by the depositional environment or by diagenetic changes.*
- *Fault trends that affect the connection of one part of an oil reservoir to adjacent areas, either because they are flow barriers or because they are open conduits that allow unlimited flow along the fault plane*. [42]

4.6.2.2: Flood Patterns and Well Spacing

These also affects the efficiency of flooding process. Pattern is the way/fashion in which injection and production wells are arranged. There are two broad categories of water flooding patterns namely;

- *Repeated patterns and*
- *Peripheral patterns*
- *Crestal and basal patterns*

Repeated Patterns

This involves sequential repetition of a particular geometrical arrangement of wells. Common arrangement is square-spacing. Various types of repeated patterns include;

- *Direct line drive*
- *Staggered line drive*
- *Five spot*
- *Nine spot and*
- *Seven spot pattern*

The types of repeated patterns are discussed below;

- *Direct line drive-The lines of injection and production are directly opposed to each other. The pattern is characterized by two parameters: a = distance between wells of the same type, and d= distance between lines of injectors and producers.*
- *Staggered line drive- The wells are in lines as in the direct line, but the injectors and producers are no longer directly opposed but laterally displaced by a distance of a/2.*
- *Five spot- This is a special case of the staggered line drive in which the distance between all like wells is constant, i.e., a = 2d. Any four injection wells thus form a square with a production well at the centre.*
- *Seven spot- The injection wells are located at the corner of a hexagon with a production well at its centre.*
- *Nine spot- This pattern is similar to that of the five spot but with an extra injection well drilled at the middle of each side of the square. The pattern essentially contains eight injectors surrounding one producer. The patterns termed inverted have only one injection well per pattern. This is the difference between normal and inverted well arrangements. Note that the four-spot and inverted seven-spot patterns are identical.*

Wherever the position of injection wells is interchanged by production wells and vice versa the inverted networks are also possible.

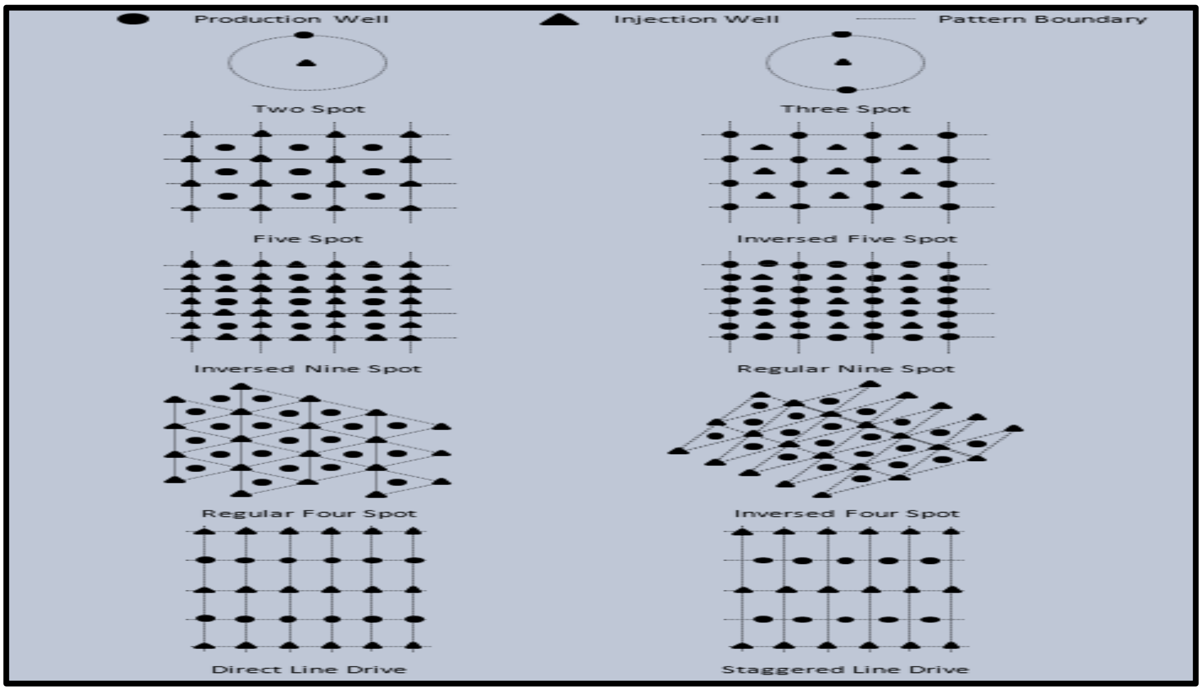


Figure 43: Waterflood Well Network for Repeated Pattern [43]

Peripheral Flooding

Injection wells are inserted along the flanks of the reservoir. This type of pattern is mostly applied to dip reservoir in order to have a more or less uniform flood front.

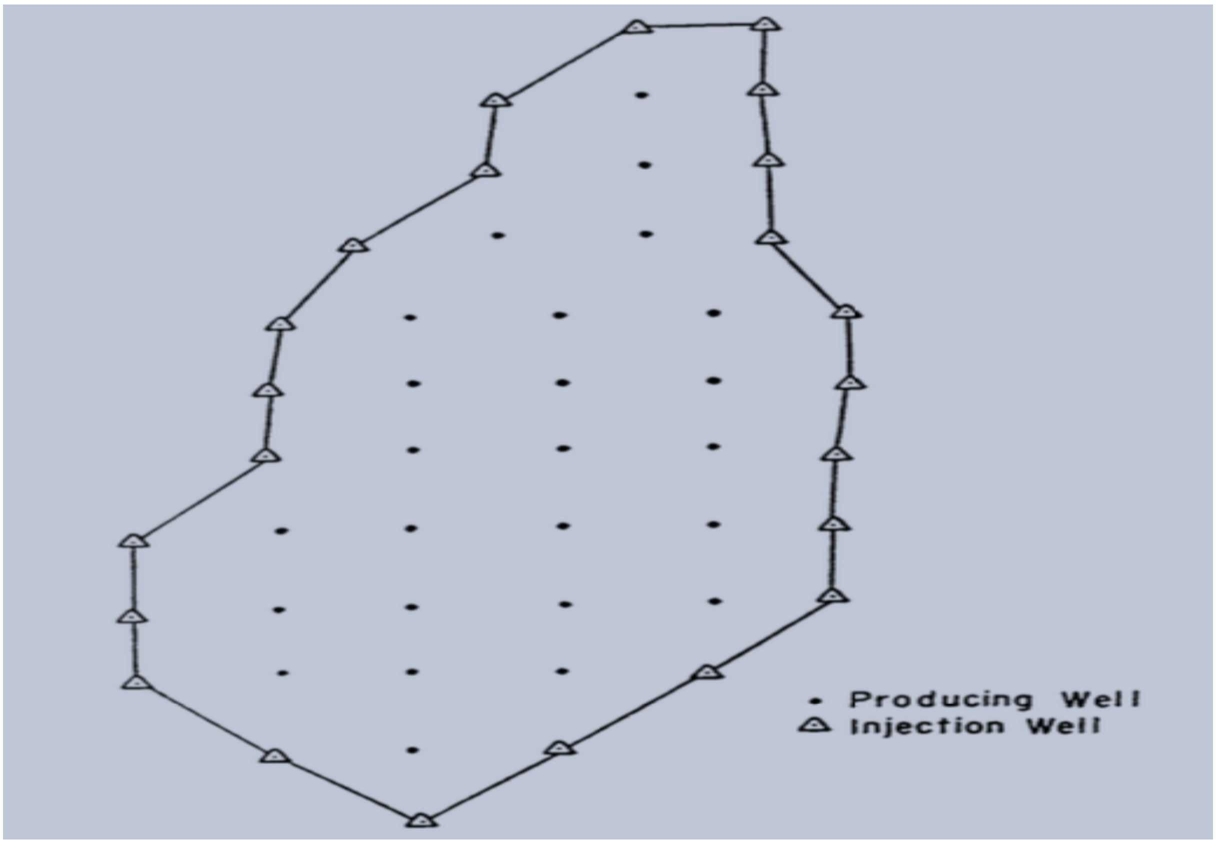


Figure 44: Typical Peripheral Waterflood [32]

In peripheral flooding, the injection wells are located at the external boundary of the reservoir and the oil is displaced toward the interior of the reservoir, as shown in Figure 44 [44] in an excellent review of the peripheral flood, points out the following main characteristics of the flood:

- *The peripheral flood generally yields a maximum oil recovery with a minimum of produced water.*
- *The production of significant quantities of water can be delayed until only the last row of producers remains.*
- *Because of the unusually small number of injectors compared with the number of producers, it takes a long time for the injected water to fill up the reservoir gas space. The result is a delay in the field response to the flood.*
- *For a successful peripheral flood, the formation permeability must be large enough to permit the movement of the injected water at the desired rate over the distance of several well spacing from injection wells to the last line of producers.*
- *To keep injection wells as close as possible to the waterflood front without bypassing any movable oil, watered-out producers may be converted into injectors. However, moving the location of injection wells frequently requires laying longer surface water lines and adding costs.*
- *Results from peripheral flooding are more difficult to predict. The dis- placing fluid tends to displace the oil bank past the inside producers, which are thus difficult to produce.*
- *Injection rates are generally a problem because the injection wells continue to push the water greater distances.*

Crestal and Basal Injection Patterns

In crestal injection, as the name implies, the injection is through wells located at the top of the structure. Gas injection projects typically use a crestal injection pattern. In basal injection, the fluid is injected at the bottom of the structure. Many waterflooding projects use basal injection patterns with additional benefits being gained from gravity segregation. A schematic illustration of the two patterns is shown in Figure 45.

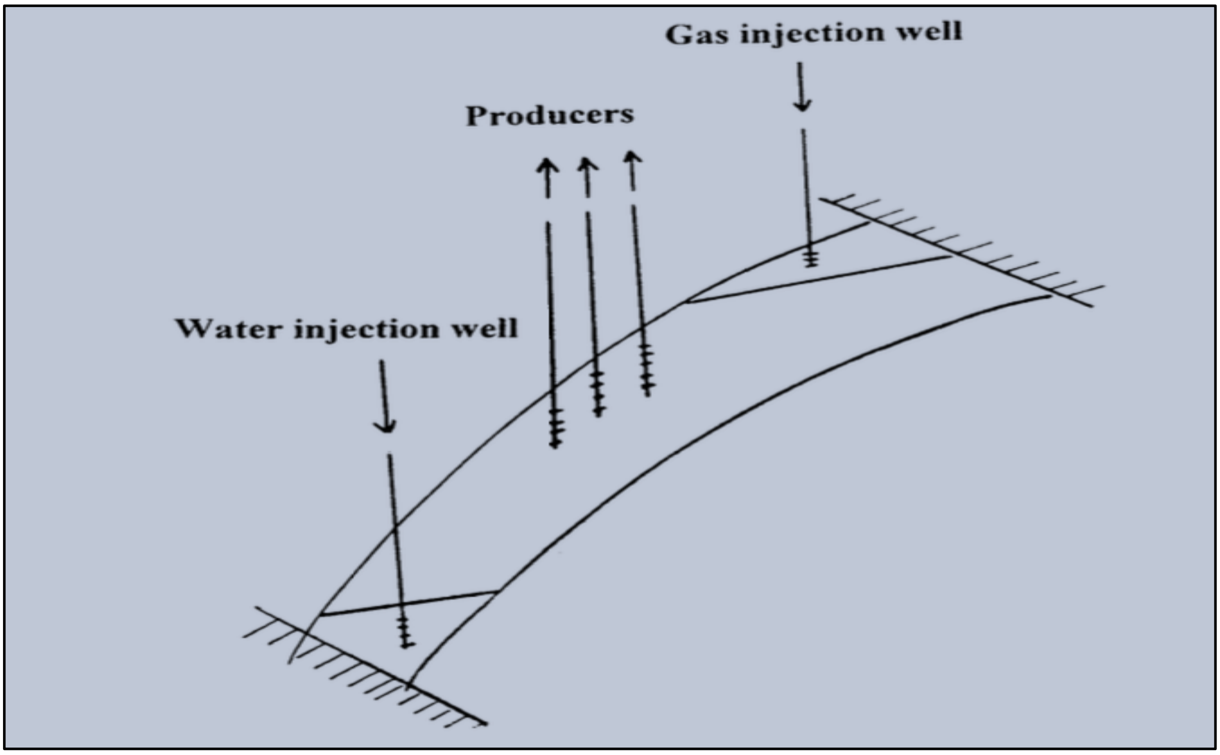


Figure 45: Well Arrangements for Dipping Reservoirs *[32]*

In general, reservoir engineering design of water flooding considers;

- *Specifying water injection rates*
- *Selection of a flood pattern*
- *Estimation of production rates and*
- *Expected oil recovery*

Specification of water injection rates is a challenging task and suffer from inaccuracies when using analytical techniques. Injection requirements depend on the reservoir states at any point in time. It is a challenging task to predict the reservoir states due to uncertainties to deal with. The only best approach is continuous determination of injection settings throughout the operational period.

4.6.2.3: Quick estimation of waterflood recovery

The amount of oil to be recovered is the function of three efficiency factors and are described by [33] namely;

- Areal sweep efficiency, Ea is defines as the fraction of the total flood pattern that is contacted by the displacing fluid. It increases steadily with injection from zero at the start of the flood until breakthrough occurs, after which Ea continues to increase at a slow rate.

The areal sweep efficiency depends basically on the following three main factors:

i. *Mobility ratio, M*
ii. *Flood pattern*
iii. *Cumulative water injected, W_{inj}*
iv. *Pressure distribution between injectors and producers*
v. *Directional permeability*

4.7: Vertical and volumetric sweep efficiencies

Reservoirs are formed over long periods of time in a variety of depositional environments. After deposition, physical, biological, and chemical reorganization occur. As none of these processes necessarily occur uniformly in time or space, it is understandable that reservoirs are generally very heterogeneous. All intensive properties of the reservoir such as permeability, porosity, wettability, connate water saturation, crude oil properties, and pore size distributions are likely to be non-uniform. Of these, permeability variations are considered more frequently in literature. [44] shows a detailed review of reservoir heterogeneity and considers three types of reservoir heterogeneities. These are areal permeability variations, vertical permeability stratification and reservoir scale fractures. Others [45] use alternative terminology microscopic, mesoscopic, macroscopic or megascopic heterogeneities.

Once consequence of reservoir heterogeneities is that the displacement front of any injected fluid will move as an irregular front and must be properly considered in reservoir calculations. For instance, a measure of the uniformity of water invasion is termed vertical efficiency (Ei).

Vertical sweep efficiency, Ei is defined as cross sectional area enclosed in all layers behind the injected fluid front. As such, the vertical sweep efficiency is a measure of the two-dimensional (i.e. vertical cross-section) effect of reservoir non-uniformities which is the fractional of the cross-section area of the reservoir contacted by the injected water.

- Unit displacement efficiency, Ed is the fraction of initial oil in place displaced by injected water [33];

$$Ed = \frac{Soi-Sor}{Soi} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \textit{(Equation 13)}$$

Where Soi = Initial oil saturation

Sor = Residual oil saturation after immiscible displacement,

Ed = Microscopic displacement efficiency

Volumetric efficiency, Ev is the combination of Ea and Ei as given by [33] and is a measure of the three-dimensional effect of reservoir heterogeneities. It is defined as the product of the pattern areal sweep and the vertical sweep as shown in the following equation:

$Ev = Ea \times Ei = (\frac{Ad}{AR}) \times h \times \emptyset \times S$ … … … … … … … … … … … … … … (*Equation 14)*

Where,

Ea = areal sweep efficiency,

Ad = area of displacement

A_R = area of reservoir

$\emptyset$ = porosity

S = gas or oil saturation.

The overall recovery efficiency (E_R) is a product of displacement efficiency (E_d), invasion or vertical sweep efficiency (Ev) and the pattern or areal sweep efficiency (Ep).

$ER = Ev \times Ed \times Ep$ … . (*Equation 15)*

where

E_R= overall recovery (fraction of initial oil in place recovered)

E_D= displacement efficiency or volume of oil displaced divided by total oil volume (fraction)

E_V= vertical or invasion efficiency (fraction of vertical reservoir section contacted by injection fluid)

E_p= pattern efficiency or pattern swept by total by total pattern area

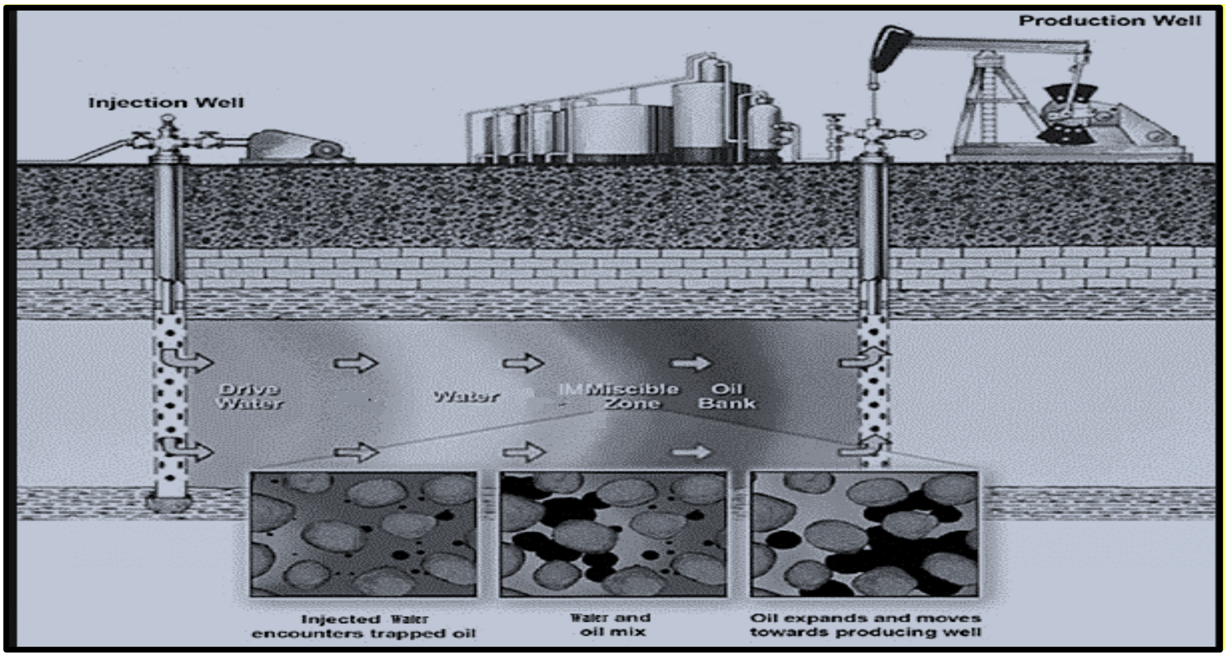


Figure 46: Waterflooding process [46].

4.8: Optimum time to waterflood

There are most common procedures to be followed when determining the optimum time to start waterflooding namely [32];

- *Anticipated oil recovery*
- *Fluid production rates*
- *Monetary investment*
- *Availability and quality of the water supply*
- *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*

These calculations should be performed for several assumed times and the net income for each case determined. The scenario that maximizes the profit and perhaps meets the operator's desirable goal is selected.

Generally, the traditional approach to operating waterflooding fields is to design one of the symmetrical patterns described above and allocating equal rates to the injection wells based on the assumption that the reservoir is homogeneous. If the assumption holds true, then the flow streamlines will have the symmetry of the well pattern. Actually, the reservoir can't be

easily homogeneous, therefore constant and equally partitioned injection rates have been found to be optimal [33].
In Reservoir Engineering Handbook [47] lists the following factors as being important when determining the reservoir pressure (or time) to initiate a secondary recovery project:

- *Reservoir oil viscosity*. Water injection should be initiated when the reservoir pressure reaches its bubble-point pressure since the oil viscosity reaches its minimum value at this pressure. The mobility of the oil will increase with decreasing oil viscosity, which in turns improves the sweeping efficiency.
- *Free gas saturation*. (1) In water injection projects. It is desirable to have initial gas saturation, possibly as much as 10%. This will occur at a pressure that is below the bubble point pressure. (2) In gas injection projects. Zero gas saturation in the oil zone is desired. This occurs while reservoir pressure is at or above bubble-point pressure.
- *Cost of injection equipment*. This is related to reservoir pressure, and at higher pressures, the cost of injection equipment increases. There- fore, a low reservoir pressure at initiation of injection is desirable.
- *Productivity of producing wells*. A high reservoir pressure is desirable to increase the productivity of producing wells, which prolongs the flowing period of the wells, decreases lifting costs, and may shorten the overall life of the project.
- *Effect of delaying investment on the time value of money*. A delayed investment in injection facilities is desirable from this standpoint.
- *Overall life of the reservoir*. Because operating expenses are an important part of total costs, the fluid injection process should be started as early as possible.

Some of these six factors act in opposition to others. Thus, the actual pressure at which a fluid injection project should be initiated will require optimization of the various factors in order to develop the most favourable overall economics.

The principal requirement for a successful fluid injection project is that sufficient oil must remain in the reservoir after primary operations have ceased to render economic the secondary recovery operations. This high residual oil saturation after primary recovery is essential not only because there must be a sufficient volume of oil left in the reservoir, but also because of relative permeability considerations. A high oil relative permeability, i.e., high oil saturation, means more oil recovery with less production of the dis- placing fluid. On the other hand, low oil saturation means a low oil relative permeability with more production of the displacing fluid at a given time.

Effect of trapped gas on waterflood recovery

Numerous experimental and field studies have been conducted to study the effect of the presence of initial gas saturation on water flood recovery. Early research indicated that the water flooding of a linear system results in the formation of an oil bank, or zone of increased oil saturation, ahead of the injection water [32]. The moving oil bank will displace a portion of the free water ahead of it, trapping the rest as a residual gas. An illustration of the water saturation profile is shown schematically in Figure 47. Several authors have shown through experiments that oil recovery by water is improved as a result of the establishment of trapped gas saturation, S_{gt}, in the reservoir.

[27]) and [44] indicate that, in some instances, oil recovery can be increased if the reservoir pressure is carefully controlled so as to leave optimum trapped gas saturation within the oil bank. The idea is to reduce the residual oil saturation value, S_{or}, by an amount equal to the trapped gas saturation. For example, if the residual oil saturation is 35% and if a trapped gas saturation can be maintained at 5%, the residual oil saturation would be 30%. In this case, S_{or} would be reduced by 14.3%. However, selecting and maintaining the optimum reservoir pressure to maintain this critical gas saturation is difficult to achieve in practice.

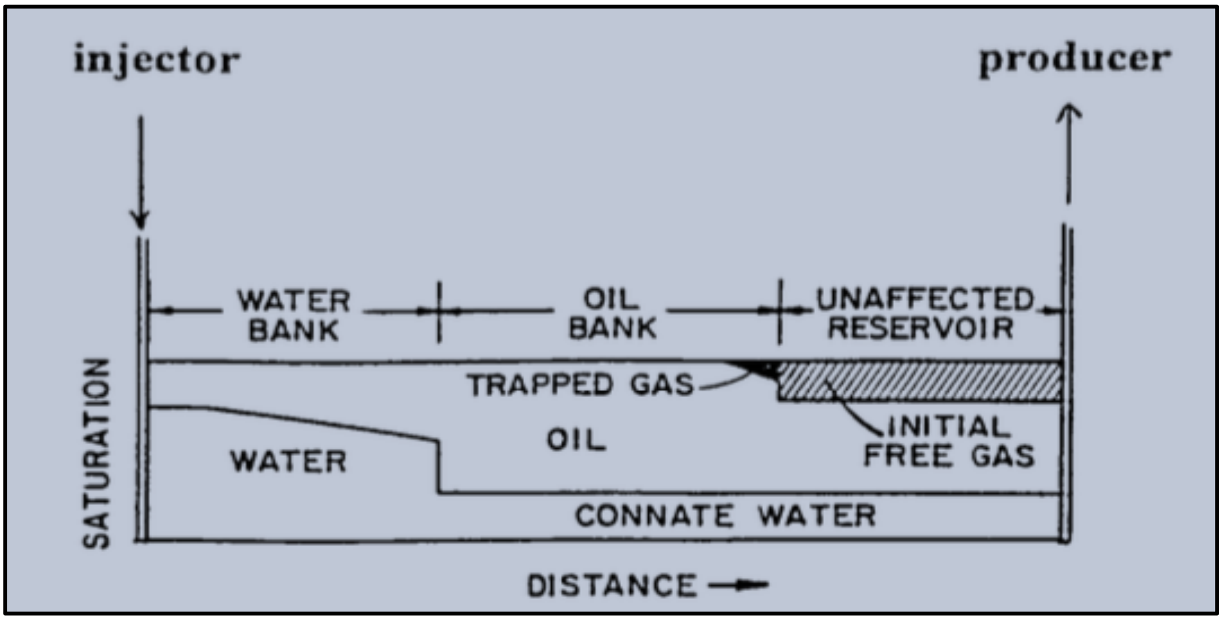


Figure 47: Water Saturation Profile During Water flooding [32]

4.9: Limitations of waterflood technology

Waterflooding can increase the volume of oil recovered from a reservoir; however, it is not always the best technology to use and it can have complicating factors. When evaluating how best to produce a particular oil reservoir, a petroleum engineer should include waterflooding in the options that are analysed, both technically and economically. Those evaluations should include such potentially complicating factors as:

- *Injection-water treatment to remove oxygen, bacteria, and undesirable chemicals*
- *The challenges involved in separating and handling the produced water that has trace oil content, naturally occurring radioactive materials (NORMS), and various scale-forming minerals.*
- *Compatibility of the planned injected water with the reservoir's connate water.*
- *Interaction of the injected water with the reservoir rock (clay sensitivities, rock dissolution, or generally weakening the rock framework)* [37].

4.10: *Overview of gas re-injection*

Gas re-injection refers to the reinjection of natural gas into an underground reservoir, typically the one which contains both crude oil and gas with the purpose of increasing the pressure within the reservoir as a result inducing the flow of crude oil. The gas produced from Norne field was re-injected back into reservoir to recover oil but re-injection ceased in 2005 when gas started to be exported to the market due to high demand and price. In this work, waterflooding simulation was discussed alone and gas re-injection is just included into literature study because it has been applied into the field before ceased.

There should be no confusion with gas lift, where gas is injected into the annulus of the well rather than the reservoir. After the crude oil has been pumped out, natural gas is then recovered.

Since most of the wells found around the World contain heavy crude oil this process boosts their production.

The difference between heavy and light crude oil is based on pump ability and viscosity. The lighter the crude oil the easier to pump. Recovery of hydrocarbons in a well is generally limited to 50% for heavy crude oil and 75-80% for light crude oils.

Recycling of natural gas or other inert gases causes the pressure to rise in the well, thus causing more gas molecules to dissolve in the oil lowering its viscosity and thereby increasing the well productivity.

Air is not suitable for repressuring wells because tends to cause deterioration of the oil, thus carbon dioxide or natural gas is used to repressure the well.

4.10.1: Immiscible gas injection in oil reservoir

A variety of gases have been used for immiscible gas displacement, with lean hydrocarbon gas used for most applications to date. Historically, Immiscible gas injection was first used for pressure maintenance.

These kinds of projects were initiated in the 1930s and used lean hydrocarbon gas (e.g., Oklahoma City field and Cunningham pool in the US (Muskat, 1949) and Bahrain field in Bahrain [48]. Over the decades, a considerable number of immiscible gas injection have been undertaken, some with excellent and others with poor performance.

Application of immiscible gas injection

Combination of technical and economic factors leads to the application of immiscible gas injection. Deferral of gas is a significant economic deterrent for many potential gas injection projects if an outlet for immediate gas sales is available. Nevertheless, a variety of opportunities still exist. [48]

- *First, if there are reservoirs with characteristics and conditions particularly conducive to gas/ oil gravity drainage and where attendant high oil recoveries are possible.*
- *Second, reservoirs with decreased depletion time resulting from lower reservoir oil viscosity and gas saturation in the vicinity of producing wells is more attractive economically than alternative recovery methods that have higher ultimate recovery potential but higher costs.*
- *Third, reservoirs where recovery considerations are augmented by gas storage considerations and hence gas sales may be delayed for several years.*

Non-hydrocarbon gases and Nitrogen have been used [49]. In general, the design of other gas injections can be the same as that of hydrocarbon however, valuing the use of other gases must include additional costs related to these gases, such as corrosion control, separating the nonhydrocarbon components to meet gas marketing specifications, and using the produced gas as fuel in field operations.

4.10.2: Mechanism of gas injection

According to [50] the primary physical mechanisms that occur as a result of gas injection are:

- Displacement of oil by gas in both horizontal and vertical direction
- *Swelling of the oil if the oil at original reservoir conditions was very under saturated with gas*
- *Partial or complete pressure maintenance*
- *Vaporization of the liquid hydrocarbon components from the oil column and possibly from the gas cap if retrograde condensation has occurred or if the original gas cap contains a relict oil saturation.*

The process of injecting gas is very effective in high-relief reservoirs where the process is called 'gravity drainage' because the vertical /gravity aspects increase the efficiency of the process and enhance recovery of up dip oil residing above the uppermost oil-zone perforations [48].

4.10.3: *Immiscible gas injection techniques*

Immiscible gas injection is usually classified as either crestal or pattern, depending on the location of gas injection wells. The same physical principles of oil displacement may be deployed to either types of operation; however, the following factors vary considerably by gas injection method

- *The overall objectives*
- *Type of field selected*
- *Analytical procedures for predicting reservoir performance*

4.10.4: Crestal gas injection

This can be alternatively called external or gas cap injection. Uses injection wells in higher structural positions as shown in Figure 38, usually in the primary or secondary cap.

Applicability

This manner of injection is generally used in reservoirs with significant structural relief or thick oil columns with good vertical permeability. Injection wells are positioned to provide good areal distribution and to obtain maximum benefit of gravity drainage. The number of injection wells required for a specific reservoir depends on the injectivity of individual wells and the distribution needed to maximize the volume the volume of oil column contacted.

Advantage over pattern gas injection

The method is superior to pattern gas injection because of the benefits of gravity drainage. In addition, crestal injection, if conducted at gravity-stable rates-e.g., less than the critical rate as shown in Equation 16 will result in greater volumetric sweep efficiency than pattern injection operations. There are many examples of ongoing crestal injection projects throughout the world, including some very large projects in the Middle East.

4.10.5: Pattern gas injection

Alternatively called dispersed or internal gas injection, consists of a geometric arrangement of injection wells for the purpose of uniformly distributing the injected gas throughout the oil-productive portions of the reservoir. Practically, injection well/ production well arrays often vary from the conventional regular pattern.

The selection of an injection arrangement is a function of:

- *Reservoir structure*
- *Sand continuity*
- *Permeability*
- *Porosity levels and variations*
- *Number and relative locations of existing wells*

Applicability

The method is applied to reservoirs having low structural relief, relatively homogeneous reservoirs with low permeability, and reservoirs with low vertical permeability.

The greater injection-well density results in the following;

- *Rapid pressure.*
- *Production response.*
- *Shortened reservoir depletion times.*
- *High installation and operating cost.*

Limitations

The following are the limitations to pattern-type gas injection;

- *Little or no improvement in recovery is derived from structural position or gravity drainage because both injection and production wells are located in all areas of the reservoir.*
- *Low areal sweep efficiency results from gas override in thin stringers and by viscous fingering of gas caused by high flow velocities and adverse mobility ratios.*

The likely results of applying pattern injection in low-dip reservoirs are:

- *Rapid gas breakthrough*
- *An improved recovery of < 10% of original oil in place (OOIP)*

- *High producing GORs*
- *Significant gas compression costs to reinject the gas into the reservoir*

Although this kind of injection method has been applied over the years now but it is not as attractive economically as alternative methods for increasing oil recovery.

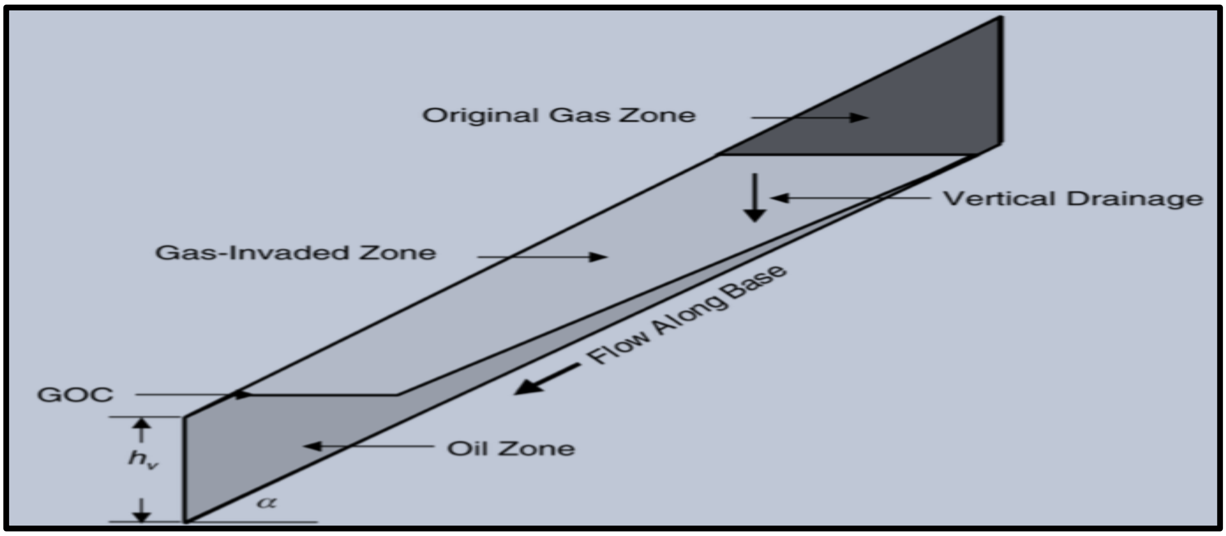


Figure 48: Mechanism of gravity drainage [36]

Mathematical model

A simple mathematical model can be used to describe the displacement of oil by gas drive and gravity drainage when the rate is less than one-half the critical rate. The critical rate is given by

$$\left(\frac{qT}{A}\right) critical = \frac{0.044 k \Delta P sin\propto}{\frac{\mu o}{kro} - \frac{\mu g}{krg}} \quad \text{……………………………………….(Equation 16)}$$

where qt = total volumetric flow rate through area A, ft^3/D, and k=permeability, darcies

The Welge equation for the fractional flow of gas at any gas saturation (Sg) is calculated as follows

$$fg = 1 + \left(\frac{\frac{0.044 k kro \Delta P A sin\propto}{qT \mu o}}{1+\frac{1}{M}}\right) \quad \text{………………………………….(Equation 17)}$$

where

A = area of cross section normal to the bedding plane, ft^2,

fg =fraction of flowing stream that is gas,

k = permeability, darcies,

k_{ro} = relative permeability to oil, fraction,

k_{rg} = relative permeability to gas, fraction,

M = mobility ratio, $\frac{krg\mu o}{kro\mu g}$

q_t = total flow rate through area A, res ft^3/D

4.10.6: Efficiency of oil recovery by immiscible gas displacement

It makes sense in most displacement processes when recovery efficiency is related to displacement efficiency and volumetric sweep efficiency. The products of these factors provide an estimate of recoverable oil expressed as percentage of OOIP. However, analytical procedures are available for evaluating each efficiency factor. The components describing the overall recovery efficiency are defined as follows:

- *Displacement efficiency: which is the percentage of oil in place within a totally swept reservoir rock volume that is recovered as a result of viscous displacement and gravity drainage processes.*
- *Volumetric sweep efficiency: which is the percentage of the total rock or PV that is swept by gas. This factor can sometimes be divided into horizontal and vertical components, with the product of the two components representing the volumetric sweep.*

The increase of recovery efficiencies may be due to continuous gas injection, but the rate of recovery diminishes after gas breakthrough occurs as the GOR increases. The overall result is that the ultimate oil recovery efficiency is a function of economic considerations, such as the cost of gas compression and the volume and availability of residue gas or potentially more expensive alternatives like N_2 from a nitrogen rejection plant.

4.10.7: Optimum time to initiate gas injection

The optimum time to begin gas injection into the reservoir depends on following factors;

- *A balance of risks*
- *Gas market availability*
- *Environmental considerations*
- *Other factors that affect project economics.*

In case only oil recovery and improvements in reservoir producing characteristics are considered, reservoir conditions for gas injection operations are usually more favourable

Generally, injection or reinjection of CO_2 also takes place in order to reduce the emission of CO_2 into the atmosphere, a form of carbon sequestration. This has been proposed as a method to combat a climatic change allowing mass storage of CO_2 over a geological timescale.

Reinjection of CO_2 may save the operator when it comes to carbon taxes. For instance, Reinjection of CO_2 in the Norwegian sleipner gas filed saves the operators 1 million Norwegian Kroners per day in national carbon taxes. [51]

CHAPTER 5

5.0: OPTIMIZATION, MODELLING AND SIMULATION

5.1: Optimization as a process

Optimization is a process of maximizing or minimizing outputs from the inputs into a system so as to make better [52]. In upstream sector of Petroleum industry optimization processes have been applied as far back as 1950's with new algorithm being explored. Numerous Field of interest within Petroleum industry are optimized including;

- *Planning*
- ***Drilling***
- *History matching*
- ***Well placement***
- ***Recovery processes***
- *Facility design and*
- *Operations etc.*

However, in this work the bolded issues are addressed in order to arrive to the objective of optimization production of gas and oil from reservoir.

Actually, different optimization processes have been employed depending on the nature of the problem.

An optimization problem can be generally represented as

min/max   f(u)

u   g(u) = 0

s.t   lbi ≤ ci(ui) ≤ ubi

where f is an objective function

u is given names as variables, decision variables, decision parameters, control variables and so on, g and ci are equality and inequality constraint functions respectively. lbi and ubi are lower and upper bounds respectively for ith variables.

The classification of optimization problems is usually based on the nature of either the control variables, objective or constraints function. [53]

These are;

- *Linear Programming (LP)*
- *Non-Linear Programming (NLP)*
- *Integer Programming (IP)*

- *Mixed Integer Programming (MIP)*
- *Constrained and*
- *Unconstrained problem*

However, in this thesis work is based on production optimization by well placement and recovery processes and was done by trial and errors decided by recovery factor for the case of water flooding, the base case was altered as changing the location of wells, recompleting the wells, introducing the new producers and injectors as well changing the oil production rates and bottom hole pressure (BHP) with the reason of covering maximum drainage area. More importantly in case of chemical flooding, ASP (Alkaline, Surfactant and Polymer), optimization of chemical flooding is done by changing concentration of chemical injection in order to ensure maximum recovery and at the same time to minimize the cost of chemicals. However, economic analysis is the tool for decision when it comes to validation of project viability/feasibility and this was done in both waterflooding and chemical injection phases.

In oil production optimization, the usual control variables are oil production rates, injection rates and/or bottom hole pressure (BHP). The objective of this work is to maximize net present value (NPV) and oil recovery accompanied by other objectives such as minimizing water breakthrough or water cut. In order to solve the problem, the reservoir model is considered firstly. In this thesis work, all of the mentioned parameters such as oil production rates, bottom hole pressure (BHP) and cut off water cut have been set in the reservoir model and after running simulation economic analysis was done in order to find out the suitable scenario of which must have highest NPV of all and this scenario was suggested as the depletion/drainage plan.

5.2: Reservoir modelling

A reservoir model is a critical tool in optimizing recovery and financial performance providing state-of-the-art visualization, analysis of oil, gas, water, and solids behaviours, as well as uncertainty analysis and optimization, so that potential recovery and artificial lift methods can be evaluated. (www.slb.com/services/technical-challenge)

5.3: Simulation for production

Sand channels, the result of sand production in a geologic basin, mean that special reservoir simulation techniques must be incorporated to adequately model and other production mechanisms. There must accurately describe the *flow paths*, *pressure drawdowns*, and *stimulated productivity* that occur because of those channels.

A reservoir model represents the physical space of the reservoir by an array of discrete cells delineated by a grid which may be regular or irregular (en.m.wikipedia.org).The array In petroleum industry, reservoir modelling involves the construction of a computer model of petroleum reservoir for the purposes of improving estimation of reserves and making decisions regarding the *development of the field*, *predicting future production*, *placing additional wells* and *evaluating alternative reservoir management scenarios*.

Characterization of oil reservoir is based on complex geometry, spatially variable geological properties i.e. porosity and permeability of the porous medium and complex fluid mixtures of water and multiple oil and gas components. Our interest is to describe the transport of these different components through the porous medium in reservoir simulation. Generally, a component can exist in any fluid phase as a result we must solve one equation per component times a set of a phase equilibrium relations. Compositional model which treats every component in every fluid phase individually and their computational expense is very high even by using the current super computers. [54]. The array of cells usually 3-D although 1-D and 2-D models are sometimes used. Values of attribute such as porosity, permeability and water saturation are associated with each cell. The value of each attribute is implicitly deemed to apply uniformly throughout the volume of the reservoir represented by the cell.

Types of reservoir model

Reservoir models typically fall into two categories

- *Geological models*

Are created by geologists and geophysicists and aim is to provide a static description of the reservoir prior to production.

- *Reservoir simulation models*

Models are created by reservoir engineers and use finite difference methods to simulate the flow of fluids within the reservoir, over its production lifetime.

Sometimes a single 'shared earth model' is used for both purposes. More commonly a geological model is constructed at a relatively high (fine) resolution. A coarser grid for the reservoir simulation model is constructed with perhaps two order of magnitude fewer cells. Effective values of attributes for the simulation model are then derived from geological model by an *upscaling method*.

5.4: Upscaling of grid properties in reservoir simulation

Upscaling or *homogenization* is a heterogeneous region consisting of fine grid cells with an equivalent homogenous regular made up of a single coarse-grid cell with an effective property value. (Equivalent in this case means either volume or flux vice, depending on the type of property that is to be up scaled.

Upscaling is performed for each of the cells in the coarse grid and for each of the grid properties needed in the reservoir flow-simulation model. Therefore, the upscaling process is essentially an averaging procedure in which the static and dynamic characteristics of a fine-scale model are to be approximated by that of a coarse-scale model and the concept illustrated in Figure 49.

(petrowiki.org/Upscaling_of_grid_properties).

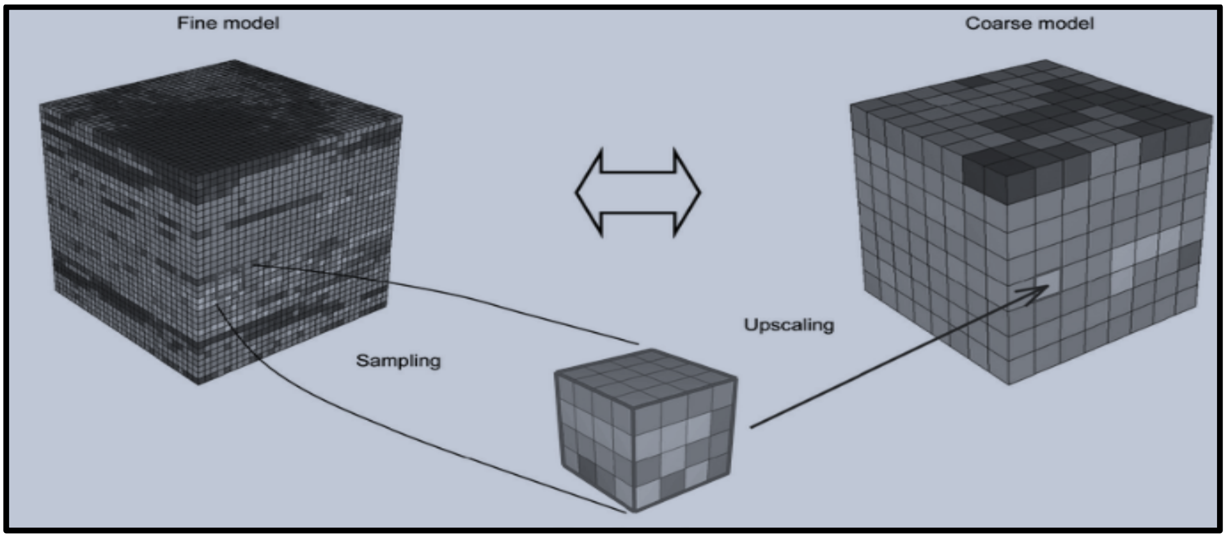


Figure 49: Upscaling concept (petrowiki.org/Upscaling_of_grid_properties).

Alternatively, if no geological model exists, the attributes values for a simulation model may be determined by a process of sampling geological maps.

Uncertainty in the true values of the reservoir properties is sometimes investigated by constructing several different realizations of the sets of attribute values.

The behaviour of the resulting simulation models can then indicate the associated level of economic uncertainty. However, in this work uncertainty of reservoir properties are not analysed instead single parameter sensitivity analysis was performed for economic purpose.

Commercially available software is used in construction, simulation and analysis of the reservoir models [55]. In Petroleum engineering, software like CMG, Petrel, Schlumberger Eclipse, Fortran prosper etc. have been used up to date for running simulations or modelling reservoirs. However, in this work Eclipse 100 simulator is deployed for running simulations.

CHAPTER 6

6.0: ECONOMIC ANALYSIS

6.1: Introduction to economic analysis

Economic analysis is the systematic approach to determine the optimum use of scarce resources which involves the comparison of two or more alternatives in achieving a specific objective under the given assumptions and constraints.

Why economic analysis is necessary?

Economic analysis is important in order to understand the exact condition of an economy of which macroeconomic issues are important aspects of the economic analysis process. However, economic analysis can also be done at microeconomic level **(www.economywatch.com).**

From the point of view, the main objective of conducting a project economic analysis is to help not only assess the sustainability of investment projects but also to inform the design and select processes/ layout that can contribute to a sustainable improvement in the welfare of company, its shareholders and the host country as a whole. Economic analysis is a means to help bring about a better of resources that can lead to enhanced incomes for investment purposes. Therefore, it is best undertaken at the early stages of the project cycle to enable decision makers to make an informed decision on whether to undertake a particular investment given various alternatives and their corresponding NPV.

NPV or NPW is the difference between the present value of cash inflows and cash outflows over a period of time. NPV or NPW is used in capital budgeting to analyse the profitability of a projected investment. **(www.investopedia.com)**

The following is the formula for calculating NPV from (en.m.wikipedia.org);

$$NPV = \sum_{t=1}^{T} \frac{Ct}{(1+r)^t} - Co$$

In this equation:

C_t = Net cash inflow during the period t

Co = Total initial investment costs

r = discount rate and

t = Number of time periods

A positive net present value indicates that the projected earnings generated by a project or investment (in present currencies) exceeds the anticipated costs (also in present currencies).

Generally, an investment with a positive NPV will be profitable and an investment with a negative NPV will result in a net loss. This concept is the basis for the Net Present Value Rule, which dictates that the only investments that should be made are those with positive NPV values as shown in Table 7.

