University of Alaska, Fairbanks

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ALKALI-SURFACTANT-POLYMER (ASP) FLOODING - POTENTIAL AND SIMULATION FOR ALASKAN NORTH SLOPE RESERVOIR

A
PROJECT
in Partial Fulfillment of the Requirements
for the Degree of
MASTER OF SCIENCE

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ABSTRACT

Enhanced oil recovery (EOR) is essential to recover bypassed oil and improve recovery factor. Alkaline-surfactant-polymer (ASP) flooding is a chemical EOR method that can be used to recover heavy oil containing organic acids from sandstone formations. It involves injection of alkali to generate in situ surfactants, improve sweep efficiency, and reduce interfacial tension (IFT) between displacing and displaced phase, and injection of a polymer to improve mobility ratio; typically, it is followed by extended waterflooding. The concentration of alkali, surfactant, and polymer used in the process depends on oil type, salinity of solution, pressure, temperature of the reservoir, and injection water quality.

This project evaluates the effect of waterflooding on recovery, calculates the recovery factor for ASP flooding, and optimum concentration of alkali, surfactant, and polymer for an Alaskan reservoir. Also, the effects of waterflooding and improvement with ASP flooding are evaluated and compared. Studies of these effects on oil recovery were analyzed with a Computer Modeling Group (CMG)-generated model for the Alaskan North Slope (ANS) reservoir. Based on a literature review and screening criteria, the Western North Slope (WNS) 1 reservoir was selected for the ASP process. A CMG - WinProp simulator was used to create a fluid model and regression was carried out with the help of actual field data. The CMG - WinProp model was prepared with a 5 spot well injection pattern using the CMG STARS simulator. Simulation runs conducted for primary and waterflooding processes showed that the recovery factor increased from 3% due to primary recovery to 45% due to waterflooding at 500 psi drawdown for 60 years with a constant producing gas oil ratio (GOR). ASP flooding was conducted to increase recovery further, and optimum ASP parameters were calculated for maximum recovery. Also, effect of alkali, surfactant and polymer on recovery was observed and compared with ASP flood. If proved effective, the use of ASP chemicals for ANS reservoirs to increase the recovery factor could replace current miscible gas injection with chemical EOR. It will help to develop chemical flooding processes for heavier crude oil produced in harsh environments and create new horizons for chemical industries in Alaska.

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CHAPTER 1. INTRODUCTION

The recovery factor is an important parameter in ultimate oil recovery. Primary recovery recovers oil using reservoir pressure. Secondary recovery methods use water or gas as injection fluids to maintain reservoir pressure and displace oil. Enhanced oil recovery is a tertiary recovery method to recover bypassed oil left behind by primary or secondary recovery.

This project discusses chemical enhanced oil recovery methods (CEOR), especially Alkali-Surfactant-Polymer flooding (ASP). Alkali helps to generate in situ surfactants, surfactants help reduce interfacial tension (IFT) between displacing and displaced phase, and polymers control mobility ratio and hence sweep efficiency. ASP can be helpful in recovering heavy oils with high acid numbers. High acid numbers in crude help generate in situ surfactants and hence increase oil recovery. This project deals with generating a CMG STARS model for an Alaskan reservoir to estimate primary and waterflooding recovery factors. The STARS simulator was also used to create an ASP flooding model with varying chemical combinations of alkali, surfactant, and polymer. Comparison of these three recovery methods aids estimation of the most efficient and economic recovery method.

CHAPTER 2. MECHANISM FOR ASP RECOVERY

Alkali surfactant polymer flooding recovers oil by emulsion and entrapment, emulsion entrainment, in situ surfactant formation, IFT reduction, mobility control, and improving sweep efficiency. The effects of alkali, surfactant, and polymer on oil and the recovery process are discussed in detail below:

2.1 Alkali

A measure of the potential of crude oil to form surfactants depends upon acid number, i.e., the amount of potassium hydroxide (KOH) required in milligrams (mg) to neutralize 1 gram (g) of petroleum acid in crude oil. Alkalis react with organic acids, present in low API gravity oils, forming soap, an in situ surfactant which helps to produce oil. This formed in situ soap lowers interfacial tension between oil and a displacing phase under suitable conditions of temperature, pressure, pH, and salinity. When alkaline water and acidic oil flow simultaneously in a reservoir, a viscous oil external emulsion forms which possesses a high, non-uniform pressure gradient in the vicinity of the emulsion front. This pressure gradient is sufficient to overcome capillary forces and displace oil from pore throats to the main stream. Sometimes, saline water is used for alkaline flooding rather than fresh water, in order to form a water in oil emulsion and change the wettability of rock from water to oil wet (in fresh water alkaline flooding, soap is soluble in the displacing phase, resulting in water wet rock*)*.

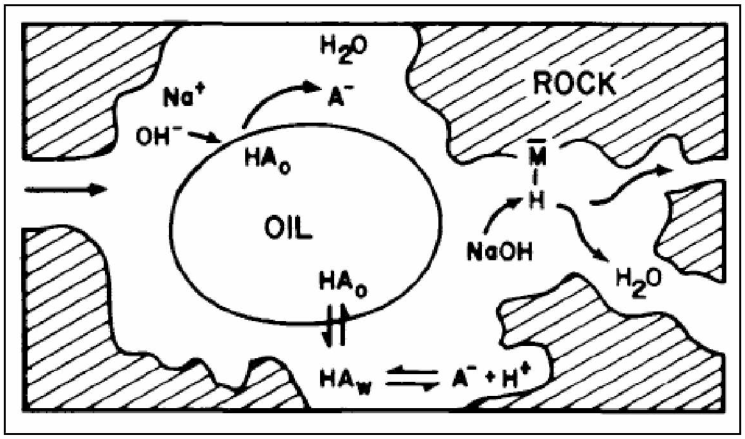


Figure 1 Alkali Recovery Process (Green & Willhite, 1998)

Mechanisms by which alkaline water flooding (Fig 1) recovery takes place include:

a. Reduction in oil/water front IFT

Leads to emulsification and entrapment improvement (in situ emulsification formation and entrained by flowing alkali solution). The IFT reduction depends upon:

   i. pH of water
   ii. Concentration and types of salt in solution
   iii. Organic acid content of oil

b. Wettability alteration

Oil recovery increases due to favorable changes in permeability accompanying changes in wettability: oil wet to water wet. Microscopic evaluation of successful alkaline models suggested that matrix material is altered from water wet to oil wet as the flood passes, due to the adsorption of soap molecules on solid surfaces. Wettability alteration helps in formation and stabilization of oil lamellae in pore spaces. It leads to low IFT values and results in viscous water in oil emulsions, producing high viscous capillary number. (Nelson *et al.*, 1984)

c. Drainage of oil to produce emulsion
d. Emulsification and entrapment (selective pore plugging by precipitation of mutual metal ions or surfactants) (Krumrine *et al.*, 1982)
e. Greater sweep efficiency
f. Emulsification and coalescence, wettability gradient, oil phase swelling, disruption of rigid films
g. Sometimes in low acid number oils, the injection of alkaline solution can enhance in situ emulsification processes, which can improve sweep efficiency.
h. Intermittent nitrogen injection can help in plugging larger pore throats, which can control the mobility front. (Tsay & Menzie, 1985)

Chemical Reaction: (deZabala et al., 1982)

Fig 1 shows effect on alkali on petroleum acids, when acid is exposed to alkali, the ensuing reaction produces a water-soluble ionic surfactant, A^-

$HA_0 + XOH \leftrightarrows XA_0 + H_2O$

Aqueous hydrolysis leads to,

$HA_w \leftrightarrows H^+ + A^-$

and distribution of molecular acid between oleic and aqueous phase,

$HA_0 \leftrightarrows HA_w$

Thus, constants derived and equations can be stated as:

Relative permeability of water and oil,

$$k_{rw} = k_{rw}^{o}\, S^{n} \tag{2.1}$$

$$k_{ro} = k_{ro}^{o}(1 - S)^{p} \tag{2.2}$$

Effective saturation is defined as,

$$S = (S_w - S_{wc})/(1 - S_{or}(c_{A}-) - S_{wc}) \tag{2.3}$$

The flooding rate also defines oil recovery. For particular reservoirs, a critical rate is present, at which emulsions or lamellae will form. At rates greater than that, the recovered oil quantity decreases. This effect of rate on oil recovery depends upon IFT, oil saturation in the column, the rate of wetting of solid matrix with oil, and stability of oil in lamellae under flow conditions. When oil saturation is higher, an emulsion bank forms and moves ahead as the flood front moves, but as higher oil saturation builds up quickly ahead of it, it can break at a higher flowrate, resulting in a discontinuity of the emulsion front that leads to fingering. The presence of clays reduces the efficiency of alkaline flooding, as hydrogen ions on clays consume the alkali present in water, making less available for oil. (Green & Willhite, 1998)