Table 7: Decision on Investment Based on NPV

If....	It means….	Then….
NPV >0	the investment would add value to the firm	the project may be accepted
NPV<0	the investment would subtract value from the film	the project may be rejected
NPV=0	the investment would neither gain nor lose value for the firm	we should be in different in the decision whether to accept or reject the project. This project adds no monetary value. Decision should be based on other criteria, e.g. strategic positioning or other factors not explicitly included in the calculation

6.2: Expected NPV

Expected net present value is a capital budgeting technique which adjusts for uncertainty by calculating NPVs under different scenarios and probability-weighting them to get the most likely NPV.

For example, instead of relying on a single NPV, companies calculate NPVs under a range of scenarios; say base case, worst case and best case. They then estimate probability of occurrence of each scenario and then weight the NPVs calculated according to their relative probabilities to find the expected NPV.

Expected NPV is a more reliable estimate than the traditional NPV because it considers the uncertainty inherent in projecting future scenarios.

Formula

Expected NPV is the sum of the product of NPVs under different scenarios and their relevant probabilities. The following formula is used to calculate expected NPV.

Expected NPV = $\sum$ (p × Scenario NPV)

Scenario NPV is the NPV under a specific scenario while p stands for the probability of occurrence of each scenario.

In this work, Probabilities to be used for different oil prices from Figure 50, with all other parameters kept unchanged are 60 % for base oil prices, 20 % for low oil prices and 20 % for high oil prices.

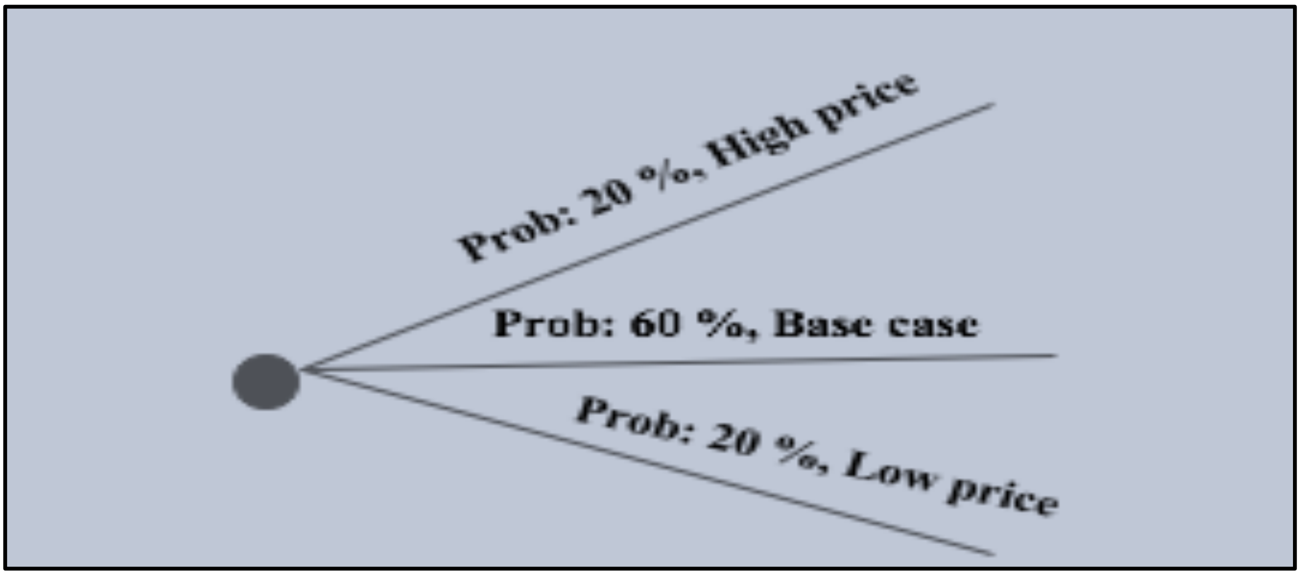


Figure 50: Probability-weighting of Prices of Oil [56]

Risk or uncertainties of a project are captured by calculating the effect on the eNPV of both positive and negative changes in these parameters such as:

- *Economic/market related assumptions*
- *Tax-related assumptions*
- *Technical assumptions*
- *IOR*
- *Start-up date*
- *Environmental assumptions*
- *Country and reputation risk.*

In the end, the Expected NPVs for all the cases were compared to come up with the proposed drainage strategy.

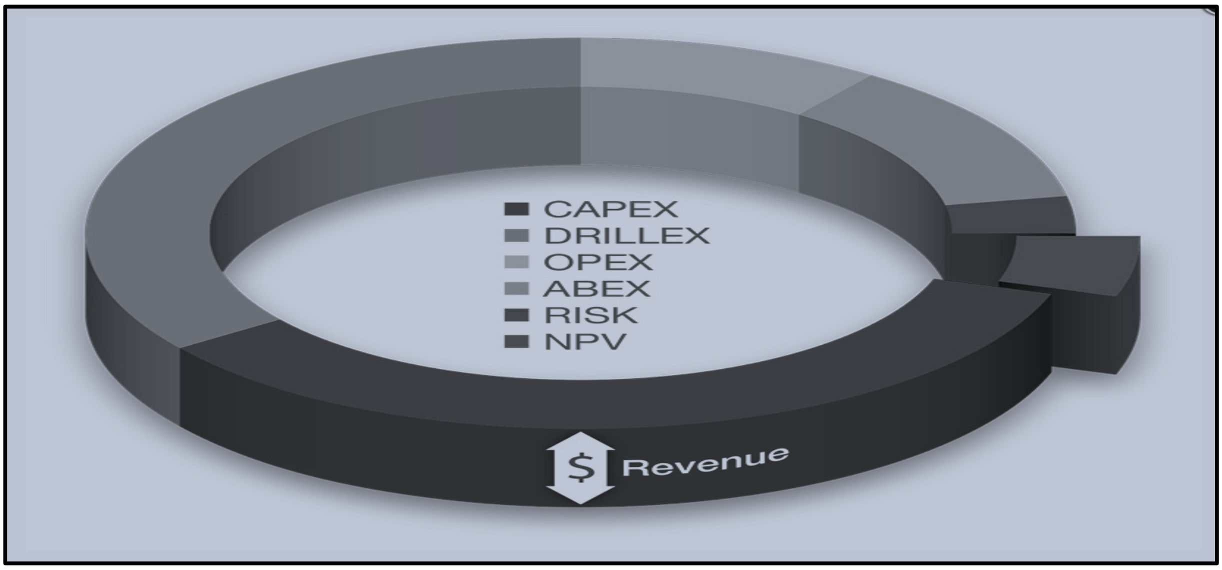


Figure 51: Value = Revenue-Capex-Drillex-Opex-Abex-Risk (www.investopedia)

6.3: Present Value optimization

A rigorous definition of present value is absolutely necessary to provide an optimization target. A robust tool is required to evaluate the myriad of economic trade-off in value optimization. We need a mathematical definition of value that compares the compromises between capital expenditures and revenue, the initial investment and operating cost; while also considering cost of capital and risk.

Each oil company can have different drivers. Most oil companies optimize present value in a holistic systemic approach. All the elements of NPV equation are considered together, although not necessarily all of them can be quantified with mathematical rigour:

$$E(NPV(i)) = Price * Prod - DRILLEX - CAPEX - OPEX - ABEX - RISK(i)$$ *(Equation 18)*

The Expected Project Net Present Value (E(NPV)) captures the cost of capital and risk in the rate of return (i). The positive term of the equation focuses on the functional requirements: production profile and quality of the products sold. The capital investment in drilling and facilities are considered as an outflow during the project execution (DRILLEX, CAPEX). The operating cost (OPEX) through the life of the field and the abandonment cost (ABEX) also detract from the E(NPV). Last but not least, cost savings can lead to unacceptable increases of risk. The optimization of value can only be achieved in a holistic approach by looking at all the terms of this equation in a system-wide approach.

'Systemic' refers to something that is spread throughout, system-wide, affecting a group or system. 'Holistic' relates to a view of a system lifecycle that addresses all phases of its existence to include system conception, design and development, production and/or construction, distribution, operation, maintenance and support, retirement, phase-out and disposal. The optimization of the value equation considers all elements of the FDP and all phases of its lifecycle. Present Value optimization is not a trivial exercise that can be achieved by maximizing cost reduction of the individual components and phases. Front end engineering creates value by exploring all the components of the value equation and finding an optimum combination that maximizes the E(NPV) by implicitly reducing the cost per barrel produced. This is only feasible during the early stages of the project when all the options are still open.

In this work, the values of risk and abandonment cost are uncertain so are not considered.

CHAPTER 7

7.0: SIMULATIONS OF WATERFLOODING

7.1: Waterflooding scenario

As seen in the Eclipse 100 simulator, the data file is originally composed of 5 wells of which 2 wells are injectors (F-3H and F-1H) and 3 production wells (E-3AH, E-3H and E-2H) as shown in Figure 15. Injector F-1H was perforated in the Tofte and Tilje formations as it was originally designed to sweep oil in the southern-west of the E-segment whereas the northern part of the segment is being swept by injector F-1H completed in the Garn, Tofte and Tilje formations.

In December, 2004, the field oil recovery factor was 0.413 as shown in Figure 19 and due to observations in Eclipse 100 for instance in Figure 18 which shows that only 25% of oil has been recovered from the top layer of E-segment which means that there is still enough producible oil in the formation. Based on these factors and other reservoir factors, several cases were created in simulation model in order to recover the remained oil.

Seven cases were created in this scenario as explained below;

7.2: Waterflooding cases

Case 1:

The new Injector G-1H with injection rate of 16,000 Sm^3/day and bottom hole pressure of 600 bara was introduced to the original injection and production wells and allowed to produce from 2004-2025 where all other wells remained the same as the base model.

The role of the new injector is to drain oil from the unswept area of the E-segment. Eventually, the new injector was drilled horizontally through Ile and Tofte formation with the location as shown in Table 8.

Table 8: Completion grids for the new injector G-1H

G-1H			
I	J	K_1	K_2
14	67	1	1
14	67	2	2
14	67	3	3
14	67	4	4

14	67	5	5
14	67	6	6
14	67	7	7
14	67	8	8
14	67	9	9
14	68	10	10
14	69	10	10
14	70	10	10
14	71	10	10
15	71	10	10

Case 2:

Under the presence of the new injector G-1H, producer E-3H is opened in order to increase production where as other wells remain as the base model. E-3H was able to drain more oil because the new injector raised pressure in the reservoir and hence increase in drainage in the northern-west part of the E-segment.

Case 3:

The injector F-3H was re-completed in order to avoid quick flow of water into the injection well in a specific period of time**.**

Table 9: Re-completion of injector F-3H

Original F-3H				**New F-3H**			
I	**J**	**K_1**	**K_2**	**I**	**J**	**K_1**	**K_2**
6	**57**	**1**	**1**	**7**	**57**	**1**	**1**
6	**57**	**1**	**1**	**7**	**57**	**7**	**7**
7	**57**	**2**	**2**	**7**	**57**	**7**	**7**
7	**57**	**3**	**3**	**8**	**57**	**7**	**7**
7	**57**	**4**	**4**				
7	**57**	**5**	**5**				
7	**57**	**6**	**6**				
7	**57**	**7**	**7**				

7	57	8	8
7	57	9	9
7	57	10	10
7	57	11	11
7	57	12	12
7	57	13	13
7	57	14	14
7	57	15	15
7	56	15	15
7	56	16	16
7	56	17	17
7	56	18	18
7	56	19	19
7	56	20	20
7	56	21	21
7	56	22	22

Case 4:

The injector F-3H was relocated and then re-completed in order to avoid quick breakthrough of water into the production well in a specific period of time which could decrease the oil production**.**

Table 10: Relocation and re-completion of injector F-1H

Original F-1H				New F-1H			
I	J	K_1	K_2	I	J	K_1	K_2
12	85	1	1	12	85	1	1
12	85	2	2	12	85	8	8
12	85	3	3	13	85	8	8
12	85	4	4	14	85	8	8
12	85	5	5	15	85	8	8
12	85	6	6	16	85	8	8
12	85	7	7	16	84	8	8

12	**85**	**8**	**8**	**16**	**83**	**8**	**8**
12	**85**	**9**	**9**	**16**	**82**	**8**	**8**
12	**85**	**10**	**10**	**16**	**81**	**8**	**8**
12	**85**	**11**	**11**	**16**	**80**	**8**	**8**
12	**85**	**12**	**12**	**16**	**79**	**8**	**8**
12	**85**	**13**	**13**	**16**	**78**	**8**	**8**
12	**85**	**14**	**14**	**16**	**77**	**8**	**8**
12	**85**	**15**	**15**	**16**	**76**	**8**	**8**
12	**85**	**16**	**16**	**26**	**75**	**8**	**8**
12	**85**	**17**	**17**				
12	**85**	**18**	**18**				
12	**85**	**19**	**19**				
12	**85**	**20**	**20**				
12	**85**	**21**	**21**				
12	**85**	**22**	**22**				

Case 5:

Introduction of the new producer Z-3H into the reservoir and allowed to produce between 2004 and 2007, re-completion of F-1H and re-completion and relocation of injector F-3H whereas the other producers remain the same as the base model.

Table 11: Completion grids for new producer Z-3H

Z-3H			
I	J	K_1	K_2
16	71	1	1
16	71	3	3
16	71	5	5
16	71	6	6
15	71	6	6
14	71	7	7
13	71	8	8
12	71	10	10

Case 6:

The new producer Z-3H, the original producers (E-2H, E-3H and E-3AH) and injectors (The original producers and injectors as the base model and the new producer.

Case 7:

Relocation and re-completion of producer E-3AH whereas other injectors and producers remain the same as the base model.

Table 12: Relocation and re-completion of producer E-3AH

Original E-3AH				New E-3AH			
I	J	K_1	K_2	I	J	K_1	K_2
7	64	1	1	7	65	1	1
7	65	2	2	7	65	2	2
7	66	2	2	7	65	5	5
8	66	2	2	7b	65	10	10
10	69	1	1	8	65	13	13
10	70	1	1	9	65	14	14
10	71	1	1	10	65	16	16
11	71	1	1	11	65	16	16
				12	65	17	17
				13	65	16	16
				14	65	16	16

The results for waterflooding scenario

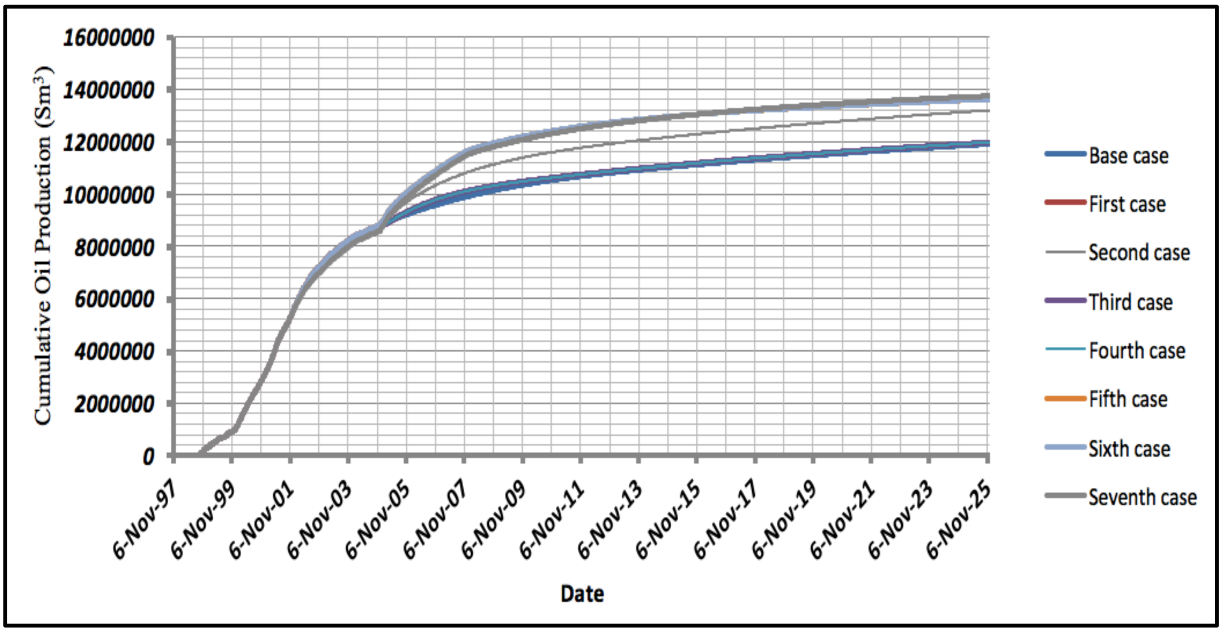


Figure 52: Cumulative oil production for waterflooding scenario

Figure 52 shows that the highest oil production of 14 MSm3 is achieved by the seventh case waterflooding due to the relocation and re-completion of the producer E-3AH in a good location of high oil saturation. E-3AH became the horizontal well in layer 16 hence recovers more oil. The fourth case waterflooding marked a minimum oil production of 12 MSm3 as the base case waterflooding because relocation of the injector F-1H was mainly due to water cut control.

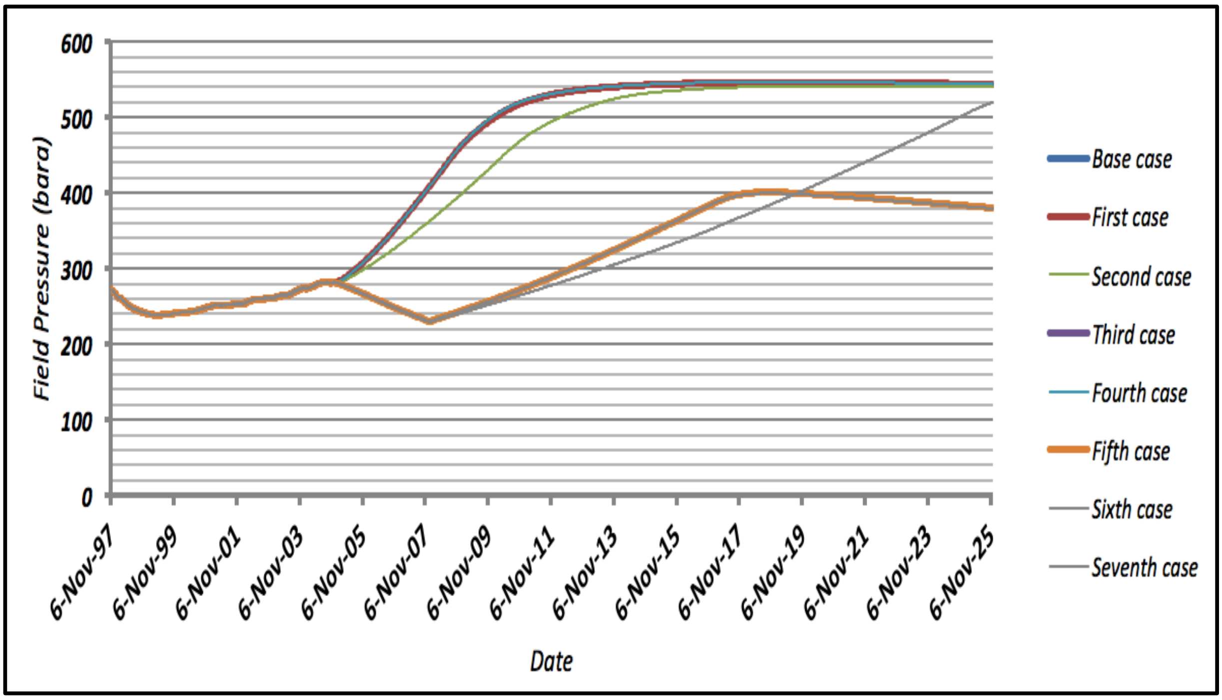


Figure 53: Field pressure profile for waterflooding scenario

Figure 53 shows that all cases with the new injector G-1H have increased reservoir pressure from the time of placement (2004) onwards unlike the cases without new injector. The reason is, placement of the new injector will increase the pressure of the reservoir by voidage replacement due to the fact that the produced water is being replaced by the injected water and hence maintaining pressure. In such it reaches a point where the reservoir pressure remains constant, the point at which produced water is wholly replaced by the injected water.

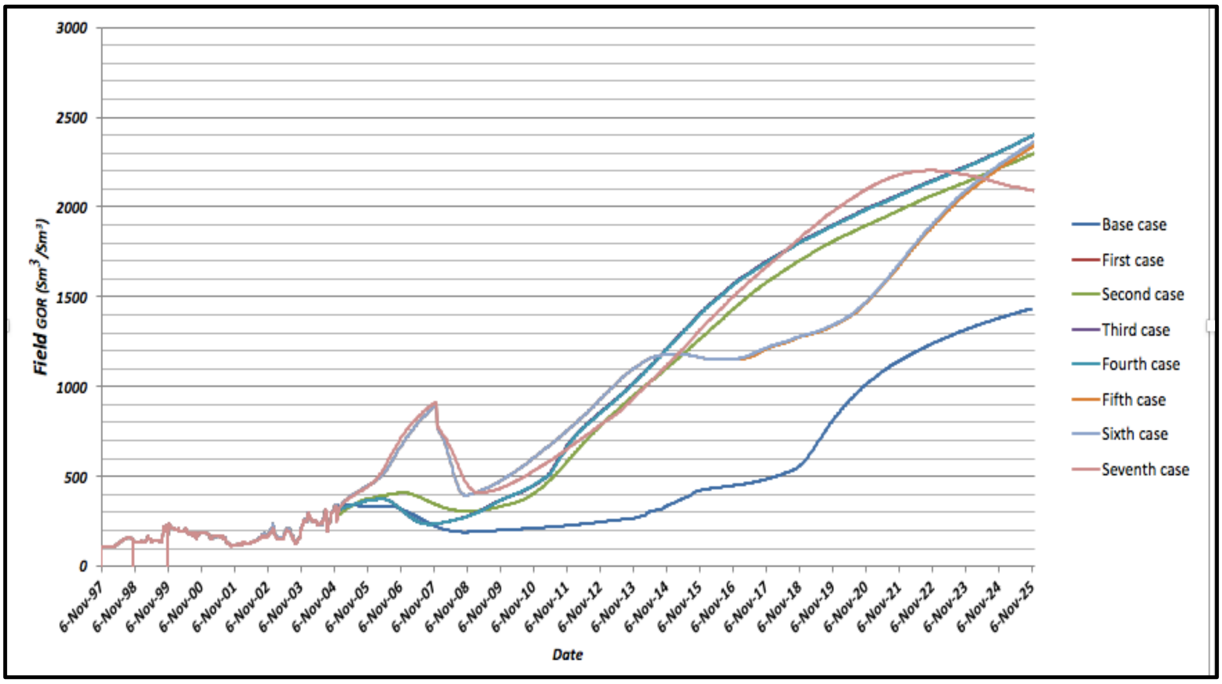


Figure 54: Field GOR for waterflooding scenario

Figure 54 shows that the GOR of the cases with new injector is higher than those without injector. The reason is, the presence of the new injector from 2004 raised the reservoir pressure as it goes on increasing until it remains constant. At higher pressures above bubble point, gas escapes from oil solution and as pressure increases more gas is evolved from the oil saturation which in turn results into higher GOR. GOR increases rapidly for first to fourth case.

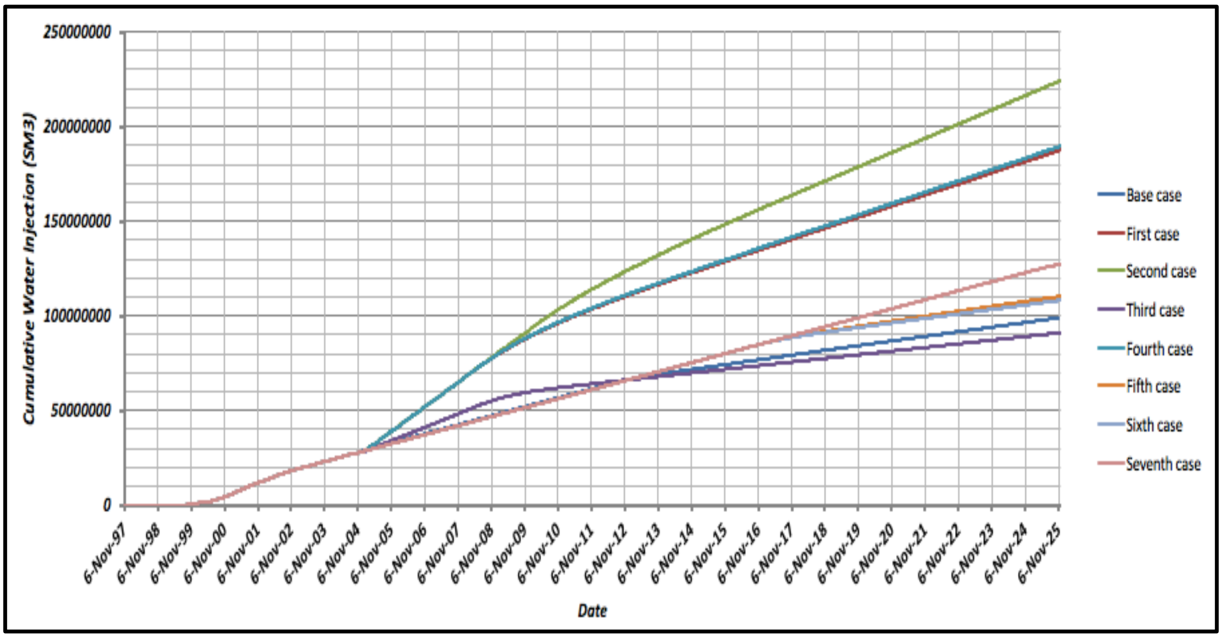


Figure 55: Cumulative water injection for waterflooding scenario

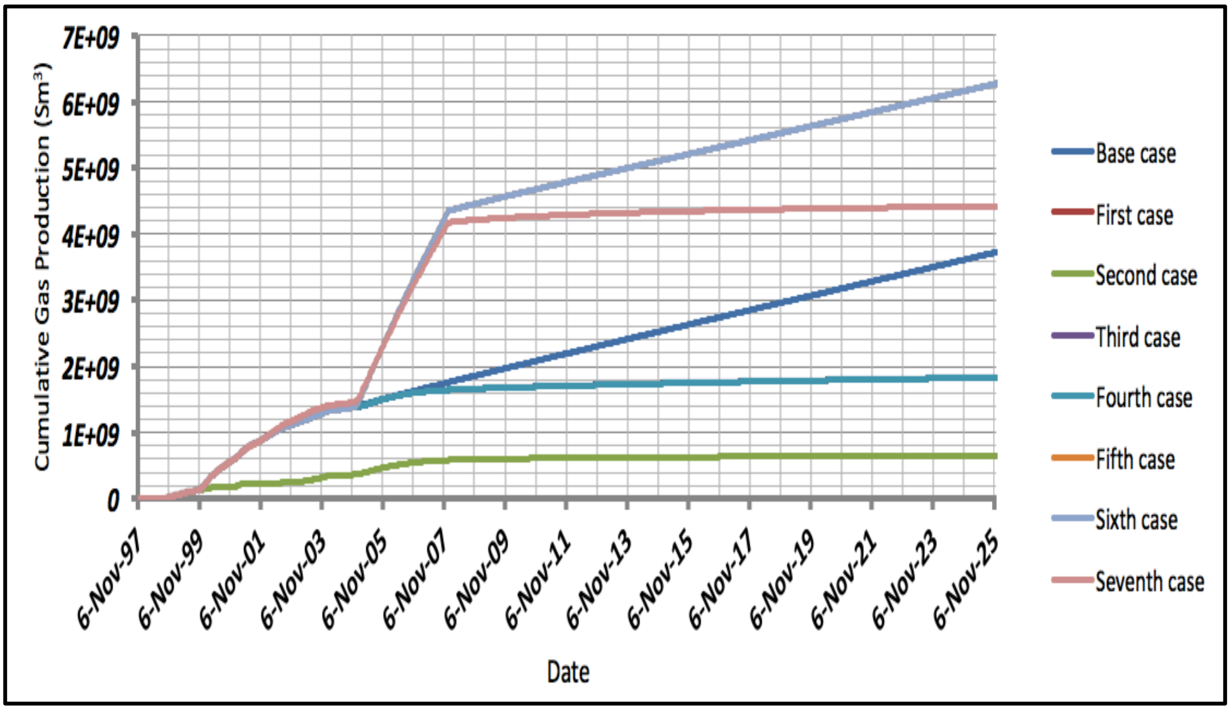


Figure 56: Gas production for waterflooding scenario

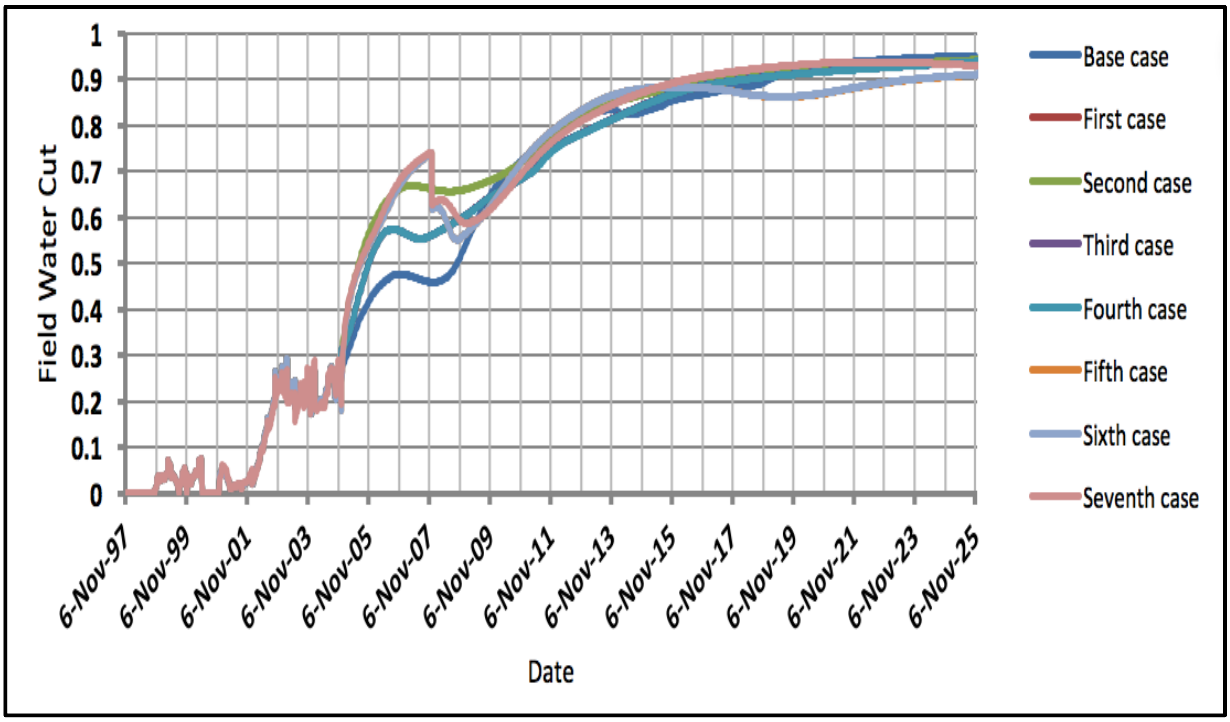


Figure 57: Field water cut for waterflooding scenario

Figure 57 shows that there is rapid breakthrough of water in 2004. The reason is, the new injector G-1H was placed into the reservoir hence increases the mobility of both oil and water in the reservoir. High mobility of water increases the chance of breakthrough.

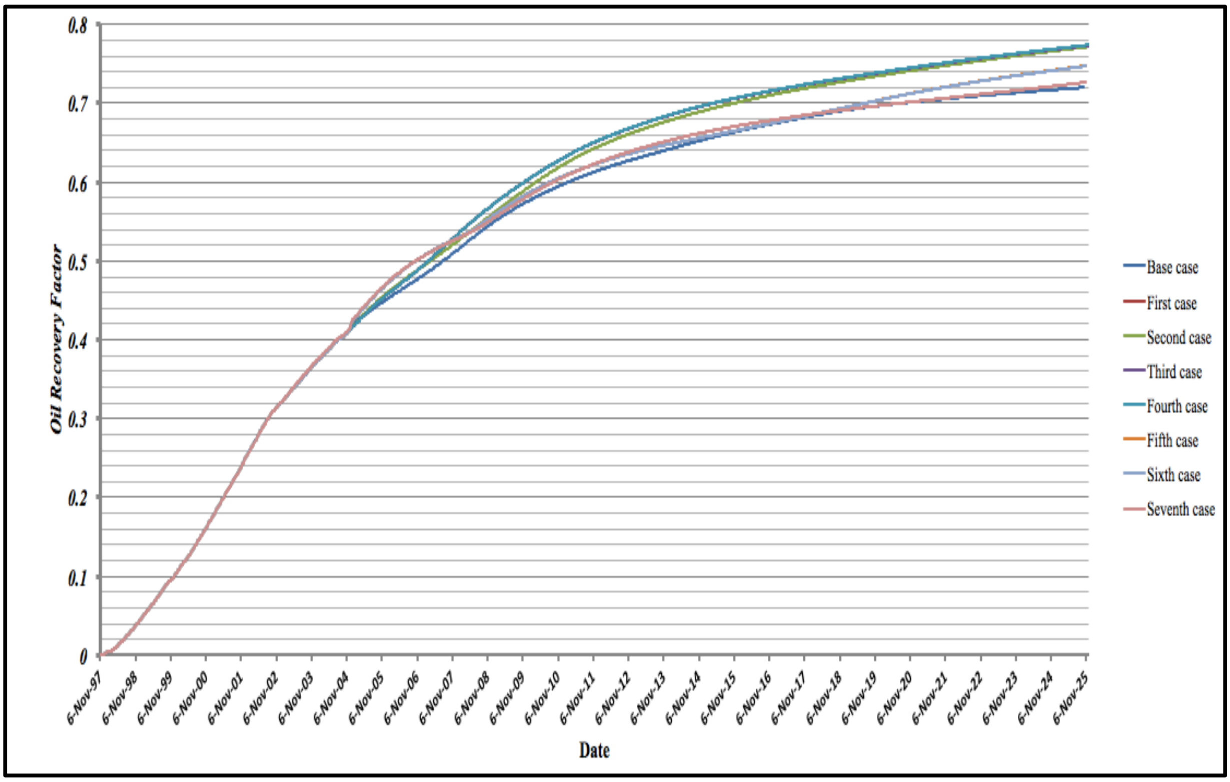


Figure 58: Field oil recovery factor for waterflooding scenario

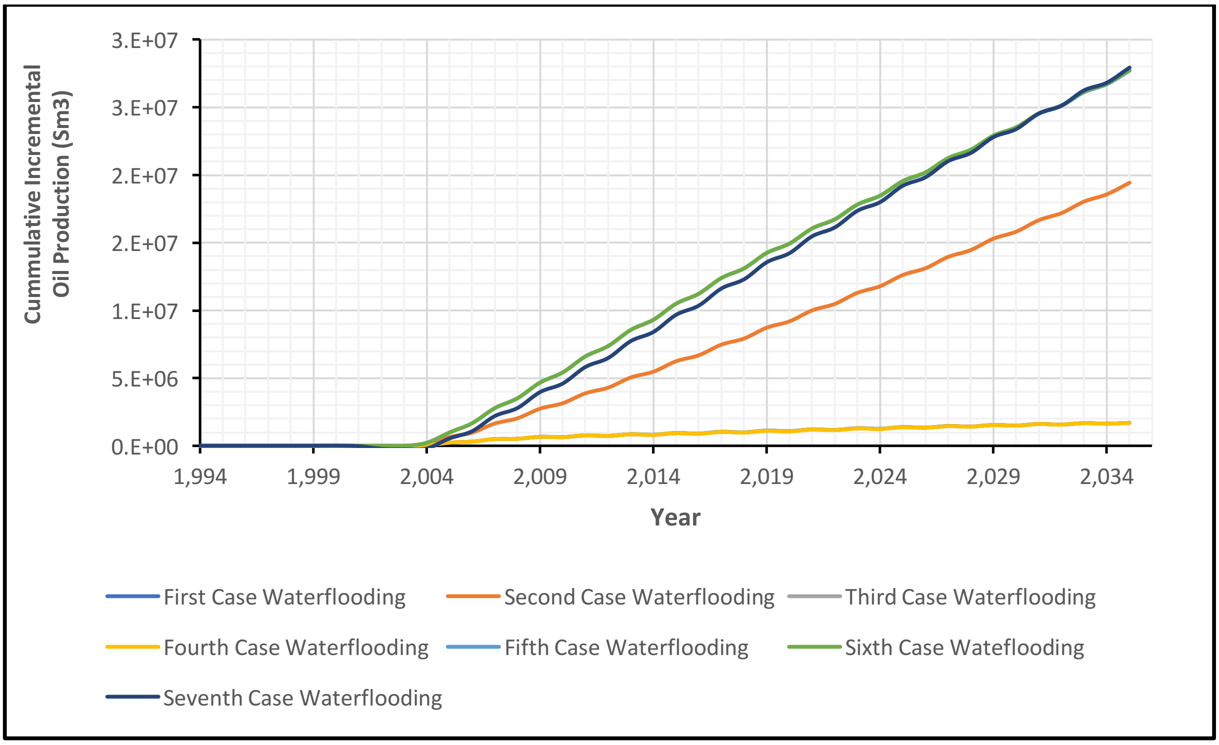


Figure 59: Cumulative incremental oil production for waterflooding scenario

Figure 58 shows that the highest recovery factor of 78% is achieved by the fourth case and the highest oil production of 27.932 MSm3 as seen in Figure 59 is achieved by the seventh case waterflooding.

7.3: EOR Potentiality in Norne E-Segment

Over the past 2 and a half decades, screening criteria for all oil recovery (EOR) methods. Different researchers have been developing detailed economic and technical screening criteria for different EOR processes through modelling/simulation, using laboratory and field data. These scholars are Taber et al. (1997a, 1997b), Al-Bahar et al. (2004), Henson et al. (2002) and Dickson et al. (2010). Data from EOR projects around the world have been examined and the optimum reservoir/oil characteristics for successful projects have been noted. The oil gravity ranges of the oils of current EOR methods have been compiled and the results are compiled graphically. The proposed screening criteria are based on both field results and oil recovery mechanism. The essence of developing EOR screening criteria is to aid in selection of an appropriate EOR method from various options of EOR methods for applying in a particular field of interest [57]. The criteria are based on oil-displacement mechanisms and the results of EOR field projects. The depth, oil gravity, and oil production from hundreds of projects are displayed in graphs to show the wide distribution and relative importance of the methods.

In this work, EOR screening for the applicability of EOR in Norne E-segment was done using screening criteria of Taber et al [58]. Table 13 shows the summary of screening criteria which is based on a combination of both reservoir and oil characteristics of successful projects in conjunction with the optimal conditions needed for good oil displacement by the different fluids. The suggested criteria in Table 13 are informative and intended to show approximate ranges of best projects but they may be misleading [57].

In accordance with [58], a best way of selecting EOR method from numerous EOR methods is by arranging them based on oil gravity as shown in Figure 60.

In Figure 60, the size of the type indicates the relative importance of each of the EOR methods with respect to incremental oil production.

Table 14 contains the reservoir and oil properties of the field of interest which have to be subjected to Table 13 in order to satisfy a certain EOR method.

The API gravity of the Norne oil is 32.7^{o} and with all the other properties of Norne field provided in Table 14, chemical methods are well compatible with them. However, the oil viscosity of the Norne field is lower than that in the compatible chemical methods and also the temperature of the reservoir is slightly higher by 5^{o}C more than the range suggested in Table 13.

So, in this work in the light of above discussion. Simulations of the chemical methods (Surfactant, Polymer, Alkaline-Surfactant-Polymer, Alkaline-Surfactant and Surfactant-Polymer) were decided and since waterflooding is the current drainage strategy for the Norne E-Segment it then becomes advantageous. However, the chemical EOR processes are complex and expensive, high adsorption and degradation of chemicals can occur at high temperatures.

Table 13: Summary of Screening Criteria for EOR Methods [59]

		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	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)										
1	Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to c7	> 40 ↗ 75 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 6,000	NC
2	Hydrocarbon	> 23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7	> 30 ↗ 80 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 4,000	NC
3	CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent Of C_5 to C_{12}	> 20 ↗ 55 ↗	Sandstone or carbonate	Wide range	NC	> 2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	> 35 ↗ 70 ↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	> 20 ↗ 35 ↗	< 35 ↘ 13 ↘	Light, intermediate, some organic acids for alkaline floods	> 35 ↗ 53 ↗	Sandstone preferred	NC	> 10 ↗ 450 ↗	> 9,000 ↘ 3,250	> 200 ↘ 80
5	Polymer Flooding	> 15	< 150, > 10	NC	> 50 ↗ 80 ↗	Sandstone Dreferred	NC	> 10 ↗ 800 ↗ [b]	< 9,000	> 200 ↘ 140
Thermal/Mechanical										
6	Combustion	> 10 ↗ 16 → ?	< 5,000 ↓ 1,200	Some asphaltic components	> 50 ↗ 72 ↗	High-porosity sand/ sandstone	> 10	> 50[c]	< 11,500 ↘ 3,500	> 100 ↗ 135
7	Steam	> 8 to 13.5 → ?	< 200,000 ↓ 4,700	NC	> 40 ↗ 66 ↗	High-porosity sand/ sandstone	> 20	> 200 ↗ 2,540 ↗ [d]	< 4,500 ↘ 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	> 8 wt% sand	Mineable tar sand	> 10[e]	NC	> 3 1 overburden to sand ratio	NC

NC = not critical.
Underlined values represent the approximate mean or average for current field projects.
[a]See Table 3 of Ref. 16.
[b]> 3md from some carbonate reservoirs if the intent is to sweep only the fracture system.
Transmissibility > 20 md-Wcp
[d]Transmissibility > 50 md-Wcp
[e]See depth.

Table 14: Reservoir and oil properties of the Norne Field [14] [7] [8]

Reservoir properties		*Oil properties*	
Formation type	oil-wet carbonate	Density, kg/m^3	859.5
Net thickness, m	110	Gravity (API)	32.7^o
Reservoir depth, m	2500-2700	Viscosity, cp	Less than 1.2
Temperature, ^{o}C	98.3		
Oil saturation, %	35-92		
Porosity	25-30		
Permeability	20-2500		

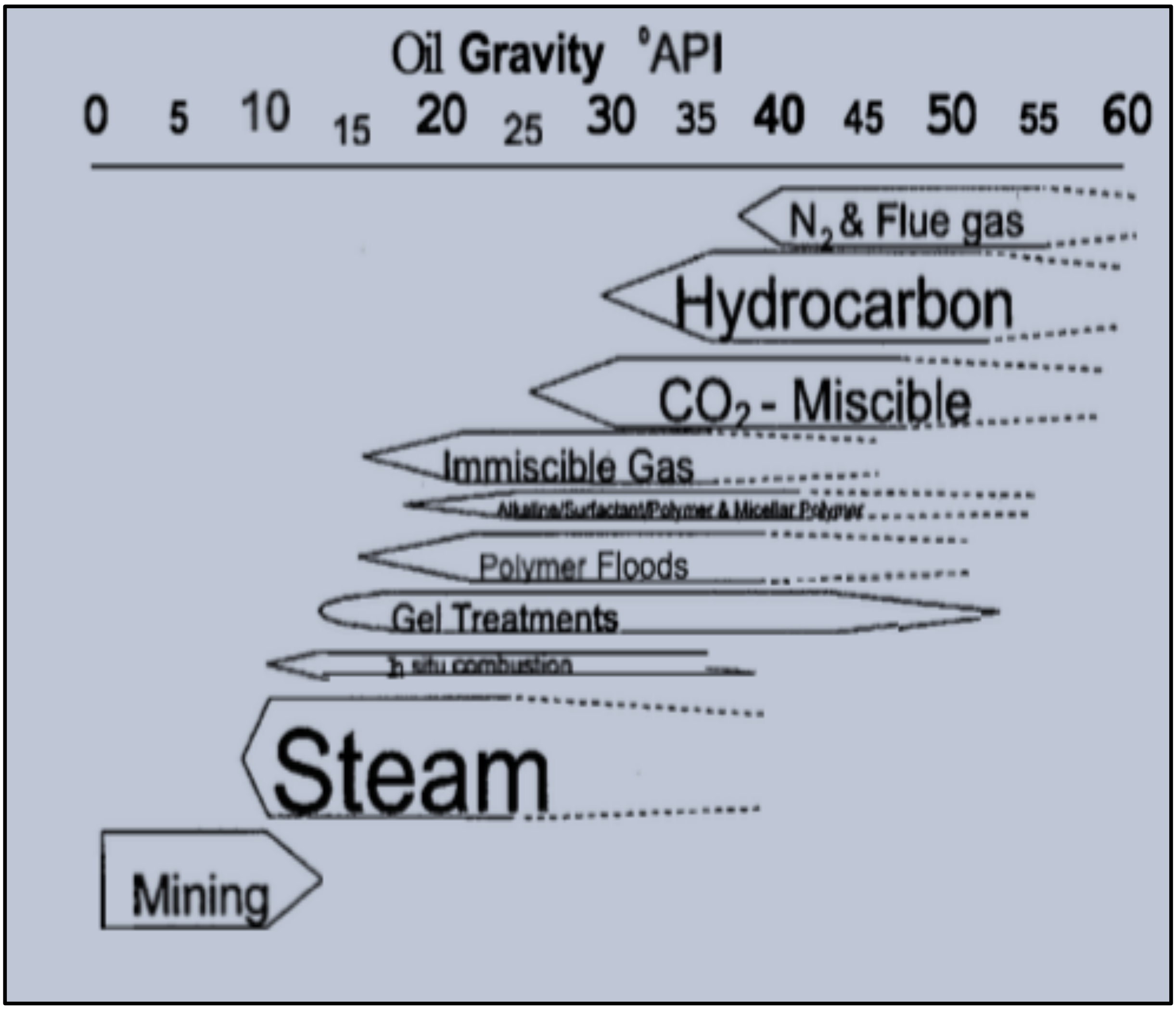


Figure 60: Oil gravity range of oils that is most effective for EOR Methods [58], [59]and [60].

CHAPTER 8

8.0: OVERVIEW OF EOR CHEMICAL FLOODING

8.1: Introduction to EOR

In the North Sea, the current average recovery is above 40%, however an average of 50% is set as the target by Norwegian Petroleum Directory (NPD). Enhanced Oil Recovery (EOR) is one of the solutions to meet this goal for Norwegian sector [61] and worldwide the EOR projects continues to supply an increasing percentage of the world's oil production [60] as shown in Figure 61 and the world's oil recovery overview in Figure 62.