The most common alkalis used for EOR processes are:

a. Sodium Hydroxide (NaOH)
b. Potassium Hydroxide (KOH)
c. Sodium Carbonate (Na_2CO_3)
d. Potassium Carbonate (K_2CO_3)
e. Sodium Orthosilicate (Na_4SiO_4)

The following graph explains the effects of alkalis at increasing concentrations:

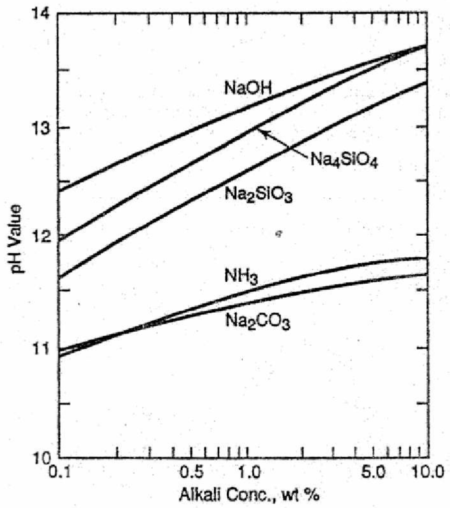


Figure 2: Effect of pH on alkali (Green & Willhite, 1998)

However, alkaline flooding can be improved by the addition of active, performed cosurfactants, like alcohols, to the injected fluid. Due to adsorption in the reservoir and consumption of alkalis to form surfactants, desired rates of propagation of the fluid front are not achievable. Hence, alkali concentrations should be increased, but as concentrations increase beyond critical values, IFT increases. Cosurfactants can be added to solve this problem. The cosurfactant added can be used to increase the salinity requirement and alkali requirement for achieving ultralow IFTs ($<10^{-3}$ dynes/cm), by considering losses in reservoir (Green & Willhite, 1998). In general, alkaline flood is used only in sandstone reservoirs because of the abundance of calcium in carbonate reservoirs. Calcium and magnesium in connate water react with alkalis and precipitate hydroxides. Also, if calcium and magnesium are present in a rock, they react with the slug and can precipitate calcium hydroxide. Hence, these are typically not used in carbonate reservoirs.

The most commonly used chemicals in caustic flooding are sodium hydroxide, sodium orthosilicate, and sodium carbonate. (Donaldson *et al.*, 1989) However, as shown in Fig. 2 sodium hydroxide gives more pH value at the same concetration when compared to other alkalis. Table 2-1 describes properties of alkalis that can be used in flooding process.

Table 2-1 Types of alkalis (Donaldson *et al.*, 1989)

Chemical	Formula	1 wt% alkaline solution in		Na2O	Solubility		Relative price range
		0%NaCl	1%NaCl		Cold water	Hot water	
		ph		%	(g/100 cm3)	(g/100 cm3)	(US $/ dry ton)
Sodium Hydroxide	NaOH	13.15	12.5	0.775	42	347	285 - 335
Sodium Orthosilicate	Na_4SiO_4	12.92	12.4	0.674	15	56	300 - 385
Sodium Metasilicate	Na_2SiO_3	12.6	12.4	0.508	19	91	310 - 415
Ammonia	NH_3	11.45	11.37	-	89.9	7.4	190 - 205
Sodium Carbonate	Na_2CO_3	11.37	11.5	0.585	7.1	45.5	90 - 95

2.2 Surfactant

Surfactants, surface acting tension reducing agents, are chemical substances that adsorb on a surface or fluid/fluid interface when present at low concentrations in a system, and reduce surface tension. As shown in Fig 3, in their most common form, they consist of a hydrocarbon (nonpolar) portion and a polar ionic portion. The hydrocarbon portion is called the tail and the ionic portion is called the head of the molecule. The molecule can be a straight or branched chain. The nonpolar and polar portions of the molecule are called the lipophilic and hydrophilic moieties, respectively.

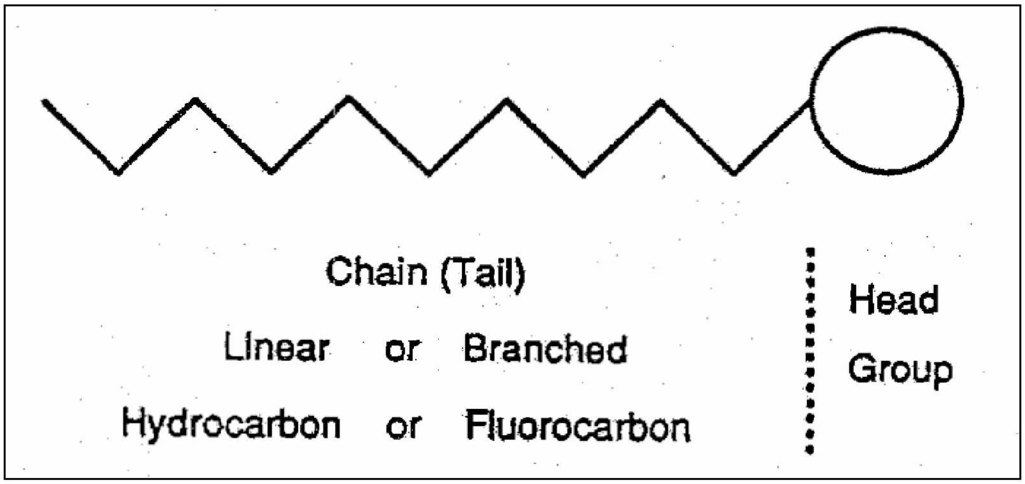


Figure 3 Schematic of surface active molecule (Donaldson *et al.*, 1989)

Surfactant shown in the Fig 4, the hydrocarbon portion interacts very weakly with water molecules in an aqueous solution. The hydrophobic tail tries to squeeze hydrocarbons out of the water, while the hydrophilic head interacts strongly with water molecules undergoing solution. Surfactants balance these hydrophilic and hydrophobic parts, sometimes characterized by an empirical number called the hydrophilic and lipophilic balance (HLB). The HLB indicates a surfactant's relative tendency to dissolve in oil or water and its tendency to form oil in water and water in oil emulsions. A lower HLB number reflects a greater tendency to form water in oil emulsions.

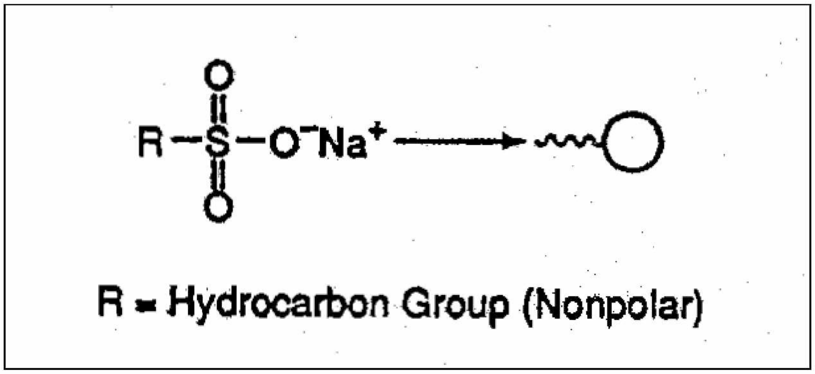


Figure 4: Commercial Petroleum sulphonates (Surfactants) (Green & Willhite, 1998)

Classification of Surfactants (Green & Willhite, 1998)

Surfactants are classified by the ionic charges they carry on their head group, as:

Anionic

These carry negative charges on their head groups. In aqueous solution, the molecule ionizes: the surfactant dissociates and the head gains a negative charge.

Example: Sodium dodecyl sulphate ($C_{12}H_{25}SO^{-}_{4}Na^{+}$)

Cationic

These carry positive charges on their head group. In aqueous solution, the molecule ionizes: the surfactant dissociates and the head gains a positive charge.

Example: Dodecyltrimethylammonium bromide ($C_{12}H_{25}SO^{-}_{4}Na^{+}Me_{3}Br^{-}$)

Nonionic

This group of molecules does not ionize. The head group is larger than the tail group.

Example: Dodecylhexaoxyethylene glycol monether ($C_{12}H_{25}\{OCH_{2}CH_{2}\}_{6}OH$)

Zwitterionic

This group of molecules contains both charges.

Example: Dodecylhexaoxyethylene glycol monether ($C_{12}H_{25}$ - N-Me_{2} - $CH_{2}CH_{2}CH_{2}SO_{3}^{-}$)

However, anionic and non-ionic surfactants are widely used in EOR processes. Anionic surfactants have good surfactant properties, e.g., stability, low adsorption capacity, and are economically manufactured. Non-ionics are commonly used as cosurfactants, as they possess a high tolerance to high salinity brine, but are not as effective as anionics. Cationic surfactants are not used, as they have a greater tendency to adsorb on rocks.

The most common surfactants used in EOR processes are sulphonated hydrocarbons. They are produced by sulphonating a relatively pure organic structure to form organic acid, followed by neutralization with sodium hydroxide. Crude oil sulphonates are produced when crude is sulphonated, while petroleum sulphonates are produced when an intermediate molecular refinery stream is sulphonated, and synthetic sulphonates are produced when a relatively pure organic compound is sulphonated. Crude oil and petroleum sulphonates have been used for low salinity applications (<2-3 wt% NaCl). They exhibit the property of attaining low IFT and are economical and chemically stable. Petroleum sulphonates are soluble because of the SO_3^- group present, and tend to precipitate in high salinity brines. However, the characteristics and structure of petroleum composition for EOR application depends upon the chemical composition of feedstock, the degree of sulphonification, and the average number of sulphonated groups attached to each molecule.

Micelles and Microemulsions

When surfactants are added to a solvent at very low concentrations, the dissolved surfactants are dispersed as monomers. As surfactant concentration increases above a particular concentration called the Critical Micellar Concentration (CMC), molecules tend to aggregate (Fig 5). Micelles are soluble colloidal surfactants that aggregate. Further addition of surfactants results in the formation of micelles, which does not change monomer concentration; there is no change in IFT after that. Properties of micelles are:

a. Micelles have a spherical shape and their radius can be as long as hydrocarbon units.
b. Micelles contain approximately 50-100 monomer units.
c. The micellization process occurs over a very narrow concentration range. For surfactants in aqueous solution, hydrocarbon chains form the interior of micelles, and may possess the ability to solubilize organic compounds.

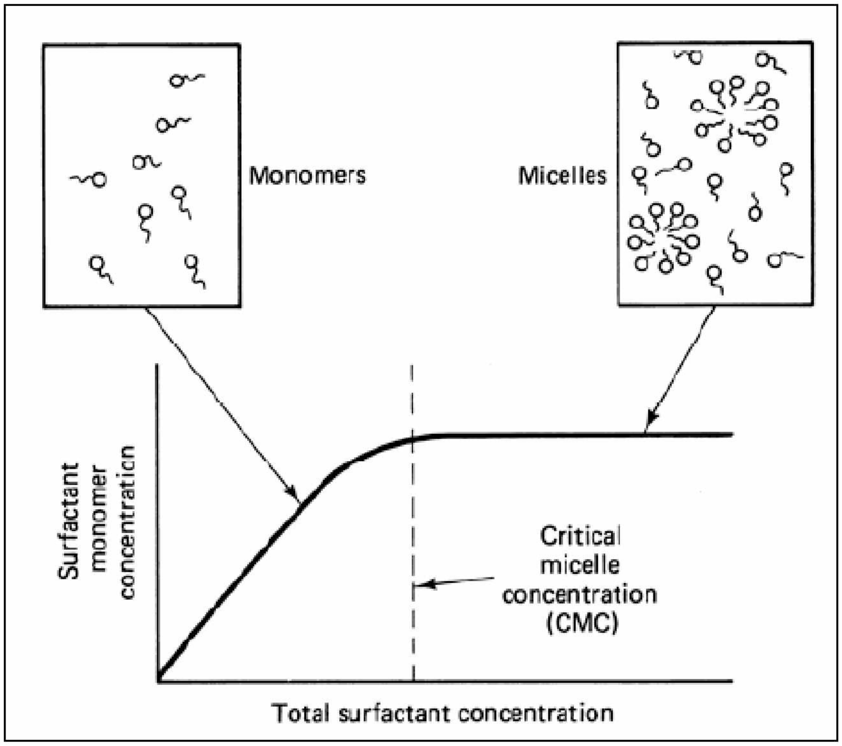


Figure 5: Critical Micelle concentration (CMC) (Green & Willhite, 1998)

Mechanism for IFT reduction by surfactants:

IFT is defined as the force acting per unit length required to create new surface area at the interface between two immiscible fluids. Consider a two-phase system separated by a planar interface, phase 1 being higher density at the bottom than phase 2. Pressure distribution across the fluid boundary is affected by the concentration of phases and the interface. Pressure in this interface varies according to distance, as densities and stresses acting on molecules deviate due to fluid properties. IFT at this interface can be given as

$$\sigma = \int_{-\infty}^{\infty} (p_N - p_T)dx \tag{2.4}$$

where

σ = IFT

p_N = pressure component normal to interface in X direction

p_T = pressure component transverse to interface in Y direction

When surfactant is added to a system, the surfactant molecules adjust themselves so that the hydrophilic part is directed towards heavier phase and hydrophobic part is towards the lighter phase (Fig 6). Hence, the accumulation of a surfactant at this interface increases p_T, resulting in a drastic reduction in IFT. However, IFT depends upon salinity, temperature, surfactant concentration, surfactant type and purity, and the nature of the hydrocarbon phase. Also, from core experiments conducted as (Larson, 1978), surfactants are used to swell the oleic phase with chemicals and water at low partition coefficients.

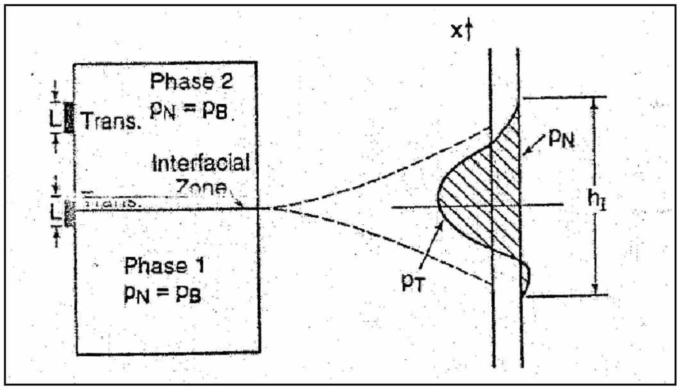


Figure 6: Two-phase system and interface (Green & Willhite, 1998)

2.3 Polymer

In certain reservoirs, polymer flooding can yield significant increases in percentage of recovery compared to conventional water flood projects. In recent years, polymer gel flooding technology has been field-tested extensively, and can now be classified as a proven technology. Polymer flooding to improve volumetric sweep efficiency and reduce channeling and breakthrough has been used by many operators to increase oil recovery. The same polymer can also be used with surfactants and alkali agents to increase the sweep efficiency of these tertiary recovery floods (e.g., ASP, SP and AP*)*. Polymer flooding can yield a significant increase in oil recovery compared to conventional water flooding techniques. Polymers are used to viscosify the injected water, which generates a more piston-like displacement of the heavy oil.

Water and gas injection in a reservoir may result in less recovery due to:

a. A partial sweep of the reservoir
b. Oil trapped by capillary forces
c. Inadequate mobility ratio

In the case of water flooding, as water saturation increases, the relative permeability of oil decreases, which results in poor sweep of the reservoir (Fig 7).

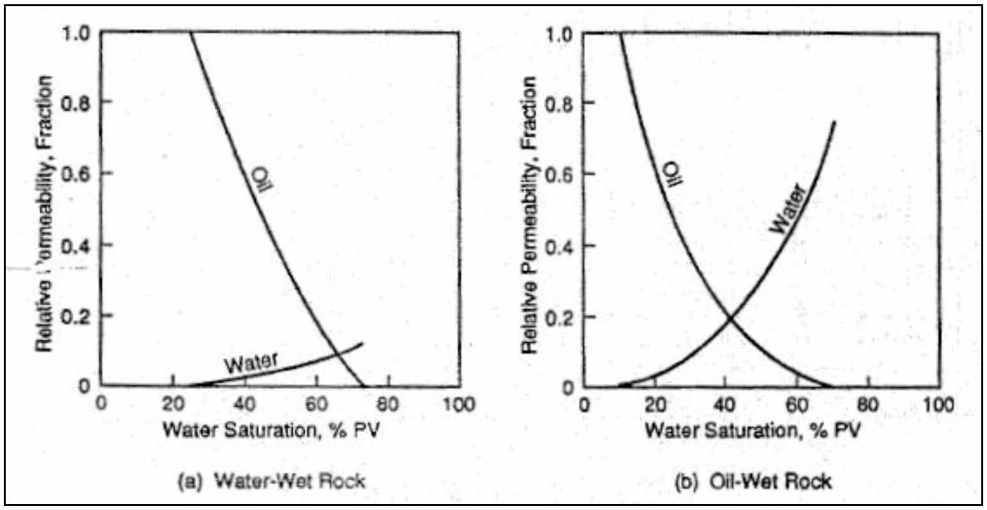


Figure 7 Water wet and oil wet systems (Green & Willhite, 1998)

Hence, the main objective of polymer flooding is to remedy the problems with waterflooding caused by water's high mobility ratio. The water-soluble polymers are injected in the reservoir soas to decrease the mobility ratio and increase areal sweep efficiency.