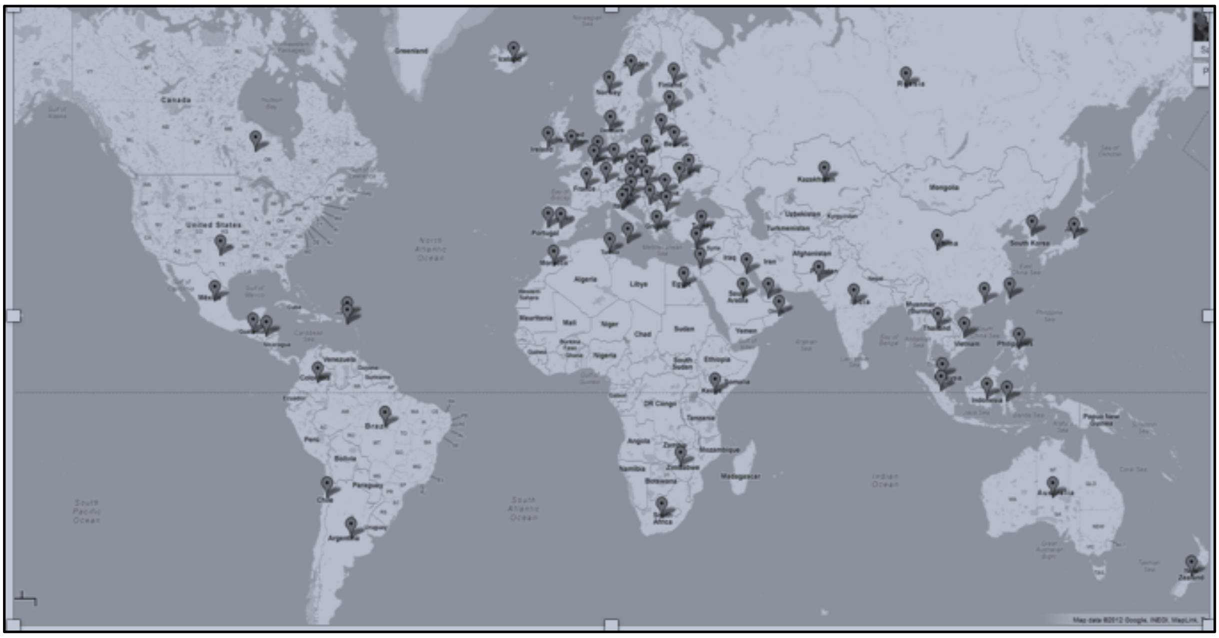


Figure 61: Chemical EOR Projects Worldwide [62].

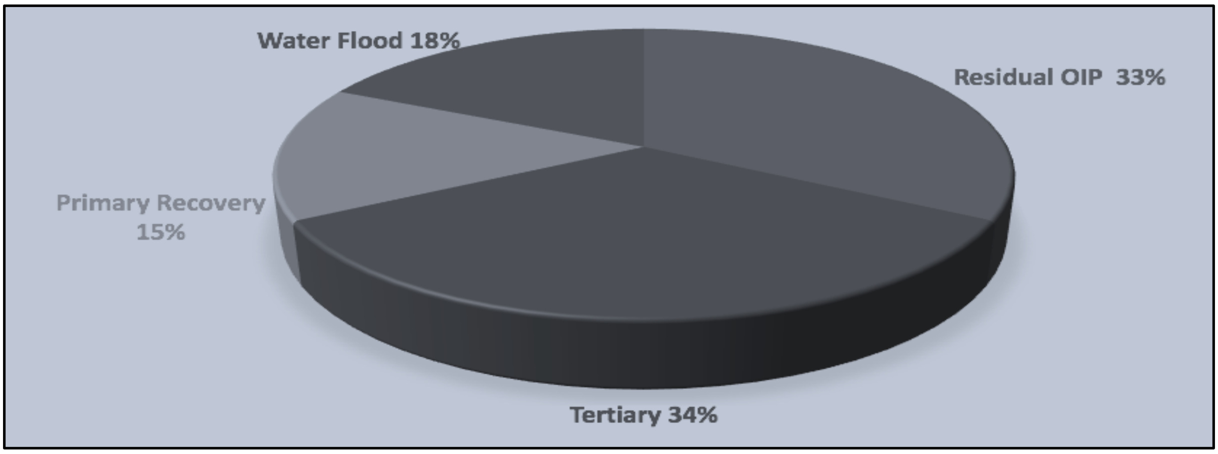


Figure 62: World's Oil Recovery Processes [63].

EOR methods that have a big potential under right circumstances but little experience on the Norwegian Continental Shelf are chemical flooding [64].There are some environmental and economic issues upon applications of these chemicals although in this work these issues are assumed to be solved. So, the aim of this part is to do an EOR study of chemical flooding on Norne E-Segment by applying chemical flooding using simulations. Practical process of injecting chemicals into the reservoir is indicated in Figure 63.

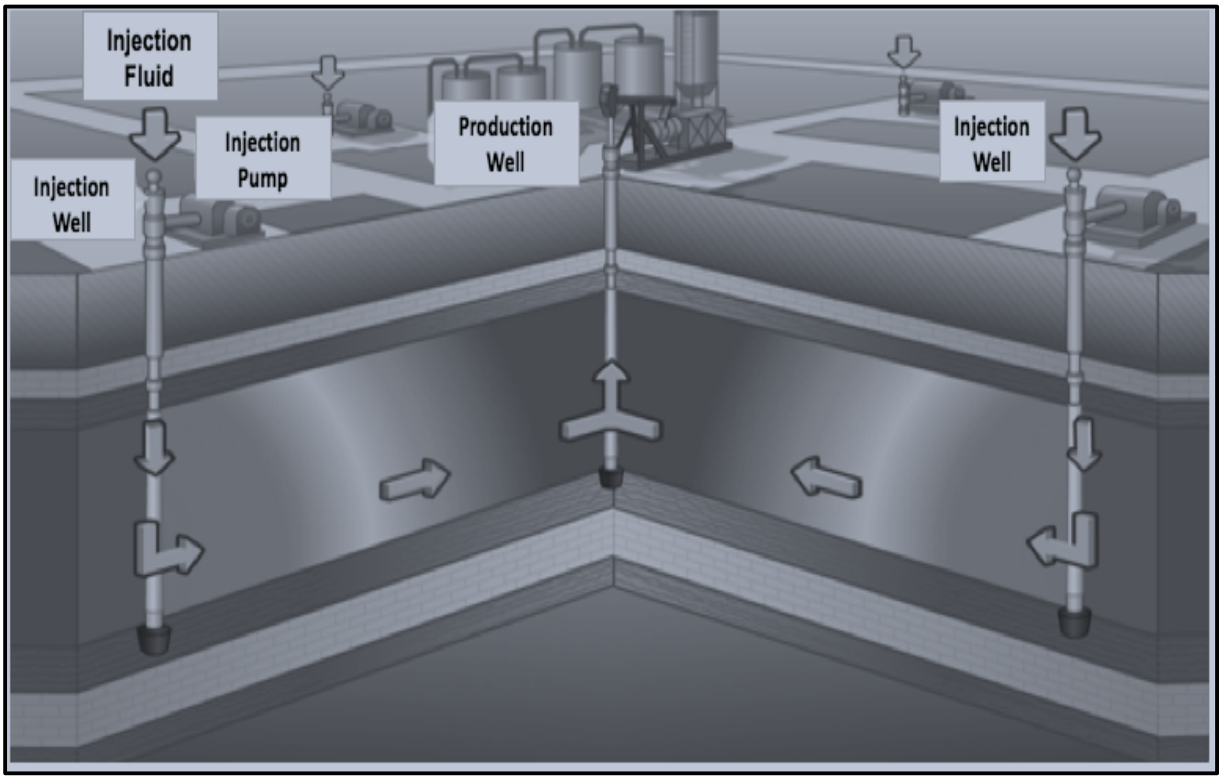


Figure 63: Chemical EOR System [62].

8.2: Surfactant Flooding

The term surfactant is the representation of the surface-active agent/substance which means that when applied to the surface or fluid/fluid contact it adsorbs on or concentrate to alter the surface properties.

Most large oil fields are produced with some type of secondary maintenance scheme, such as water flooding. Water flooding can increase recovery from around 20-40% range. The remaining oil can be divided into two classes, firstly residual oil to the water flood, and secondly oil bypassed by the water flood. A surfactant flood is a tertiary recovery mechanism aimed at reducing the residual oil saturation in water swept zones.

Typically, a water flood that contacts 100% of a given oil zone will leave a residual oil saturation of, say, 30%. This is the saturation at which the oil phase relative permeability value is zero. The oil is immobile at this saturation because of the surface tension between oil and water, the water pressure alone is unable to overcome the high capillary pressure required to move oil out of very small pore volumes.

A surfactant offers a way of recovering the residual oil by reducing the surface tension between the oil and water phases. A very low oil-water surface tension reduces the capillary pressure and hence allows water to displace extra oil. If it is possible to reduce the surface tension to zero, then theoretically the residual oil can be reduced to zero. In practice the residual oil to even high concentration is unlikely to lead to 100% recovery of swept zones.

One of the effects that will influence the success or failure of a surfactant flood is the tendency of the surfactant being used to be adsorbed by the rock. If the adsorption is too high, then large quantities of surfactant will be required to produce a small quantity of additional oil.

Surfactants tend to decrease surface tension or interfacial tension (IFT) thereby spreading in fluids with its wetting properties. Being organic compounds, surfactants are amphiphilic, meaning that they are made up of two functional groups which are hydrophobic (water-hating, the *tail*) and polar hydrophilic (water-loving, the *head*). In accordance with these properties, surfactants are soluble in both organic solvents and water. Surfactants may act as detergents, wetting agents, emulsifiers, foaming agents, and dispersants.

Basic classification of surfactant

There are four groups of surfactants groups in accordance with the ionic nature of head group as anionic, non-ionic, cationic and Zwitterionic (amphoteric).

Anionic

The surfactant is classified as anionic when it has a negative charge on its head group. These are mostly used in chemical EOR processes because they are stable, efficiency to reduce IFT, relatively resistant to retention, exhibit relatively low adsorption on sandstone rocks which negatively charged on their surface. Anionic surfactants are not suitable in carbonate rocks because they tend to strongly adsorb on the surface of the carbonate rocks due to the presence of positive charge.

Non-ionic

The surfactants are anionic since they have no charge. They primarily serve as co-surfactants to improve the phase behaviour and more tolerant of high salinity brine unless mixed with anionic surfactants. Their surface-active properties to reduce IFT are not as good as anionic surfactants.

Cationic

The surfactants are cationic since they are positively charged and they strongly adsorb in sandstone rocks; therefore, they are not used in sandstone reservoirs rather in carbonate rocks to change wettability from oil-wet to water-wet.

Zwitterionic

The alternative name of zwitterionic surfactants is amphoteric due to the fact that they have both positive and negative charges as two groups. The types of zwitterionic surfactants are

onionic-anionic, non-ionic-cationic, or anionic-cationic and are expensive because they are salinity-tolerant and expensive [42] [65].

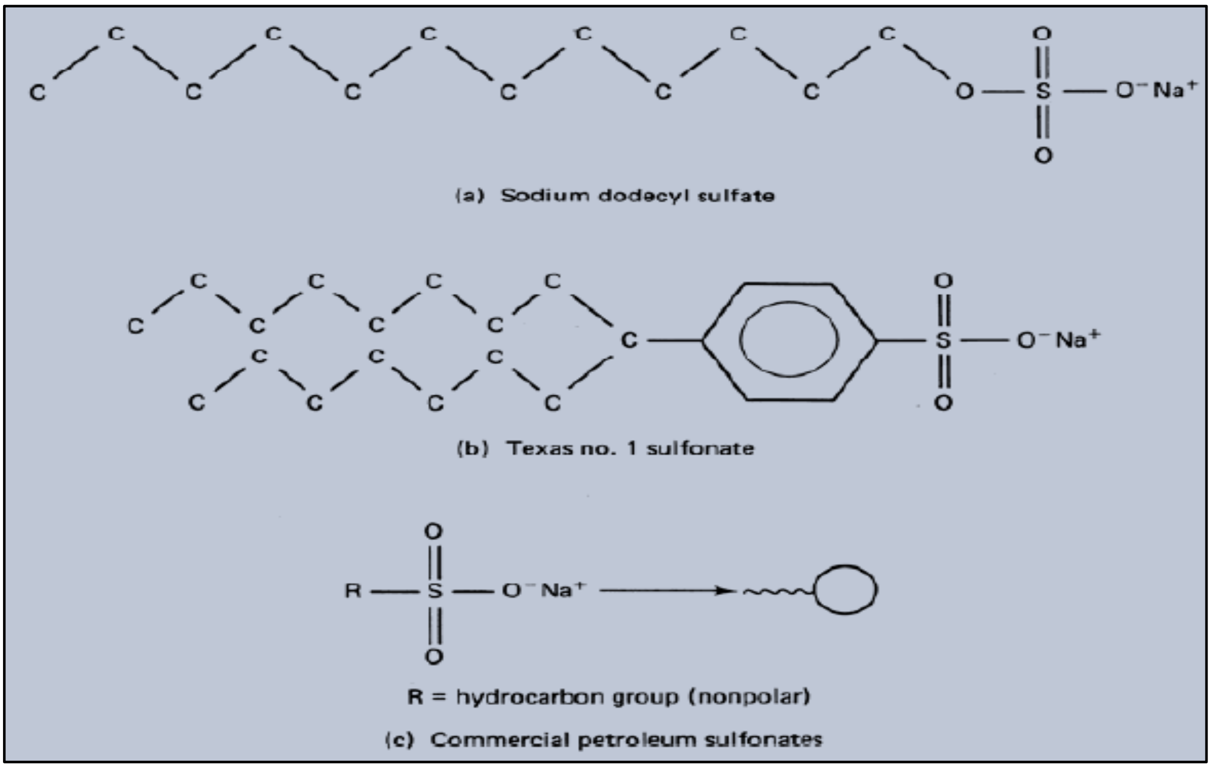
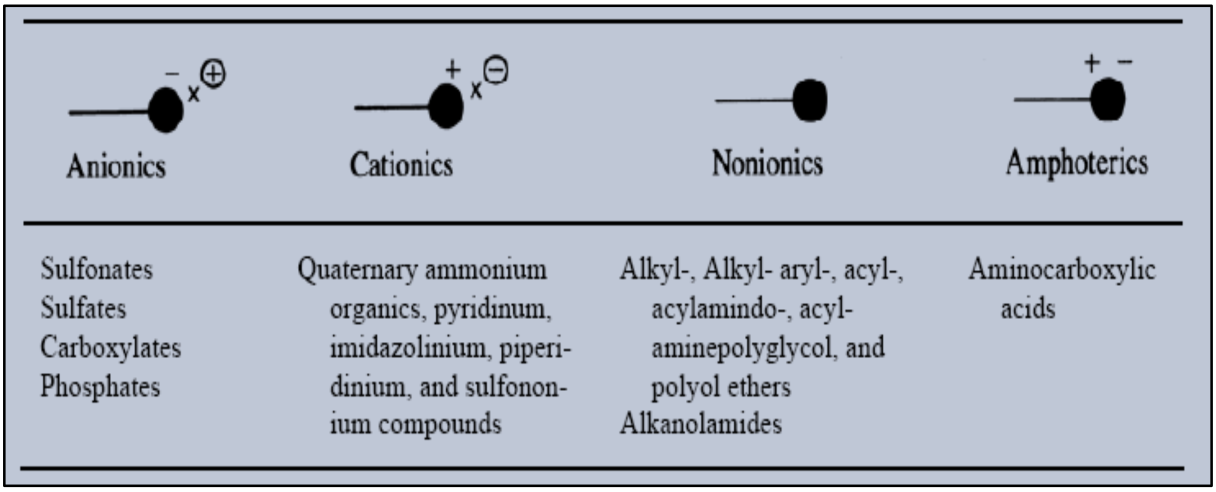


Figure 64: Representative surfactant molecular structures [28]



Anionics	Cationics	Nonionics	Amphoterics
Sulfonates Sulfates Carboxylates Phosphates	Quaternary ammonium organics, pyridinum, imidazolinium, piperi-dinium, and sulfonon-ium compounds	Alkyl-, Alkyl- aryl-, acyl-, acylamindo-, acyl-aminepolyglycol, and polyol ethers Alkanolamides	Aminocarboxylic acids

Figure 65: Classification of surfactants and examples [66]

Critical Micelle Concentration

CMC is defined as the concentration of surfactants above which micelles are spontaneously formed. Micelle is an aggregation of molecules which usually consists of 50 or more surfactant molecules. When surfactants are injected into the system, they will initially partition into the interface, reducing the system free energy by lowering the energy of the interface and removing the hydrophobic parts of the surfactant from contact with water. As the concentration of surfactant increases and the surface free energy (surface tension) decreases, the surfactants start aggregating into micelles. Above a specific concentration, called as critical micelle concentration (CMC), further addition of surfactants will just increase number of micelles as shown in Figure 66. In other words, before reaching the CMC, the surface tension decreases sharply with the concentration of the surfactant whereas the surface tension stays more or less constant after reaching the CMC.

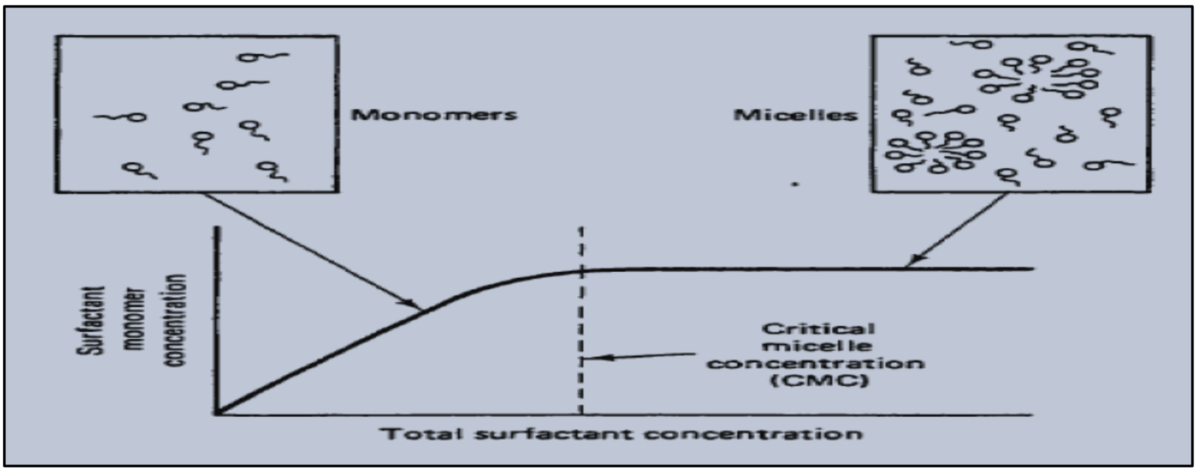


Figure 66: Schematic definition of the critical micelle concentration (CMC) [28]

Solubilization Ratio

Solubilization is the process of making a normally insoluble material soluble in a given medium. Solubilization ratio for oil (water) is defined as the ratio of the solubilized oil (water) volume to the surfactant volume in the micro emulsion phase. Huh (1979) formulated that solubilization ratio is closely related to IFT. When the solubilization ratio for oil is equal to that for water, the IFT reaches its minimum [65]

8.2.1: Surfactant Flooding in Petroleum Reservoirs

The purpose of surfactant flooding is to recover the capillary trapped oil after water flooding. When a surfactant solution has been injected into the reservoir, the trapped oil droplets are mobilized due to a reduction in the interfacial tension between oil and water. The coalescence of these drops leads to a local increase in oil saturation and oil bank is generated. The oil bank will start to flow, mobilizing any residual oil in front of the bank. Behind the flowing oil bank, the surfactant will prevent the mobilized oil to be re-trapped. The interfacial tension, the viscosity, and the volume of the surfactant solution behind the oil bank will therefore be of importance for the final residual oil saturation.

If the efficiency of surfactant is very good, then the reduction in Interfacial tension (IFT) could be as much as 10^4 which corresponds to a value in the neighbourhood of 1μN/m. Due to high cost of surfactant, mostly a small surfactant slug is displaced by water, usually containing polymer to increase viscosity which prevents fingering and breakdown down of slug [66]. The main aspects of surfactant flooding are discussed below;

8.2.2 Capillary Desaturation Curve (CDC)

To reduce waterflood residual oil saturation, the pressure drop across the trapped oil has to overcome the capillary forces that keep the oil trapped. This is done with surfactant which provides such a pressure drop. A large number of studies have shown that the residual oil saturation corresponds to the capillary number ($N_{c)}$, the dimensionless ratio between the viscous and capillary forces. In general, the capillary number must be higher than a critical capillary number, $(N_C)_c$, for a residual phase to start to mobilize. Practically, this $(N_C)_c$ is much higher than the capillary number at normal waterflooding conditions. Another parameter is maximum desaturation capillary number, $(N_C)_{max}$, above which the residual saturation would not be further decreased in practical conditions even if the capillary number is increased.

The general relationship between residual saturation of a non-aqueous (nonwetting phase) or aqueous phase (wetting phase) and a local capillary number is called capillary desaturation curve (CDC). The residual saturations start to decrease at the critical capillary number as the capillary number increases, and cannot be decreased further at the maximum capillary number (Figure 67). The CDC for the wetting phase is shifted to the right of the CDC of the non-wetting phase by two orders of magnitude (see Figure 67); this indicates that surfactant should have better performance in a water-wet system. Figure 68 shows that oil saturation starts to drop as pore size becomes narrower at high capillary number (NC), which means that a reservoir with narrow pore-size distribution will give the lowest residual oil saturation. In a simulation model, the efficiency of the surfactant will rely upon CDC, and should therefore be measured for every distinct rock type.

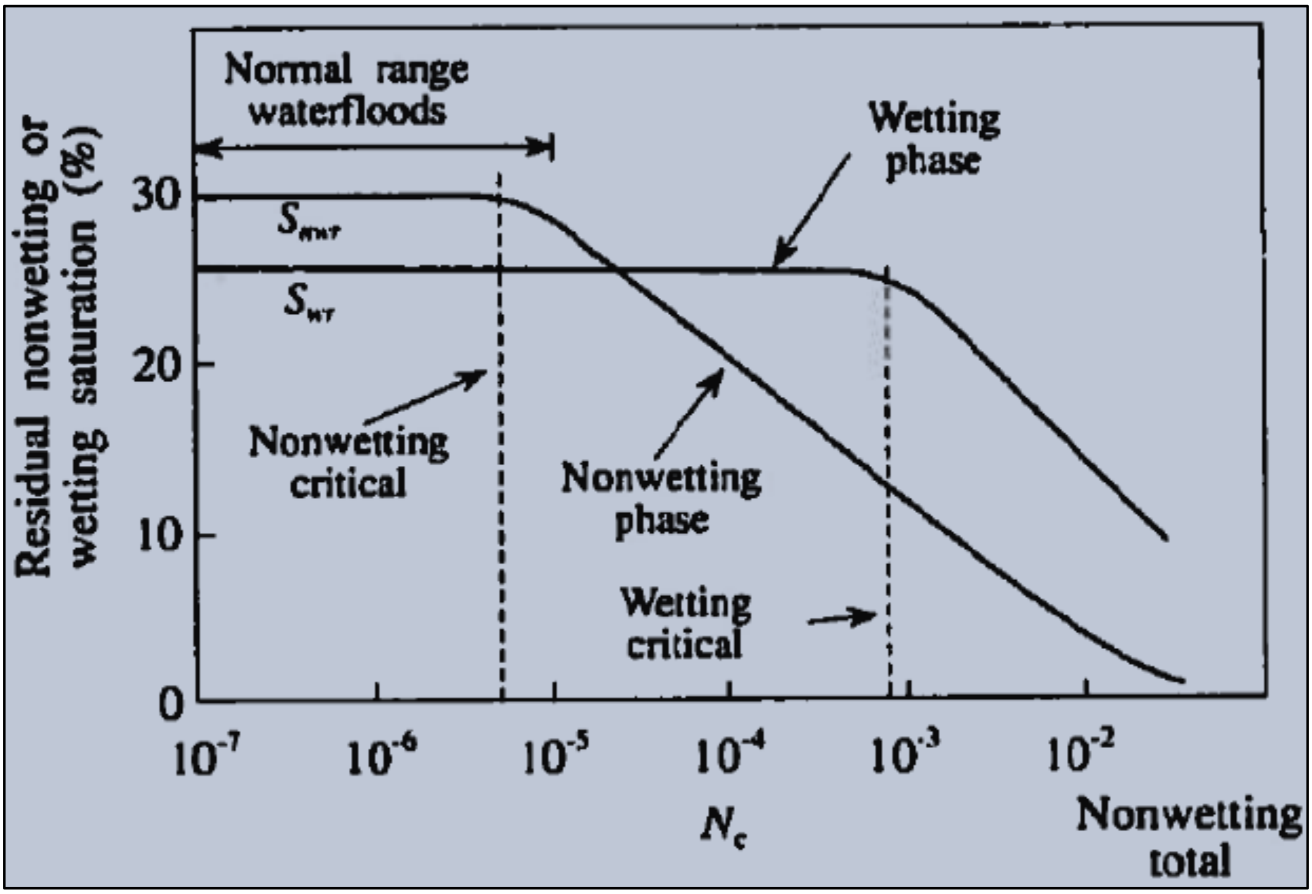


Figure 67: Effect of wettability on residual saturation of wetting and non-wetting phase [65]

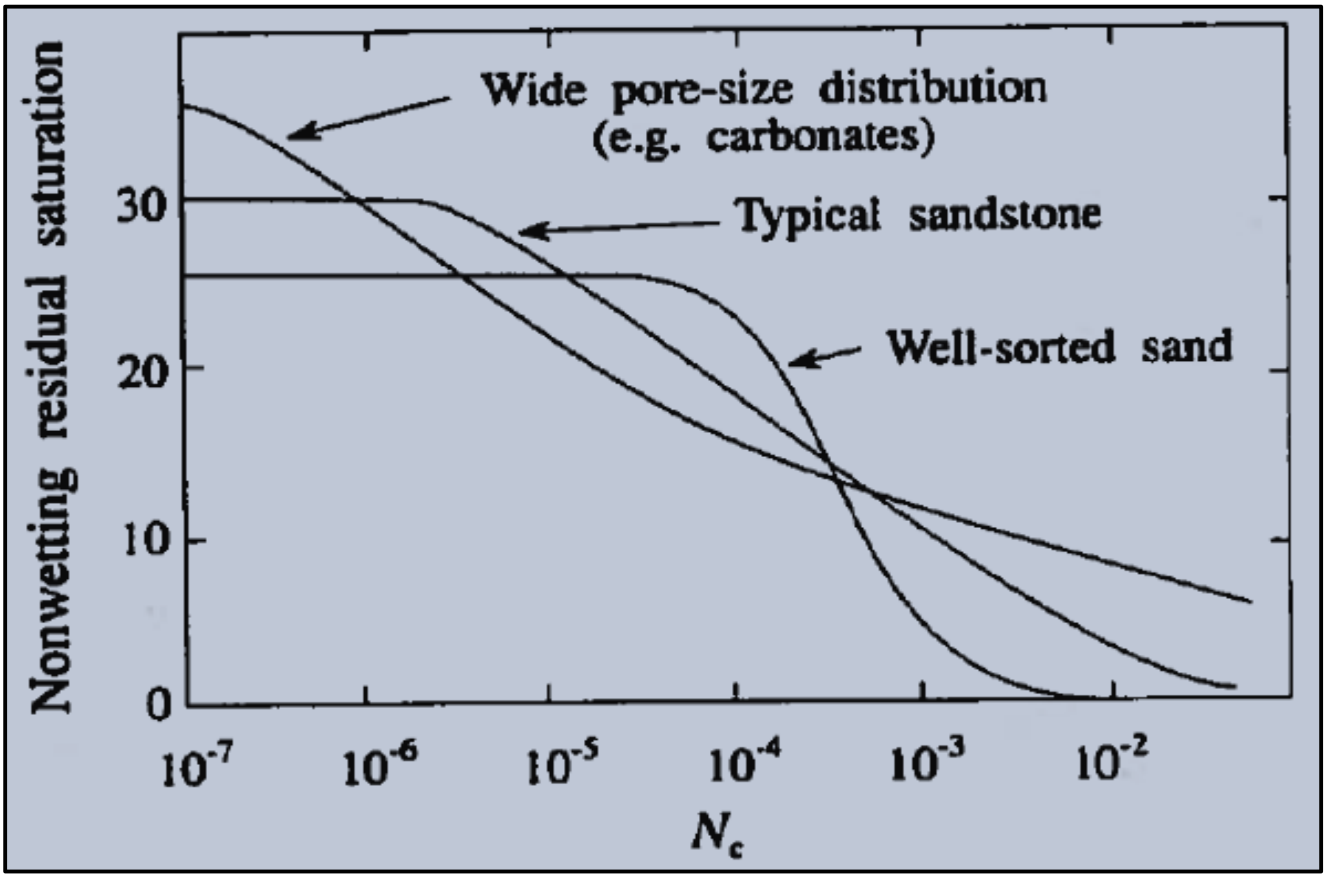


Figure 68: Effect of pore-size distribution on the CDC [65].

8.2.3: Volumetric Sweep Efficiency and Mobility Ratio

Volumetric sweep efficiency E_V is the volume of oil contacted divided by the volume of target oil. E_V is a function of surfactant/polymer slug size, retention and heterogeneity. The mobility ratio has to be as low as possible for an efficient displacement of the oil bank towards the producing wells. Low mobility ratio prevents fingering of the surfactant slug into the oil bank and also reduces large- scale dispersion due to permeability contrasts, gravity segregation and well pattern. The mobility control agent in the slug can be a polymer or oil. It is of paramount importance that the slug-oil bank front be made viscosity stable since small slugs cannot tolerate even a small amount of fingering. It has been confirmed from simulation studies that low mobility ratio is of great importance according to recovery, while the size of the surfactant slug gave small differences in performance [28] [65].

8.2.4: Relative Permeabilities

In chemical flooding process, relative permeability is most likely one of the least- defined parameters. The classic relative permeability curves represent a situation in which fluid distribution in the system is controlled by capillary forces. The concept of relative permeability is fundamental to the study of the simultaneous flow of immiscible fluids in porous media. Relative permeabilities are influenced by the following factors; saturation, saturation history, wettability, temperature, viscous, capillary and gravitational forces [67]. In surfactant-related processes, the interfacial tension is reduced. As IFT is reduced, the capillary number is increased, leading to reduced residual saturations. Obviously, residual saturation reduction directly changes relative permeabilities and the relative permeability curves become closer to straight lines (exponents close to 1), and the immobile saturations are closer to 0. Many researchers observed from their experimental results that as water/oil IFT was reduced, both oil and water relative permeabilities were increased, their end points were raised, had less curvature, and residual saturations were decreased. These observations were obvious only when the IFT was below 0.1 mN/m [65].

8.2.5: Surfactant Retention

The success or failure of a surfactant flooding project is mostly determined by the control of surfactant retention. According to mechanisms, surfactant retention has been identified as precipitation, adsorption, and phase trapping. These mechanisms all result in retention of surfactant in a porous medium and deterioration of the composition of the chemical slug and hence leading to poor displacement efficiency. Surfactant retention in reservoirs depends on surfactant type, surfactant equivalent weight, surfactant concentration, rock minerals, clay content, temperature, pH, flow rate of the solution, etc. As the equivalent weight of the surfactant increases surfactant retention also increases and vice versa. Petroleum sulfonates are widely used in surfactant flooding. The presence of divalent cations (Ca^{2+}, Mg^{2+}) in the solution causes surfactant precipitation.

Adsorption

Most solid surfaces including reservoir rocks are charged due to different mineralogy. The reservoir minerals like quartz (silica), kaolinite show a negative charge while calcite, dolomite and clay have positive charge on their surfaces at neutral pH of the brine. The adsorption of surfactants at the solid/liquid interface comes into play by electrostatic interaction between the charged solid surface (adsorbent) and the surfactant ions (adsorbate). Ion exchange, ion pairing and hydrophobic bonding are some of mechanisms by which surfactants adsorb onto mineral surfaces of rock. Non-ionic surfactants have much higher adsorption on a sandstone surface than anionic surfactants whereas for calcite is reverse. Thus, non-ionic surfactants might be candidates for use in carbonate formations from the adsorption point of view as already discussed in classification of surfactants [65] [68].

An example of an isotherm for the adsorption of a negatively charged surfactant onto an adsorbent with positively charged sites is S-shaped. Figure 69 shows four different regions reflecting distinct modes of adsorption [65].

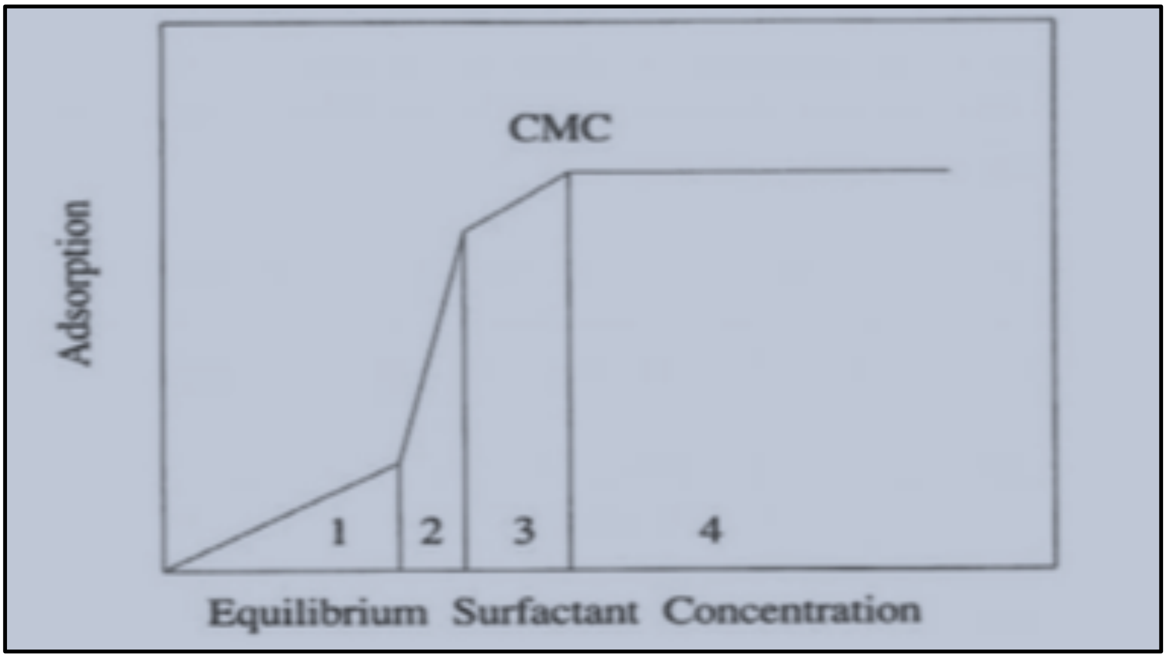


Figure 69: Schematic S-shaped adsorption curve [65]

Region 1: In this region, the surfactant is mainly adsorbed by anionic exchange and shows a linear relationship between adsorbed material and equilibrium concentration.

Region 2: A remarkable increase in adsorption due to the interaction between the hydrophobic chains of the oncoming surfactant and the surfactant that already has been adsorbed.

Region 3: A decrease in adsorption of surfactants because the adsorption has to overcome the electrostatic repulsion between surfactant and the similarly charged solid.

Region 4: A plateau adsorption is obtained above the Critical Micelle Concentration (CMC), which means that surfactant adsorption will not increase onto the surface.

The interfacial tension between oil and water decreases until the CMC is reached. The shape of the adsorption isotherm may vary for different systems, and some factors that influence the plateau are salinity, pH-value, temperature and wettability. With increased salinity, the plateau adsorption will increase while a decrease in pH will cause an increase in adsorption. It is suggested that surfactant adsorption decrease as the temperature increases [70].

One of the ways of reducing adsorption in chemical flooding is by doing a 'pre- flush' with different type of sacrificial chemicals like NaCl, NaOH, phosphates, silicates, lignosulfonates and polyethylene oxide in order to reduce hardness, make the reservoir rock more negative charged and block the active sites of the rock [65].

Phase Trapping

This form of retention is strongly affected by the phase behaviour. Phase trapping could be caused by mechanical trapping, phase partitioning, or hydro dynamical trapping. It is related to multiphase flow. The mechanisms are complex, and the magnitude of surfactant loss owing to phase trapping could be quite different depending on multiphase flow conditions. Glover et al. (1979) found that the onset of phase trapping with a surfactant flooding process generally occurred at higher salt concentrations because it would form upper-phase micro emulsion so that the surfactant would be trapped in the residual oil. Krumrine (1982) proposed that the addition of alkali would reduce the concentration of hardness ions that may cause surfactant retention. Therefore, ASP will have little surfactant retention due to ion exchange [69].

8.2.6: Other key applications of surfactants in oil field

- Heavy oil recovery without steam

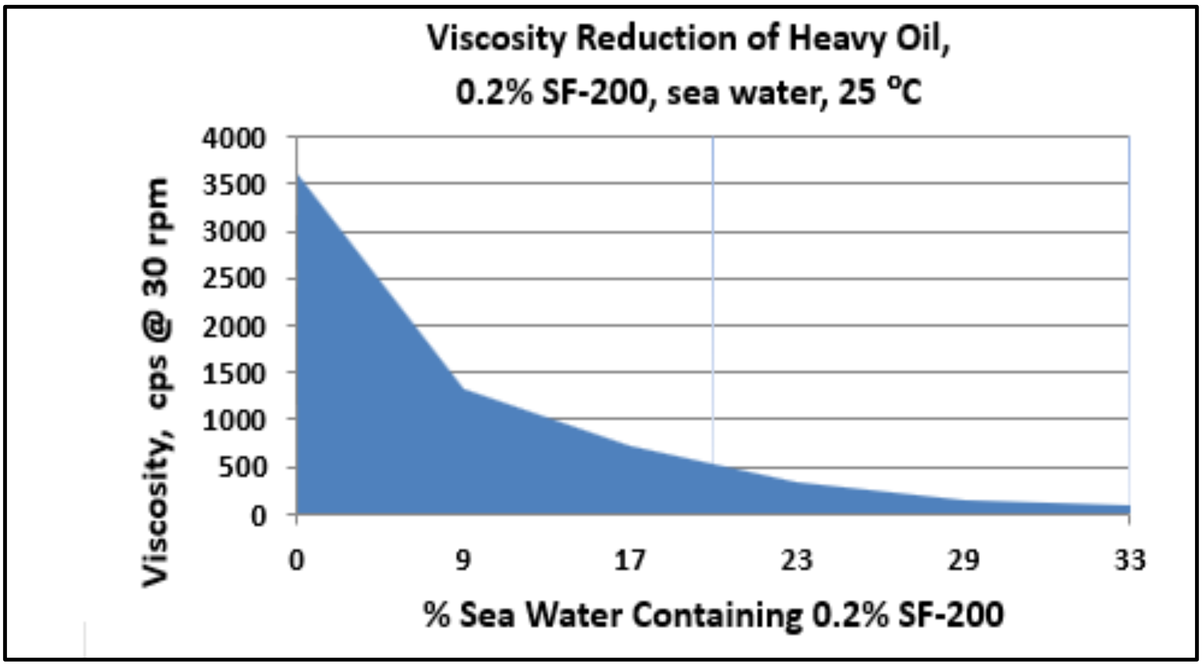


Figure 70: Viscosity reduction of heavy oil [62]

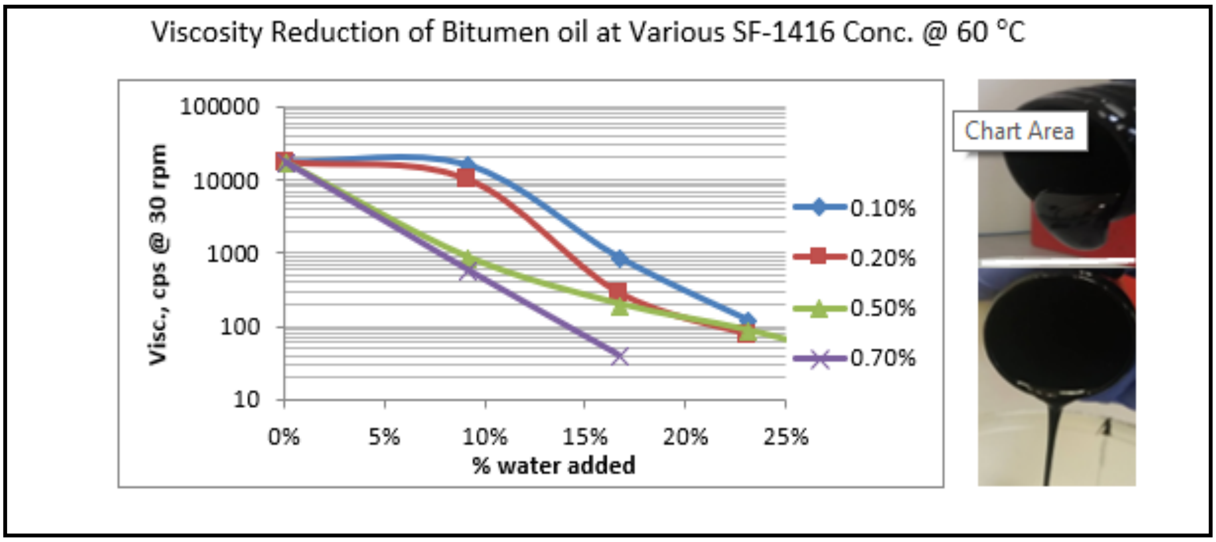


Figure 71: Viscosity reduction of bitumen oil at various SF-1416 conc.@ 60 °C [62]

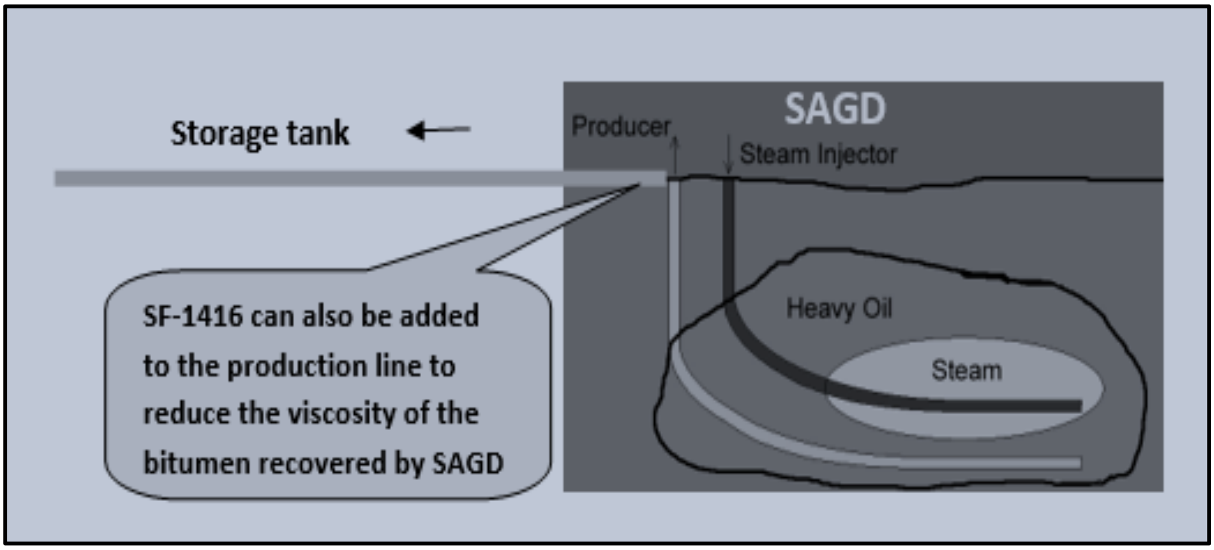


Figure 72: Reduction of the viscosity of bitumen recovered by SAGD [62]

- Heavy oil pipeline flow improver

Advantages

- *Easy to use*

  The flow improvers can be gravity fed downhole through annulus. No special pumping equipment is required.

- *Uniqueness*

  The process produces a low viscosity pseudo-emulsion allowing the heavy crude to be easily transported through the pipeline.

- *Effectiveness*

Very low concentrations of the flow improver are required. 50 ppm to 500 ppm is generally recommended for field application.

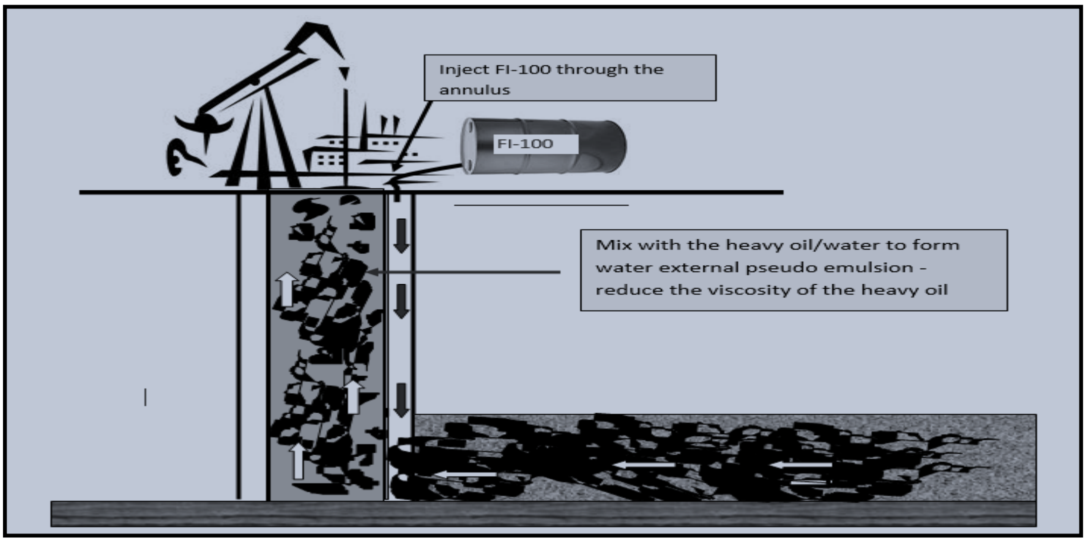


Figure 73: Improving heavy oil pipeline flow [62]

- *Versatility*
  Various oil/water ratios, type of flow improvers, separation time etc. can be used based on the individual treatment conditions.
- *Economical*
  The flow improvers produce a pseudo-emulsion and the emulsion is readily separated upon standing. The demulsifier generally required in the treating station is minimized or eliminated.