Polymers have low molecular weights and are used in aqueous solutions at concentrations of .1 to 1 parts per million (ppm), depending upon field conditions. Three types of polymers are used most commonly (Latil, 1980) and properties are mentioned in Table 2-2 :

a. Polyacrilamides
b. Polysaccarides
c. Ethylene Polyoxide

Table 2-2 Types of polymers (Latil, 1980)

Polymers	Properties
Polyacrylomides	Synthetic, Usually anionic, dry powder, water solution, emulsion, gel
Xanthum Gum	Natural biopolymer, anionic, water solution, dry powder
Cellulosics	Semi - synthetic, non - ionic or anionic, dry powder
Polyacrylate copolymers	Synthetic, anionic, dry powder, water solution

BASIC MECHANISM:

A typical polymer flood project involves mixing and injecting polymer over an extended period of time until a slug volume equal to about 1/3 of the reservoir pore volume has been injected. This polymer slug is then followed by continued long-term water flooding in order to drive the polymer slug and the oil bank in front of it towards the production wells. Polymer is injected continuously over a period of years to reach the desired injected pore volume resulting in a decrease in its mobility ratio given by:

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} = \frac{K_{rw}/\mu_w}{K_{ro}/\mu_o} \leq 1 \tag{2.5}$$

This is due to the increase in water viscosity and decrease in aqueous phase permeability. This results in increased efficiency of water flood through greater volumetric sweep efficiency and lower swept zone oil saturation.

Water-soluble polymers are used to increase water viscosity and reduce the permeability of rock to water, thus improving the water-oil mobility ratio. Injection of water-soluble polymers also results in improved volumetric sweep efficiency and higher oil recovery. As water breaks through into producers fractional flow can be given by Buckley Leverett principle, (Donaldson, 1985)

$$f_w = \frac{1}{1 + \frac{(kw/\mu w)}{(ko/\mu o)}} \tag{2.6}$$

where,

f_w= fraction of water in flowing stream passing any point in swept area

k_o, k_w = effective rock permeabilities to oil and water, respectively, at a given water saturation

μ_o, μ_w= oil and water viscosities (cp)

Hence, as water viscosity increases and the permeability of rock to water, k_w, decreases, the fractional flow of oil increases, improving oil recovery. However, adding polymer to surfactants to improve their mobility ratio may result in adverse polymer transportation behavior during flow through porous media. Polymers usually lag behind in the displacing phase, despite the fact that two phases are injected simultaneously in a reservoir; this may be due to low formation permeability, insufficient fluid velocity, or insufficient continuity of phases in a system. This lag can be minimized by changing cosurfactants. (Chiou & Kellerhals, 1981)

CHAPTER 3. EFFECT OF PARAMETERS ON ASP RECOVERY

3.1 Phase Behavior

Microemulsion systems have ultralow IFT values (10^{-3} dynes/cm), resulting in solubilization of oil and water. The complex phase behavior of microemulsions depends on a number of parameters, including types and concentration of surfactants, cosurfactants, hydrocarbons, and brine, temperature, and pressure. It consists of five components:

a. Surfactant
b. Cosurfactants
c. Hydrocarbon
d. Water
e. NaCl

The phase behavior of microemulsions can be explained by ternary diagrams. However, when brine is present as a pseudo-component, the apices of the triangles are 100% surfactant, cosurfactant, brine, and hydrocarbon (Fig 8). Generally, surfactant and cosurfactant are treated as one surfactant, so one apex of the pseudoternary diagram represents 100% surfactant.

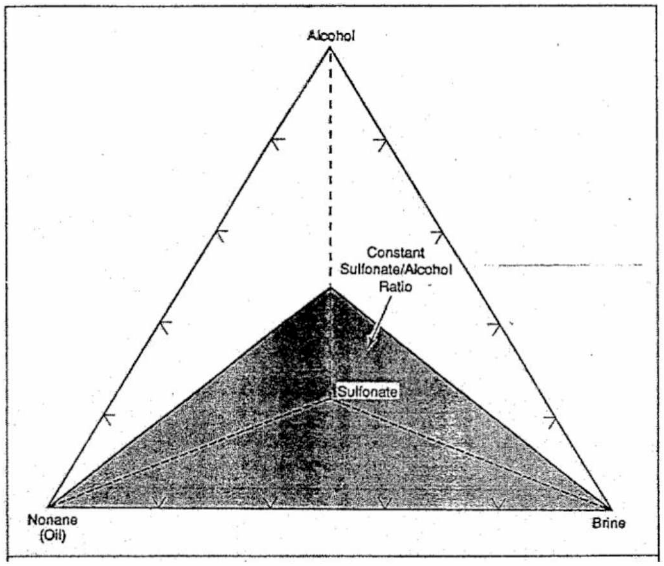


Figure 8 Ternary diagram of constant surfactant/alcohol ratio (Green & Willhite, 1998)

The ideal phase behavior of a surfactant system is shown by the figure 9 given below. Surfactant, water, and oil are the apices of the triangle. The concentrations of these components can be stated by mass or volume. A solution present in microemulsion or micellar solution over most of the concentration range, except below CMC, exists in the single-phase region. At point S1, microemulsions would be a water external system, with oil solubilized in cores of micelles, and at point S2, they would be an oil external system, with water solubilized in cores of micelles.

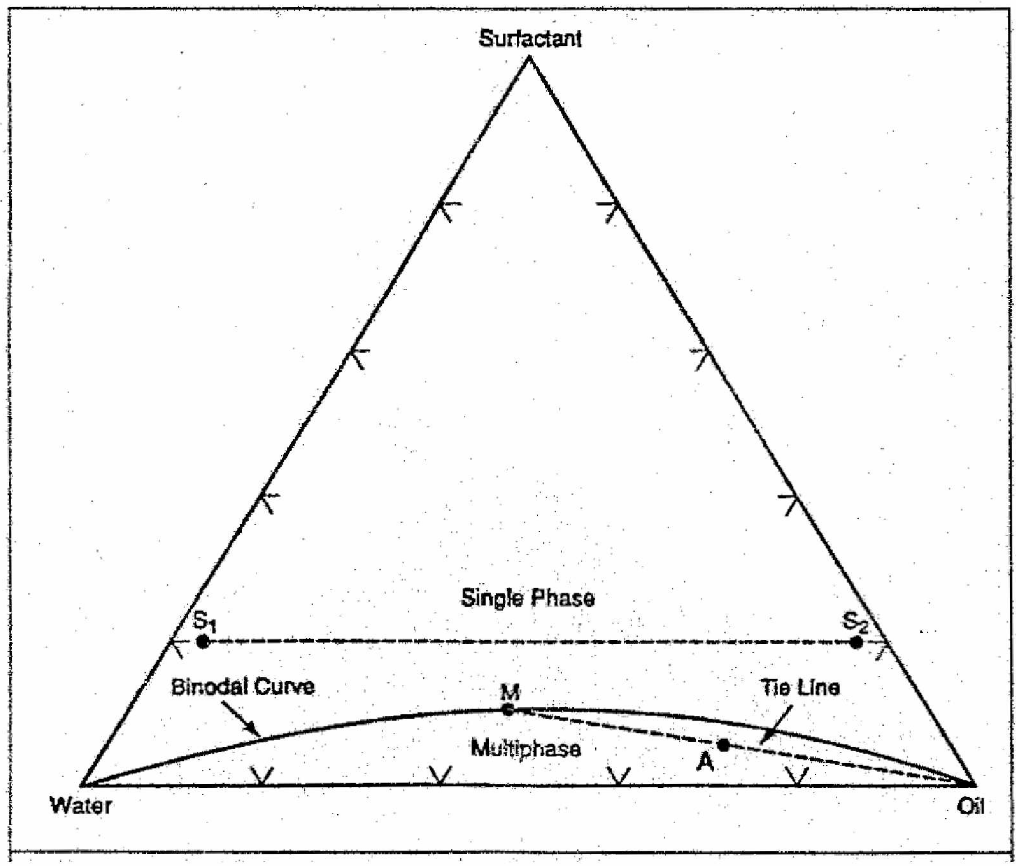


Figure 9 Pesudoternary phase diagram for micellar solution (Green & Willhite, 1998)