➢ Wettability alteration: SS-7593
  Its application

- After the wettability of the formation, enhance the injectivity.
- Reduce the surface tension and interfacial tension.
- Flow back additive and in low surfactant water flooding.
- In contrast to the traditional hydraulic fracturing process, the SS-7593 can be added to the pre-pad fluid and pumped at a slower rate to encourage the fluid leak off. The leaked off fluid will penetrate deeply into the formation generating micro-fractures, after the wettability of the reservoir, reduce interfacial tension between the oil and injection fluid, and increase the oil/ gas production as shown in Figure 74.

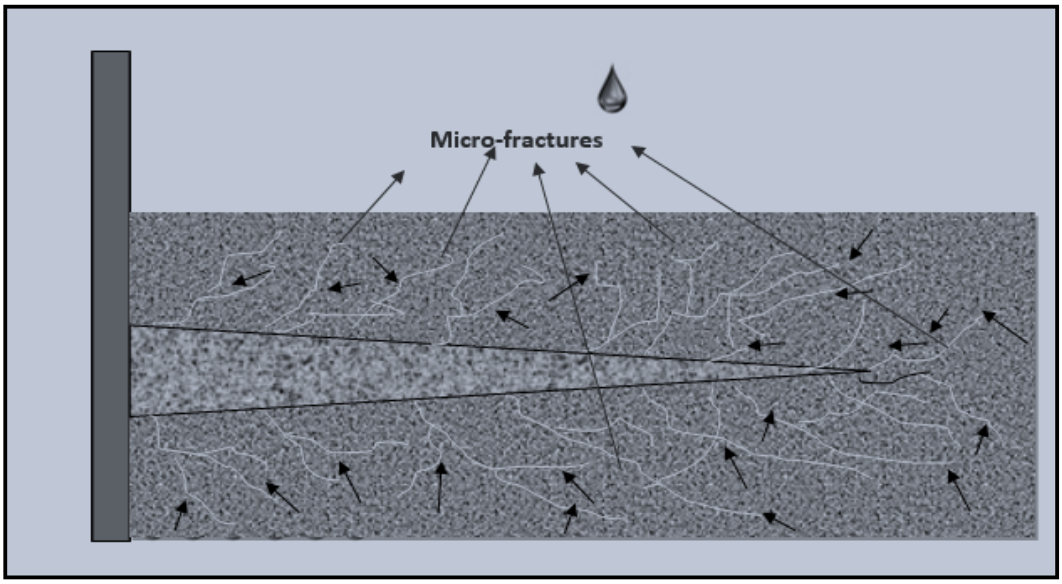


Figure 74: Hydraulic fracturing using surfactant [62]

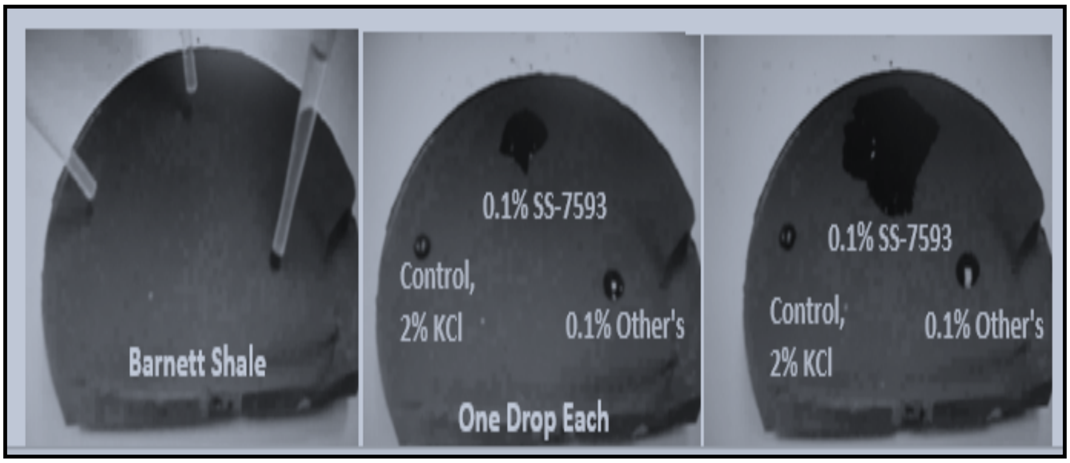


Figure 75: Wettability alteration [62]

- Stimulation chemical

  SC-88 is a mixture of surfactants formulated to reduce the surface tension, interfacial tension, alter the wettability and combined with the dispersant to increase and sustain the production over time. SC-88 is completely miscible in oil, acid and water based fluid system.SC-88 causes trapped oil droplets to move out of the pore spaces by overcoming strong capillary forces trapping the droplets.

  SC-88 can be used as fracturing flow back additive, asphaltene and paraffin dispersant and acid stimulation. Recommended concentrations for various applications are recommended in Table 15.

Table 15: Concentrations of SC-88 in different applications

Application	Concentration recommended
Fracturing fluid to reduce the interfacial tension, reduce fluid retention and minimize the emulsion	0.1-0.2 GPT
Add cleaning near the wellbore damage	0.7-1.2 GPT
Completion job	0.1-0.2 GPT
Asphaltene/ paraffin dispersion in hot oil treatment	0.5-2 GPT
Secondary stimulation, refracturing	0.1-0.2 GPT

8.3: Polymer Flooding

8.3.1: Principles of Polymer flooding

In any enhanced oil recovery process mobility control is one of the most important concepts and can be achieved through chemical injection to change displacing fluid viscosity or to preferentially reduce specific fluid relative permeability through injection of foams. The commonly used mobility control agent is polymer because it can significantly increase the apparent viscosity of the injected fluid. Foam is also a good mobility control method with water, surfactant and gas, but here we will only focus on polymer [67].

Polymer flooding consists of adding polymer to the water of a waterflood to decrease its mobility, increasing viscosity as well as a decrease in aqueous phase permeability and hence causes a lower mobility ratio. This lowering increases the volumetric sweep efficiency and lower swept zone oil saturation. The polymer flooding will be effective only when the waterflood mobility ratio is high, the reservoir heterogeneity is serious, or a combination of these two happens and useful when polymer is relatively cheap as they are used in high concentration [28].

Polymer flooding can yield a significant increase in oil recovery compared to conventional water flooding techniques. A typical polymer flood project involves mixing and injecting polymer over an extended period of time until about 1/3– 1/2 of the reservoir pore volume has been injected. This polymer “slug” is then followed by continued long term water flooding to drive the polymer slug and the oil bank in front of it toward the production wells. Polymer is injected continuously over a period of years to reach the desired pore volume [66].

Polymers are often used with surfactant and alkali agents to improve volumetric sweep efficiency, reduce channelling and breakthrough and they can also provide mobility control at the low IFT front. Otherwise, the front is not stable and will finger and dissipate. Figure 76 shows the fingering effect with water flooding while use of polymers (Figure 77) has reduced the effect of fingering significantly [71].

8.3.2: Polymer chemistry

Polymers are smaller molecules (monomers) joining together and forming a repeating unit called a polymer and are characterized by high molecular weight and flexibility.

Types of Polymers

Two main types of polymers, synthetic polymers such as hydrolyzed polyacrylamide (HPAM) and biopolymers such as xanthan gum are commonly used in enhanced oil recovery. Less commonly used are natural polymers and their derivatives, such as guar gum, sodium carboxymethyl cellulose, and hydroxyl ethyl cellulose (HEC).

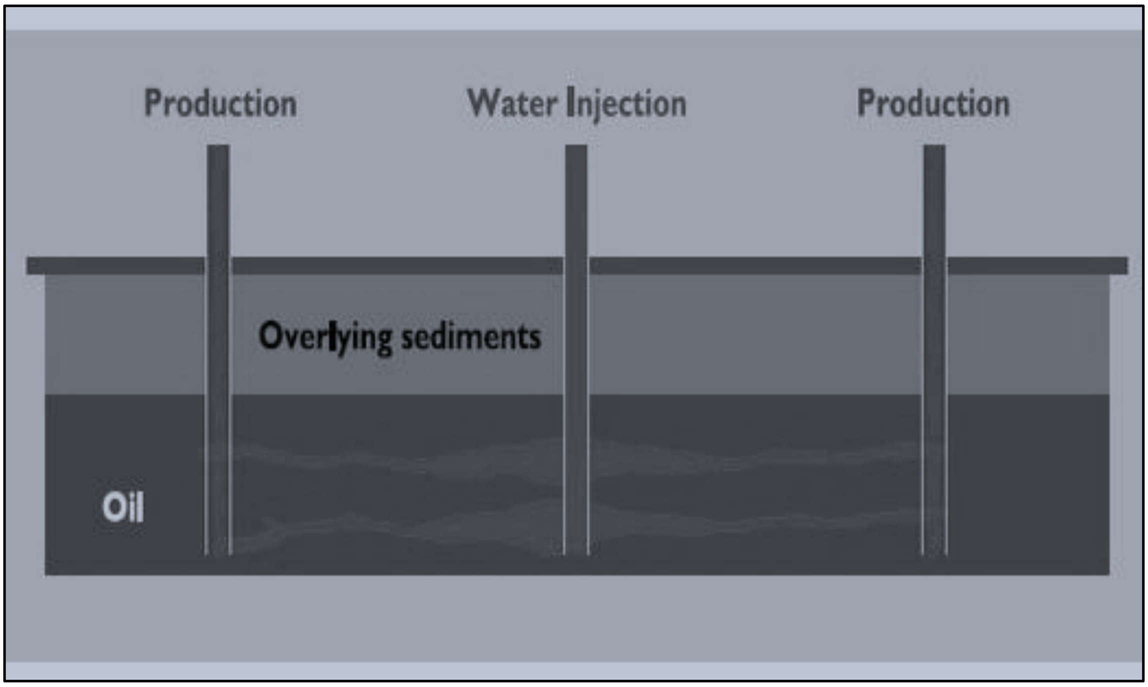


Figure 76: Fingering effect with water flooding [72]

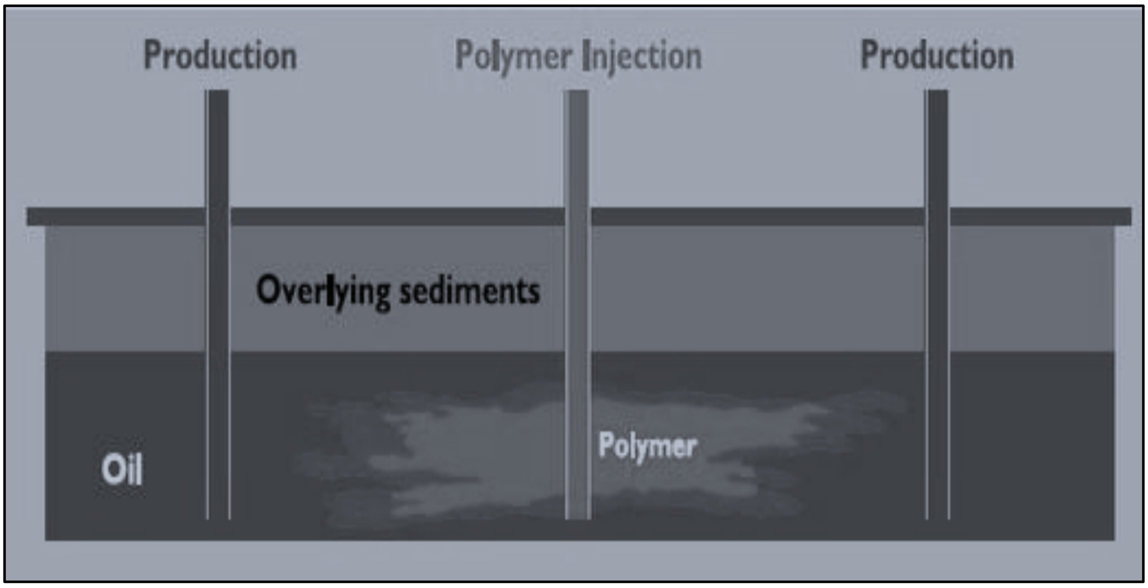


Figure 77: Decreased effects of fingering with polymer flooding [72]

8.3.3: Hydrolyzed Polyacrylamide (HAPM)

HPAM is the most widely used polymer in EOR applications. In China's Daqing field, HPAM solutions have provided significantly greater oil recovery for either a given polymer concentration or viscosity level. The reason is that HPAM solutions exhibit significantly greater viscoelasticity than xanthan solutions [28]. Polyacrylamide adsorbs strongly on mineral surfaces; therefore, it is partially hydrolyzed to reduce adsorption by reacting polyacrylamide with a base (sodium or potassium hydroxide or sodium carbonate) [57]. Hydrolysis converts some of the amide groups (CONH2) to carboxyl groups (COO−), as shown in Figure 78.

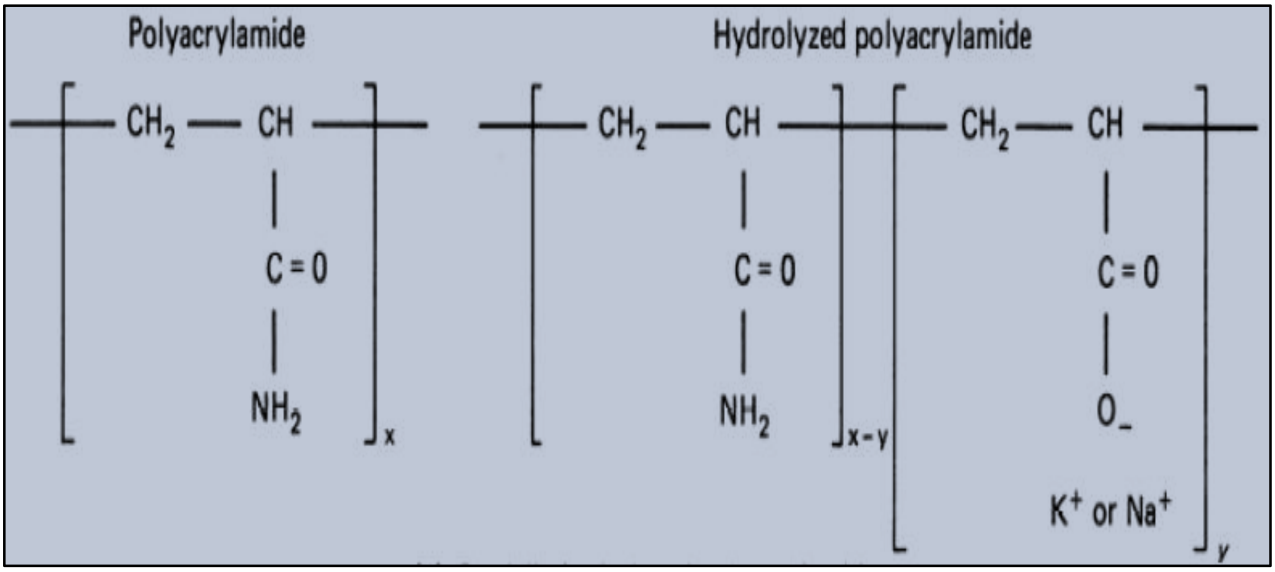


Figure 78: Partially hydrolyzed polyacrylamide [65]

Typical degrees of hydrolysis are 15 to 35% of the acrylamide monomers; hence the HPAM molecule is negatively charged that have a large effect on the rheological properties of the polymer solution. According Green and Willhite (1998), polyacrylamide is mainly anionic, but could be non-ionic or cationic. The molecular weights of HPAM used in EOR processes are up to higher than 20 million Daltons [57] [65].

Advantages/disadvantages: They are relatively cheap, develop high viscosities in fresh water, and adsorb on the rock surface to give a long-term permeability reduction. The main disadvantages are their tendency to shear degradation at high flow rates, sensitive to high temperature and their poor performance in high salinity brine.

Xanthan Gum

Another widely used polymer, a biopolymer, is xanthan gum (corn sugar gum). These polymers are formed from the polymerization of saccharide molecules, a bacterial fermentation process. The structure of a xanthan biopolymer is shown in Figure 79. Xanthan gum has a more rigid structure and is quite resistant to mechanical degradation.

These properties make it relatively insensitive to salinity and hardness. It is susceptible to bacterial attack after it has been injected into the reservoir. The polymer is relatively non-ionic and, therefore, free of ionic shielding effects of HPAM. Molecular weights of xanthan biopolymer used in EOR processes are in range of 1 million to 15 million.

Xanthan is supplied as a dry powder or as a concentrated broth. It is often chosen for a field application when no fresh water is available for flooding. Some permanent shear loss of viscosity could occur for polyacrylamide, but not for polysaccharide at the wellbore. However, the residual permeability reduction factor of polysaccharide polymers is low. Other potential EOR biopolymers are scleroglucan, simusan, alginate, etc [67] [28].

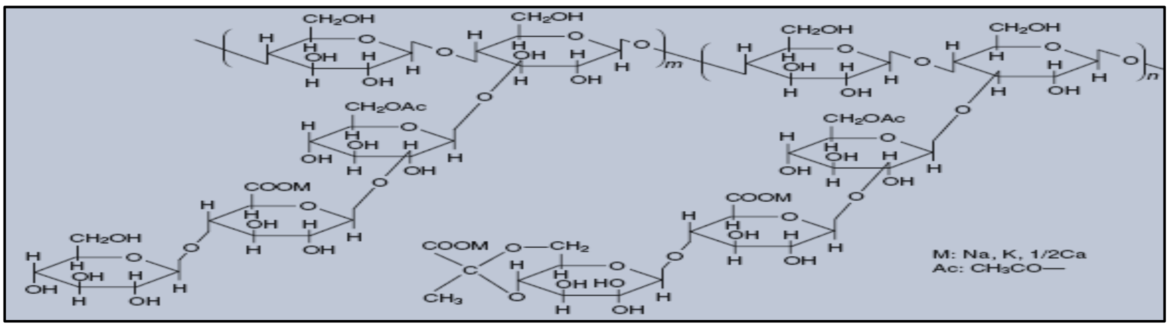


Figure 79: Molecular structure of Xanthan [33].

8.3.4: Polymer Flow Behaviour in Porous Media

Polymer Retention

Retention of polymer in a reservoir includes adsorption, mechanical trapping, and hydrodynamic retention. Adsorption refers to the interaction between polymer molecules and the solid surface. This interaction causes polymer molecules to be bound to the surface of the solid, mainly by physical adsorption, and hydrogen bonding. Mechanical entrapment and hydrodynamic retention are related and occur only in flow-through porous media. Retention by mechanical entrapment occurs when larger polymer molecules become lodged in narrow flow channels. The level of polymer retained in a reservoir rock depends on permeability of the rock, nature of the rock (sandstone, carbonate, minerals, or clays), polymer type, polymer molecular weight, polymer concentration, brine salinity, and rock surface [67] [65].

Inaccessible Pore Volume

When size of polymer molecules is larger than some pores in a porous medium, the polymer molecules cannot flow through those pores. The volume of those pores that cannot be accessed by polymer molecules is called inaccessible pore volume (IPV) [67]. The inaccessible pore volume is a function of polymer molecular weight, medium permeability, porosity, salinity, and pore size distribution. In extreme cases, IPV can be 30% of the total pore volume. Sometimes IPV is the result of lack of interconnection of pore spaces [28].

Permeability Reduction and the Resistance Factor

Polymer adsorption/retention causes the reduction in apparent permeability. Therefore, rock permeability is reduced when a polymer solution is flowing through it, compared with the permeability when water is flowing. This permeability reduction is defined by the permeability reduction factor (R_k) [67]:

$$Rk = \frac{Rock\ perm.when\ water\ flows}{Rock\ perm.when\ aqueous\ polymer\ solution\ flows} = \frac{kw}{Kp} \qquad \textit{(Equation 19)}$$

The resistance factor (R_f) is defined as the ratio of mobility of water to the mobility of a polymer solution flowing under the same conditions.

$$Rf = \frac{\frac{kw}{\mu w}}{\frac{kp}{\mu p}} \qquad \textit{(Equation 20)}$$

The residual resistance factor (R_{rf}) is the ratio of the mobility of water before to that after the injection of polymer solution [28]

$$Rrf = \left(\frac{\frac{kw}{\mu w}}{\frac{kp}{\mu p}}\right)a \qquad \textit{(Equation 21)}$$

The resistance factor (R_f) is defined as the ratio of mobility of water to the mobility of a polymer solution flowing under the same conditions.

The residual resistance factor (R_{rf}) is the ratio of the mobility of water before to that after the injection of polymer solution.

Residual resistance factor is a measure of the tendency of the polymer to adsorb and thus partially block the porous medium. Permeability reduction depends on the type of polymer, the amount of polymer retained, the pore-size distribution, and the average size of the polymer relative to pores in the rock [27].

Relative Permeabilities in Polymer Flooding

Some of the researchers have proved from their experiments that polymer flooding does not reduce residual oil saturation in a micro scale. The polymer function is to increase displacing fluid viscosity and thus to increase sweep efficiency. Also, fluid viscosities do not affect relative permeability curves. Therefore, it is believed that the relative permeabilities in polymer flooding and in water flooding after polymer flooding are the same as those measured in waterflooding before polymer flooding [67].

Polymer Rheology in Porous Media

The rheological behaviour of fluids can be classified as Newtonian and Non- Newtonian. Water is a Newtonian fluid in that the flow rate varies linearly with the pressure gradient, thus viscosity is independent of flow rate. Polymers are Non-Newtonian fluids. Rheological behaviour can be expressed in the terms of 'apparent viscosity' which can be defined as

$$\mu = \frac{\tau}{\gamma} \qquad \textit{(Equation 22)}$$

where τ = shear stress

γ = shear stress

The apparent viscosity of polymer solutions used in EOR processes decreases as shear rate increases. Fluids with this rheological characteristic are said to be shear thinning. Materials that exhibit shear thinning effect are called pseudoplastic. Polysaccharides such as Xanthan are not shear sensitive and even high shear rate is employed to Xanthan solutions to obtain proper mixing, while polyacrylamides are more shear sensitive. Most significant change in polymer mobility occurs near the wells where fluid viscosities are large [27].

8.4: Alkaline Flooding

8.4.1: Principles of Alkaline flooding

The alkaline flooding method relies on a chemical reaction between high-pH chemicals such as sodium carbonate and sodium hydroxide (most common alkali agents) and organic acids (saponifiable components) in crude oil to produce in situ surfactants (soaps) that can lower interfacial tension. In most of the literature, these saponifiable components are described as petroleum acids, even though their structure is not known. The addition of the alkali increases pH and lowers the surfactant adsorption so that very low surfactant concentrations can be used to reduce cost. This process is generally applied with crude oils of relatively low API gravity and containing high acidic components [57].

Mobility control can improve displacement efficiency in alkaline floods. For this, mostly polymer is used as a mobility buffer to displace the primary slug. In addition, the reservoir is also conditioned with preflush before the injection of primary slug.

Alkaline flooding is also called caustic flooding. Most commonly used alkalis for in situ generation of surfactants are sodium hydroxide, sodium carbonate, sodium orthosilicate, sodium tripolyphosphate, sodium metaborate, ammonium hydroxide, and ammonium carbonate. Nowadays, ASP formulations use moderate pH chemicals such as sodium bicarbonate ($NaHCO_3$) or sodium carbonate (Na_2CO_3) instead of sodium hydroxide (NaOH) to reduce emulsion and scale problems. Chinese Daqing oil field ASP projects have had difficulty in breaking emulsion when using a strong alkali such as NaOH.

Addition of the alkali chemicals results in a high pH because of the dissociation in the aqueous phase. High pH indicates large concentration of hydroxide ions (OH^-). For example, NaOH dissociates to yield (OH^-) as below:

$$NaOH \rightarrow Na^+ + OH^- \qquad \textit{(Equation 23)}$$

Sodium Carbonate dissociates as

$$Na_2CO_3 \rightarrow 2Na + CO_3^{2-} \qquad \textit{(Equation 24)}$$

Followed by the hydrolysis reaction

$$CO_3^{2-} + H_2O \rightarrow HCO_3^- + OH^- \qquad \textit{(Equation 25)}$$

In carbonate reservoirs where anhydrite ($CaSO_4$) or gypsum ($CaSO_4{\cdot}2H_2O$) exists, the $CaCO_3$ or $Ca(OH)_2$ precipitation occurs when Na_2CO_3 or NaOH is added. Carbonate reservoirs also contain brine with a higher concentration of divalents and could cause precipitation. To overcome this problem, Liu (2007) suggested $NaHCO_3$ and Na_2SO_4. $NaHCO_3$ has a much lower carbonate ion concentration, and additional sulfate ions can decrease calcium ion concentration in the solution [67].

8.4.2: Alkaline Reaction with Crude Oil

In Situ Soap Generation

In alkaline flooding, the injected alkali reacts with the saponifiable components in the reservoir crude oil. These saponifiable components are described as petroleum acids (naphthenic acids). Naphthenic acid consists of carboxylic acids, carboxyphenols, porphyrins, and asphaltene with molecular weight of 120 to well over 700. If the crude oil contains an acidic hydrocarbon component then hydroxide ion must react with a pseudo-acid component (HA) to form a surfactant. If no HA is originally present in the crude oil, little surfactant can be generated. A useful procedure for identifying crudes for their attractiveness to alkaline flooding is through acid number which (also called total acid number, TAN) is a measure of the potential of a crude oil to form surfactants. The acid number is the mass of potassium hydroxide (KOH) in milligrams required to neutralize one gram of crude oil. The alkali–oil chemistry is described by partitioning of this pseudo-acid component between the oleic and aqueous phases (Equation 27) and subsequent hydrolysis in the presence of alkali to produce a soluble anionic surfactant A^-, as shown in Figure 80.

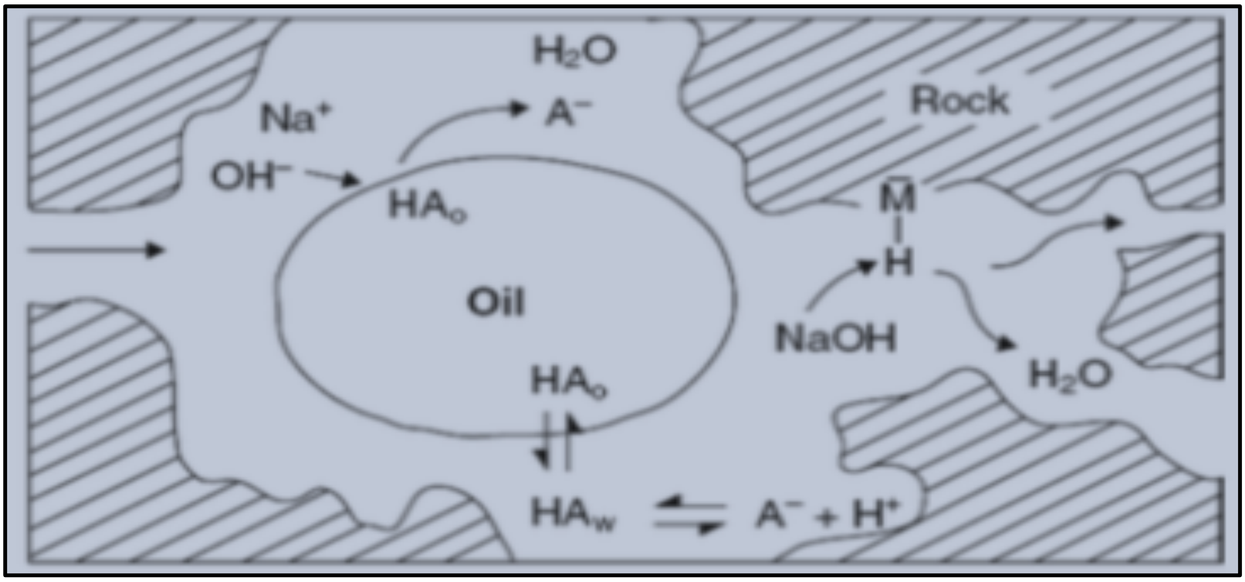


Figure 80: Schematic diagram of alkaline recovery process [57]

The overall hydrolysis and extraction are given by

$$HA_o + NaOH^{-} \leftrightarrow NaA + H_2O \qquad \text{(Equation 26)}$$

The extent of Equation 26 reaction depends strongly on the aqueous solution pH. This reaction occurs at the water/oil interface. A fraction of organic acids in oil become ionized with the addition of an alkali, whereas others remained electronically neutral. The hydrogen-bonding interaction between the ionized and neutral acids can lead to the formation of a complex called acid soap. Thus, the overall reaction, Equation 26, is decomposed into a distribution of the molecular acid between the oleic and aqueous phases,

$$HA_o \leftrightarrow HA_w \qquad \text{(Equation 27)}$$

And an aqueous hydrolysis,

$$HA_w \leftrightarrow H^+ + A^- \qquad \text{(Equation 28)}$$

Where, HA denotes a single acid species, A^- denotes anionic surfactant, and subscripts o and w denote oleic and aqueous phases, respectively [67].

8.4.3: Emulsification

Alkaline chemicals can cause improved oil recovery through the formation of emulsions. In alkaline flooding, emulsification is instant, and emulsions are very stable. Emulsification mainly depends on the water/oil IFT. The lower the IFT, the easier the emulsification occurs. The stability of an emulsion mainly depends on the film of the water/oil interface. The acidic components in the crude oil could reduce IFT to make emulsification occur easily, whereas the asphaltene surfactants adsorb on the interface to make the film stronger so that the stability of emulsion is enhanced. Local formation of highly viscous emulsions is not desirable since these would promote viscous instability [57] [65].

8.5: Alkaline-Surfactant-Polymer (ASP)

ASP has been one of the major EOR techniques used in producing light to medium residual oil [73]. The success of this method depends on the identification of the proper alkali, surfactant, and polymer in the way they combine to produce compatible formulation which yields good crude oil emulsification / mobilization, low chemical losses and good mobility control [74]. The synergistic effect of alkaline, surfactant and polymer results in less surfactant required to recover significantly incremental oil. An ASP flood involves injecting a predetermined pore volume of ASP slug into the reservoir. Typically, the ASP formulation consists of about 0.5-1% alkali, 1% surfactant, and 0.1% polymer. The alkali reacts with acidic components in the crude oil creating natural soap and also helps with reducing the adsorption of the surfactant on the rock. It also alters rock wettability (from oil-wet to water-wet) and adjusts pH and salinity. Surfactant component helps in releasing the oil from the rock by reducing the interfacial tension between oil and water while polymer acts as viscosity modifier and helps mobilize the oil. Often, the ASP slug is followed by polymer "push" solution for conformance control, mobility control (reduce fingering). This also helps reduce the slope of oil recovery decline and helps extend the production for a longer period of time. Upon the completion of polymer injection, driving fluid (water) is injected to move the chemicals and resulting oil bank towards production wells. Generally, the reservoir is conditioned by preflush (with water, alkali or polymer depending on rock mineralogy) before the injection of ASP slug into reservoir [75].

8.5.1: Displacement mechanisms in ASP

Displacement mechanisms in ASP may be summarized as follows [67];

- Surfactant adsorption is reduced on both sandstone and carbonates at high PH.
- High PH also improves microemulsion phase behaviour.

- Improved macroscopic sweep efficiency because of the viscous polymer drive.
- Increased capillary number effect to reduce residual oil saturation because of low to ultra-low IFT.

8.5.2: Modelling Polymer Flooding, Surfactant Flooding and ASP (Alkaline, Surfactant and Polymer) with ECLIPSE

Different chemical EOR methods in Norne E-segment were simulated using a simulator. The economic analysis was done based on incremental oil recovery over water flooding using the NPV analysis.

The surfactant Flood Model

A simulator lacks a provisional detailed chemistry of a surfactant process rather it models the important features of a surfactant flood on a full field basis. Meanwhile, it has no options for what type of surfactant to use for a given reservoir structures and its fluid characteristics. It only presents the surfactant option as a blanket over all types of reservoir and fluid characteristics. The injection of surfactant is modelled by solving a conservation equation for surfactant within the water phase. The surfactant concentrations are updated fully-implicitly at the end of each time-step after the oil, water and gas flows have been computed. The surfactant is assumed to exist only in the water phase, and the input to the reservoir is specified as a concentration in water injector [65]. The detailed description of the surfactant model is presented in Eclipse Manual.

The polymer flood model

The polymer flood option uses a fully implicit five-component model (oil/water/gas/polymer/brine) to allow the detailed mechanisms involved in polymer displacement process to be studied. The flow of the polymer solution through the porous medium is assumed to have no influence on the flow of the hydrocarbon phases [65]. A full description of the polymer model can be found in Eclipse Manual.

The Alkaline Flood Model

The simulator does not take into account the in-situ surfactant creation and the phase behaviour. This simplified model is focused on looking at some of the impacts of the alkaline on an ASP performance and also to analyse its impact on the water-oil surface tension and adsorption reduction of surfactant.

The Alkaline Flood Model

The simulator does not take into account the in-situ surfactant creation and the phase behaviour. This simplified model is targeted at looking at some of the effects of the alkaline on an ASP flooding performance and also to analyse its effect on the water-oil surface tension and adsorption reduction of surfactant [65]. A more detailed description of the alkaline model is given in Eclipse Manual.

Alkaline, Surfactant and Polymer Properties

Currently, the drive mechanism for Norne field is water flooding and there is ongoing project for IOR under NPD. Therefore, the chemical properties used in this work were not actual and therefore they are not compatible to Norne reservoir and fluid characteristics instead they were just used for a study.

Generally, for the assurance of data laboratory measurement is needed in order to validate data. I assumed that these properties are compatible with Norne reservoir and fluid properties for simplification.

The chemical properties (alkali, surfactant and polymer) for this study were gathered from different sources. The surfactant and polymer properties were taken from master Charles A. Kossack presentation of 4/10/2011 with the permission of Professor Jon Kleppe and the other data were also taken from the master thesis of Yugal K. Maheshwari after the permission of his supervisor Professor Jon Kleppe (*www.ipt.ntnu.no/~kleppe/pub/kossack-file)* and co-supervisor Richard Wilfred Rwechungura (Project Manager: Norne Benchmark Project, <*www.ipt.ntnu.no*/~*norne*). These are realistic data and might have a practical implementation. The reduced input file of alkali, surfactant and polymer properties can be seen in Appendices C, D and E respectively as 110 tables of each property need to be included in the simulation run.

CHAPTER 9

9.0: SIMULATION OF EOR CHEMICAL FLOODING

9.1: Overview of base case

The previous base case waterflooding started production in November 1997 and ended in December 2025. As of December 2025, the top layer of the segment in Ile formation as shown in Figure 81 is still having 13% of its initial oil in place and the other bottom layers still they have some residual oil. Figure 82 shows that the field recovery factor is 72% which may go up if more oil would be recovered.

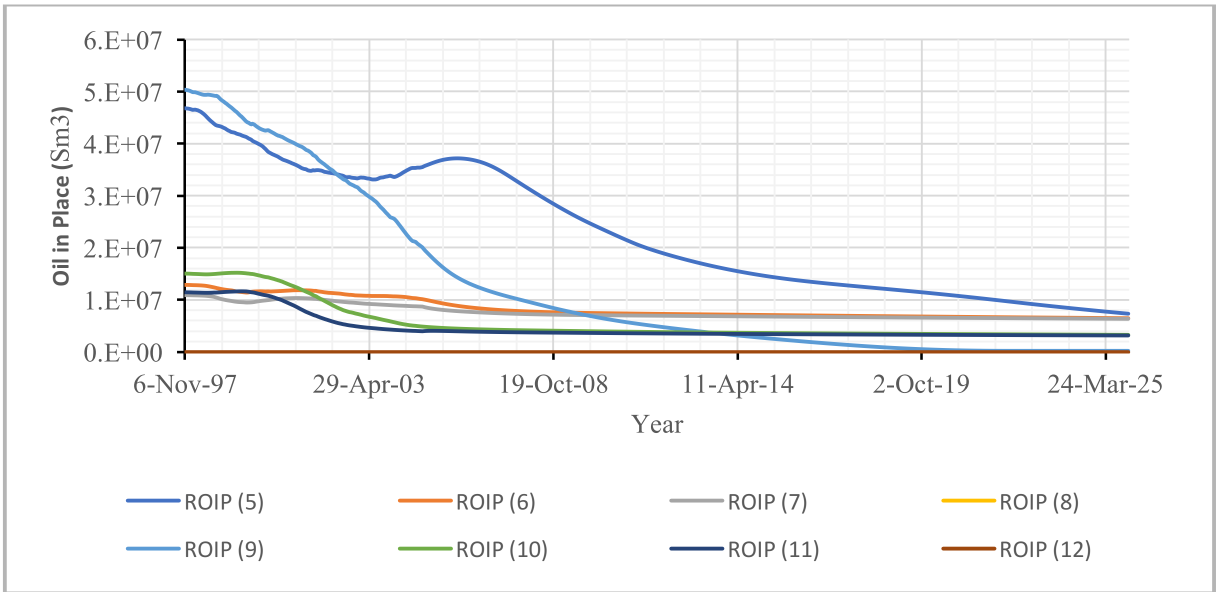


Figure 81: Initial oil in place in layers of E-segment for base case waterflooding

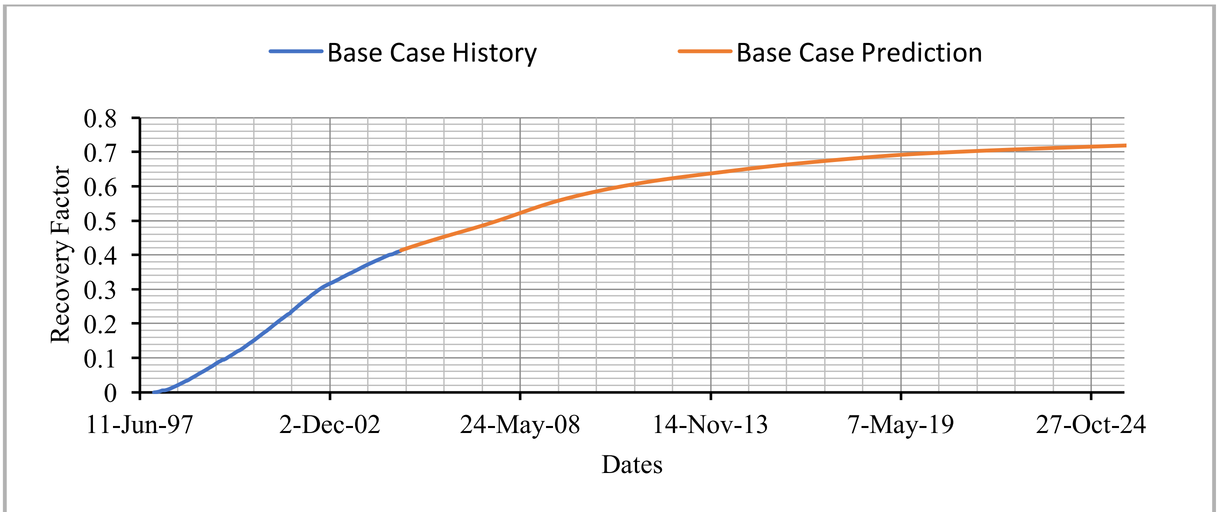


Figure 82: Field recovery factor for base case waterflooding

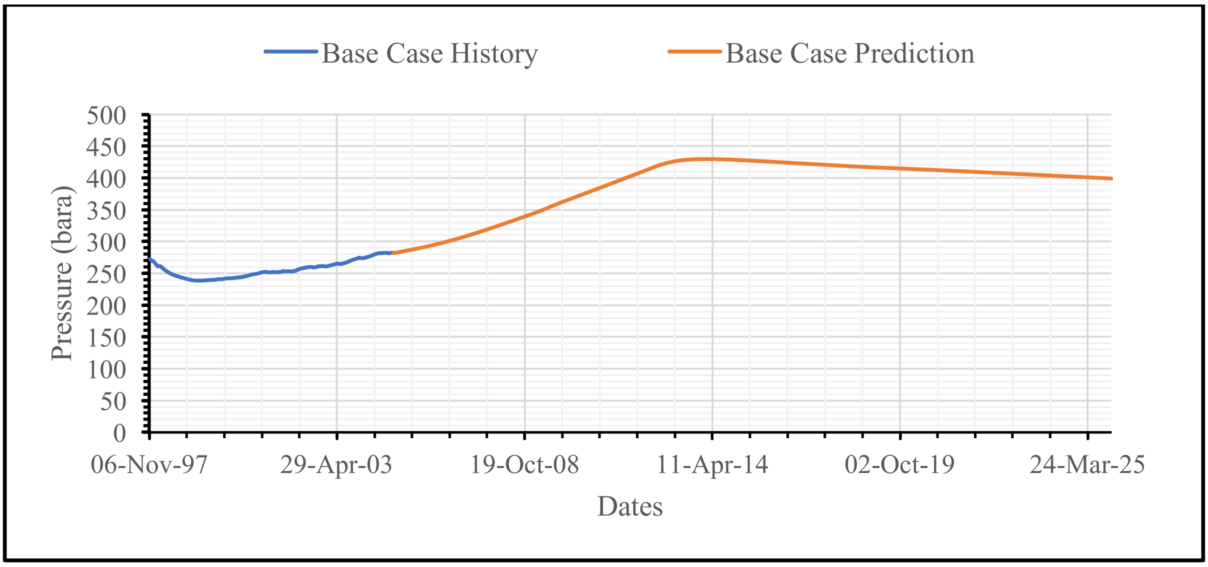


Figure 83: Field pressure profile for base case waterflooding.

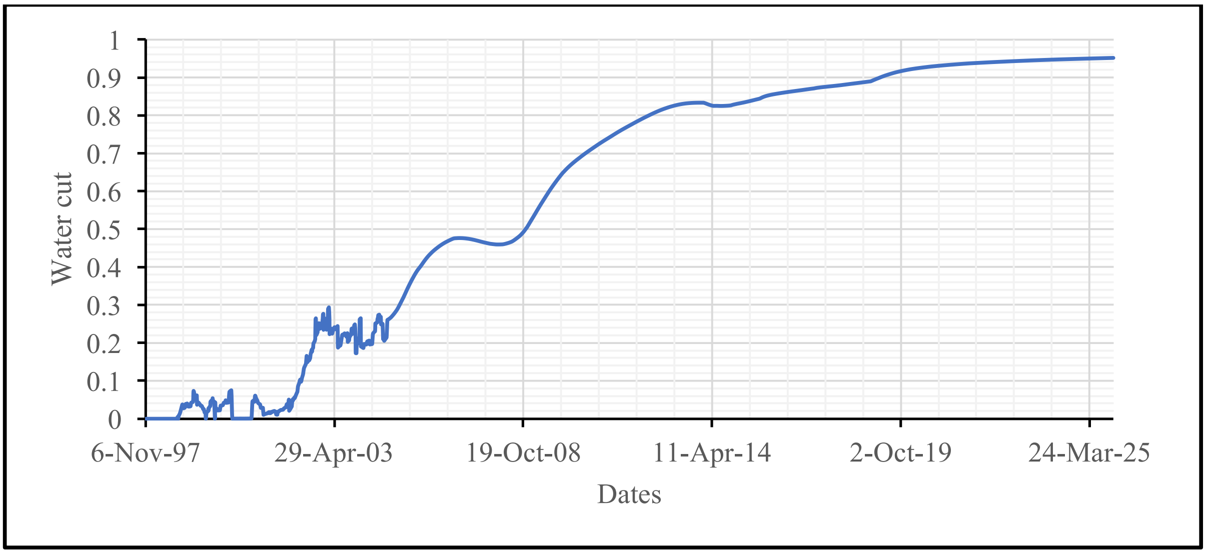


Figure 84: Field water cut for base case waterflooding.

From the light of the above discussion supported by Figures 81 through 84. There are still some pockets of by-passed residual oil which are still trapped in the reservoir especially in the Ile and Tofte formations. The continuation of both rise in water cut and reduced oil production depict that waterflooding method is probably not efficient in recovery of oil, thus chemical EOR methods are required to release capillary trapped oil.

In this part, much emphasis is on optimization of chemical flooding (alkali, surfactant and polymer) and their efficiency to maximize the volume of incremental oil production per unit quantity of chemicals injected. Five different scenarios such as surfactant flooding, polymer flooding, alkaline-surfactant, surfactant-polymer and ASP flooding and in the end comparison among all cases were discussed in order to come up with the most suitable and profitable method in terms of expected NPV for the Norne E-segment. Finally, single parameter sensitivity analysis at different oil prices, gas prices, chemical prices, drilling costs and discount rate for low case, base case and high case was addressed. Assumptions to be accounted in simulation of chemical flooding are;

- *Norne E-segment was assumed to be producing at its residual oil saturation,*
- *All chemicals are injected with pure water,*
- *Provisional properties of chemicals were assumed to be compatible with Norne E-segment reservoir and fluid properties,*
- *No desorption of chemicals during the simulation runs,*
- *The fixed alkaline concentration of 2.3 kg/m^3 was used in scenario 3 and scenario 4.*
- *Maximum constrain on reservoir pressure was assumed to be 300 bara to avoid cracking of formation.*
- *Maximum allowable bottom hole injection pressure for injector F-1H was 600 bara.*

9.2: Selection of injector and producer

At the E-Segment in the reservoir model, there are two injectors which are F-1H and F-3H as shown in Figure 85. Since, chemical injection is the expensive process hence it requires optimization to control excess unnecessary injections which in turn increases cost. Thus, it is strongly recommended to test the effectiveness of injectors upon chemical injection and then the results were measured in the production yield and the best option is the one with the highest production yield. Surfactant injection was selected because of all the chemicals, surfactant is the most expensive.

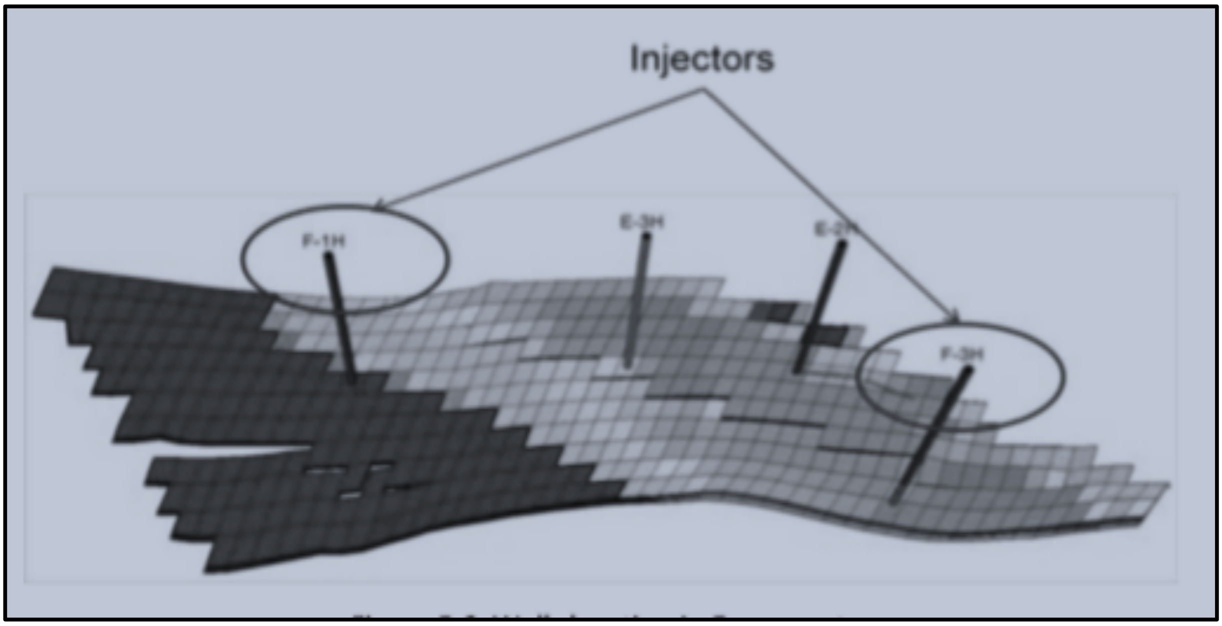


Figure 85: Position of injectors in E-segment

9.2.1: Test I: Injection of surfactant in base case waterflooding

There were three cases to do this of which the first one was to inject surfactant into the base case waterflooding with concentration of 28.53 kg/m3 in both injectors (F-1H and F-3H) from 1st of Dec 2004 for 20 consecutive years and the rest was to inject surfactant of the same concentration in F-1H and later F-3H as shown in Figure 86 then production results were observed by looking the cumulative total production of producers (E-2H, E-2AH and E-3AH). If the injectors yield to the same production, selection of the injector was based on how less the surfactants are consumed to that particular production.

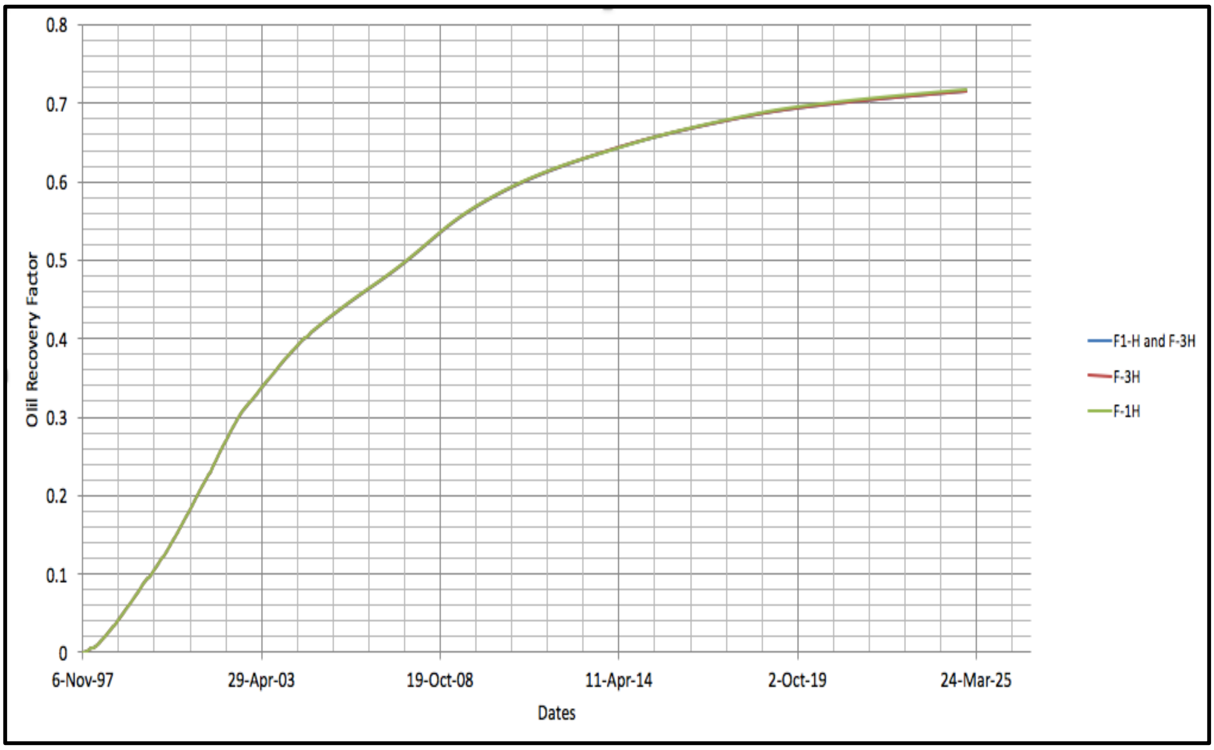


Figure 86: Effect of surfactant injection in different injectors on oil recovery factor

It can be seen in Figure 86 that injection of surfactant in different injection scenario leads to the same field oil recovery which means all the injection scenarios have the same effect on recovery factor.

The best injector must be questionable and there is no doubt that it should be selected on economic basis in terms of consumption of chemicals.

Figure 87 shows that injector F-1H consumes less chemicals compared to other injectors and hence it is chosen as the best injector.

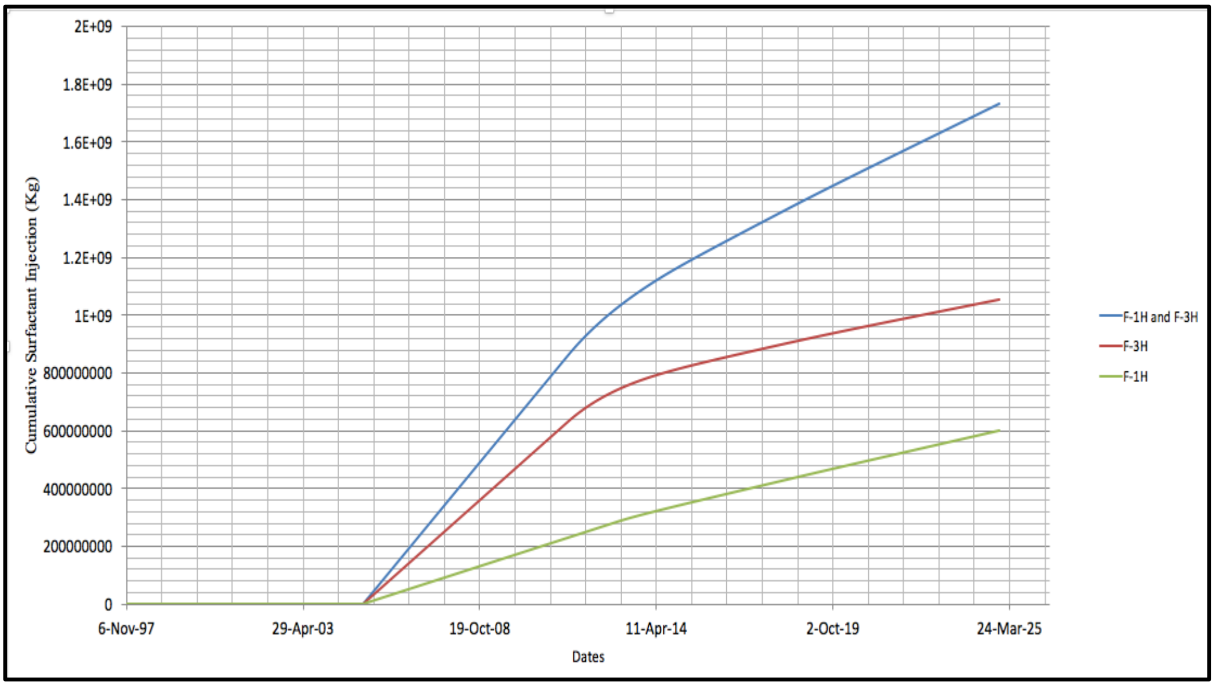


Figure 87: Total surfactant injection for different injectors.

9.2.2: Test II: Injection of surfactant in fourth case waterflooding

There were seven cases to do this of which the first was to inject surfactant into the fourth case waterflooding with concentration of 28.53 kg/m3 in all injectors (F-1H, F-3H and G-1H) from 1st of Dec 2004 for 20 consecutive years and the rest was to inject surfactant of the same concentration in other injection scenarios as shown in Figure 88. Later on, production results were observed by looking the cumulative total production of producers (E-2H, E-2AH and E-3AH). If the injectors yield to the same production, selection of the injector was based on how less the chemicals are consumed to that particular production.

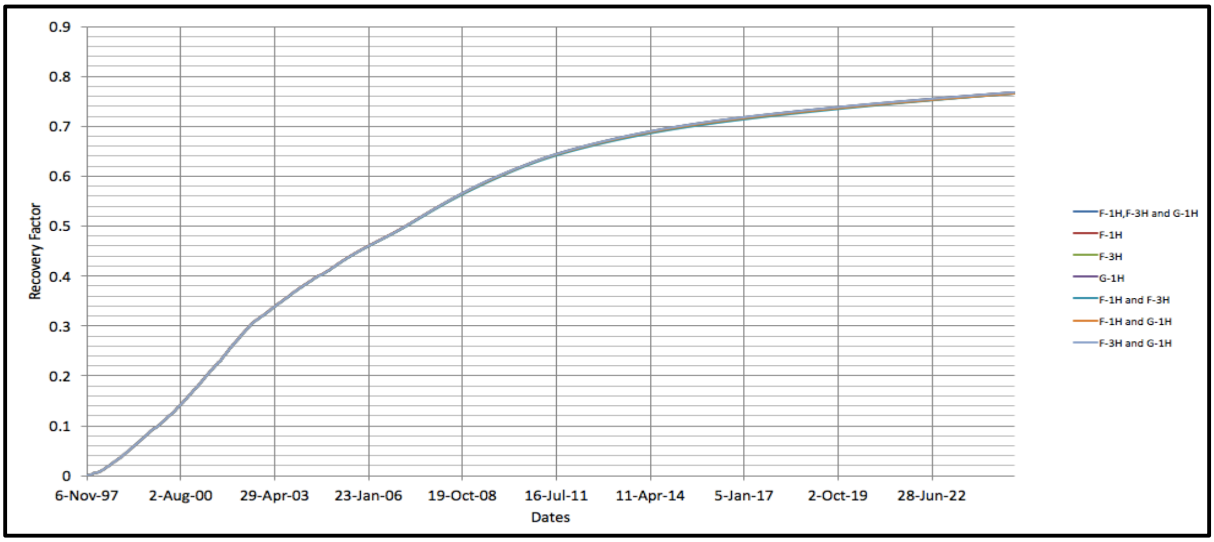


Figure 88: Effect of surfactant injection in different injectors on oil recovery factor

It can be seen in Figure 88 that injection of surfactant in different injection scenario leads to the same field oil recovery which means all the injection scenarios have the same effect on recovery factor.

The best injector must be questionable and there is no doubt that it should be selected on economic basis in terms of consumption of chemicals.

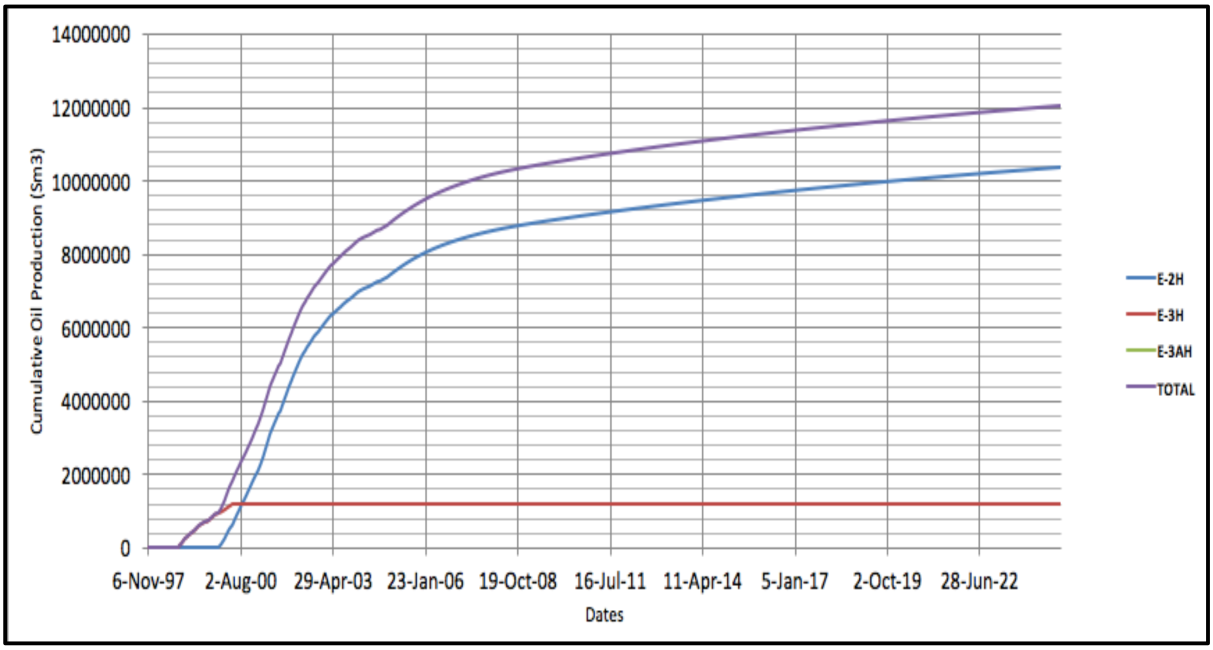


Figure 89: Effect of injector F-3H on producers

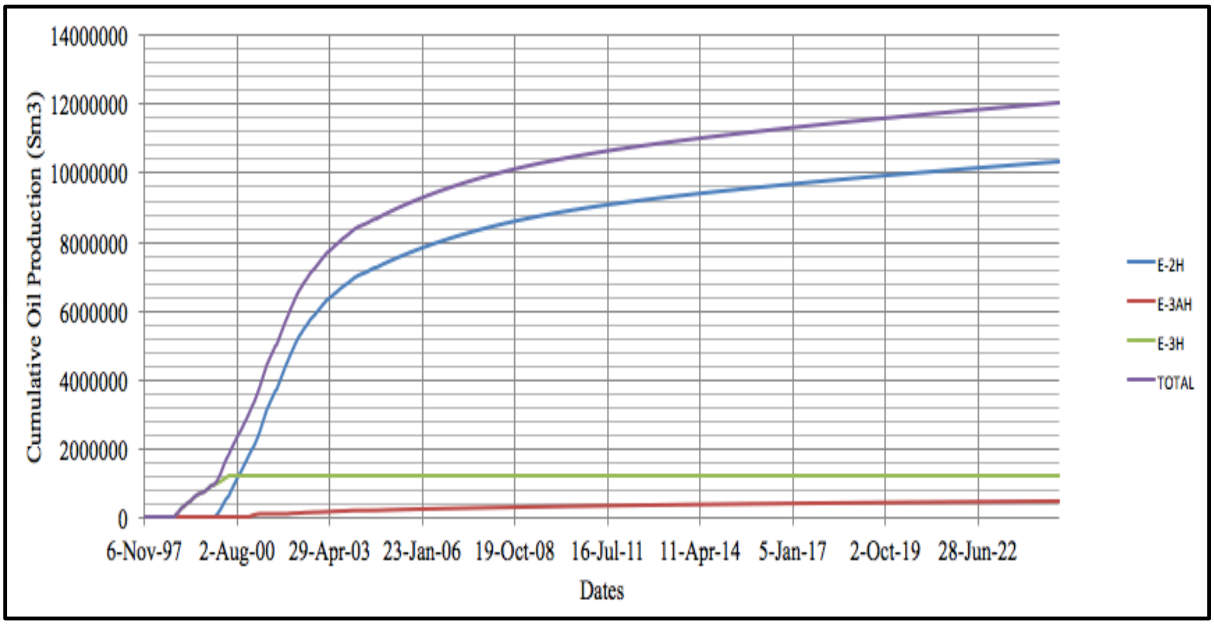


Figure 90: Effect of injector F-1H on producers

From the depiction of Figure 89 and 90, both injectors recover the same oil from the reservoir which is 12 MSm^3. The best injector must be questionable and there is no doubt that it should be selected on economic basis.

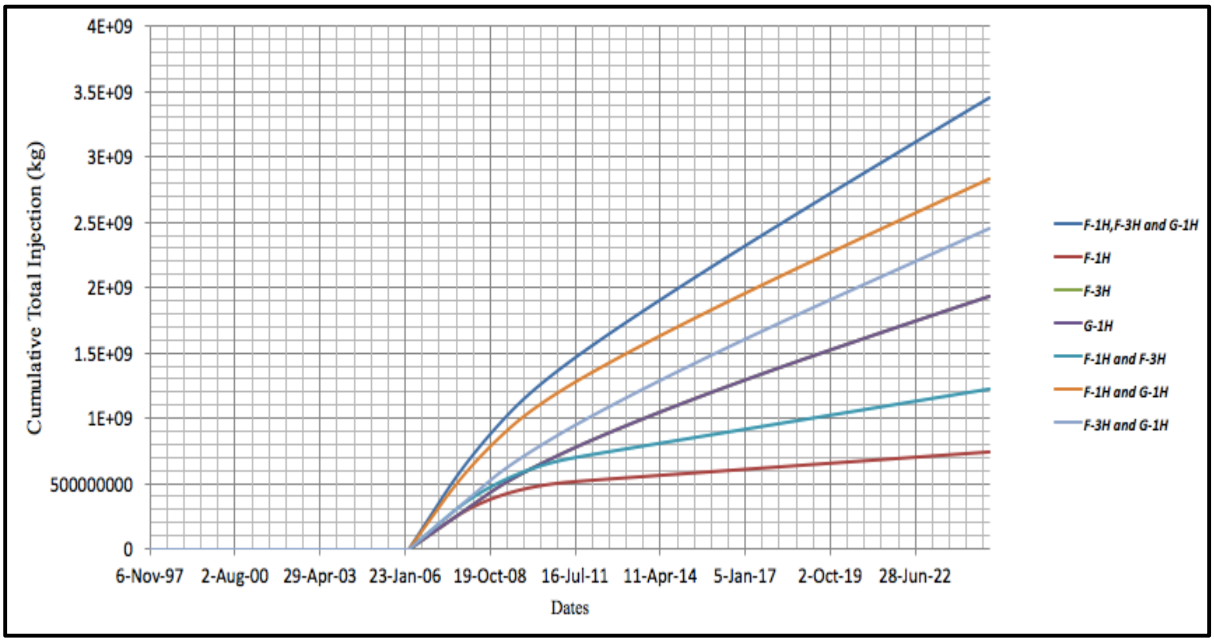


Figure 91: Total Surfactant injection for different injectors

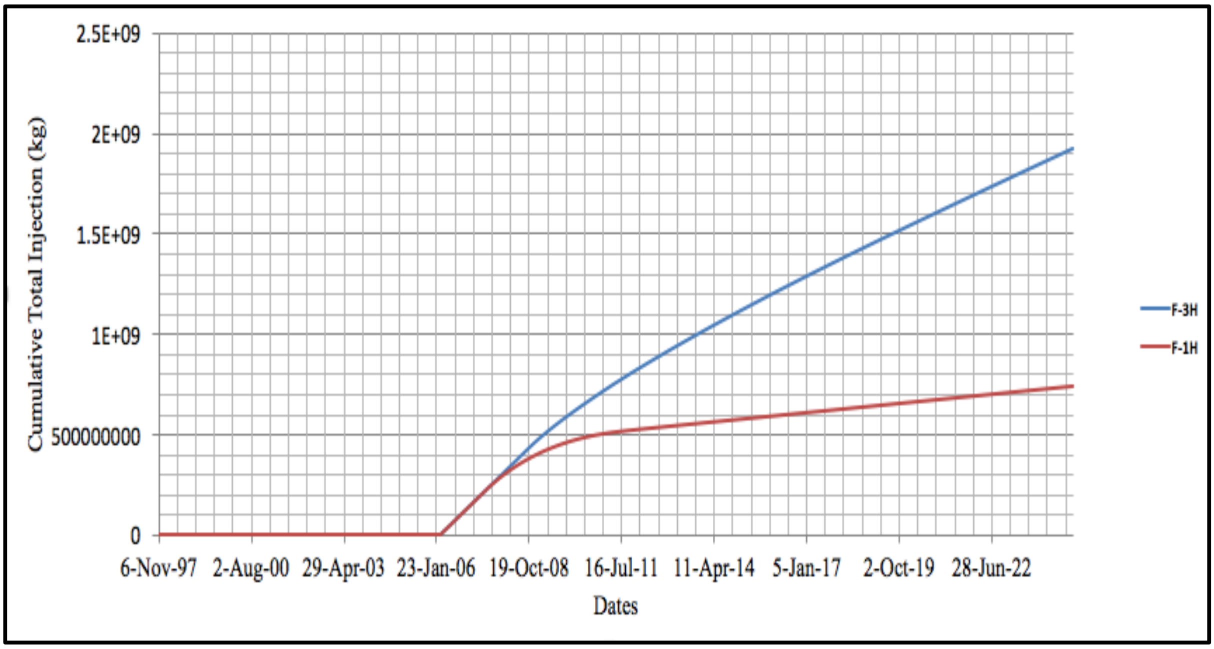


Figure 92: Total surfactant injection between the two Injectors

Figure 91 and 92 show that injector F-1H consumes less chemicals compared to other injectors and hence it is chosen as the best injector. F-1H consumes less chemicals because it is located in the oil zone while F-3H is located in the water zone as most of chemicals dissolve in water. Meanwhile, Figure 91 and 92 shows that E-2H is the best producer.

It was concluded that F-1H is the best injector whereas E-2H is the best producer because it is also located in oil zone and easily produces oil.

9.3: EOR Chemical flooding scenarios

For better enhancement of oil recovery, a systematic process is required in order to model chemicals into an oil reservoir. The reason why we do this is just because the chemicals are very expensive and there is complexity in doing injection. For instance, there is a choice of using either slug injection or continuous injection and the choice of which one to use is based on economic analysis. Slug injection was chosen because it is economical as less chemicals are consumed in injectors and less chemicals are produced either which minimizes injection and processing cost.

First Scenario: Surfactant flooding

Surfactants are used to lower the interfacial tension between injection brine and residual oil and thus reduce energy necessary to mobilize and recover oil. The reduced interfacial tension will make it possible to overcome capillary forces trapping the residual oil in the microscopic pores of the reservoir matrix. 2 oil fields were successfully increasing in terms of production using 0.1% SS-780 since 2003 [62].

On trial basis, surfactant slug of concentration in the range 10-100 kg/m^3 was injected in order to find the economic concentration which would keep the residual oil at a possible minimum.

It was found that concentration of 28.53 kg/m^3 is the most economic as far as consumption of chemicals is concerned. The choice for this concentration was based on rough economic analysis in order to avoid injecting too much surfactants which would cost much.

After preflush of water for 100 days. Surfactant slug of concentration 28.53 kg/m^3 was injected into all the cases of the previous waterflooding for 3500 days with a preflush of water for 100 days. Chemical injection started on 1st December, 2025.

Results for Surfactant flooding

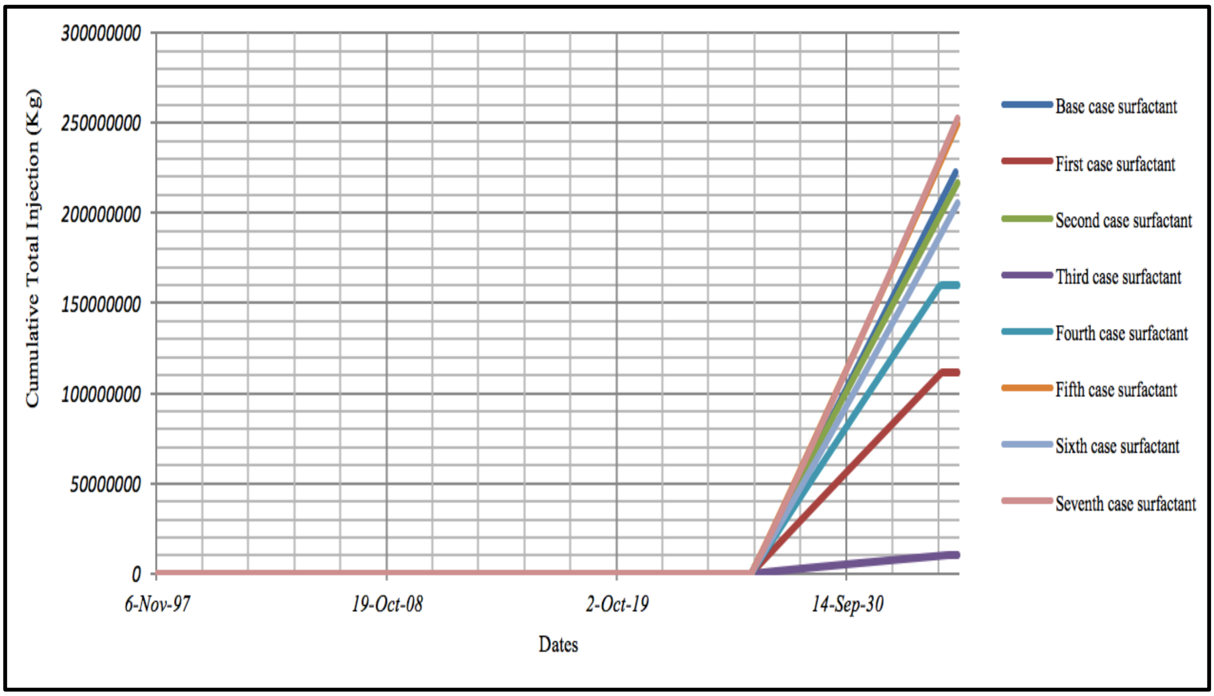


Figure 93: Cumulative surfactant injection for surfactant scenario

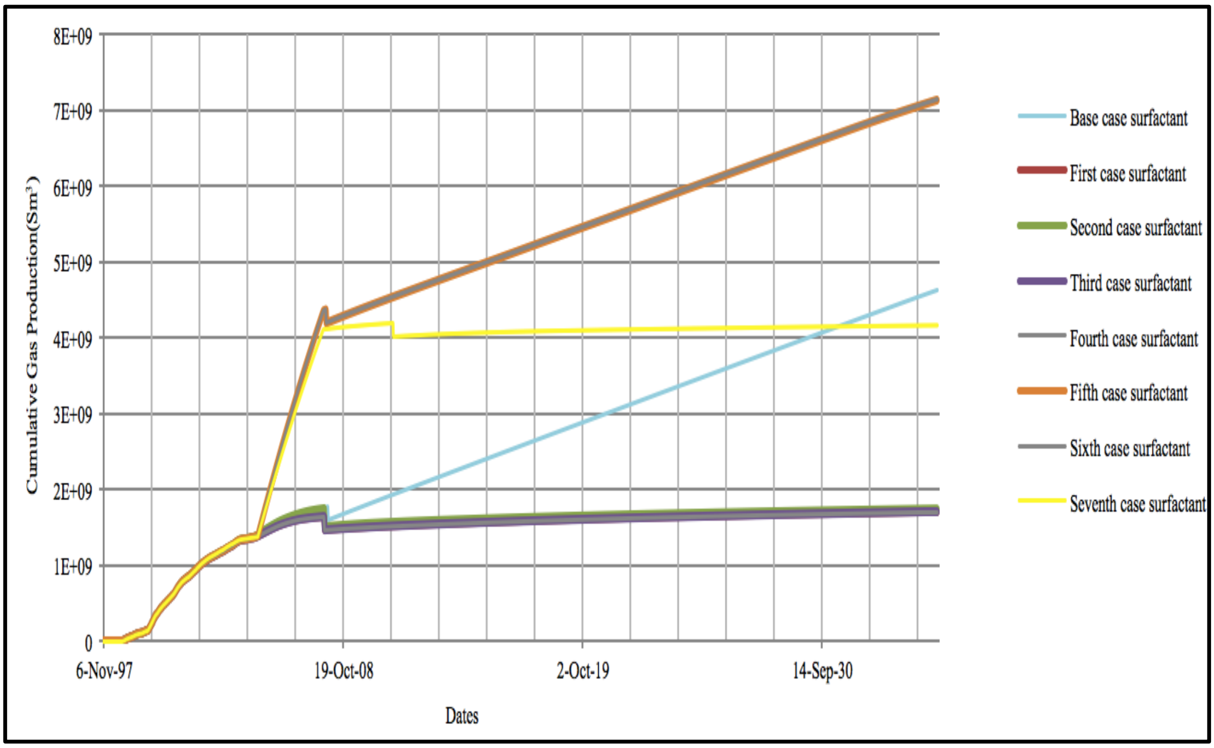


Figure 94: Cumulative gas production for surfactant scenario

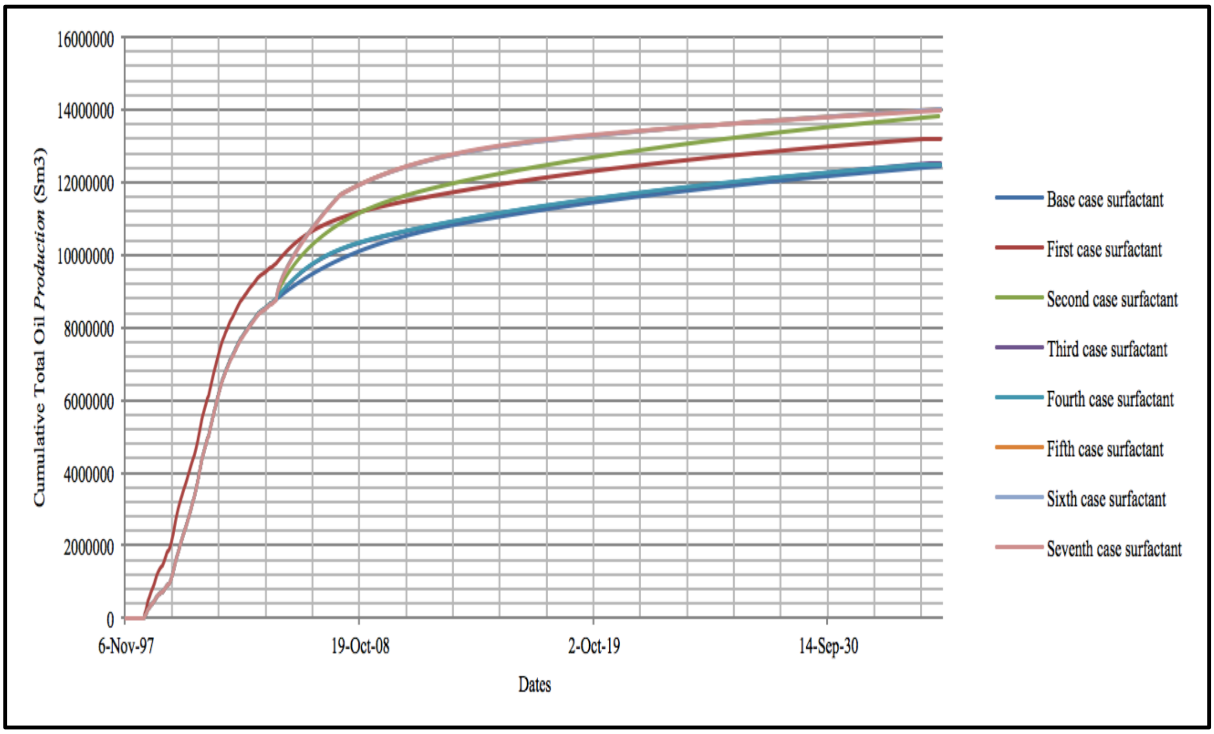


Figure 95: Cumulative oil production for surfactant scenario

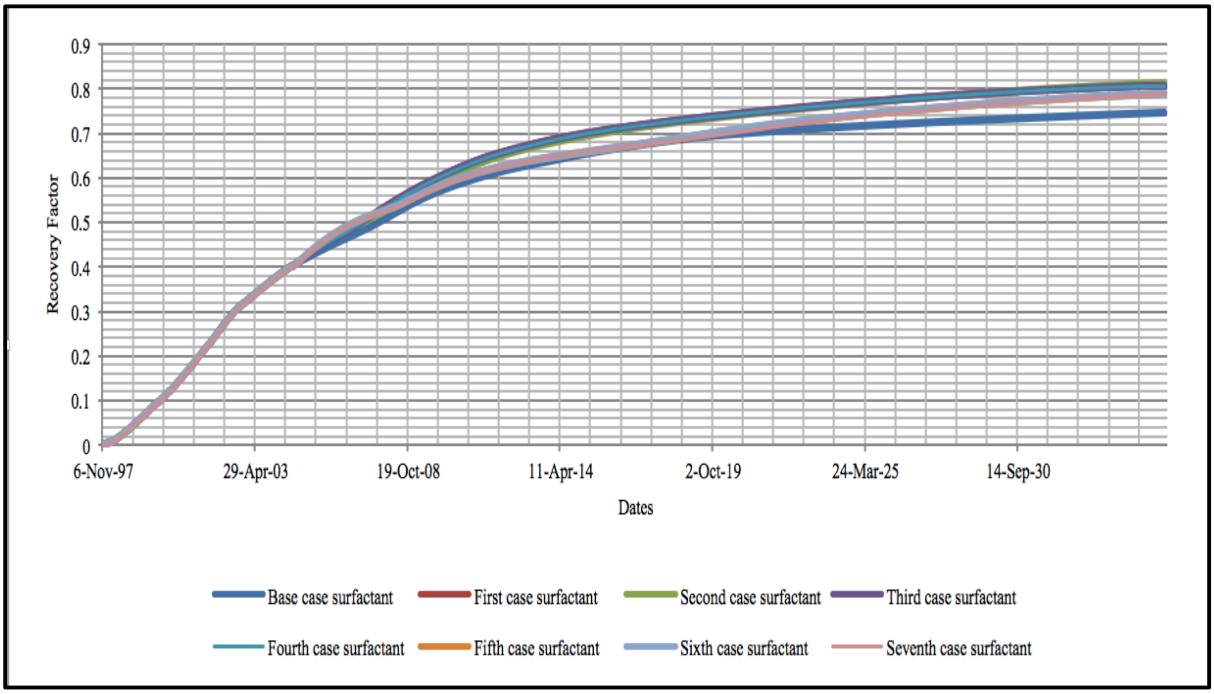


Figure 96: Field recovery factor for surfactant scenario

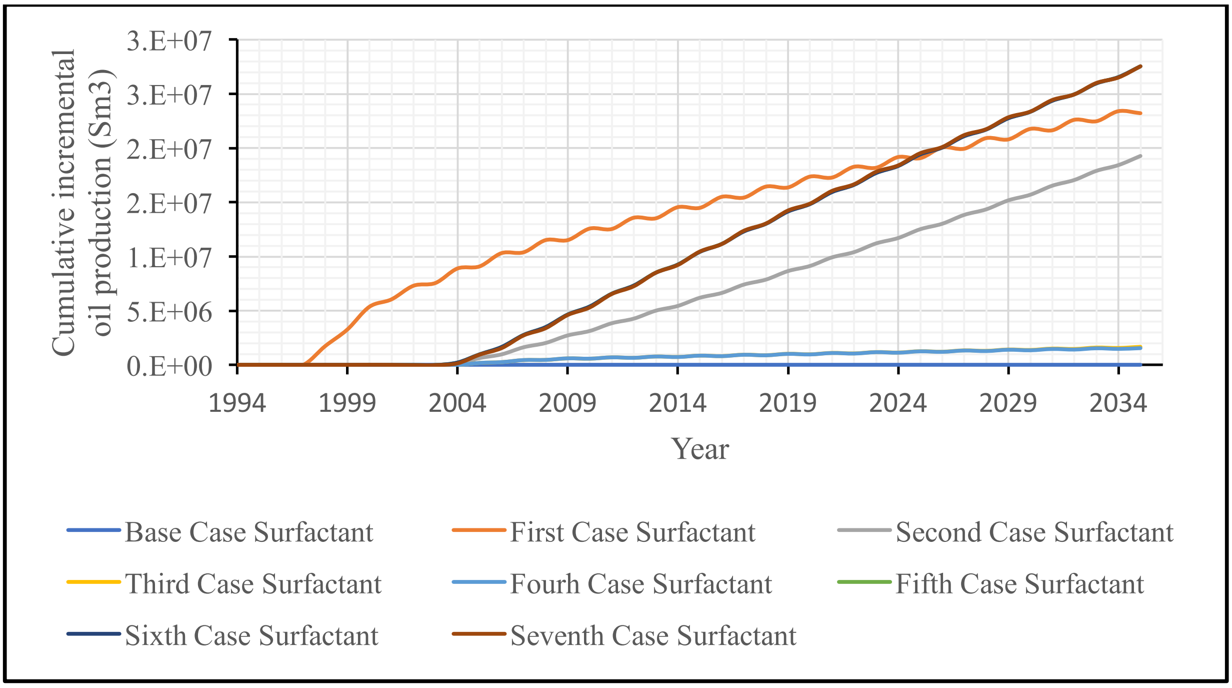


Figure 97: Cumulative incremental oil production for surfactant scenario

Figure 96 shows that the highest recovery factor is 81.2 % achieved by the Second case surfactant but Figure 97 shows that the highest incremental oil production of 27.553 MSm^3 is achieved by the seventh case surfactant but then there is high consumption of surfactants (250 M kg) as shown in Figure 93 in this case which will affect its NPV.

Second Scenario: Polymer flooding

A high-molecular-weight and viscosity-enhancing polymer is added to the water of the waterflood to decrease the mobility of the floodwater and, as a consequence, improve the sweep efficiency of the waterflood.

Polymer slug of concentration 28.53 kg/m^3 was injected into all the cases of the previous waterflooding for 3500 days with a preflush of water for 100 days. The results are displayed in the next page;

Results for Polymer flooding

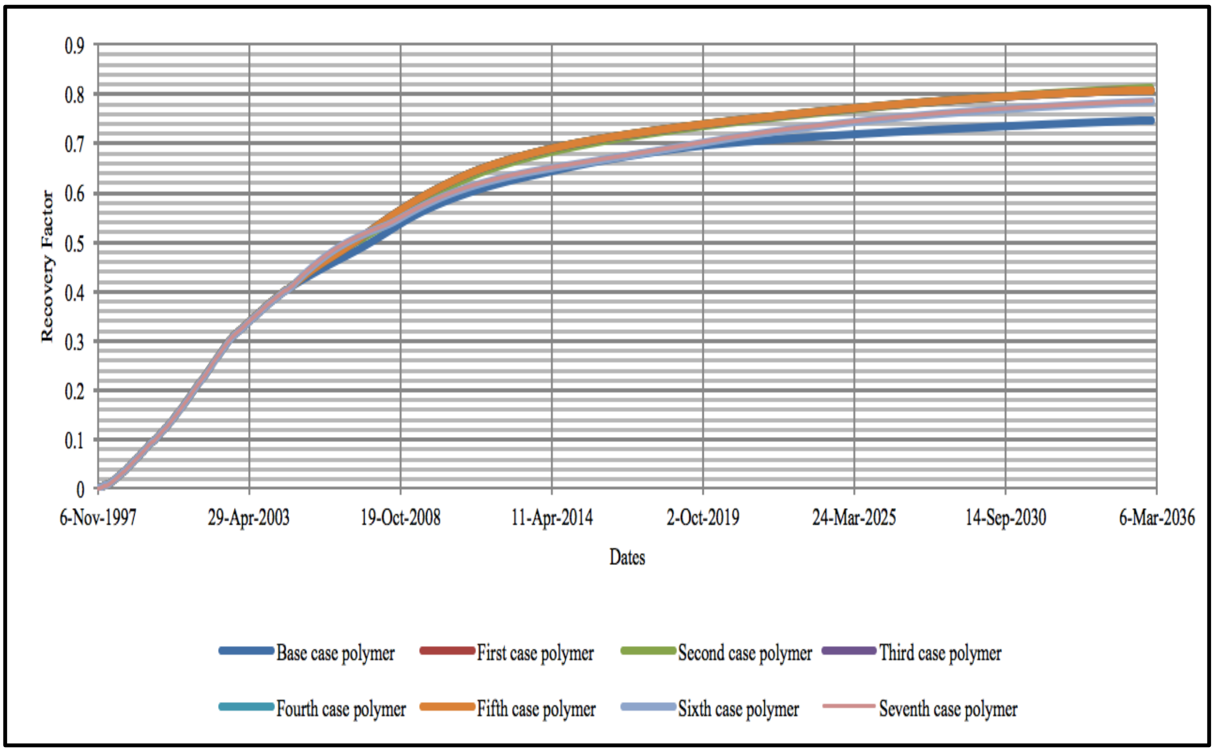


Figure 98: Field recovery factor for polymer scenario

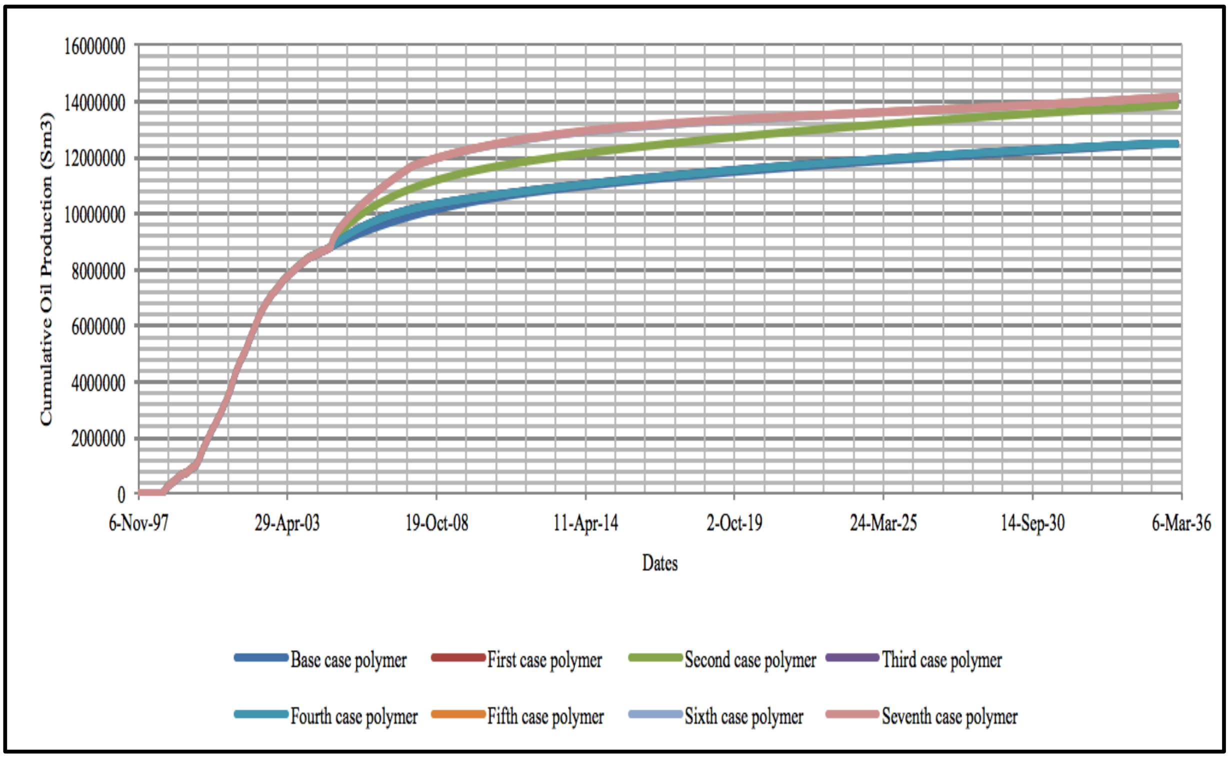


Figure 99: Cumulative oil production for polymer scenario

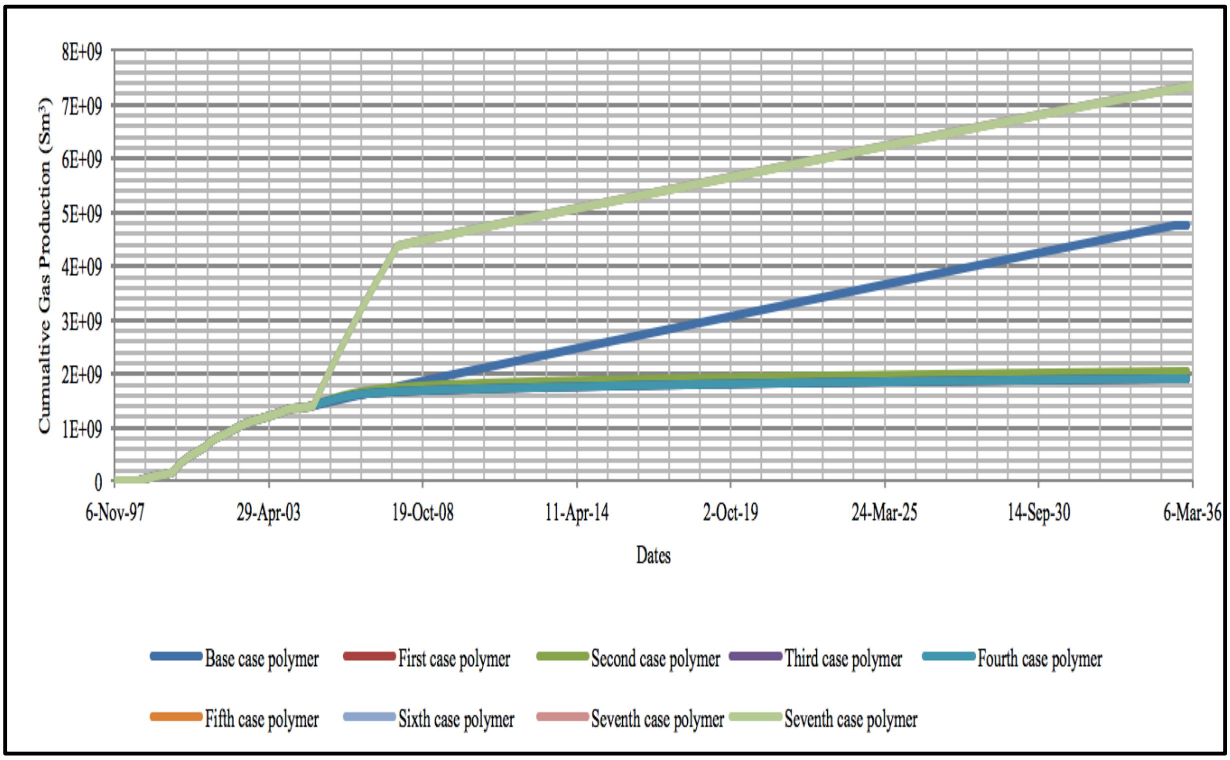


Figure 100: Cumulative gas production for polymer scenario

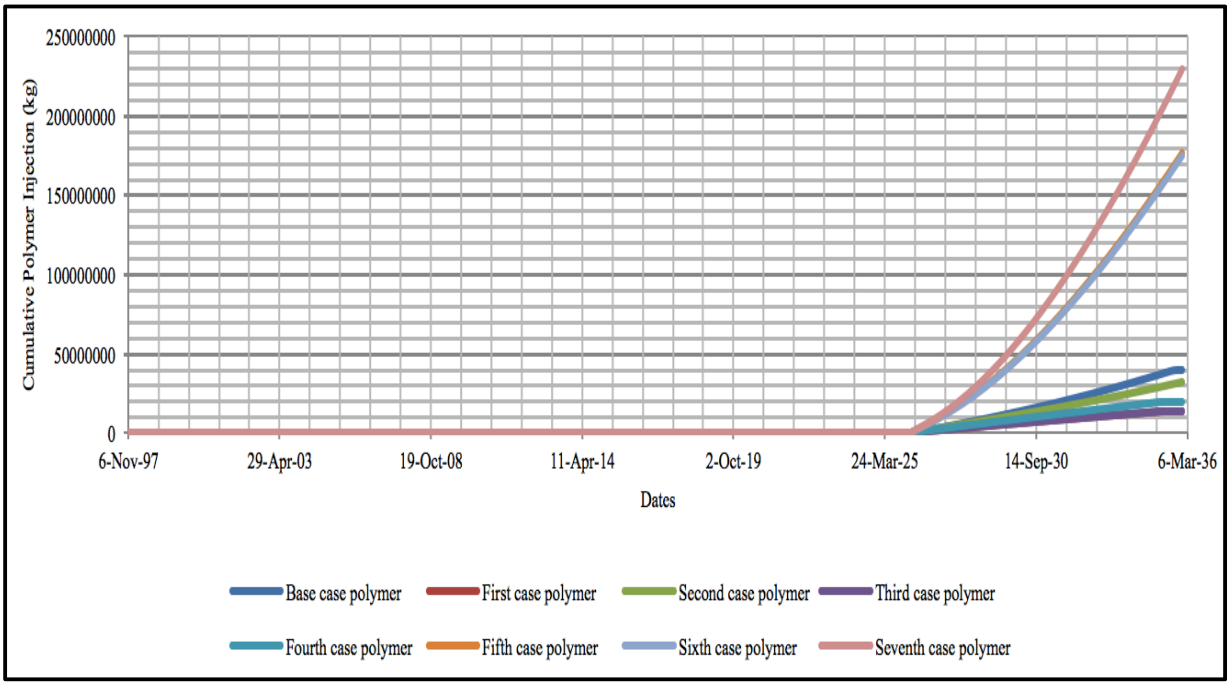


Figure 101: Cumulative polymer injection for polymer scenario

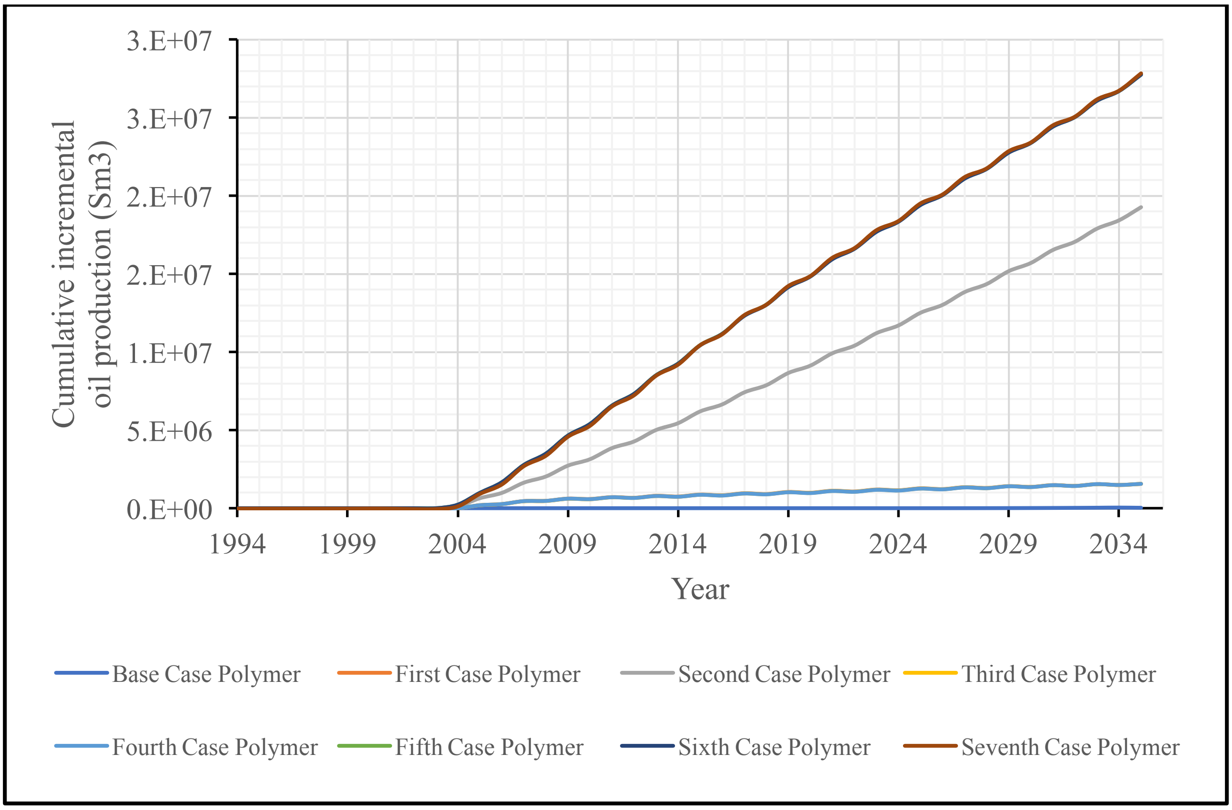


Figure 102: Cumulative incremental oil production for polymer scenario

Figure 98 shows that the highest recovery factor is 81.2 % achieved by the second case polymer but Figure 102 shows that the highest incremental oil production of 27.845 MSm^3 is achieved by the seventh case polymer but then there is high consumption of surfactants (230 M kg) as shown in Figure 101 in this case which will affect its NPV.