3.2 Effect of brine salinity on phase behavior

Generally, increasing brine salinity decreases the solubility of ionic surfactant as a result of surfactant being expelled out of brine solution as electrolyte concentration increases. The effect of salinity on the ideal microemulsion system can be explained by the following figure 10, 11 and 12:

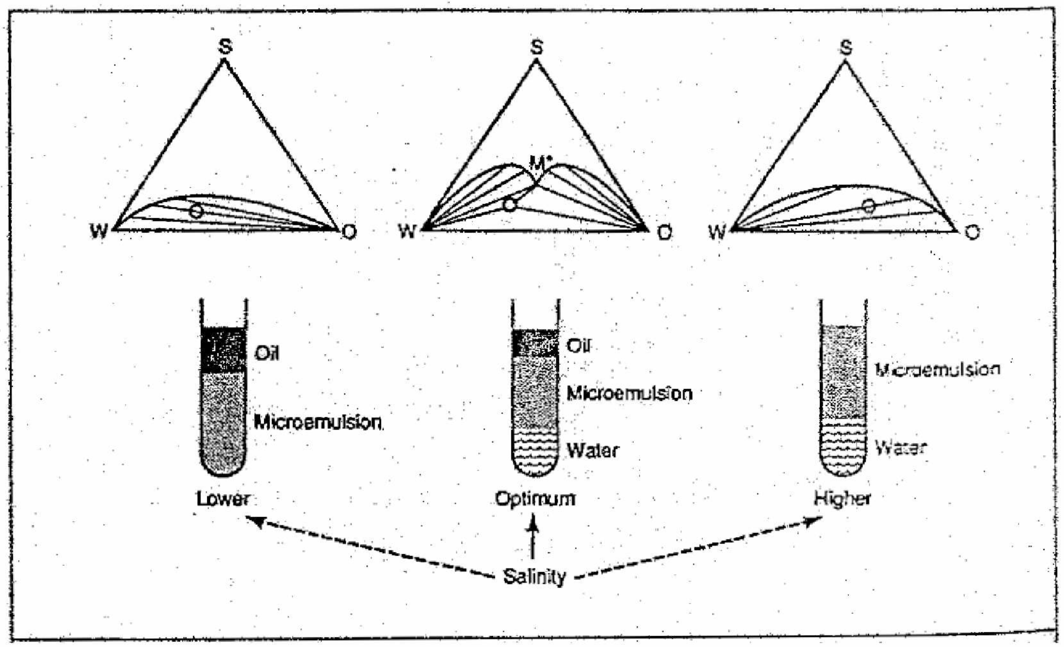


Figure 10 Salinity effect on microemulsion system (Green & Willhite, 1998)

At low brine salinity, solutions at concentrations existing in the multiphase region separate into water external microemulsion and excess oil phases. As the microemulsion is heavier than the oil phase, it resides below the oil phase, and, hence, is called the lower phase microemulsion (Type II (-)). At higher salinity, the phases separate into an oil external microemulsion and a heavier excess water phase. As oil external phase emulsions are lighter than water, these are called upper phase microemulsions (Type II (+)).

At intermediate salinity, a three-phase region exists, i.e., oil, microemulsion, and water. For an ideal composition with fixed salinity, the microemulsion composition is invariant for any concentrations within the three-phase triangle. As the microemulsion density is intermediate between that of oil and water, it is called a middle phase microemulsion (Type III).

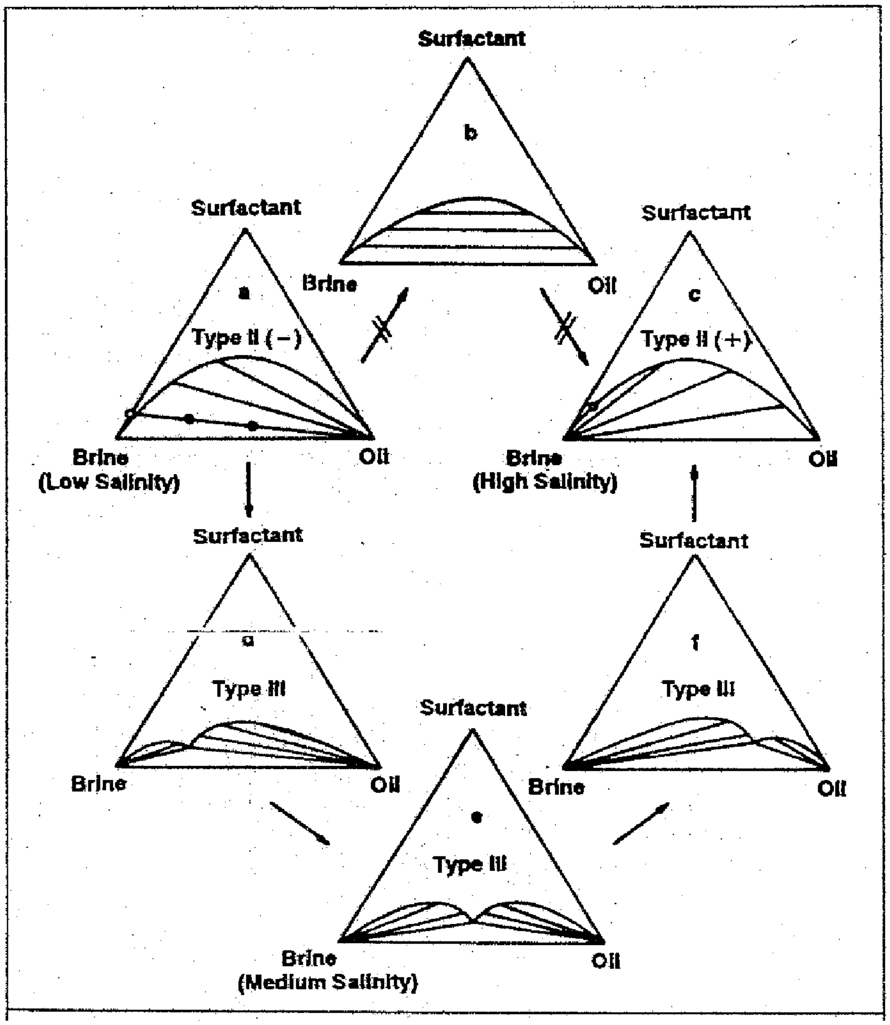


Figure 11 Phase change with change in salinity (Green & Willhite, 1998)

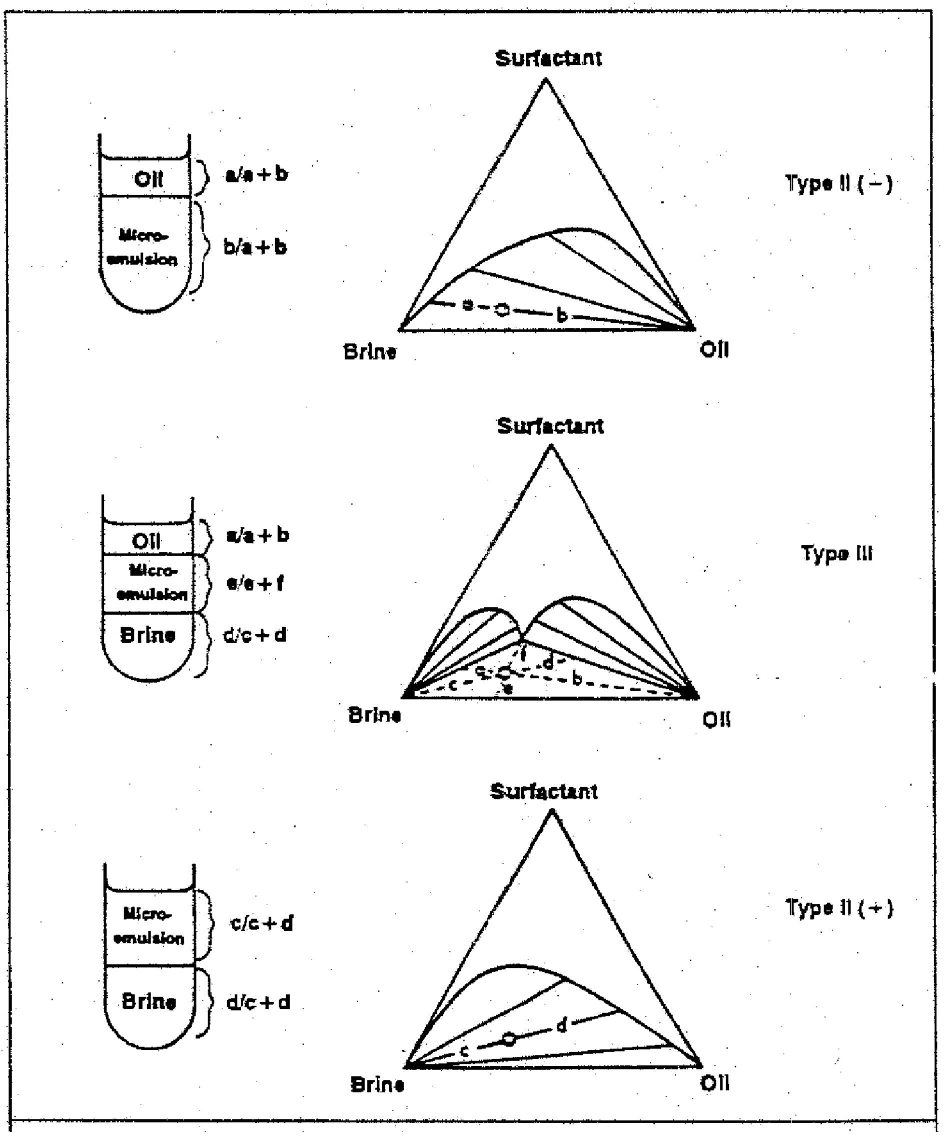


Figure 12: Types of microemulsions (Green & Willhite, 1998)

At low salinities, the system is in oil phase equilibrium with alcohol-rich brine. At the plait point, the two phases of liquid are indistinguishable. As salinity increases, the lower alcohol-rich phase gets saturated with NaCl and the third phase emerges from the critical point line. This behavior of phases changes depending upon the salinity of brine and can also be explained by volume-based diagrams. As salinity increases, the system passes from lower to middle to upper phase microemulsion. The volume of oil and brine solubilized by microemulsion is defined as the amount of oil and water that can be solubilized by a unit of surfactant.

The solubilization parameters for oil and water can be defined as:

$$Po = \frac{Vo}{Vs} = \frac{Volume\ of\ oil\ in\ microemulsion\ phase}{Volume\ of\ surfacant\ in\ microemulsion\ phase} \tag{3.1}$$

$$Pw = \frac{Vw}{Vs} = \frac{Volume\ of\ water\ in\ microemulsion\ phase}{Volume\ of\ surfacant\ in\ microemulsion\ phase} \tag{3.2}$$

The following figure 13 explains the effect of salinity on solubilization parameters.

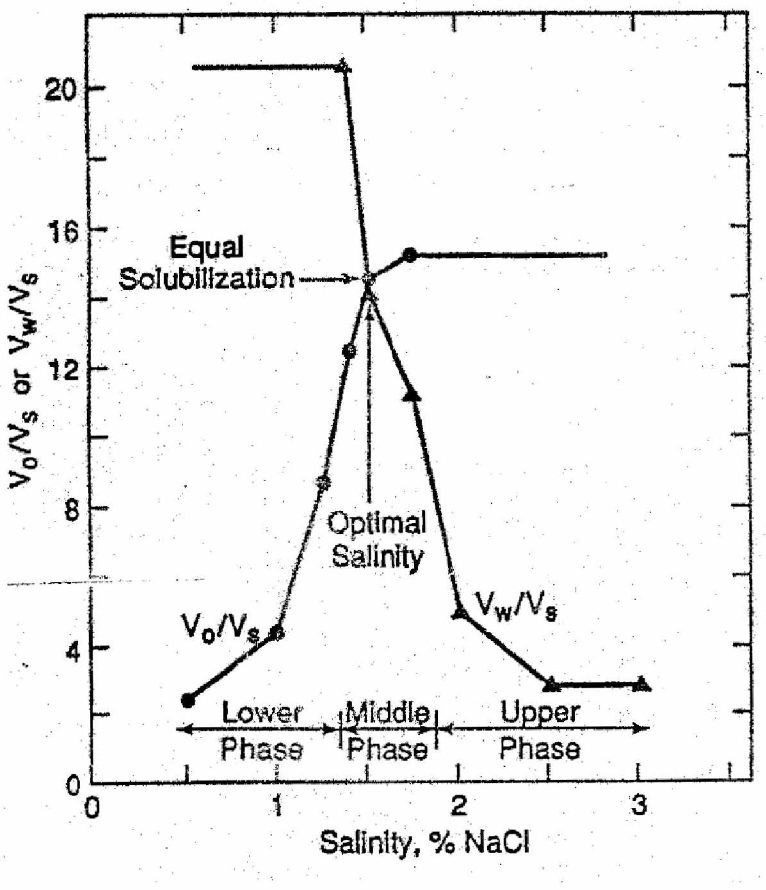


Figure 13: Effect of salinity on solubilization (Green & Willhite, 1998)

3.3 Effect of Salinity on IFT

As the salinity of brine changes, phase behavior changes and, hence, IFT. The following diagram defines the clear relationship between salinity and IFT. σ_{mo} represents IFT between the microemulsion phase and the excess oil phase, while σ_{mw} represents IFT between the microemulsion and excess water phases. As salinity increases, σ_{mo} decreases, because phase behavior advances from the lower phase system (Type II (-)), to the middle phase system (Type III), toward the upper phase system (Type II (+)).

As shown in Figure 14, as salinity increases further, σ_{mw} increases between the transition from the middle phase system (Type III) and toward the upper phase system (Type II (+)) as water is expelled out of the microemulsion system, and the volume of water solubilized by microemulsion decreases. Hence the value of salinity at which $\sigma_{mo} = \sigma_{mw}$ and $\frac{Vo}{Vs} = \frac{Vw}{Vs}$ is called the optimal salinity value of a solution. At optimal salinity values, the IFT of a microemulsion system reaches ultra low values (10^{-3} dynes/cm). This ultralow IFT can be related to the plait point or critical point of system, as at the critical point, all phases coexist in equilibrium at the same time and are indistinguishable. Hence, at optimal salinity, phases are near the critical point, and hence possess ultralow IFTs. **(Green & Willhite, 1998)**

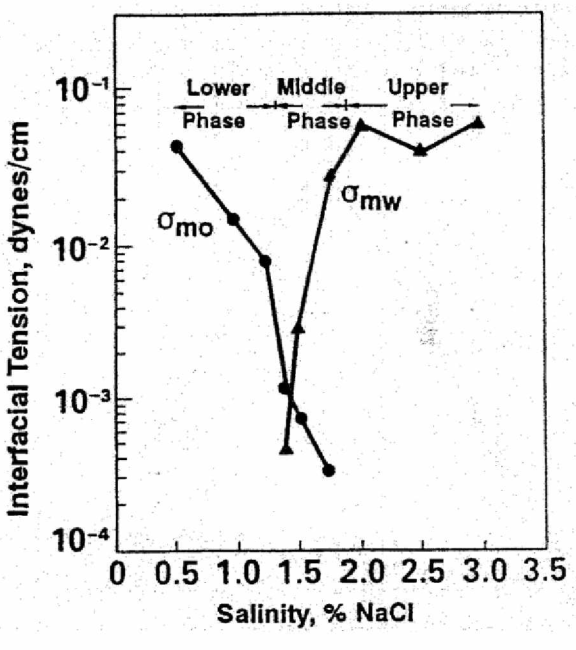


Figure 14: Effect of salinity on IFT (Green & Willhite, 1998)

Midpoint salinity is the salinity at which the middle phase microemulsion contains equal volumes of oil and water and corresponds to minimum IFT; it is also called optimal salinity.

3.4 Parameters affecting IFT:

Various parameters affect the IFT of a system, including phase behavior, salinity, temperature, types of ions in brine, oil and cosurfactant phase, water oil ratio (WOR), type of polymer used, pressure, and surfactant used for recovery.