Third scenario: ASP

ASP is alternatively called Chemical flooding and starts with the injection of alkali agents to reduce interfacial tension (IFT) and residual oil saturation or injected combined slug of A+S+P.

In the Alkaline Surfactant Polymer (ASP) process a very low concentration surfactant is used to achieve ultra-low interfacial tension between the trapped oil and the injection fluid /formation water. The ultra-low interfacial tension also allows alkali present in the injection fluid to penetrate deeply into the formation and contact the trapped oil globules. The alkali then reacts with the acidic components in the crude oil to form additional surfactant in-situ, thus, continuously providing ultra-low interfacial tension and freeing the trapped oil. In the ASP Process, polymer is used to increase the viscosity of the injection fluid to minimize channelling and provide mobility control.

One of the world's first field-wide ASP projects started in Daqing, China, using low-concentration one component ORS-41 surfactant since 1995, the other projects are Husky Taber Manville ASP project which started in 2006 till now, Tanner, Wyoming ASP project, Sho-vel-Tum Field (ASP started in 1998 using Na_2CO_3 and ORS-62 which led to total incremental oil of 10,444 bbl. in less than 1.3 years) [62].

In this case, quarter of the initial concentration of the surfactant which was used in surfactant flooding was used here. The aim of doing this is to reduce the surfactant cost.

ASP slug of concentration (2.3 kg/m3 for alkaline, 7 kg/m3 for surfactant and 7 kg/m3 for polymer) was injected into all the cases of the previous waterflooding for 3500 days with a preflush of water for 100 days. The results are displayed below;

Results for ASP flooding

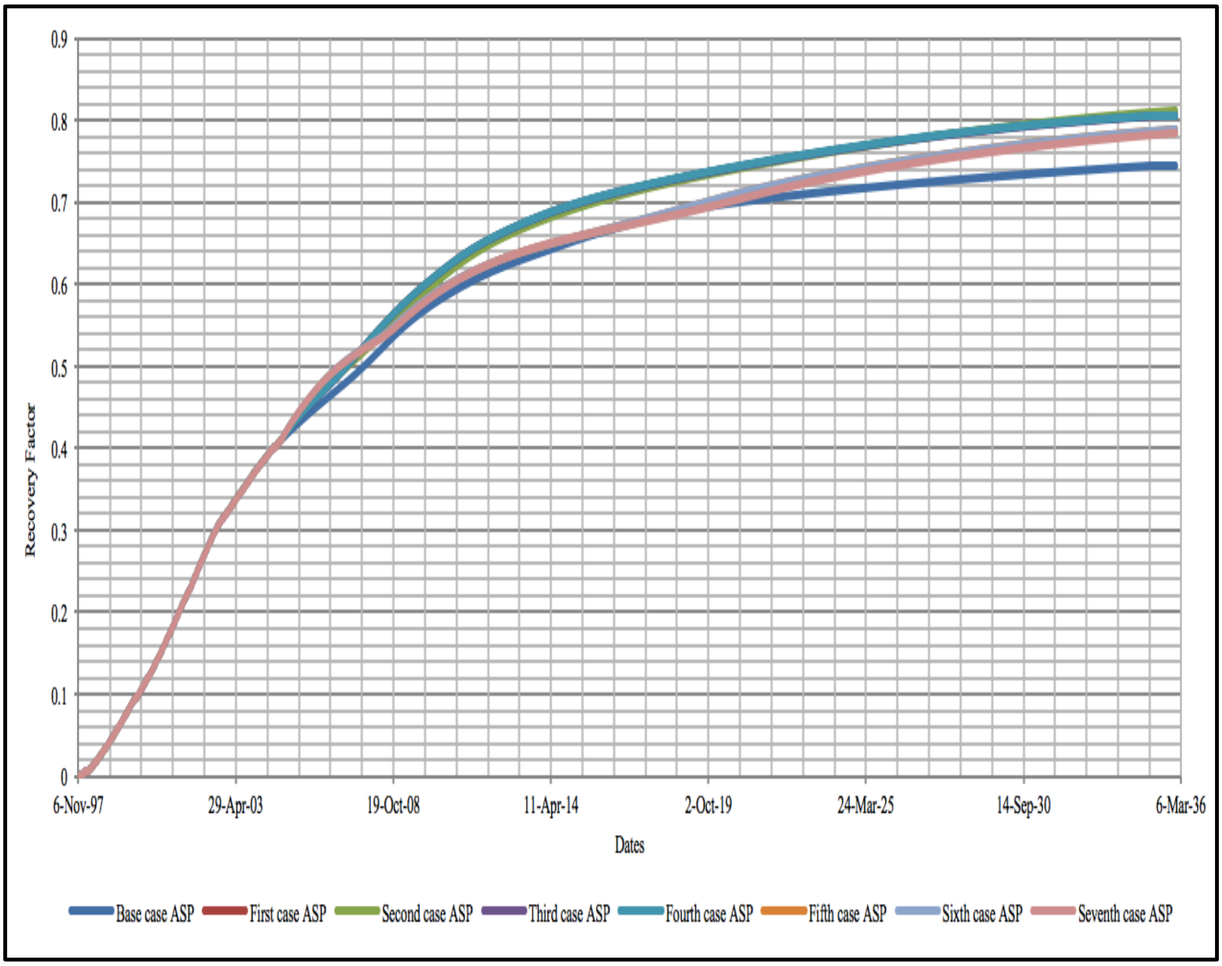


Figure 103: Field recovery factor for ASP scenario

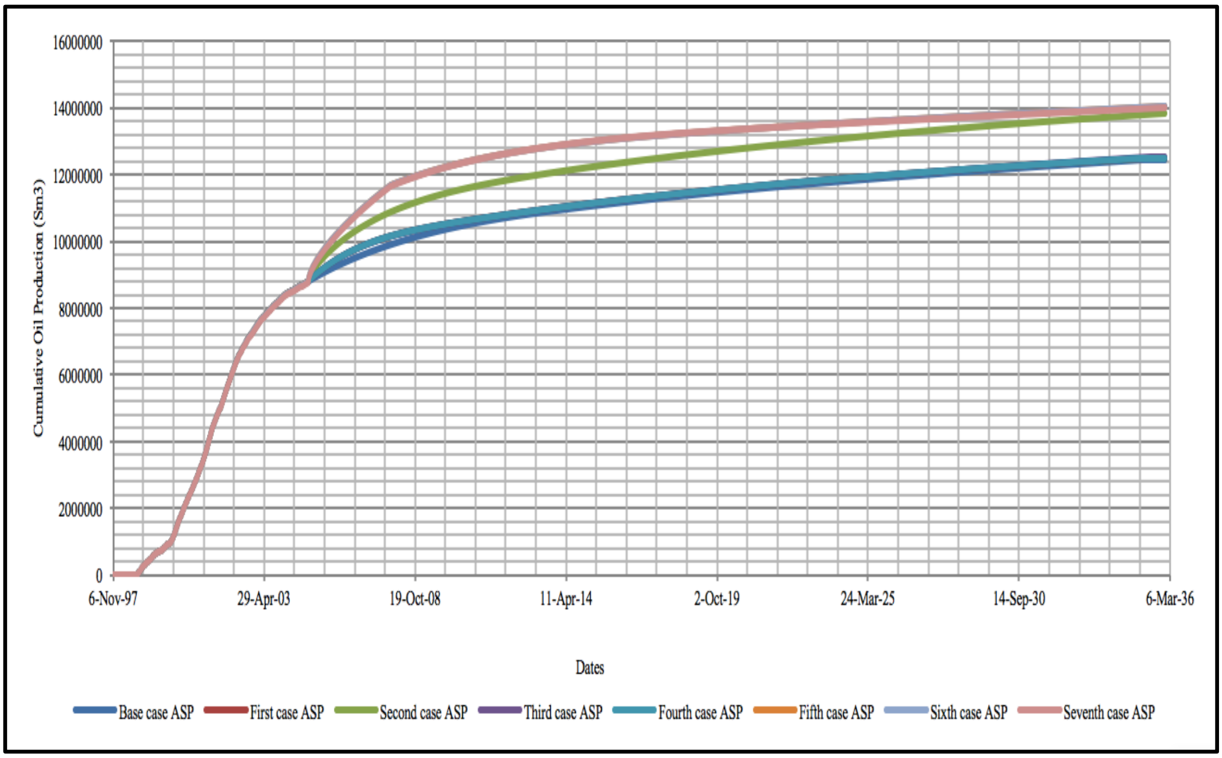


Figure 104: Cumulative oil production for ASP scenario

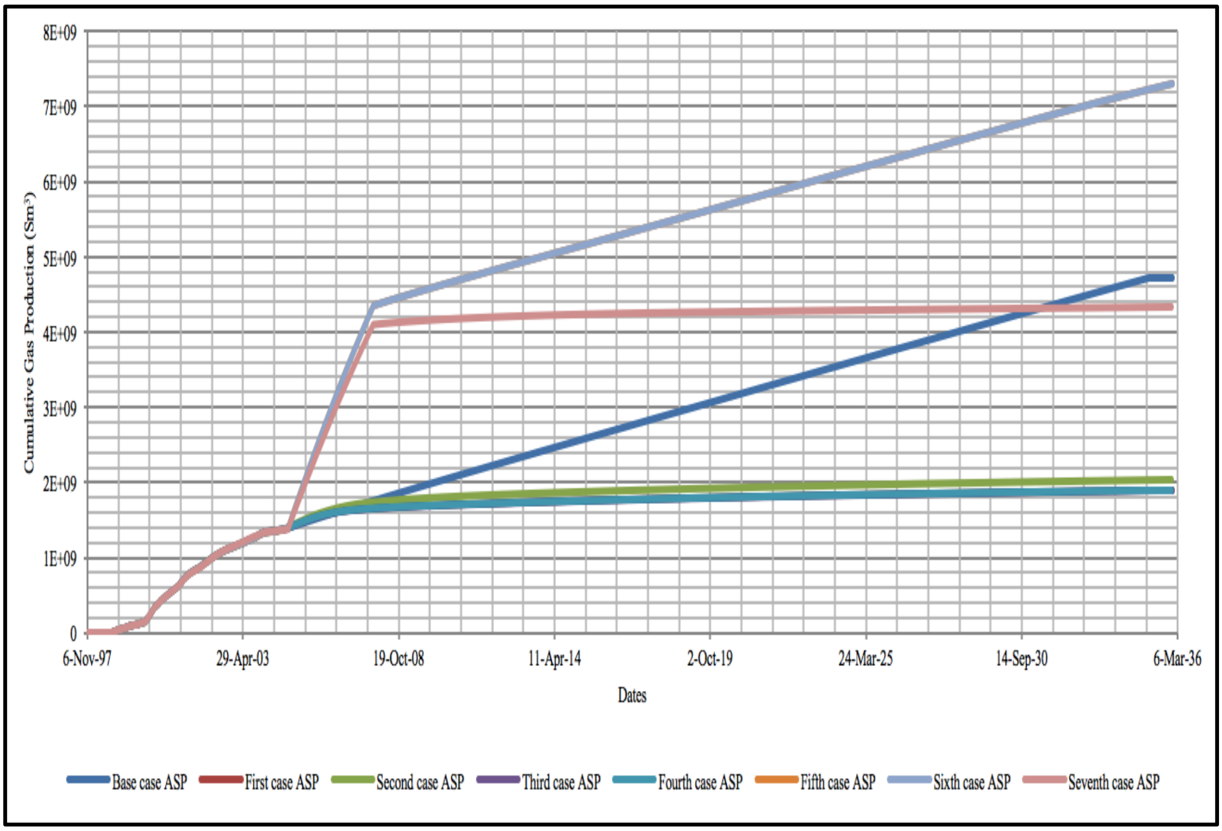


Figure 105: Cumulative gas production for ASP scenario

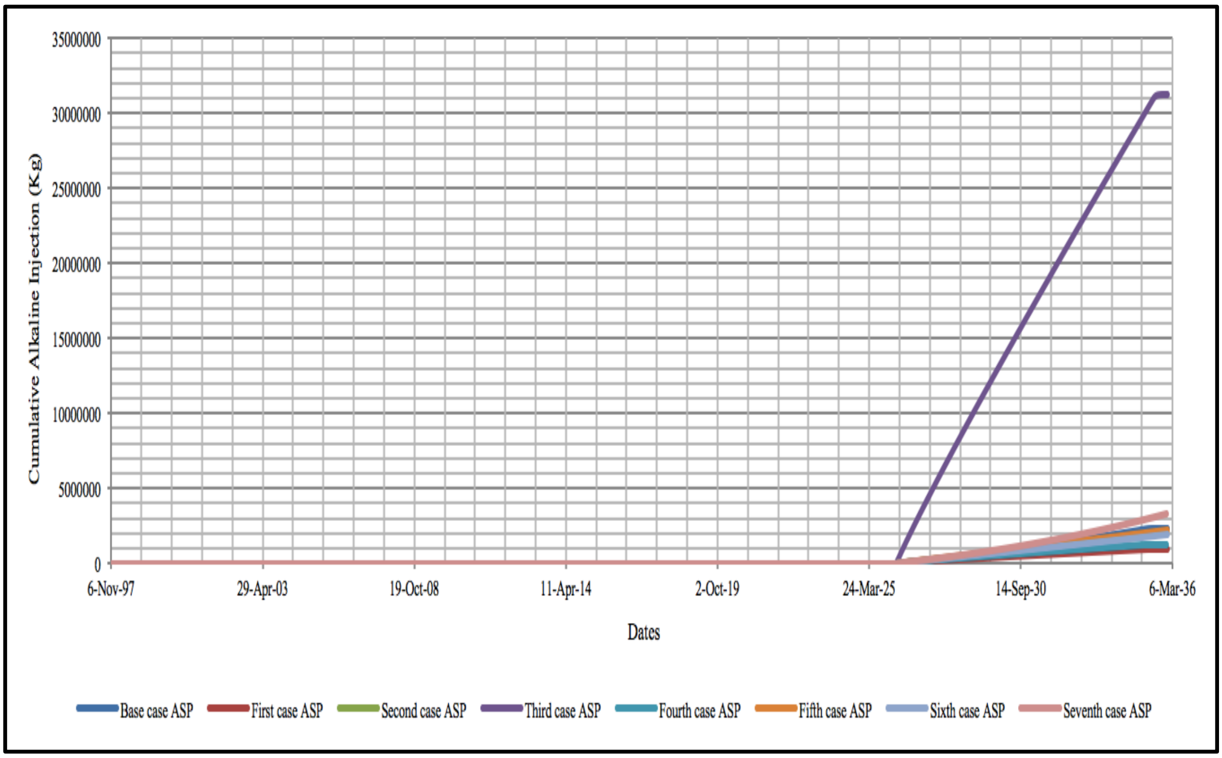


Figure 106: Cumulative alkaline injection for ASP scenario

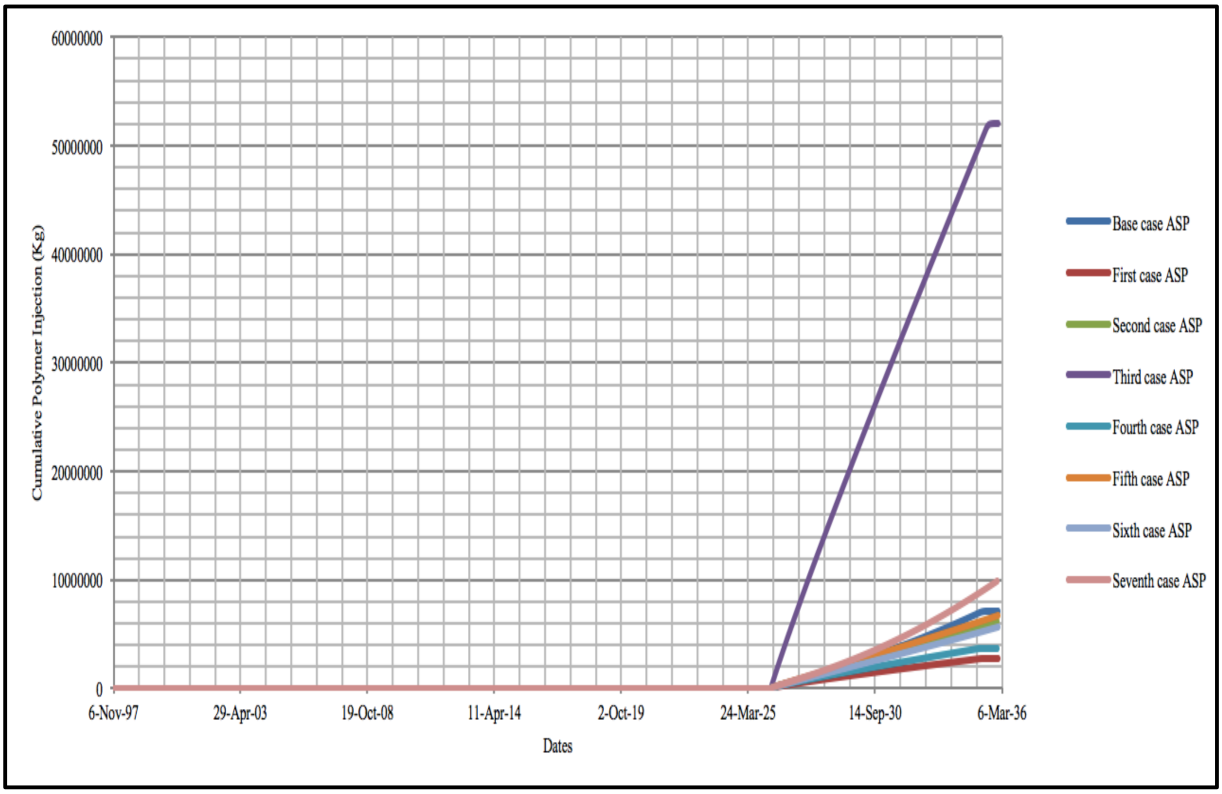


Figure 107: Cumulative polymer injection for ASP scenario

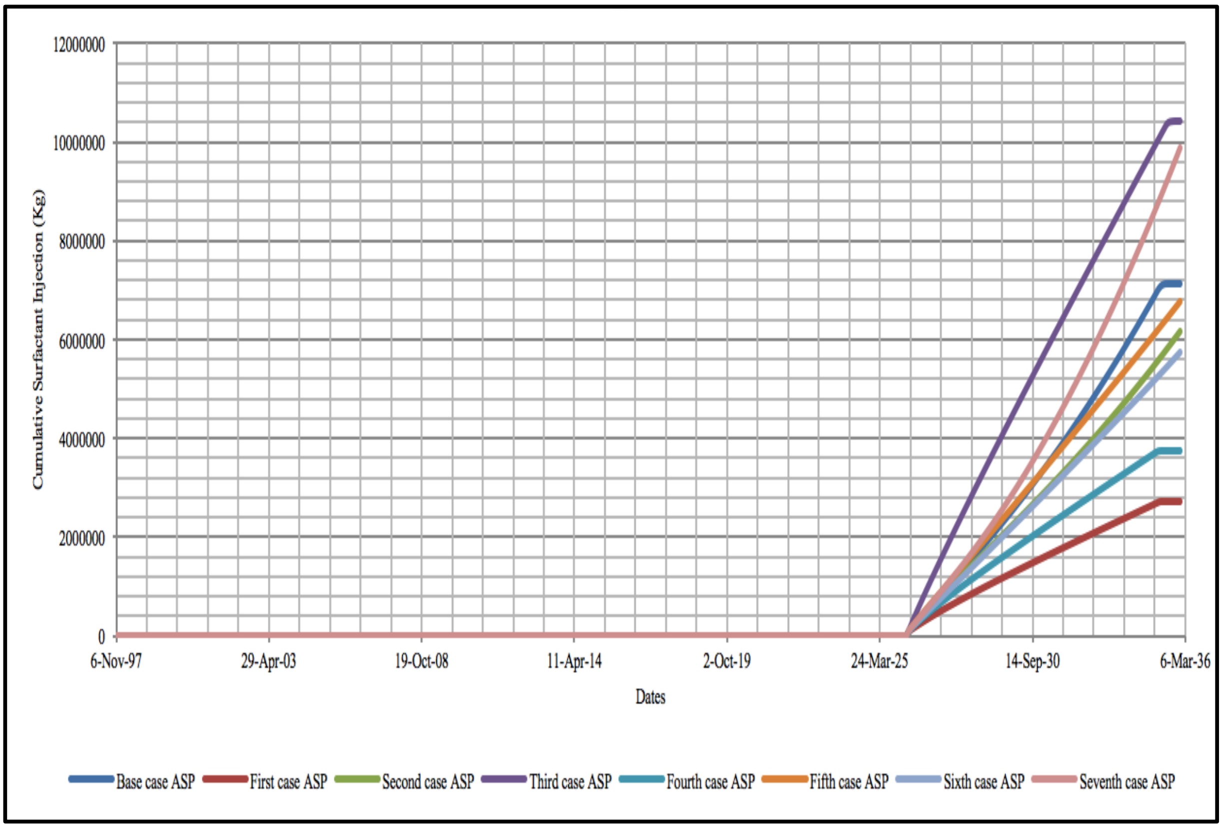


Figure 108: Cumulative surfactant injection for ASP scenario

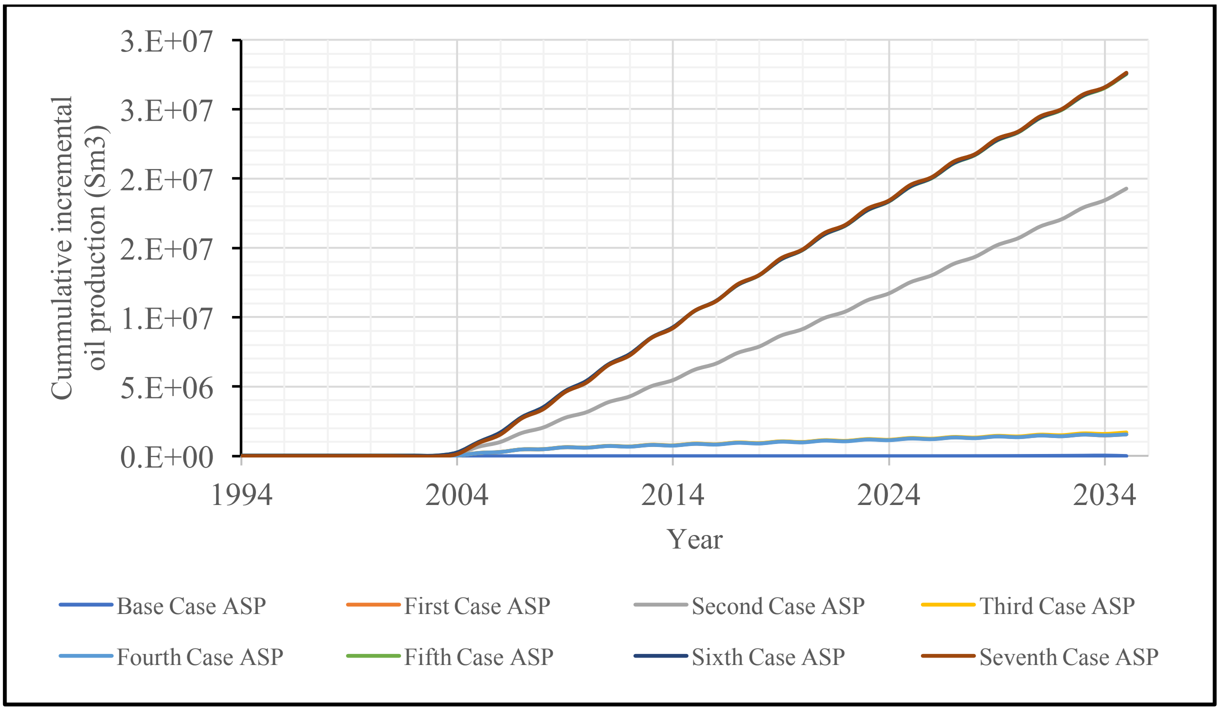


Figure 109: Cumulative incremental oil production for ASP scenario

Figure 103 shows that the highest recovery factor is 81 % achieved by the second case ASP but Figure 109 shows that the highest incremental oil production of 27.609 MSm^3 is achieved by the seventh case ASP but then there is high consumption of surfactants (10 Mkg) as shown in Figure 108 in this case which will affect its NPV.

Fourth scenario: AS

Alkali has effects when interacting with surfactant solution. In this case, alkali is added to the surfactant solution. The following are the effects of alkali when added to the surfactant solution;

- *addition of an alkali in a surfactant solution equivalently adds salt;*
- *addition of an alkali in a surfactant solution changes the surfactant phase behaviour; and*
- *addition of an alkali in a surfactant solution reduces surfactant adsorption.*

the Interactions between alkali and surfactant Addition of alkaline reduces surfactant adsorption

Seawater is softened on the platform. Single well test successfully performed using SS 6 -72 LV injected with NaOH in ANGSI FIELD, Kuala Lumpur, Malaysia.

AS slug of concentration (2.3 kg/m3 for alkaline and 7 kg/m3 for surfactant) was injected into all the cases of the previous waterflooding for 3500 days with a preflush of water for 100 days. The results are displayed below;

Results for AS flooding

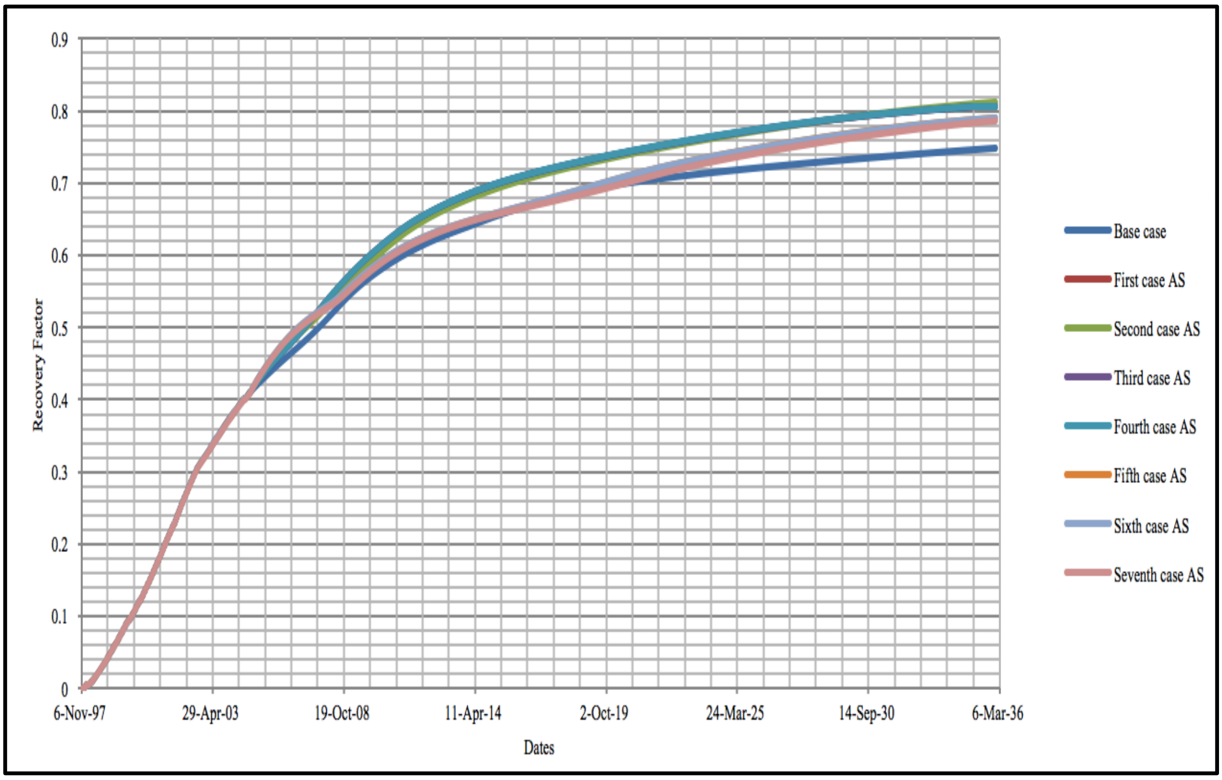


Figure 110:: Field recovery factor for AS scenario

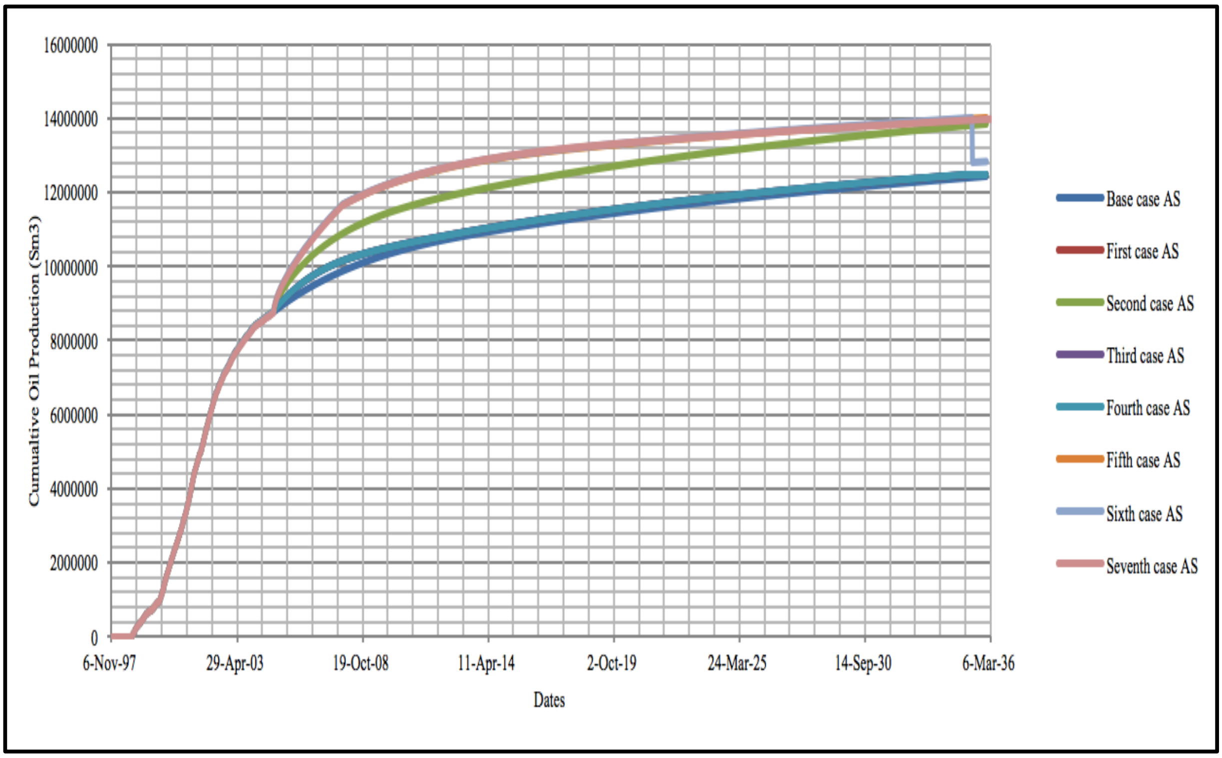


Figure 111: Cumulative oil production for AS scenario

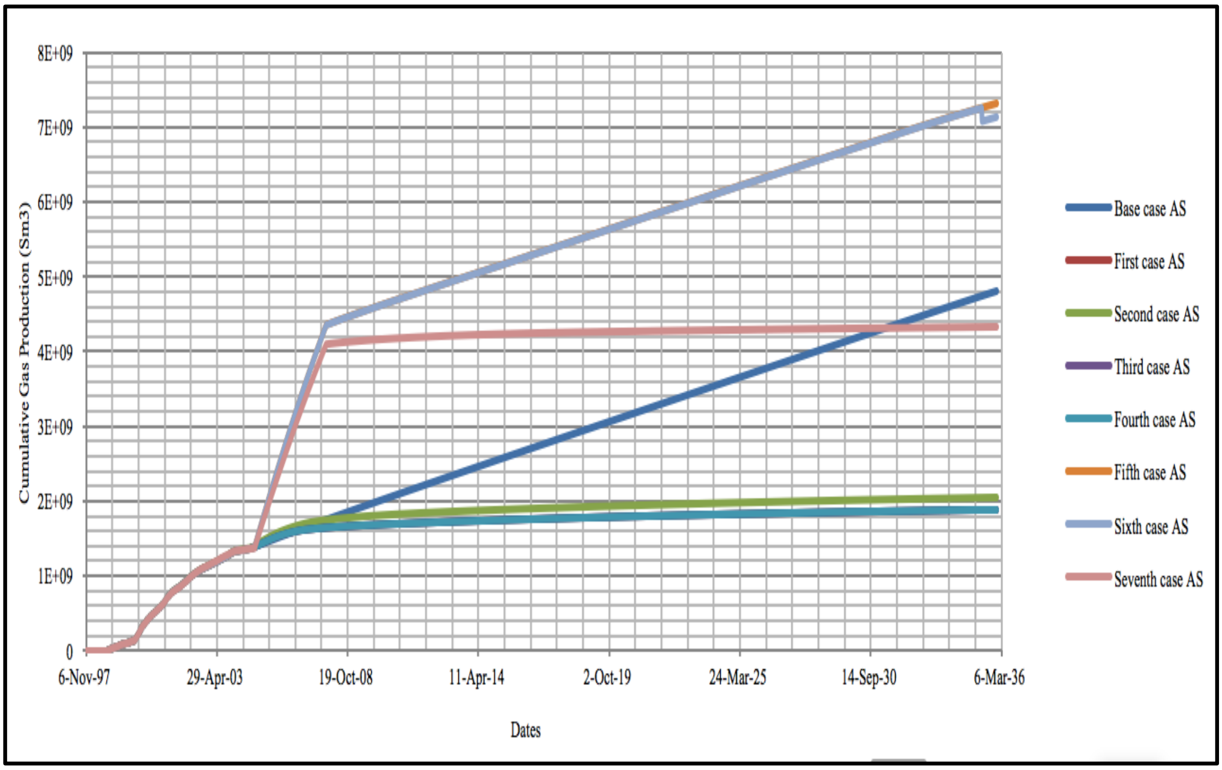


Figure 112: Cumulative gas production for AS scenario

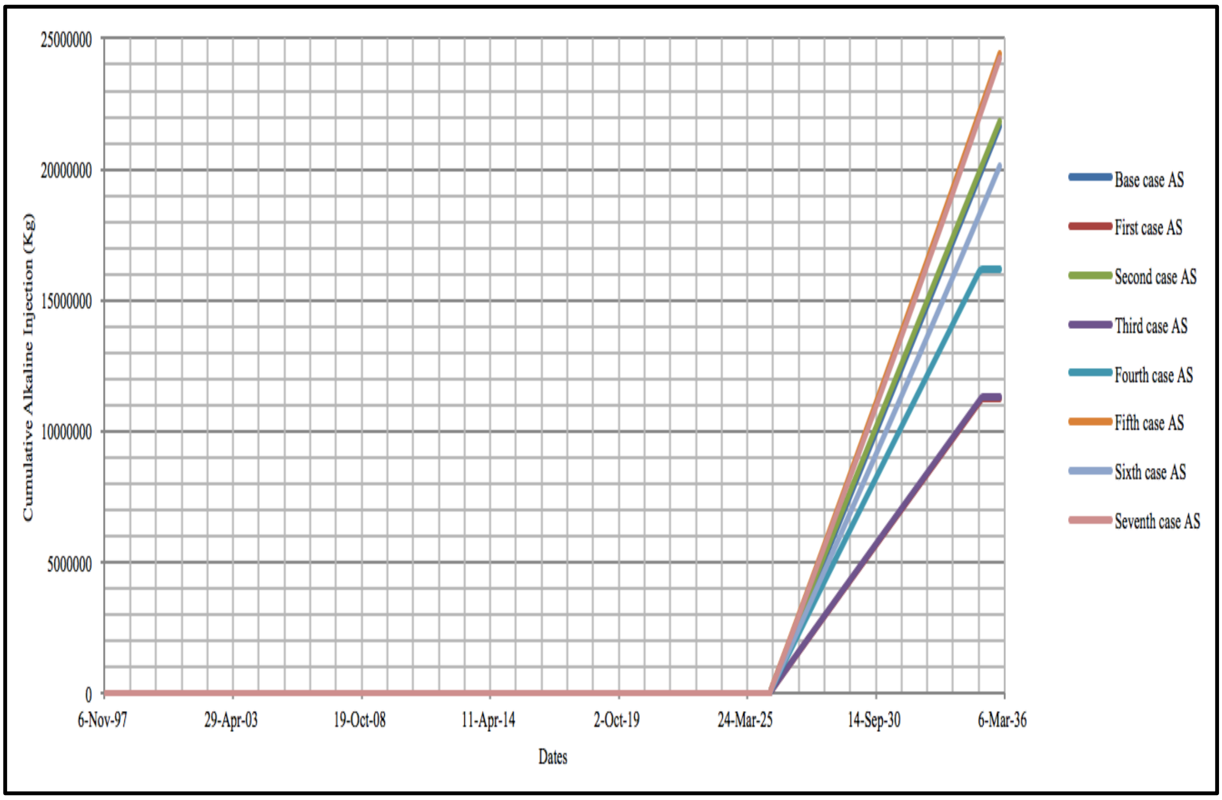


Figure 113: Cumulative alkaline injection for AS scenario

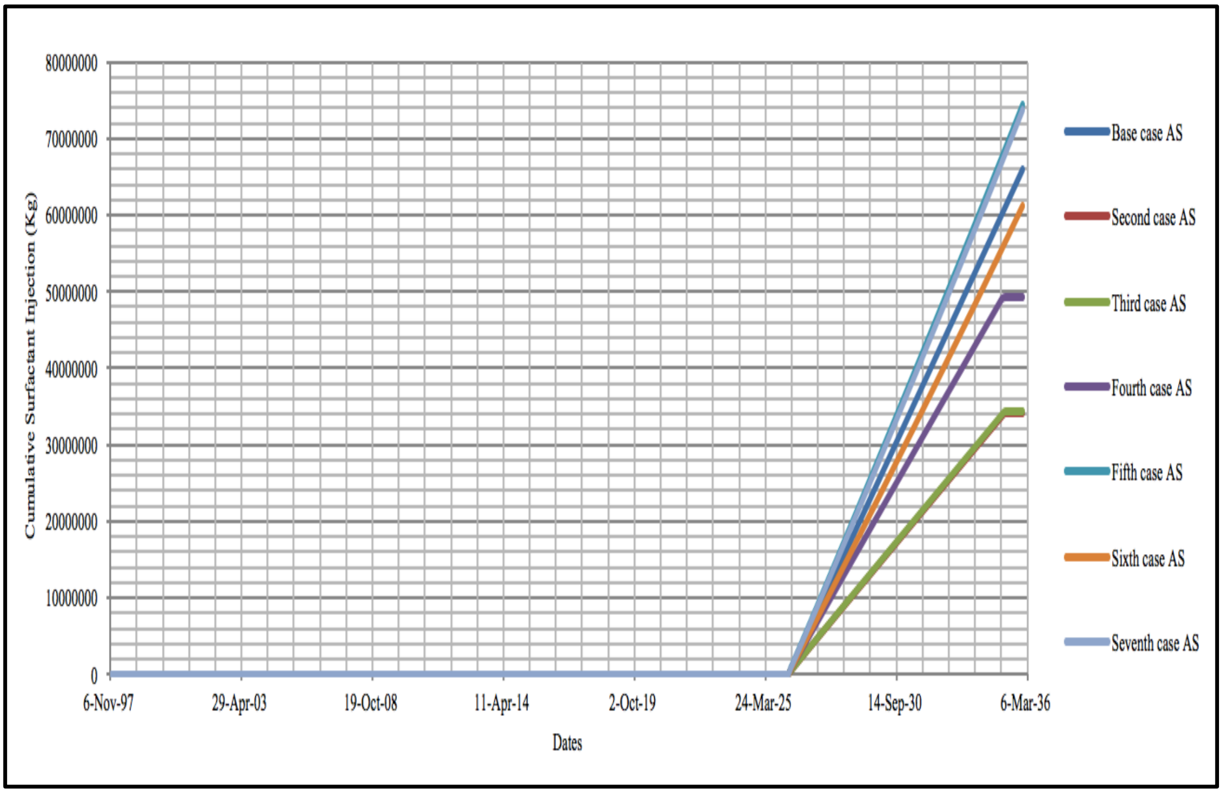


Figure 114: Cumulative surfactant injection for AS scenario

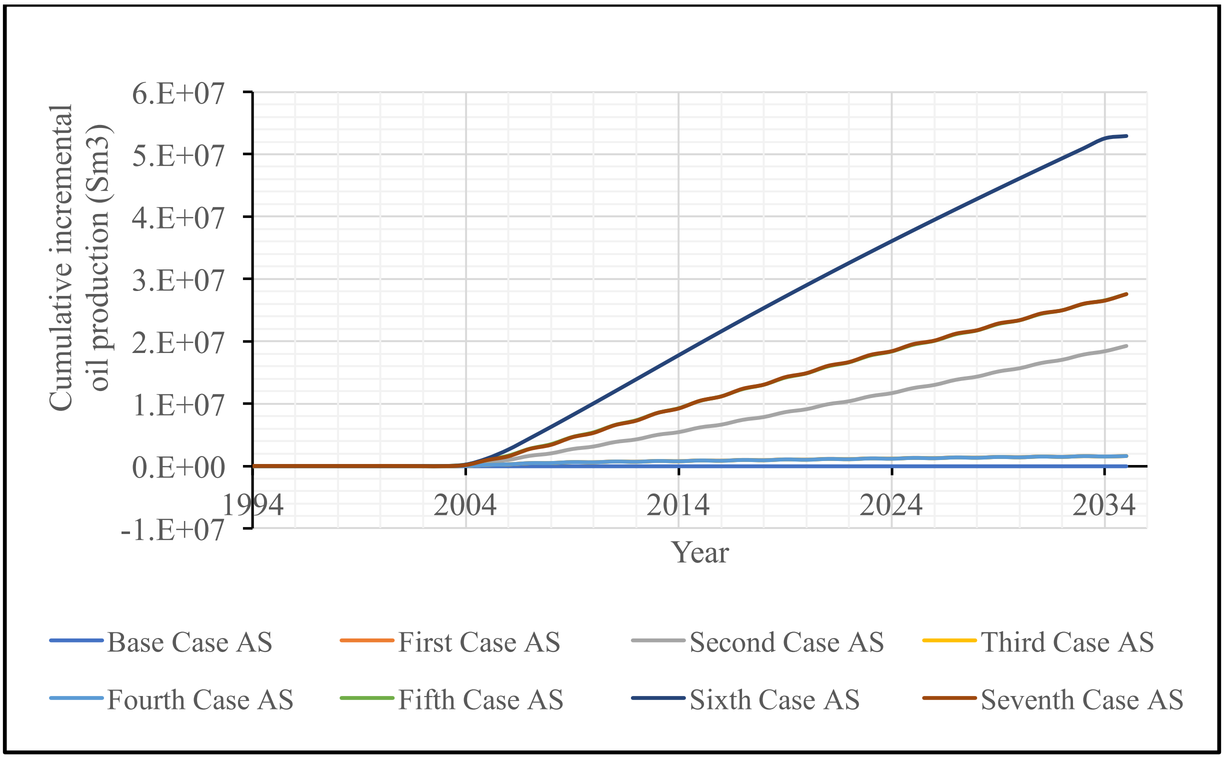


Figure 115: Cumulative incremental oil production for AS scenario

Figure 110 shows that the highest recovery factor is 82 % achieved by the second case AS but Figure 115 shows that the highest incremental oil production of 52.905 MSm^3 is achieved by the sixth case AS but then there is high consumption of surfactants (62 M kg) as shown in Figure 114 in this case which will affect its NPV.

Fifth scenario: SP

In the Alkaline Surfactant Polymer (ASP) process a very low concentration surfactant is used to achieve ultra-low interfacial tension between the trapped oil and the injection fluid /formation water. SP eliminates scale issues and polymer degradation issues associated with ASP. The higher viscosity injection fluid results in oil recovery levels similar to ASP.

There are several SP projects worldwide, North America SP project which is the heavy oil field and 0.1% surfactant with polymer has been applied in less than 3 months later, the water cut reduced from 97% to 58%. In Big Sinking, Kentucky 0.8 % NaOH + 0.1% ORS-162 HF was applied and several problems were overcome which include IFT lowered from 23.6 to 0.001 mN/m, poor water injectivity, high water cuts and 220% increase in injectivity [62].There are also many SP projects in South America at the San Jorge Gulf Basin in Atlantic Ocean [62].

SP slug of concentration (7 kg/m3 for surfactant and 7 kg/m3 for polymer) was injected into all the cases of the previous waterflooding for 3500 days with a preflush of water for 100 days.

Results for SP flooding

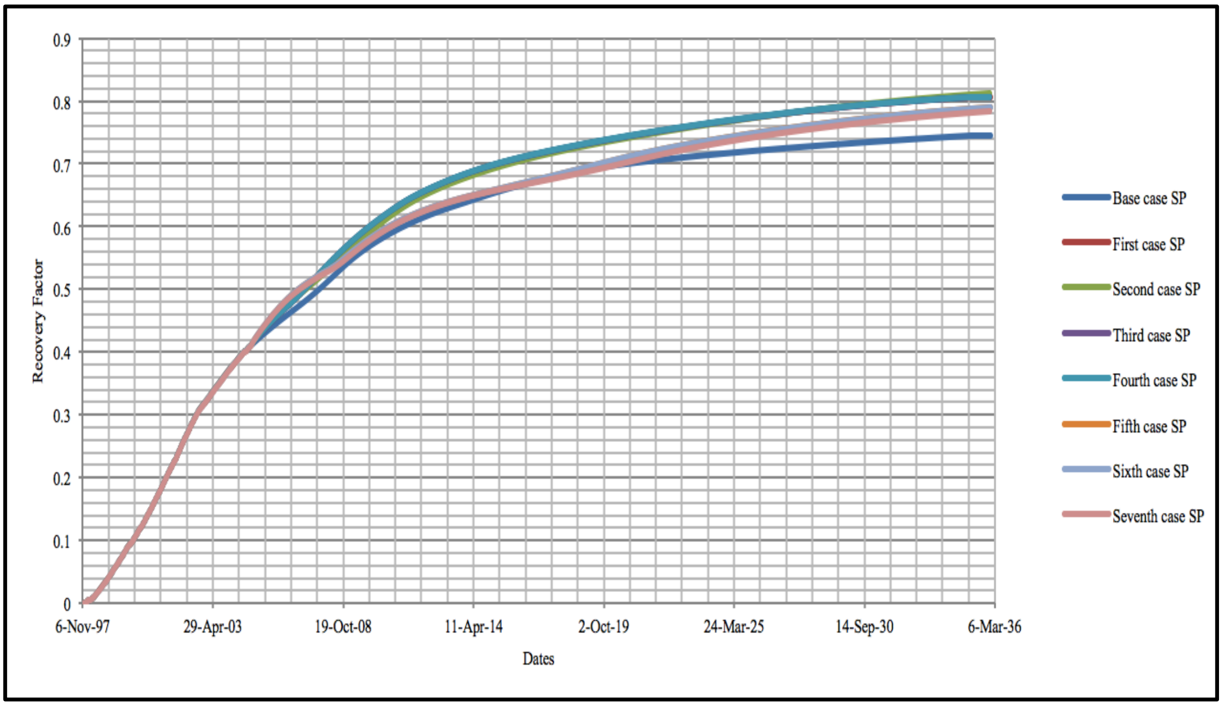


Figure 116: Field recovery factor for SP scenario

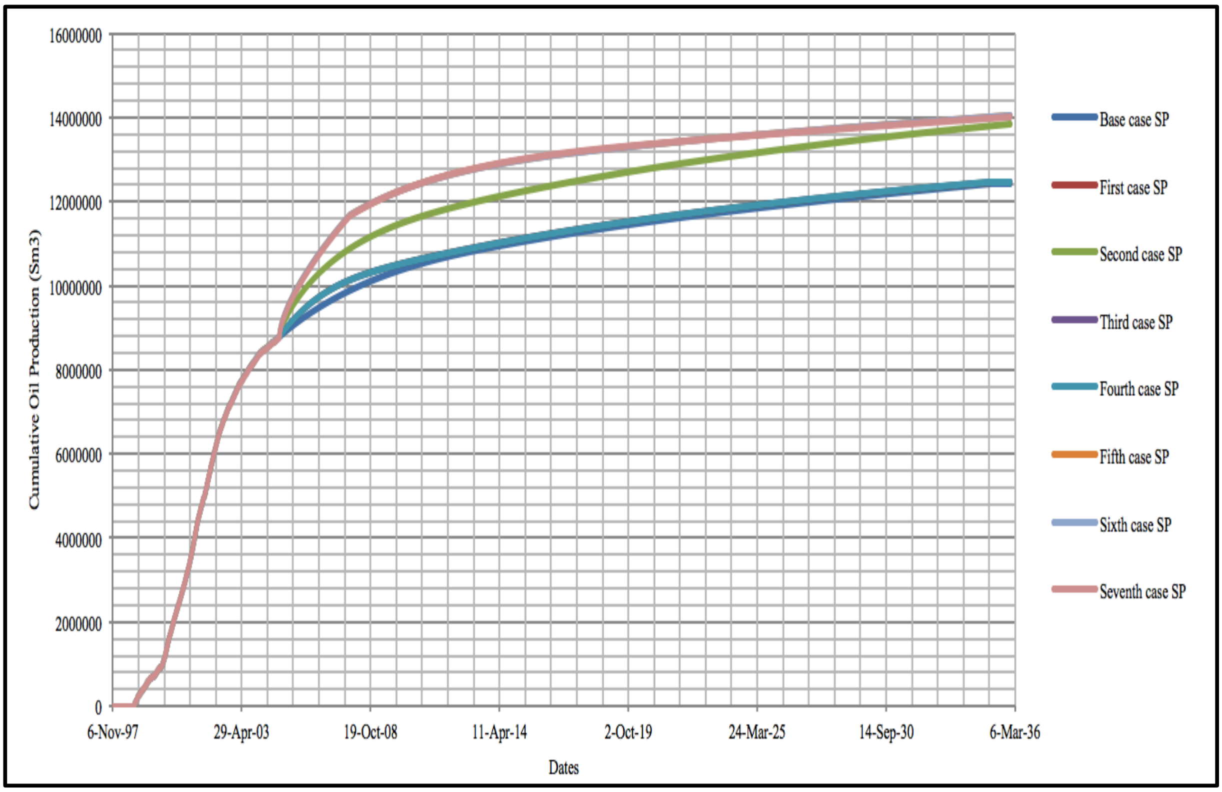


Figure 117: Cumulative oil production for SP scenario

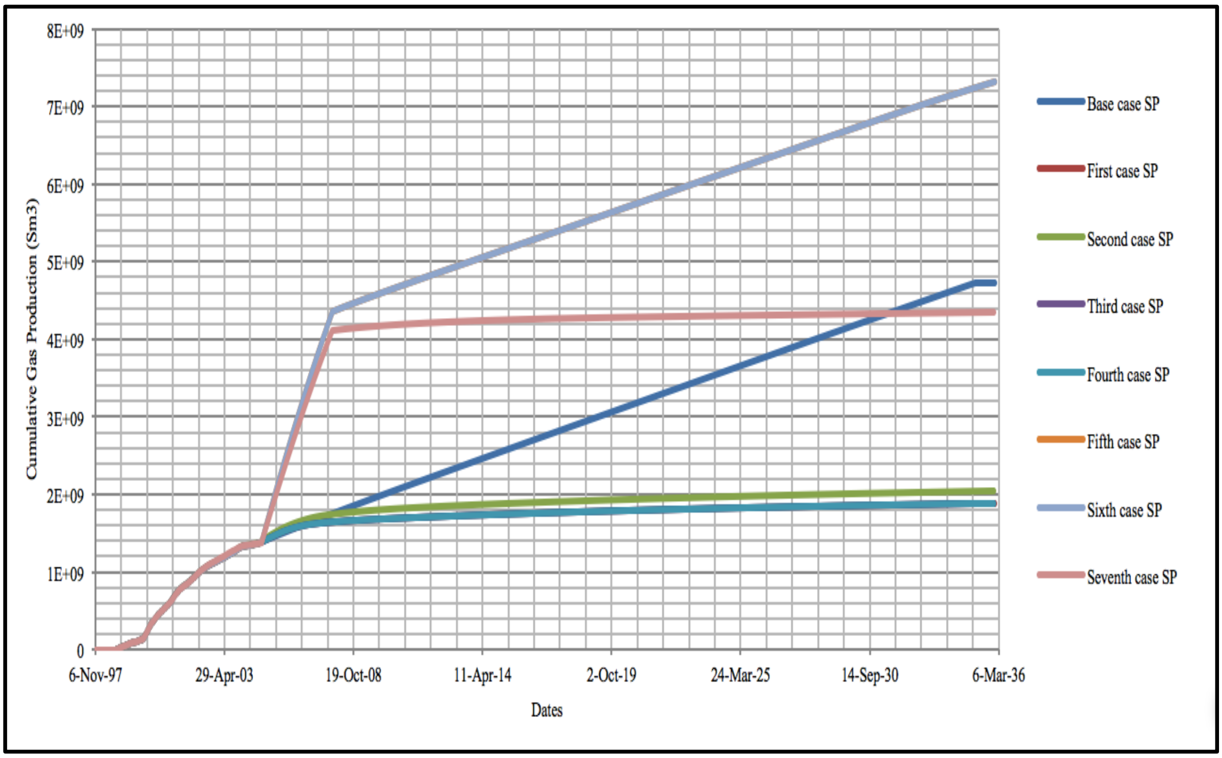


Figure 118: Cumulative gas production for SP scenario

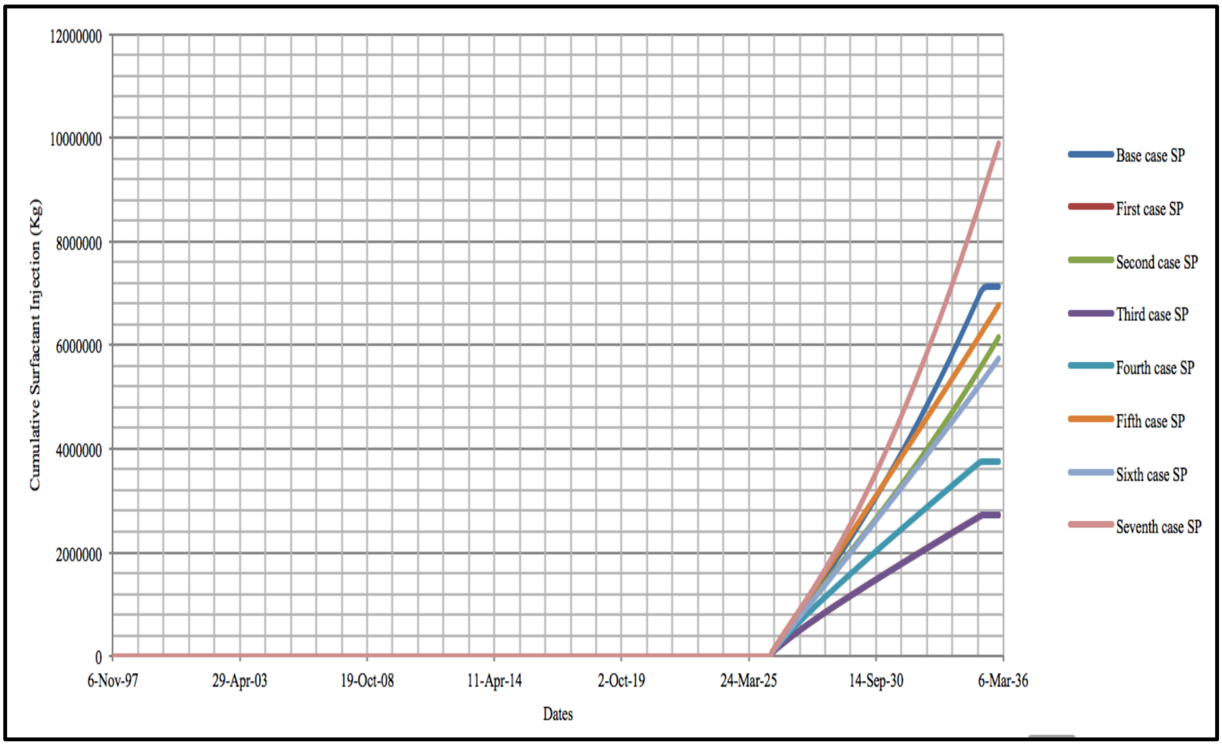


Figure 119: Cumulative surfactant injection for SP scenario

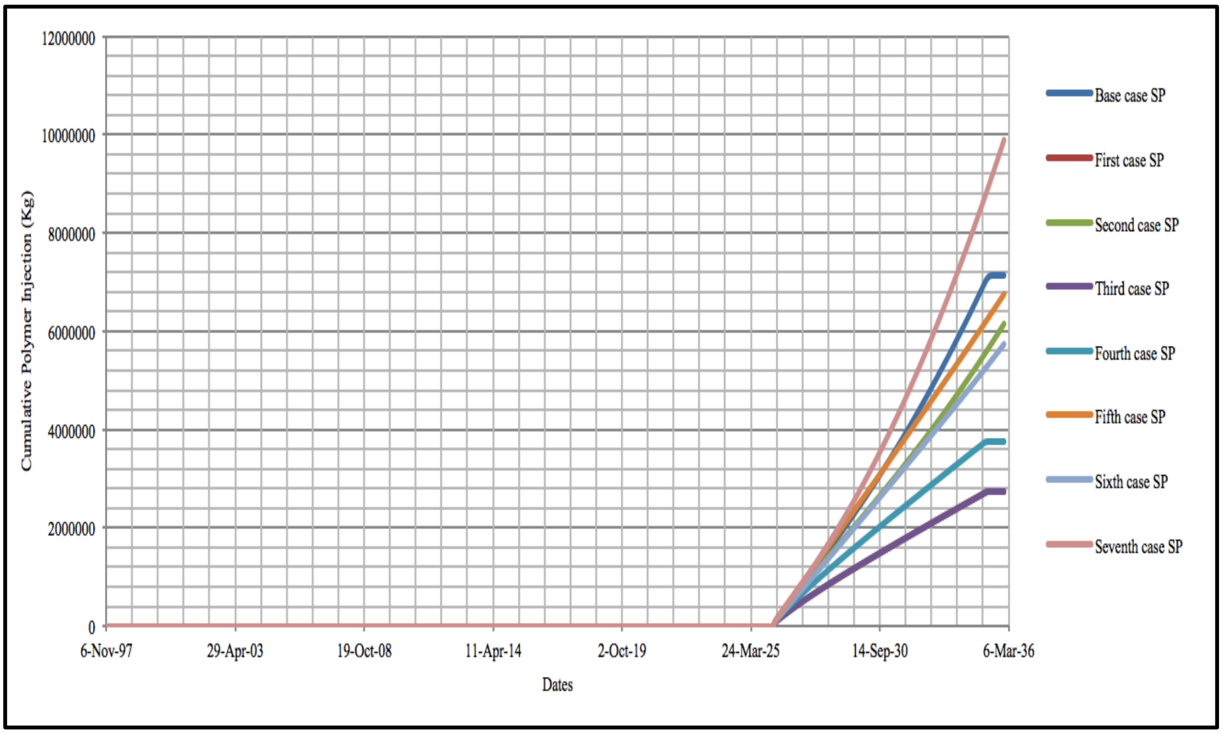


Figure 120: Cumulative polymer injection for SP scenario

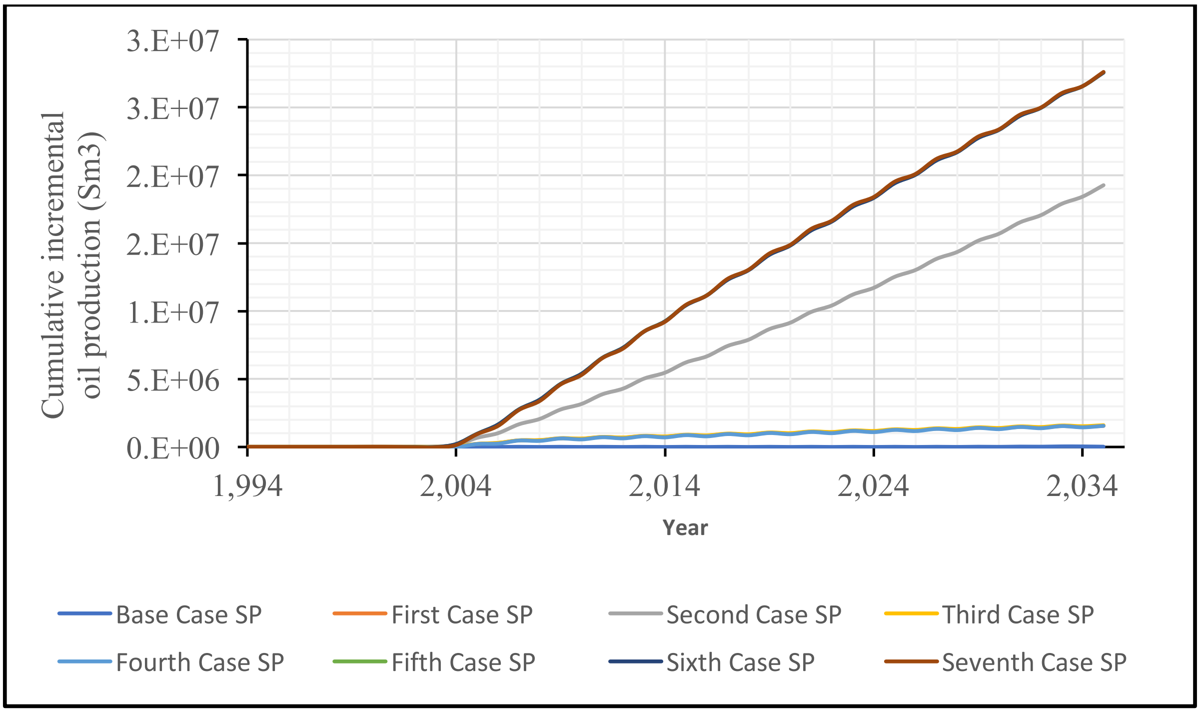


Figure 121: Cumulative incremental oil production.

Figure 116 shows that the highest recovery factor is 81 % achieved by the second case SP but Figure 121 shows that the highest incremental oil production of 27.609 MSm^3 is achieved by the seventh case SP but then there is high consumption of surfactants (10 M kg) as shown in Figure 119 in this case which will affect its NPV.

9.4: Feasibility and Economic Evaluation

The success of a drainage/depletion strategy is measured technically by the amount of incremental oil production [66] over the base case water flooding [67]. After running all cases and getting results the most suitable case for the Norne E-segment was determined by the Expected Net Present Value, E(NPV) which is based on incremental oil production from other cases compared to the base case water flooding and probability-weighting of the prices of oil were used to calculate the E(NPV). Oil price has been fluctuating for the last few years but Figure 122 indicates that the oil price is expected to go on increasing from 2016 onwards due to steady grow in global demand for energy worldwide.

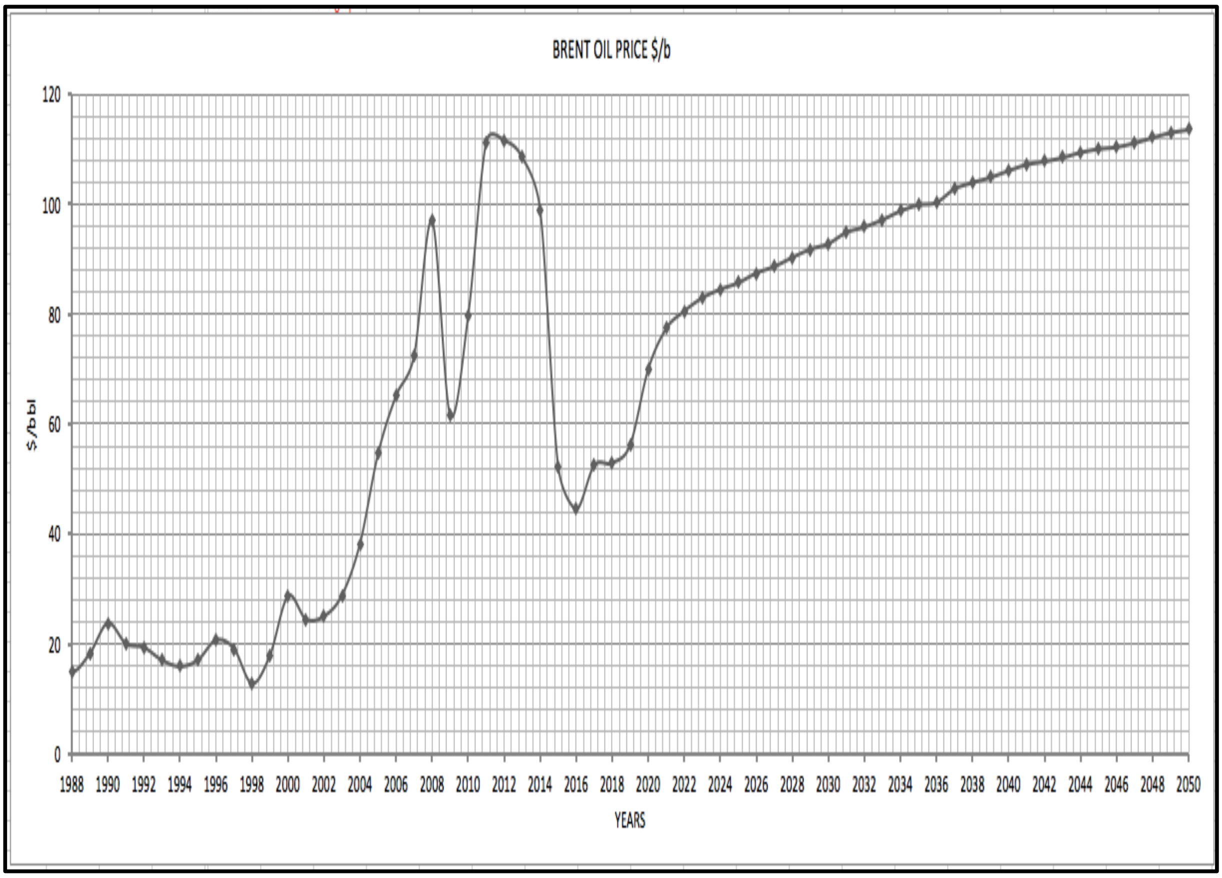


Figure 122: History and Predicted Oil Price [68]

Table 16: Parameters extracted from Figure 122

PARAMETERS	
Maximum	113.5585
Minimum	12.76
Mean	70.92489
Standard deviation	35.8118

Table 16 indicates that the oil price is approximately *71±36 USD* per barrel.

Table 17: Discount rate, Oil price, Gas price, Chemical prices and Drilling cost

Discount factor		0.08
Oil Price	USD/bbl.	71
Gas Price	USD/m^3	0.11
Drilling Cost	USD/well	80,000,000
Alkaline Price	USD/kg	1.33
Surfactant Price	USD/kg	2.1
Polymer Price	USD/kg	2.2

Table 18: Oil prices, Gas prices, Drillex, Chemical prices and Discount rate for Sensitivity Analysis (Spider Chart) of Case 5.

Cases	Oil Price (USD/bbl.)	Discount rate	Gas Price (USD/m^3)	Drillex (USD/well)
Low Case	35.5	0.06	0.0825	60M
Base Case	71	0.08	0.11	80M
High Case	106.5	0.10	0.1375	100M

9.5: Comparison between incremental E(NPVs) and E(NPVs) for different cases

The Expected Incremental Net Present Value (E(NPV)) criterion was selected in order to determine the most appropriate drainage strategy for the Norne E-segment. The NPV calculation is based on incremental oil production from the drainage strategies (waterflooding and chemical EOR) over benchmark case waterflooding.

Table 19:All cases with E(NPV) in ascending order

NO	CASE	Expected Incremental (USD)	Expected (USD)
1	Fifth Case Waterflooding	996,542,183	2,115,868,940
2	Sixth Case Waterflooding	996,521,476	2,115,848,234
3	Sixth Case SP	994,089,607	2,113,416,365
4	Sixth Case ASP	993,858,601	2,113,185,359
5	Fifth Case SP	993,680,414	2,113,007,171
6	Fifth Case ASP	993,380,207	2,112,706,965
7	Fifth Case Waterflooding	980,526,011	2,099,852,768
8	Sixth Case Waterflooding	969,598,675	2,088,925,433
9	Sixth Case Polymer	965,979,590	2,085,306,347
10	Fifth Case Polymer	965,593,024	2,084,919,781
11	Seventh Case Polymer	957,217,088	2,076,543,845
12	Sixth Case Surfactant	915,086,382	2,034,413,140
13	Fifth Case Surfactant	906,528,647	2,025,855,404
14	Seventh Case	738,898,471	1,858,225,228
15	Seventh Case SP	702,105,321	1,821,432,078
16	Seventh Case ASP	701,751,907	1,821,078,665
17	Seventh Case AS	688,207,104	1,807,533,862
18	Seventh Case Surfactant	624,376,269	1,743,703,026
19	First Case Waterflooding	215,126,494	1,334,453,251
20	Base Case SP	211,939,920	1,331,266,677
21	Base Case ASP	211,668,178	1,330,994,936
22	Base Case Polymer	207,410,895	1,326,737,653
23	Base Case AS	199,538,979	1,318,865,737
24	Base Case Surfactant	129,998,908	1,249,325,666
25	Second Case	28,701,484	1,148,028,241
26	Second Case SP	26,148,718	1,145,475,475
27	Second Case ASP	25,908,224	1,145,234,982
28	Second Case Polymer	22,240,350	1,141,567,108
29	Second Case AS	12,670,282	1,131,997,039
30	Base Case Waterflooding	893,730,936	1,119,326,757
31	First Case Surfactant	-18,018,188	1,101,308,569
32	Third Case Waterflooding	-37,002,614	1,082,324,143
33	Fourth Case Waterflooding	-37,083,530	1,082,243,227
34	Third Case SP	-38,418,292	1,080,908,465
35	First Case SP	-38,468,306	1,080,858,451
36	First Case ASP	-38,589,960	1,080,736,797
37	Fourth Case SP	-39,083,675	1,080,243,082
38	Fourth Case ASP	-39,083,675	1,080,211,937
39	Third Case Polymer	-40,284,331	1,079,042,427
40	First Case Polymer	-40,333,389	1,078,993,368
41	Fourth Case Polymer	-41,519,446	1,077,807,311
42	First Case AS	-45,939,783	1,073,386,975
43	Third Case AS	-45,942,203	1,073,384,554
44	Fourth Case AS	-49,860,276	1,069,466,481
45	Third Case ASP	-54,771,184	1,064,555,574
46	Second Case Surfactant	-83,372,831	1,035,953,926
47	Third Case Surfactant	-84,520,478	1,034,806,279
48	Fourth Case Surfactant	-116,320,632	1,003,006,125
0	Base Case Waterflooding	0	996,542,183

From Table 19, which arranges different cases for this work in accordance with their Expected Incremental Net Present Value corresponding to Expected Net Present Value. It can be seen that all the cases improved E(NPV) of the benchmark case. However, not all cases improved incremental E(NPV). Since, incremental E(NPV) is the decision factor as shown in Table 7, all the cases with –ve incremental E(NPV) were inviable which means that No. 31-48 are rejected whereas cases with +ve. incremental NPV are viable and hence accepted and these are No. 1-30 in Table 19. The highest incremental E(NPV) is **996.542 million USD** corresponding to the E(NPV) of **2.116 billion USD.**

The graphs for the incremental E(NPV) and E(NPV) for different scenario

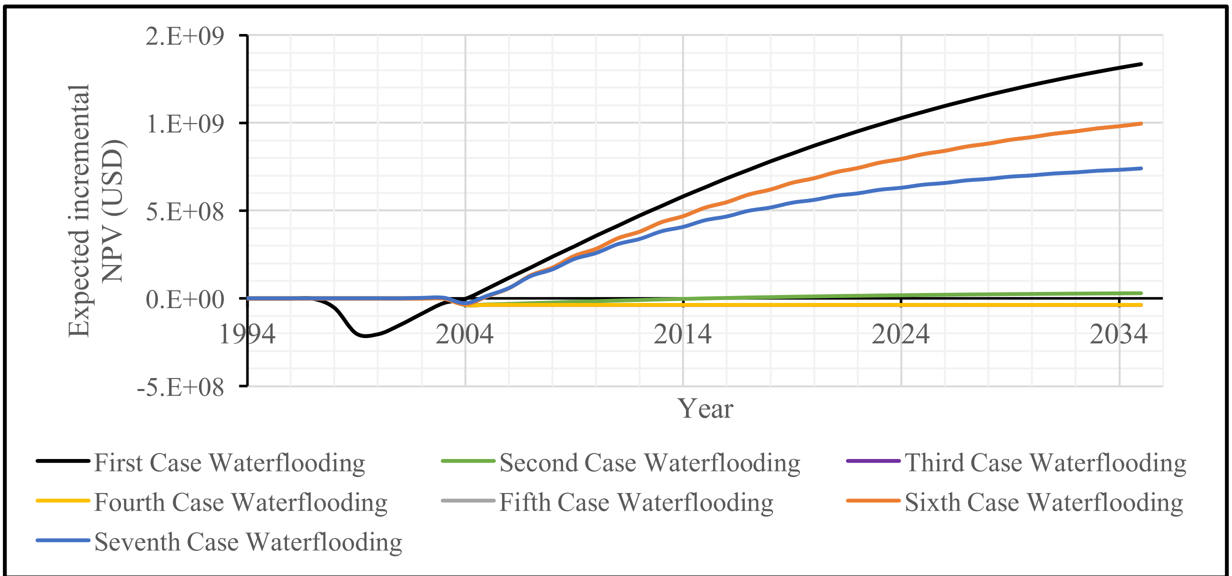


Figure 123: Expected incremental NPV for waterflooding scenario

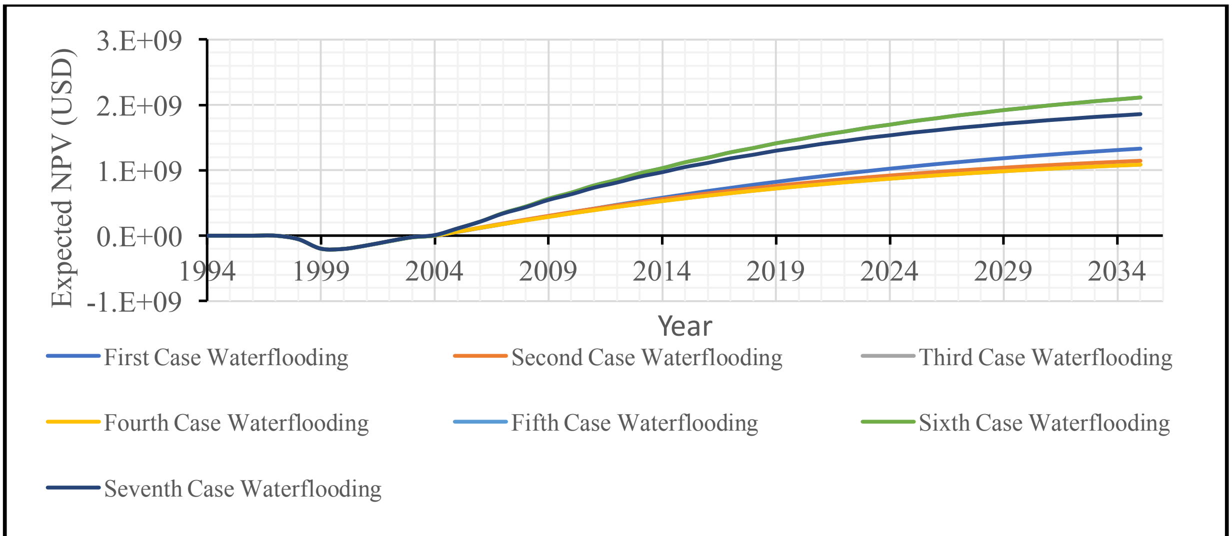


Figure 124: Expected NPV for waterflooding scenario.

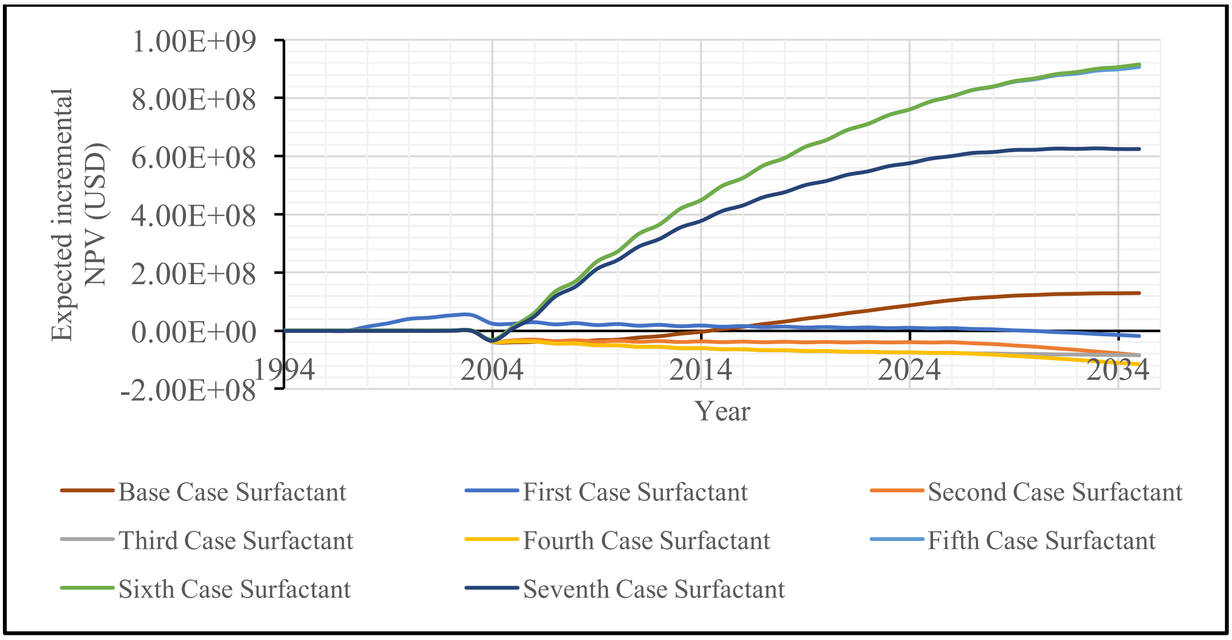


Figure 125: Expected incremental NPV for surfactant scenario.