3.4.1 Salinity and alkali concentration

The salinity and pH of a brine solution have an important role to play in IFT reduction. Salinity is important to determine the phase behavior of a system and maintain the proper ionic environment on both sides of the oil/water interface to produce low IFT surfaces. The IFT is determined by the relative solubility of the surfactant in oil and brine, which controls phase behavior. Pressurizing a three-phase system (surfactant, brine, and oil) at optimal salinity for dead crude with methane can result in an increase in solubility of surfactant in oil to a greater extent than brine, shifting phase equilibrium to optimum. Hence, the salinity requirement for the system decreases, returning the solution to an optimal salinity value (Southwick *et al.*, 2010). The pH of the solution is linearly proportional to IFT across the interface. The addition of alkalis to brine solution can help to reduce surfactant retention by forming carboxylic soaps, resulting in greater efficiency of IFT reduction and oil sweeping. Also, the addition of alkalis can enhance emulsion and entrapment, improving sweep efficiency by increasing viscoelasticity of the solution, leading to better sweep and displacement efficiency. It can also lead to polymer hydrolysis, which can decrease solution viscosity if hydrolysis intensifies. (Krumrine *et al.*, 1982 and Hou *et al.*, 2006)

3.4.2 Oil type

When the aromacity of a system increases, the optimal values of salinity and IFT increase, while the addition of paraffinic components decreases the values of optimal salinity and IFT. As aromacity decreases, keeping salinity constant, phase behavior shifts from lower to middle to upper phase microemulsions. Values of σ_{mo} and V_w/V_s decrease, and values of σ_{mw} and V_o/V_s increase. This effect on IFT can be related to the equivalent alkane carbon number (EACN), which is the sum of the mole fraction of weighted alkane carbon number (ACN) of pure species. Hence, as EACN of crude increases, IFT decreases.

3.4.3 Cosurfactants

Cosurfactants like alcohols are added to surfactant systems to increase the solubility of particular surfactants and to change the viscosity of a system. Water-soluble alcohols make brines hydrophilic, increasing the solubility of water in a microemulsion system (V_W), but decreasing the solubility of oil (V_o). Hence, as the molecular weight of alcohol decreases, i.e., becomes water-soluble, optimal salinity and IFT increase. Also, at fixed salinity, an increase in molecular weight of alcohol, i.e., a more oil-soluble system, causes phase behavior to shift from lower to middle to upper phase, resulting in a decrease in σ_{mo} and V_w/V_s and an increase in σ_{mw} and Vo/V_s.

3.4.4 Temperature

At lower temperatures, as temperature increases, intermolecular distance in aqueous phases decreases, narrowing the difference between aqueous and oil phases, hence decreasing net molecular interaction and IFT. On the other hand, at higher temperatures, molecular thermodynamic movement increases, causing solubility of surfactant in aqueous phases and desorption from the interface, increasing IFT. Increasing the temperature of the solution shifts the system from lower to middle to upper phase, changing microemulsion phases and hence IFT.

3.4.5 Divalent ions

Ca^{++} and Mg^{++} ions are generally found in oil field brines. The presence of ions shifts optimal salinity to a lower value, showing that surfactants are less compatible with divalent ions present in brines. Divalent ions drive the system to upper phase, and a decrease in the concentration of divalent ions over time can be due to association of ions with surfactants.

3.4.6 Surfactants

The type and equivalent weight of the surfactant affects IFT and hence recovery. As seen from Fig 15, for a particular system, the equivalent weight (EW) and type of surfactant is defined as that which will give ultralow IFT with minimum adsorption. Core flooding experiments with varying ranges of equivalent weights of petroleum sulphonate surfactants showed that, at low EW (i.e., water soluble surfactants), IFT reduction was greater than at high EW, due to less adsorption.

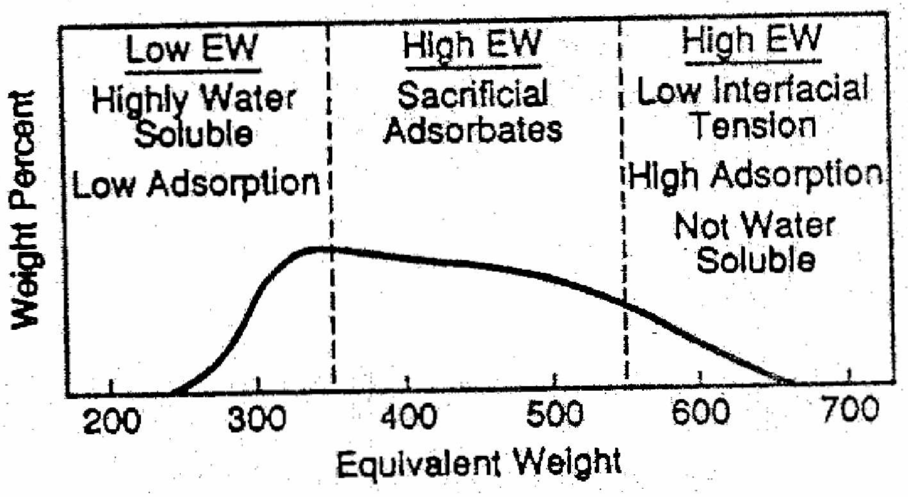


Figure 15: Effect of EW of petroleum surfactants on IFT (Green & Willhite, 1998)

3.4.7 Pressure and polymer addition

The effect of pressure on liquid phase systems is small. It is observed that as pressure is increased, phase behavior is shifted towards lower-phase microemulsions. Hence, for a particular system, optimal salinity increases as pressure increases. As pressure increases, the difference between the densities of fluids increases because of compressibility; IFT also increases. Polymers are added to a system to increase the viscosity of the solution and control the mobility ratio to increase sweep and displacement efficiency for better recovery. According to Zhu *et al.*, 2013, recovery of oil is maximized when the ratio of viscosity of solution to oil is greater than 2. Polymers are not directly added to micellar solutions, as they displace micellar slugs and separate out. In aqueous surfactant/polymer systems, surfactant-rich and polymer-rich phases form; this phase separation is a function of salinity.

CHAPTER 4. CASE STUDY

Miscible gas injection is usually implemented in low permeability reservoirs, but it is not always successful due to availability of injection gas. In this case, chemical EOR is chosen as tertiary recovery method. (Delamaide *et al.*, 2014, Fletcher & Morrison, 2008)

Chemical EOR has been conducted in low permeability reservoirs before in 1963, in Veron field in Kanas where permeability ranges from 1 md to 150 md. Main concern with chemical flooding in low permeability reservoir are:

a. Chemical adsorption/retention

b. Chemical degradation

c. Injectivity

Proper study of these factors, lab experiments and core flooding experiments can help in implementing effective flood. Following examples states effect of chemical flooding in low permeability reservoirs:

Big Muddy Field, Wyoming USA

Big muddy field is located in Wyoming and produces fro second wall creek sand in Frontier formation. Average air permeability is 56 md, and water permeability is in range of 1-2 md, with oil viscosity of 4 cp. Surfactant injection with 5 spot pattern was conducted in field. Surfactant, polymer of 1100 ppm concentration was injected in reservoir, which results in recovery of 36%.

Isenhour

Isenhour is located in Wyoming with average permeability of 21 md, oil viscosity of 2.1 cp from Almy Sand series. Alkaline (Soda ash - Na_2O) polymer (250 ppm) flood was implemented with water as preflush. It results into increase in production of 26.4% OOIP.

Slaughter

Present in northern part of Permian basin producing from San Andres dolomite reservoir, with low reservoir porosity (8 - 18%) and permeability (avg 5.9 md). Surfactant polymer flooding resulted in recovery of 77% of OIP.

Windalia Field

Windalia field was located in Australia, with porosity of 28% and low permeability of (5 - 20 md), fluid viscosity (0.65 cp) and water flooded for 40 years and produced ~288 mmbbls. To improve recovery factor, polymer flooding was used as tertiary recovery method. Coreflooding experiments were conducted with varying polymer concentration (250 - 500 ppm) and MW. Coreflooding conducted with 250 ppm polymer concentration and 6 md formation, (Fig 16) showed that medium MW polymer can be injected at both 250 and 500 ppm concentration without blocking.