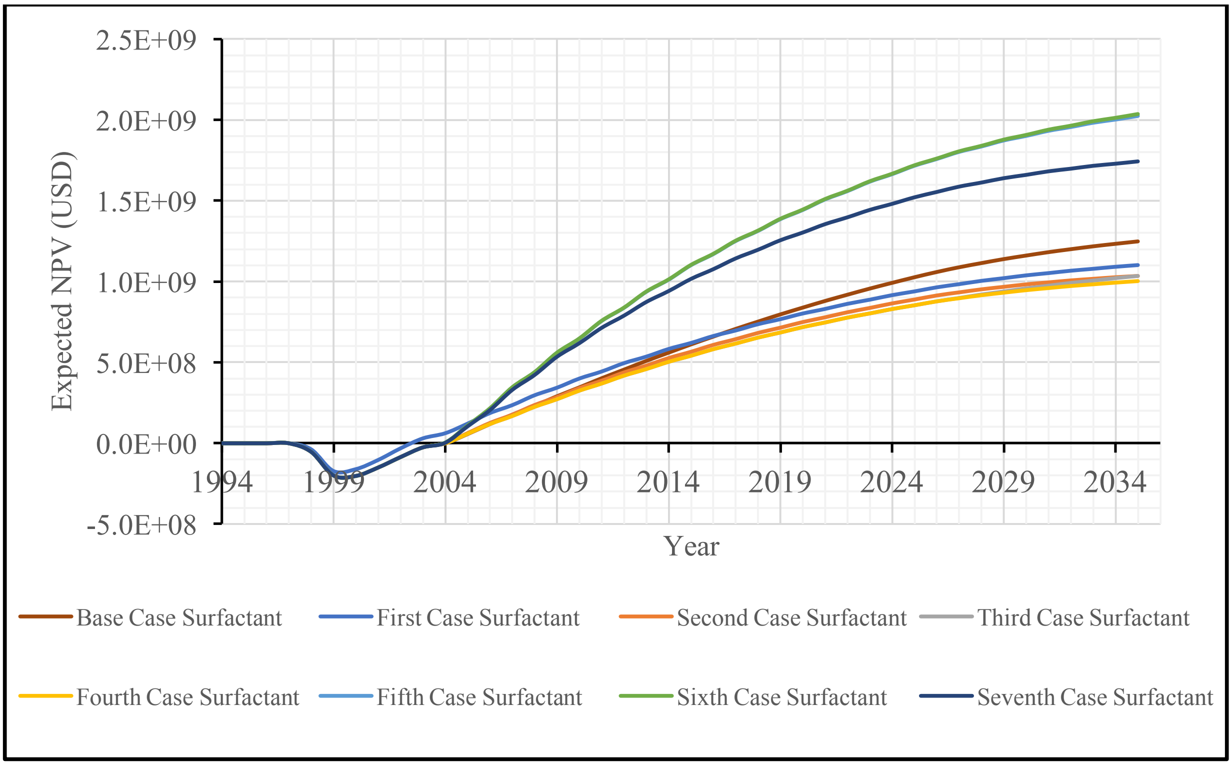


Figure 126: Expected NPV for surfactant scenario

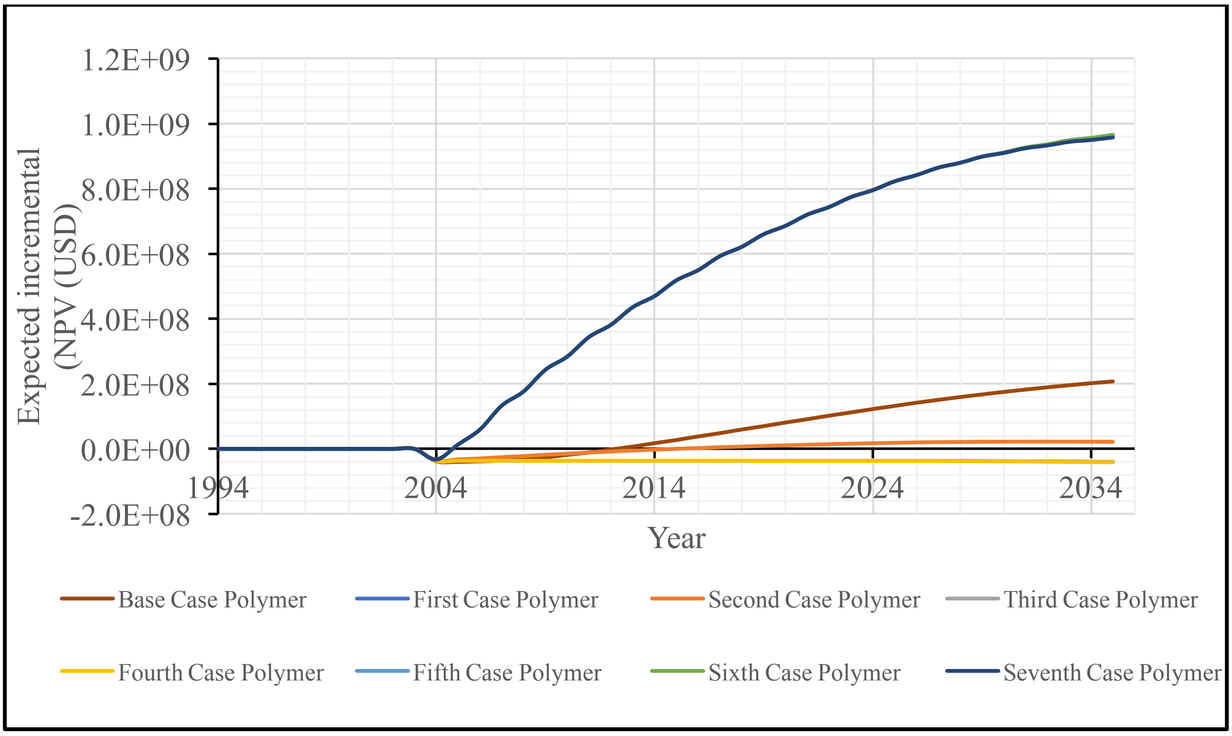


Figure 127: Expected incremental NPV for polymer scenario

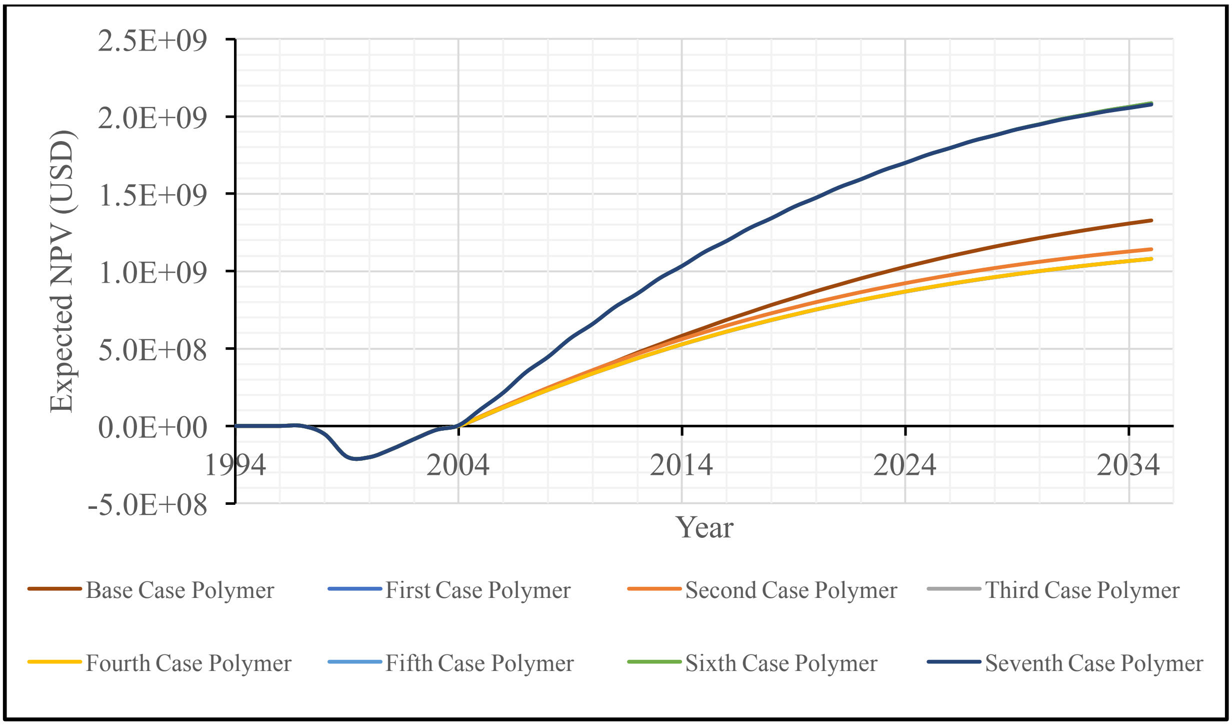


Figure 128: Expected NPV for polymer scenario

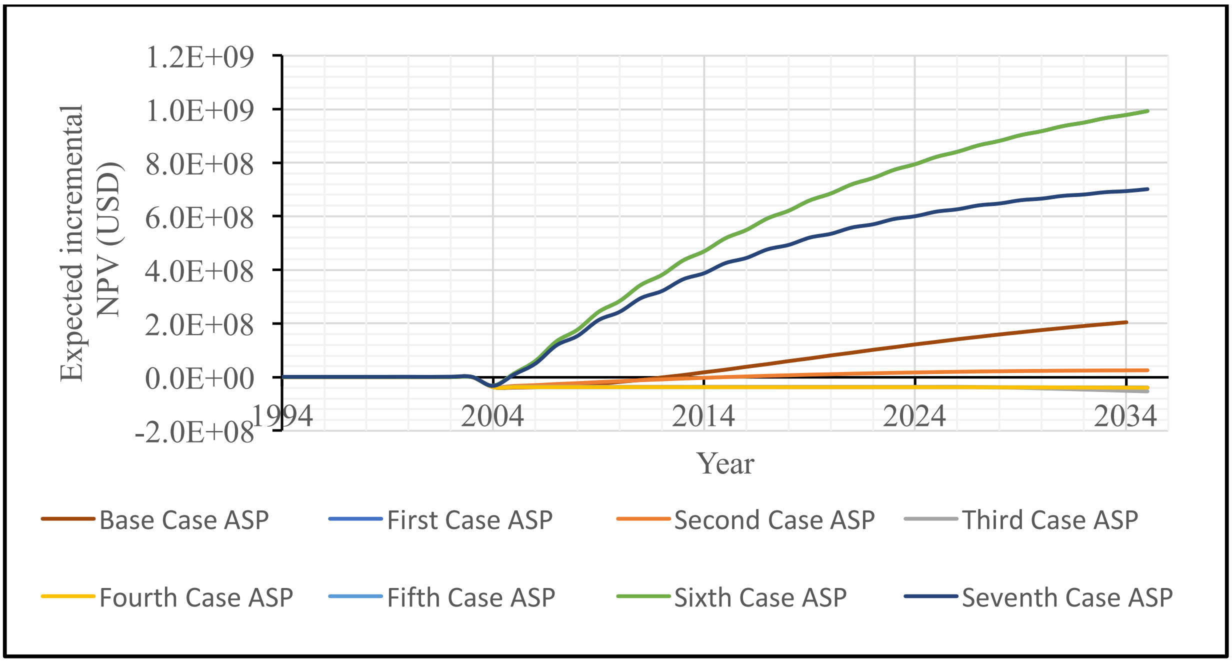


Figure 129: Expected incremental NPV for ASP scenario

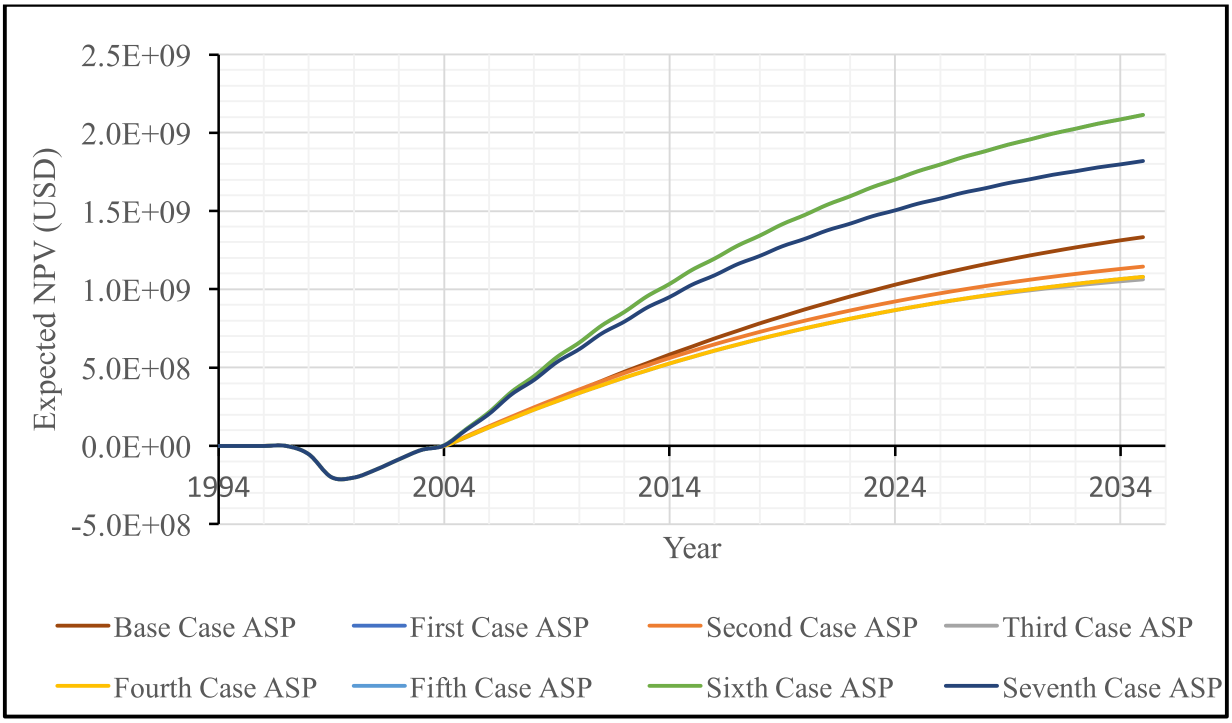


Figure 130: Expected NPV for ASP scenario

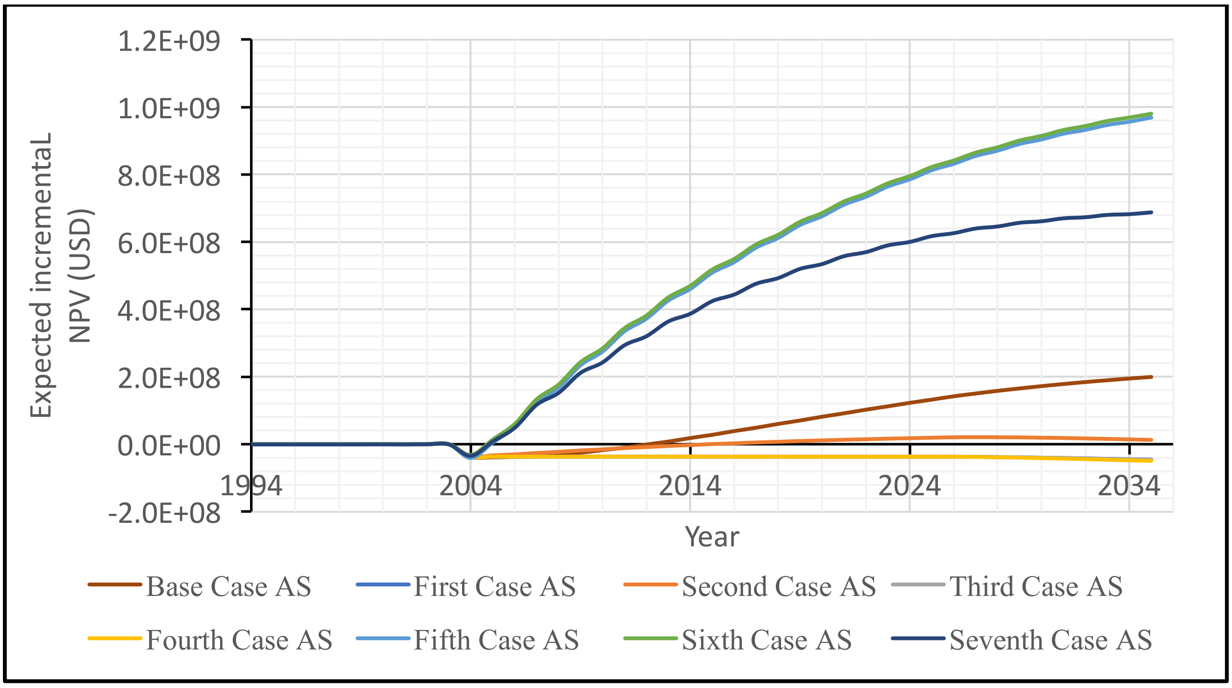


Figure 131: Expected incremental NPV for AS scenario

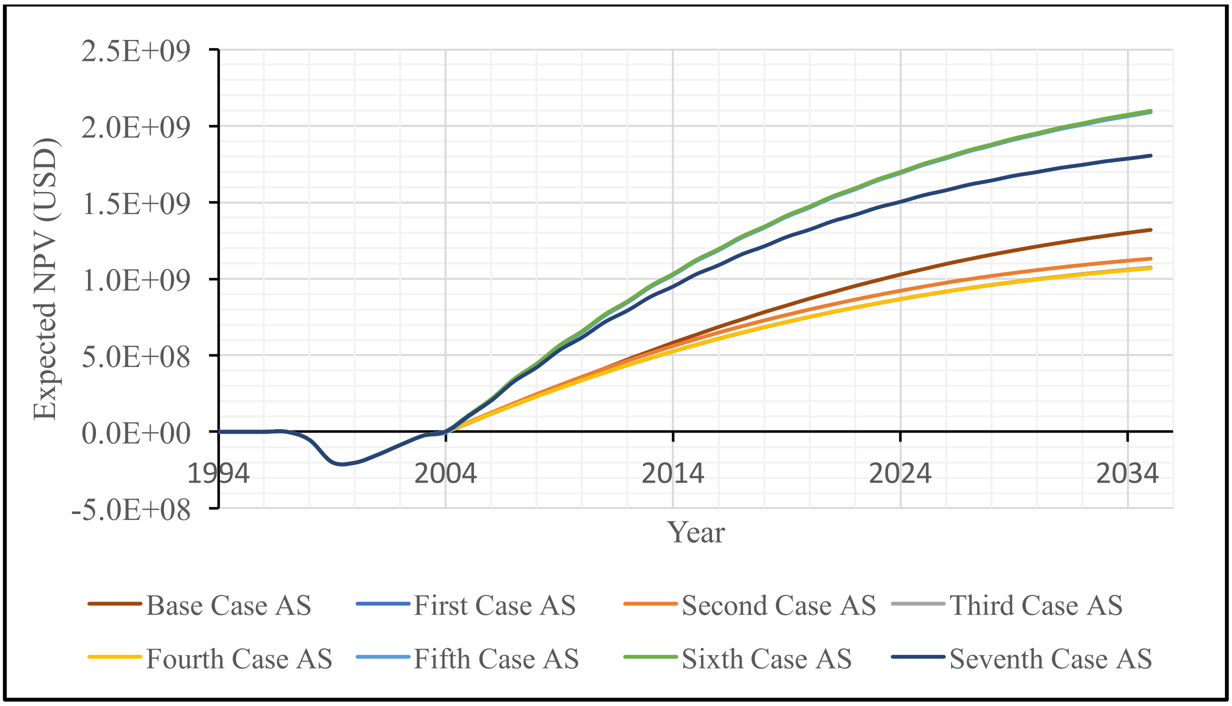


Figure 132: Expected NPV for AS scenario

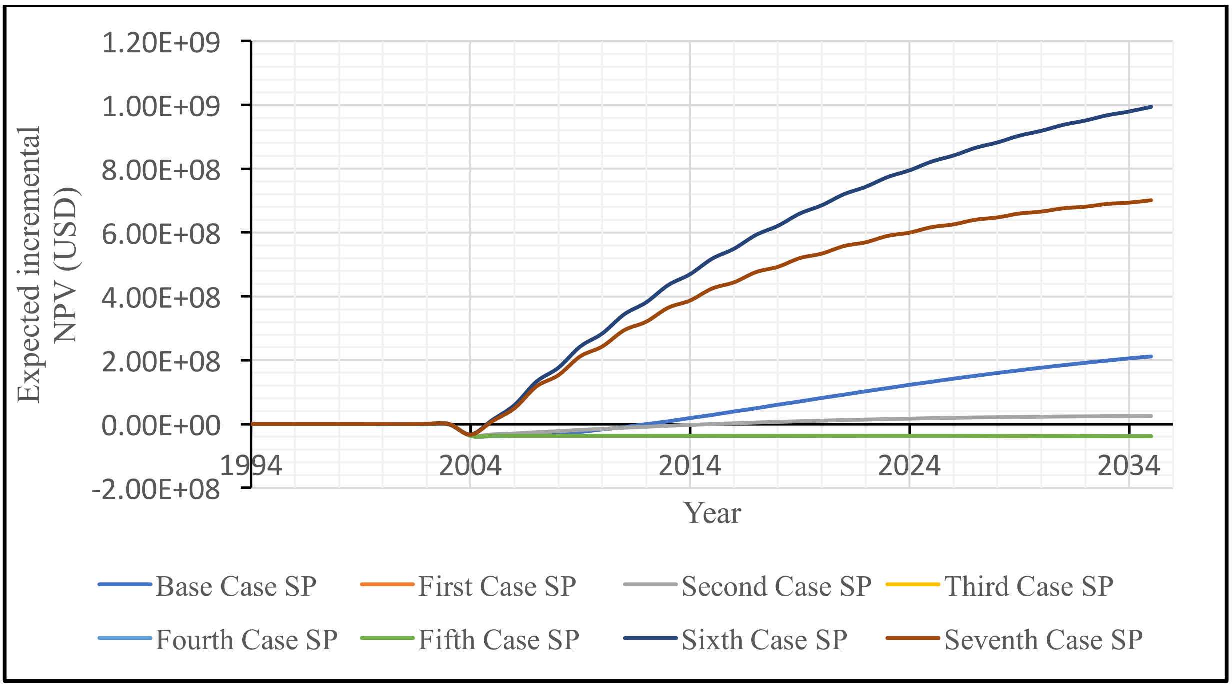


Figure 133: Expected incremental NPV for SP scenario

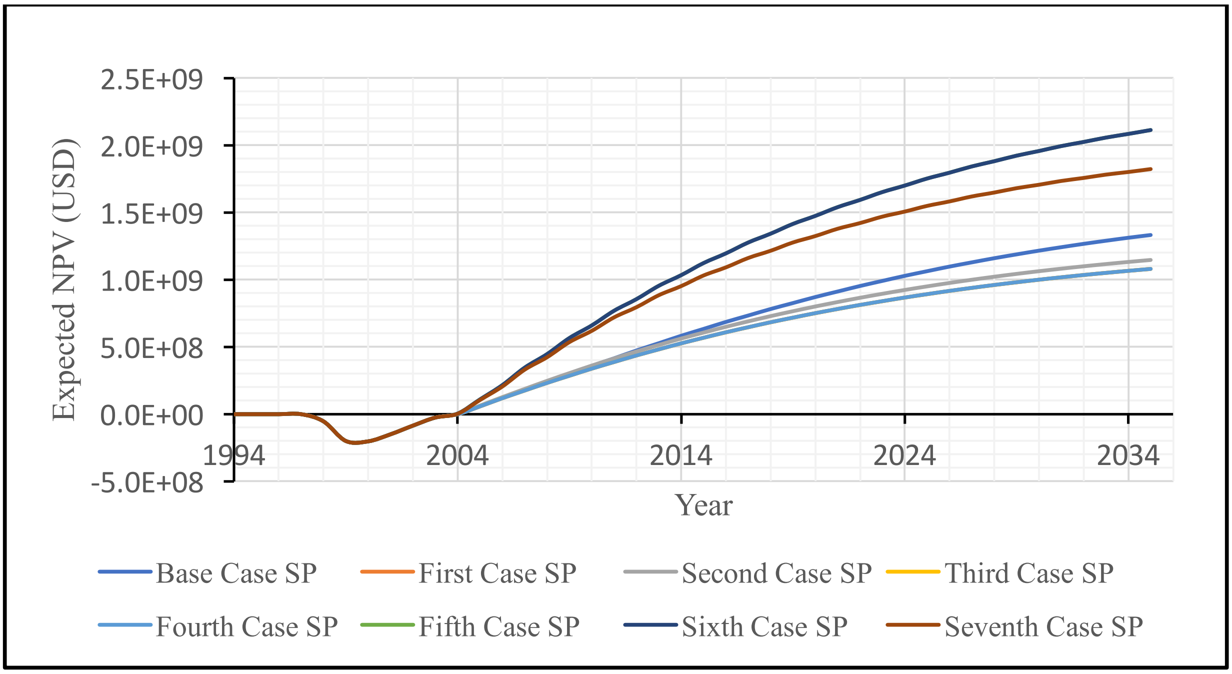


Figure 134: Expected NPV for SP scenario

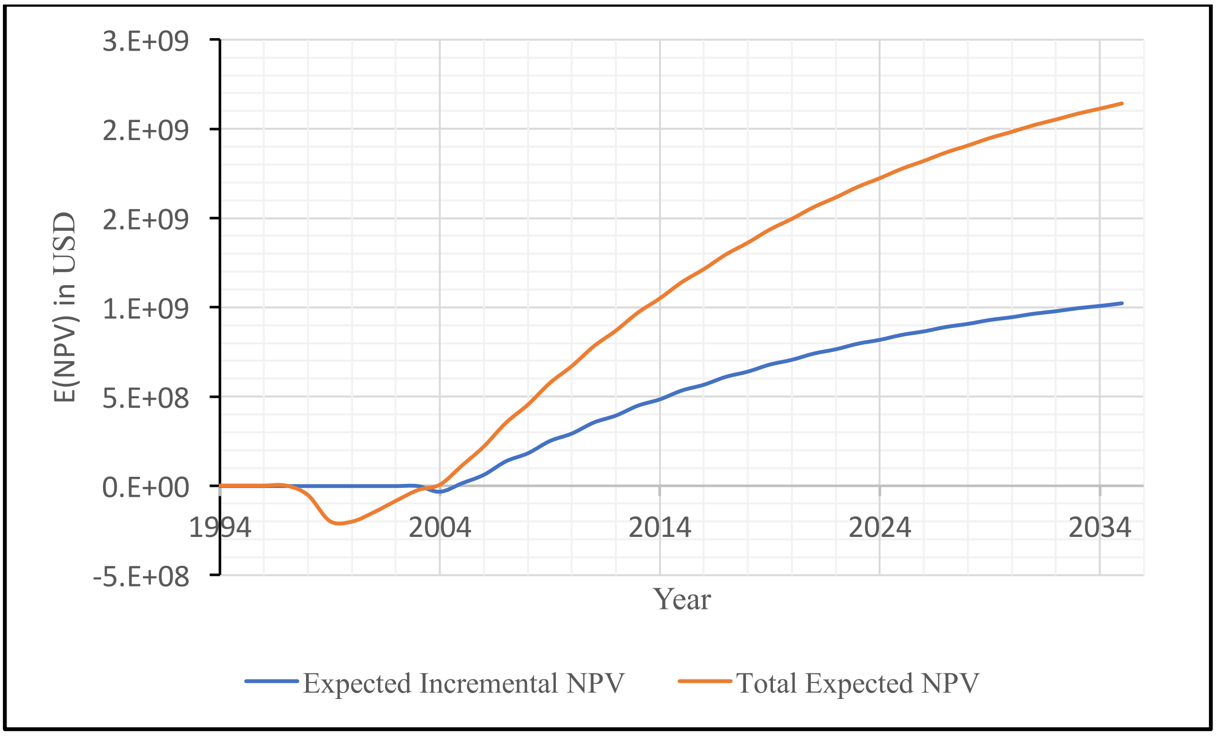


Figure 135: Expected NPV for the optimum drainage strategy

Figures 123 through 135 shows the expected incremental NPV and total expected NPV. It is noticed that in 2004 NPVs start to increase, the reason is, the new injector G-1H and producer Z-3H were placed in the good location of the reservoir in 2004 which means production of gas and oil must increase and hence increasing NPV.

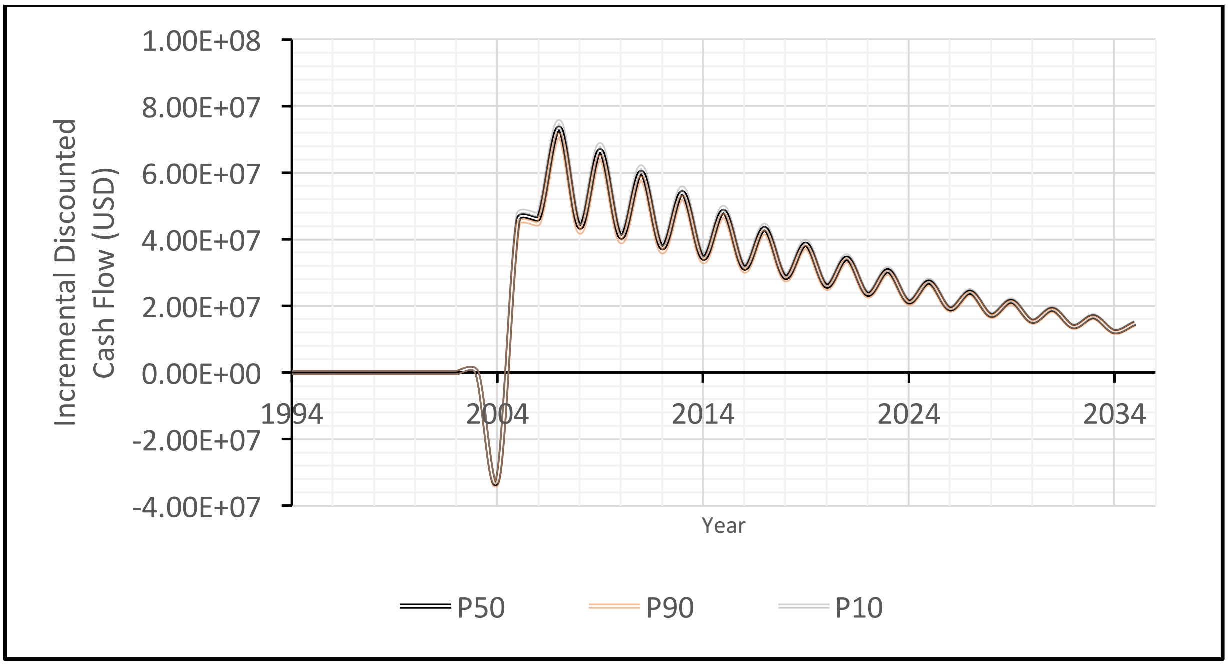


Figure 136: Incremental discounted cash flow for the optimum drainage strategy

Figure 136 shows that the present value increases from 2004 to 2007 and then decreases up to the end of 2035 due to the fact that, the new producer Z-3H was added into the reservoir in a good location of high oil saturation and allowed to produce between 2004 and 2007 thus increasing production between the production span, apart from that both injectors were also re-completed in order to improve the sweep of oil to the production wells and thus increasing oil production and hence present value. The new producer Z-3H was then shut in 2007 to avoid rapid water production as a result oil production decreases resulting to decreasing present value.

9.6: Single Parameter Sensitivity Analysis (Spider Plot) for Waterflooding Flooding

Sensitivity analysis plays the role in measuring the impact on project outcome(s) by changing one or more key input variables to account uncertainty. Spider plot is one of the standard tools used in risk and uncertainty analysis. Spider plot is a graph that compares the potential impact, taking one input variable of several uncertain input variables while putting constant the rest to check the impact on a certain project outcome(s).

The uncertain parameters for this work are oil price, gas price, discount rate, and drilling cost. The sensitivity analysis is done on the basis of base case sheet by varying a single parameter while keeping all other base case parameters constant in Microsoft Excel. The expected NPVs (based on discount rate and prices of oil, prices of gas and drilling cost) for high case, base case and low case extracted from Table 18 are presented in Table 20, where sensitivity is done in terms of percentage change.

From Figure 136, it can be seen that when the change in oil price is +50%, the change in E(NPV) is +1.181%; whereas for the low case, the change in E(NPV) is -1.181% with the change of -50%.

The changes in gas price which are +25% and -25% have great effect on expected NPV of which the changes are +12.67% & -12.67% respectively but relatively lower than the discount rate.

The changes in drilling cost +25% and -25% have little change in expected NPV of which the changes are -0.425% & +0.425% respectively.

The changes in discount rate which are +25% and -25% have the great effect on expected NPV -15.69% & +25.709% respectively. This means that an expected NPV is very sensitive to the change in discount rate.

From above analysis, it is obvious that change in discount rate has massive effect on expected NPV followed by gas price, oil price and lastly the drilling cost which is least effective in this case.

Table 20: Single Parameter Sensitivity Analysis

No		Low	Base	High
1	Oil Price (USD/bbl.)	35.5	71	106.5
2	% Change	-50.00	0	50.00
3	E(NPV) (billion	2.091	2.116	2.141
4	% Change	-1.181	0	1.181
		Low	Base	High
1	Drillex (billion	60	80	100
2	% Change	-25.00	0	25.00
3	E(NPV) (billion	2.125	2.116	2.107
4	% Change	0.425	0.00	-0.425
		Low	Base	High
1	Gas Price (USD/m^3)	0.0825	0.11	0.1375
2	% Change	-25.00	0	25.00
3	E(NPV) (billion	1.848	2.116	2.384
4	% Change	-12.67	0	12.67
		Low	Base	High
1	Discount rate	0.06	0.08	0.10
2	% Change	-25.0	0	25.0
3	NPV (billion USD)	2.660	2.116	1.784
4	% Change	25.709	0	-15.69

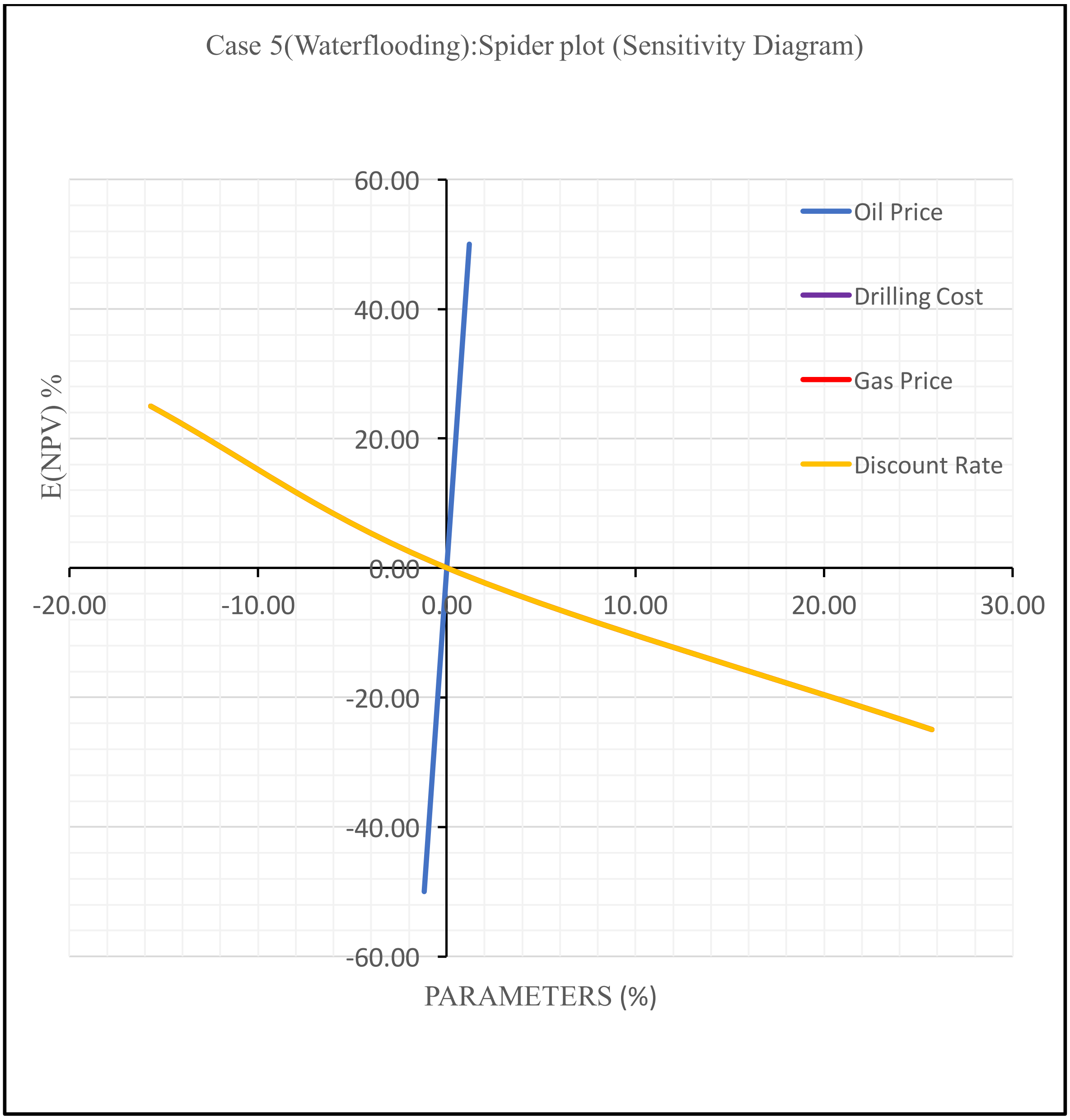


Figure 137: Single Parameter Sensitivity Analysis (Spider Plot) for Case 5 (Waterflooding))

From Figure 137, the line for discount rate is non-linear because NPV varies as inversely as the discount raised to time but directly proportional to the discount factor.

CHAPTER 10

10.0: CONCLUSION AND RECOMMENDATION

10.1: Conclusion

- The benchmark recovery will be **74.8%** by the end of 2035 and its corresponding expected NPV is **+996.542 million USD**.
- Waterflooding with new producer Z-3H and re-completed injectors (Case 5) is the optimum drainage strategy.
- Waterflooding with new producer Z-3H and re-completed injectors (Case 5) can increase the recovery factor by **4.24 %** in the target formation.
- Waterflooding with new producer Z-3H and re-completed injectors (Case 5) can increase the expected NPV by **996.542 million USD** resulting to the total expected NPV of +**2.116 billion USD**.
- The minimum and maximum present values for the optimum drainage strategy are obtained in **2004** and **2007** respectively since because the new producer Z-3H was introduced into the reservoir in 2004 and allowed to produce between 2004 and 2007.
- Sixth waterflooding case is the second-best drainage strategy which can increase the recovery factor and expected NPV by **4.2%** and **996.522 million USD** respectively resulting to the total expected NPV of **+2.116 billion USD.**
- Sixth case SP is the best EOR chemical flooding which can increase the recovery factor and expected NPV by **4.1%** and **994.090 million USD respectively** by resulting total expected NPV of **2.113 billion USD**.
- The injector **F-1H** will be the feasible candidate for EOR chemical flooding.
- The producer **E-2H** will be better candidate for EOR chemical flooding as it is located in the main target of formation.
- Surfactant concentration of **10 lb/stb (28.53 kg/m3)** gave the same oil production with less surfactant consumption compared to other concentrations which were subjected to trials.
- From Single parameter sensitivity analysis (Spider plot), it was found that the change in discount rate (for low case, base case and high case) is the most sensitive on expected NPV compared to the rest such as change in oil price, drilling cost and discount rate and the least sensitive parameter is the change in drilling cost. Discount rate affects the long-time projects as it changes throughout the project life time.

10.2: Recommendation

It is recommended that the drainage strategy with the new producer Z-3H and re-completed injectors should be implemented as an optimum drainage strategy because it ultimately recovers oil and gas at a minimum cost and hence maximizing the economic value of the reservoir. Furthermore, in order to effectively test the efficiency of EOR chemical flooding into Norne E-Segment, the right structures of alkali, surfactant and polymer that would be compatible with the Norne fluid and rock properties should be developed in the laboratory aided by proper up-scaling to a field-scale usage. It is also suggested that 0.1-0.2% SS-7593 which is the wettability alteration agent/ interfacial tension reducer can be used at low concentration and effectively alters the wettability of oil wet reservoir rocks and reduces the interfacial tension to increase the oil recovery. However, compatibility of the SS-7593 with other additives used in the job should be determined prior to the applications.

CHAPTER 11

11.0: ABBREVIATIONS AND NOMENCLATURE

11.1: *List of abbreviations*

ANTHEI	Angolan Norwegian and Tanzanian Higher Education Institution
BHP	Bottom Hole Pressure
CW	Conventional Wells
EOR	Enhanced Oil Recovery
FGPR	Field Gas Production Rate
FGPT	Field Gas Production
FGOR	Field Gas Oil Ratio
FOE	Field Oil Efficiency
FOIP	Field Oil in Place
FOPR	Field Oil Production Rate
FOPT	Field Oil Production
FPR	Field Pressure
FWPT	Field Water Production
GOC	Gas Oil Contact
GOR	Gas Oil Ratio
ICV	Inflow Control Valve
IP	Integer Programming
LP	Linear Programming
MIP	Mixed Linear Programming
MOV	Movable Oil Volume
MSL	Mean Sea Level
NCW	Non-Conventional Wells
NLP	Non-Linear Programming
NPD	Norwegian Petroleum Directorate
NPV	Net Present Value
NTNU	Norges Teknisk Naturvitenskapelige Universitet
OGJ	Oil and Gas Journal
OOIP	Original Oil in Place

UOR	Ultimate Oil Recovery
UDSM	University of Dar es salaam
WC	Water Cut
IFT	Interfacial tension
IPV	Inaccessible Pore Volume
IOR	Improved Oil Recovery
E(NPV)	Expected Net Present Value
IO	Integrated Operations

11.2: *Nomenclature*

A	area of cross section normal to the bedding plane, ft^2
A_d	area of displacement
A_R	area of reservoir
ci	inequality constraint function
Ea	areal sweep efficiency,
E_d	displacement efficiency
Ep	pattern or areal sweep efficiency (Ep)
E_R	overall recovery efficiency
Ev	invasion or vertical sweep efficiency
f	objective function
f_g	fraction of flowing stream that is gas
f_o	fraction of flowing stream that is oil
f_w	fraction of flowing stream that is water
g	equality constraint function
k	permeability, darcies
L	distance along the bedding plane, ft
lbi	lower bounds for ith variables
k_r	relative permeability.
k_{rg}	relative permeability to gas, fraction
k_{ro}	relative permeability to oil, fraction
M	mobility ratio

Ø	porosity
q_T	total flow rate through area
S	gas or oil saturation
Sor	residual oil saturation after immiscible displacement
So_{rw}	oil residual in displacement by water
S_{wf}	shock front water saturation
u	names as variables, decision variables, decision variables, control variables, etc
ubi	upper bounds for ith variables

CHAPTER 12

12.0: REFERENCES

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CHAPTER 13

13.0: APPENDICES

13.1: Appendix A

Table 21: Keywords for ASP Model [65]

RUNSPEC	**SCHEDULE**
ALKALINE	WALKALIN
SURFACTANT	WSURFACT
POLYMER	WPOLYMER

Table 22: ASP Keywords in PROPS Section [65]

Keyword	Description
ALSURFAD	Table of surfactant adsorption as a function of alkaline concentration
ALSURFST	Table of oil/water surface tension as a function of alkaline concentration
ALKADS	Table of adsorption functions
ALKROCK	Specifies alkaline-rock properties
ALPOLADS	Table of polymer adsorption as a function of alkaline concentration
SURFST	Water-oil surface tension with the presence of surfactant
SURVISC	Modified water viscosity
SURFCAPD	Capillary-desaturation data
SURFADS	Adsorption isotherms

SURFROCK	Rock adsorption and adsorption model indicator
PLYADS	Polymer adsorption isotherms
ADSORP	Analytical adsorption isotherms with salinity and permeability dependence
PLYMAX	Polymer/salt concentrations for mixing calculations
PLYROCK	Specifies the polymer-rock properties
PLYSHEAR	Polymers shear thinning data
PLYVISC	Polymer solution viscosity function
PLYVISCS	Polymer/salt solution viscosity function
RPTPROPS	Controls output from the props section
SALTNODE	Salt concentration for polymer solution viscosity
TLMIXPAR	Todd-Longstaff mixing parameter

13.2: *Appendix B*

Table 23: Eclipse 100 Data File Sections [65]

Section Name	Obligatory/Optional	Description
RUNSPEC	Obligatory	The specification of the running which includes title, dimensions, switches, phases and components
GRID	Obligatory	Gives specification of grid geometry and rock properties in each grid block
EDIT	Optional	All the modifications on calculated pore volumes, grid block centre depths and transmissibility are defined in this section
PROPS	Obligatory	Consists of all the tables of properties for reservoir rock and fluids as functions of fluid saturations, compositions and pressures
REGIONS	Optional	Divides computational grids into regions for calculation of PVT properties, saturation properties, initial conditions and fluids in place.
SOLUTIONS	Obligatory	Composed of specified reservoir initial conditions
SUMMARY	Optional	The output results are collected in this section after each time step
SCHEDULE	Obligatory	States operations to be simulated including

		production and injection controls besides constraints and the times at which output reports are required.
WELLSPEC	Obligatory	The section specifies the type of well whether injector/producer of oil or gas
COMPDAT	Obligatory	The section contains the completion data of the well

13.3: Appendix C

Alkaline Input File

```
ALSURFST
--Water/oil surface tension multipliers as a function of alkaline concentration
--Alkaline              Water/oil
--concentration         Tension Multiplier
--kg/m3
   0.0                  1.0
   6.0                  0.5
   15.0                 0.3
   20.0                 0.1
   30.0                 0.0 /
ALPOLADS  --Alkaline multipliers for polymer adsorption
--Alkaline conc.        Adsorption
 --Kg/m3                Multiplier
   0.0                  1.0
   3.0                  0.7
   6.0                  0.5
   9.0                  0.3 /
ALSURFAD  --Alkaline multipliers for surfactant adsorption
--Alkaline              Adsorption
--concentration         Multiplier
--Kg/m3
    0.0                 1.0
    3.0                 0.7
    6.0                 0.5
    9.0                 0.0 /
ALKADS
--Alkaline adsorption
--Alkaline              Adsorbed
 --concentration        on rock
```

--Kg/m3 (kg/kg)

0.0	0.000000
3.0	0.000005
6.0	0.000007
9.0	0.000008
10.0	0.000009 /

ALKROCK

-- No desorption

1/

13.4: Appendix D

Surfactant Input File

SURFST

-- Surfactant	Water/ oil surface
--conc., kg/m^3	Tension
0	30.0E-03
0.1	10.0E-03
0.25	1.60E-03
0.5	0.40E-03
1.0	0.07E-03
3.0	0.006E-03
5.0	0.004E-03
20.0	0.001E-03

SURFVISC

--Surf conc.	Water viscosity
--Kg/m3	Centipoise
0.0	0.42
5.0	0.449
10.0	0.503
15.0	0.540
20.0	0.630 /

```
SURFADS
--Surfactant          Adsorption by rock
--Surf conc           Adsorbed mass
--Kg/m3              (kg/kg) = kg surf /kg rock
  0.0          0.00000
  1.0                  0.00017
  5.0                  0.00017
  10.0                 0.00017 /
SURFCAPD
--Capillary De-saturation curve
--Log10 (capillary Miscibility
 --number)            function 0 = immiscible, 1= miscible
 -8                   0.0
 -7                   0.0
 -6                   0.0
 -5.0                 0.0
 -2.5                 1.0
  0                    1.0
  5                    1.0
 10                    1.0 /
SURFROCK
-- No desorption
 1                     2650 /
```

13.5: Appendix E

Polymer Input File

```
PLYSHEAR
--Polymer shear thinning data
-- Wat. Velocity    Visc reduction CP
 -- m/day            CP
```

```
   0.0                  1.0
   2.0                  1.0 /
PLYVISC
-- Polymer Solution Viscosity Function
-- Ply conc.          Wat. Visc. mult.
  -- kg/m3
  0.0                   1.0
  0.1                   1.55
  0.3                   2.55
  0.5                   5.125
  0.7                   8.125
  1.0                   21.2 /
PLYADS
-- Polymer   Adsorption Function
-- Ply conc.  Ply conc. Adsorbed
 -- kg/m^3                by rock, Kg/kg
   0.0                  0.0
   0.5                  0.0000017
   1.0                  0.0000017
TLMIXPAR
-- Todd-Long Staff Mixing Parameters
   1                      1* /
PLYMAX
-- Polymer-Salt concentration for mixing maximum polymer and salt concentration
-- Ply conc.          Salt conc.
 -- kg/m3            kg/m3
  1.0                   0.0 /
PLYROCK
--Polymer-Rock Properties
--dead pore -- residual resistance mass        Ads.          max. Polymer adsorption
--space           factor                    density      Index
  0.16              1.0                       2650           1                    0.000017 /
```

13.6: Appendix F

Alkaline-Surfactant-Polymer Model

```
DATES
 1 'DEC' 2025 /
/
--START Injecting Alkaline-Surfactant-Polymer(ASP)
TSTEP
 10*10 /

-- start injecting alkaline-surfactant-polymer mixture in injection well
-- for 3600 days
--Sets alkaline-surfactant-polymer concentration for injection
--wells
WSURFACT
--well      surfactant injection
--name       conc Kg/m3
  F-1H         7 /
/
WALKALINE
--well      alkaline injection
--name       conc Kg/m3
  F-1H         2.3 /
 /
WPOLYMER
--well      polymer injection
--name       conc Kg/m3
  F-1H         7        0.0 /
 /
-- note 1 Kg/m3 = 0.3505 lb/stb

TSTEP
120*30 /

-- STOP alkaline-surfactant-polymer injection - follow with water only for 1440 days
WSURFACTANT
--well      surfactant injection
--name       conc Kg/m3
  F-1H        0 /
 /
WALKALINE
--well      alkaline injection
--name       conc Kg/m3
  F-1H         0 /
 /
WPOLYMER
--well      polymer injection
--name       conc Kg/m3
  F-1H         0            0.0/
 /
TSTEP
 120*30 /
-- END OF SIMULATION
```

13.7: Appendix G

Surfactant-Polymer Model

```
DATES
 1 'DEC' 2025 /
/
--START Injecting Surfactant-Polymer (SP)
TSTEP
 10*10 /

-- start injecting surfactant-polymer mixture in injection well
-- for 3600 days
--Sets surfactant-polymer concentration for injection
--wells
WSURFACT
--well     surfactant injection
--name      conc Kg/m3
  F-1H        7 /
/
WALKALINE
--well     surfactant injection
--name      conc Kg/m3
  F-1H        0 /
 /
WPOLYMER
--well     surfactant injection
--name      conc Kg/m3
  F-1H        7         0.0/
 /
-- note 1 Kg/m3 = 0.3505 lb/stb

TSTEP
120*30 /

-- stop surfactant-polymer injection - follow with water only for 1440 days
WSURFACTANT
--well     surfactant injection
--name      conc Kg/m3
  F-1H       0 /
 /
WALKALINE
--well     alkaline injection
--name      conc Kg/m3
  F-1H        0 /
 /
WPOLYMER
--well     polymer injection
--name      conc Kg/m3
  F-1H        0             0.0/
 /
TSTEP
 120*30 /
-- END OF SIMULATION
```

13.8: Appendix H

Alkaline-Surfactant Model

```
DATES
1 'DEC' 2025 /
/
--START injecting Alkaline-surfactant(AS)
TSTEP
 10*10 /

-- start injecting Alkaline-Surfactant mixture in injection well
-- for 3600 days
--Sets Alkaline-Surfactant concentration for injection
--wells
WSURFACT
--well     surfactant injection
--name      conc Kg/m3
  F-1H        7 /
/
WALKALINE
--well     alkaline injection
--name      conc Kg/m3
  F-1H        2.3 /
 /
WPOLYMER
--well     polymer injection
--name      conc Kg/m3
  F-1H        0        0.0 /
 /
-- note 1 Kg/m3 = 0.3505 lb/stb

TSTEP
120*30 /

-- stop surfactant injection - follow with water only for 1440 days
WSURFACTANT
--well     surfactant injection
--name      conc Kg/m3
  F-1H       0 /
 /
WALKALINE
--well     alkaline injection
--name      conc Kg/m3
  F-1H        0 /
 /
WPOLYMER
--well     polymer| injection
--name      conc Kg/m3
  F-1H        0            0.0/
 /
TSTEP
 120*30 /
-- END OF SIMULATION
```

13.9: Appendix I

POLYMER MODEL

```
DATES
 1 'DEC' 2025 /
/
--START Injecting polymer
TSTEP
 10*10 /

-- start injecting polymer mixture in injection well
-- for 3600 days
--Sets polymer concentration for injection
--wells
WSURFACT
--well     surfactant injection
--name      conc Kg/m3
  F-1H        0 /
/
WALKALINE
--well     alkaline injection
--name      conc Kg/m3
  F-1H        0 /
 /
WPOLYMER
--well     polymer injection
--name      conc Kg/m3
  F-1H        28.35     0.0/
 /
-- note 1 Kg/m3 = 0.3505 lb/stb

TSTEP
 120*30 /

-- stop polymer injection - follow with water only for 1440 days
WSURFACTANT
--well     surfactant injection
--name      conc Kg/m3
  F-1H       0 /
 /
WALKALINE
--well     alkaline injection
--name      conc Kg/m3
  F-1H        0 /
 /
WPOLYMER
--well     polymer injection
--name      conc Kg/m3
  F-1H        0            0.0/
 /

TSTEP
120*30 /

-- END OF SIMULATION
```

13.10: *Appendix J*

Prediction Input File

```
1 'DEC' 2025 /
/
--START injecting surfactant
TSTEP
 10*10 /
-- start injecting surfactant mixture in injection well
-- for 3600 days
--Sets surfactant concentration for injection
--wells
WSURFACT
--well     surfactant injection
--name      conc Kg/m3
  F-1H        28.53 /
/
WALKALINE
--well     alkaline injection
--name      conc Kg/m3
  F-1H        0 /
 /
WPOLYMER
--well     polymer injection
--name      conc Kg/m3
  F-1H        0        0.0/
 /
-- note 1 Kg/m3 = 0.3505 lb/stb
TSTEP
 120*30 /
-- stop surfactant injection - follow with water only for 1440 days
WSURFACTANT
--well     surfactant injection
--name      conc Kg/m3
```

```
 F-1H      0 /
 /
WALKALINE
--well    alkaline injection
--name     conc Kg/m3
 F-1H      0 /
 /
WPOLYMER
--well    polymer injection
--name     conc Kg/m3
 F-1H      0          0.0/
 /
TSTEP
 120*30 /
-- stop surfactant injection - follow with water only for 1440 days
WSURFACTANT
--well    surfactant injection
--name     conc Kg/m3
 F-1H      0 /
 /
WALKALINE
--well    alkaline injection
--name     conc Kg/m3
 F-1H      0 /
 /
WPOLYMER
--well    polymer injection
--name     conc Kg/m3
 F-1H      0          0.0/
 /
TSTEP
 120*30 /
-- END OF SIMULATION
```