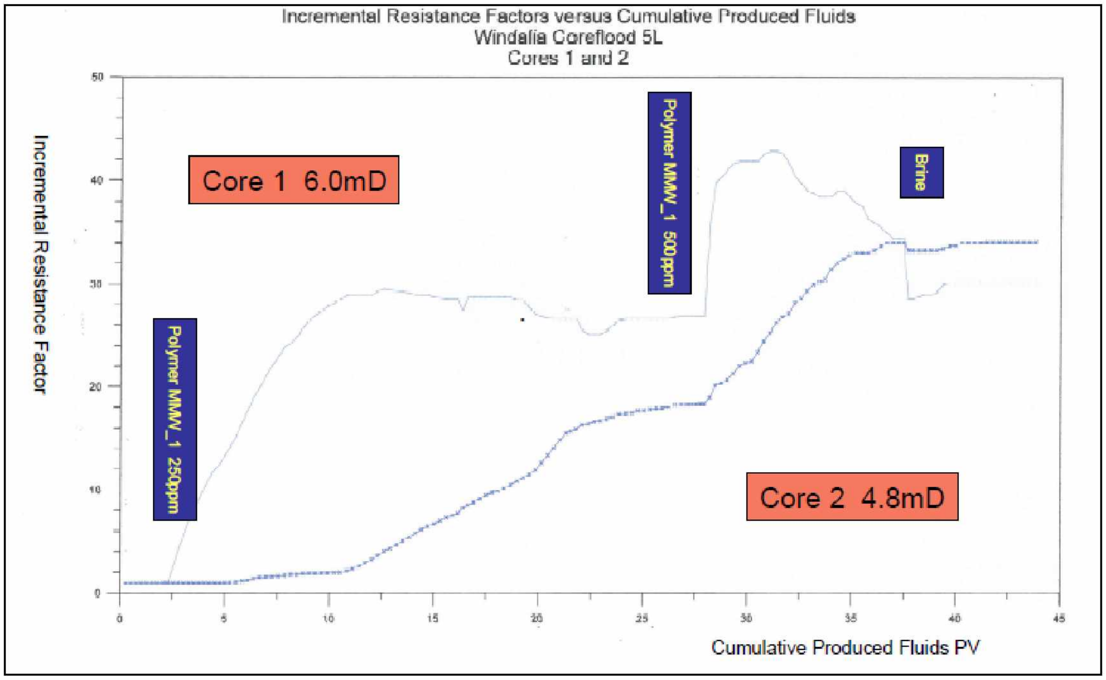


Figure 16 Coreflooding results for medium MW polymer (Fletcher & Morrison, 2008)

Coreflooding experiments suggested that low MW weight polymer (11.6E006 VAMW) is necessary for continuous injection and high MW (29.6E006 viscosity average MW-VAMW) results in injectivity problems.

Different simulation model were built with UTCHEM (University of Texas) and polymer flooding effect was analyzed (Fig 17). Polymer concentration varying from 100 - 500 ppm injected in reservoir and its effect on resistance factor, economics, and effect of polymer concentration for varying oil prices (50 - 70 $/bbl) and exchange rate (0.6 - 0.85 $A/US) was studied. It resulted in determining impact of resistance factor on incremental reserves.

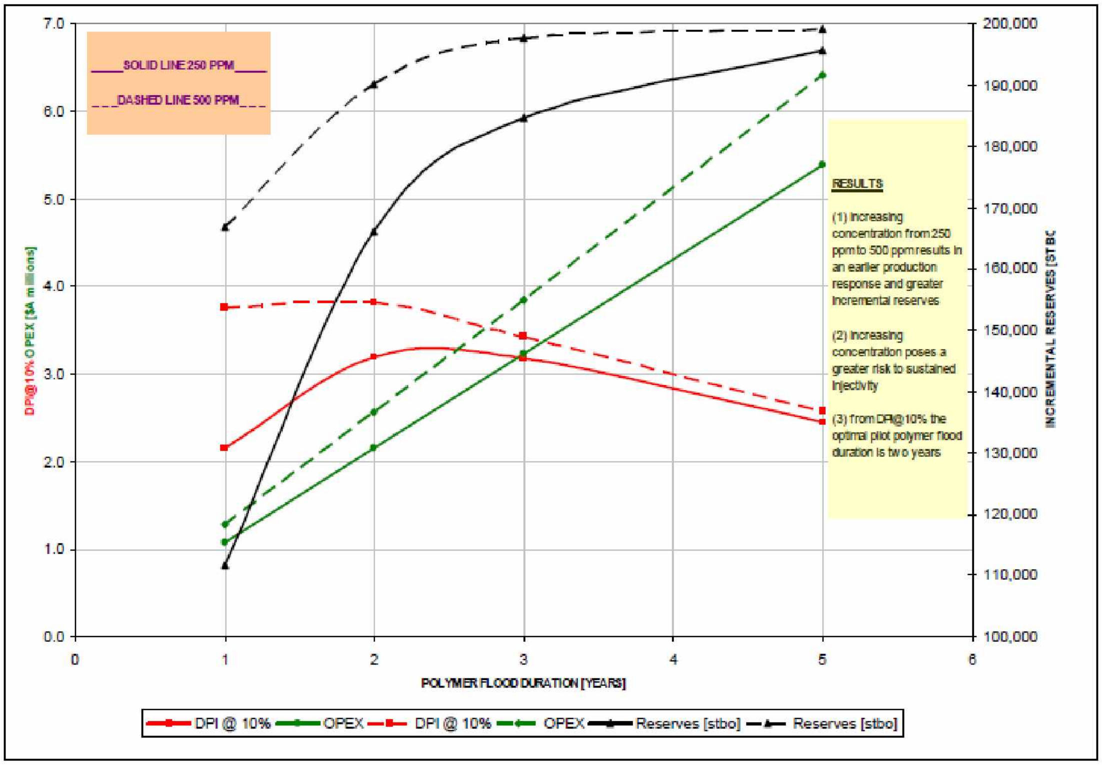


Figure 17 Simulation results for varying polymer concentration (Fletcher & Morrison, 2008)

Increase in polymer concentration from 250 ppm from 500 increases recovery and earlier production response but decreases sustained injectivity. Results of coreflooding, simulations showed that low MW polymer can be propagated through low permeability formation without plugging and loss of injectivity.

CHAPTER 5. ALASKAN FIELD

4.1 Overview

The WNS 1 reservoir was discovered in 2006 and is assumed to be an accumulation of 79 MMBO OOIP in sandstone. The first well in this reservoir was completed in 2006, and test produced for three months beginning in June 2006. A total of six horizontal producers and three horizontal injectors were drilled in the field development plan. A total of 54.8 MMBO was recovered by a combination of waterflood and gas cap drive processes. Production decreased gradually from 2006 to 2011, declining at a rate of 7.5% per year.

WNS 1, after starting oil production in July 2008, peaked in February 2010 at 3000 barrels per day (bpd) (AOGCC, 2010). The WNS1 oil pool is also composed of Cretaceous-aged depositions of very fine- to fine-grained sandstone. The WNS1 accumulation has been observed to be a stratigraphic trap. At 4000 feet of true vertical depth subsea, a gas-oil contact has been located; no oil-water contact has been observed (AOGCC, 2010).

4.2 Reservoir Description

The WNS reservoir was developed with a producer to injector ratio of 2:1. Production and injection wells range from 6000'-9000' in reservoir and are parallel to each other. A line drive flood pattern was implemented to increase recovery, with wells spaced 2700' to 3400' apart. This pattern resulted in annual peak production of 3000-6000 bpd from the field, with waterflooding average injection rates of 5000 bpd at 5100 psi.

Geological Deposition and Reservoir Properties

Stratigraphy: The WNS reservoir's stratigraphy consists of Cretaceous-aged sediments deposited as topset beds in a shallow, north-trending marine shelf environment. It consists of a thin layer of very fine- to fine-grained sandstone along depositional dip. The net pay for the formation is 22' thick; it averages about 10-15' thick. The porosity of the formation is 20-25%, with permeability ranging from 10 to 50 md and 38% water saturation. The structure is synclinal, with no faults present. Seismic sections and well logs indicate a stratigraphic trap. A gas-oil contact exists at about 4000' TVDSS, and no oil-water contact has been observed in the development area.

4.3 Screening Criteria

Reservoirs containing more than 0.1% gypsum anhydrite should be ruled out for the ASP mechanism, as it reacts and consumes alkali in solution, and hence decreases the effectiveness of flooding. For high pH floods, the presence of kaolinite can act as a barrier; hence, low pH (8.2-10) floods are suitable. Montmorillonite has high surface area and cation exchange capacity, and so can consume alkali and precipitate. Hence, reservoirs containing more than 1% montmorillonite and 0.4 wt% of divalent ions in brine are not suitable candidates for ASP. Sandstone reservoirs are generally preferred for alkaline flooding, which reacts with carbonates to form a precipitate. High acid number crude oils benefit from alkaline flooding, which helps generate in situ surfactants.

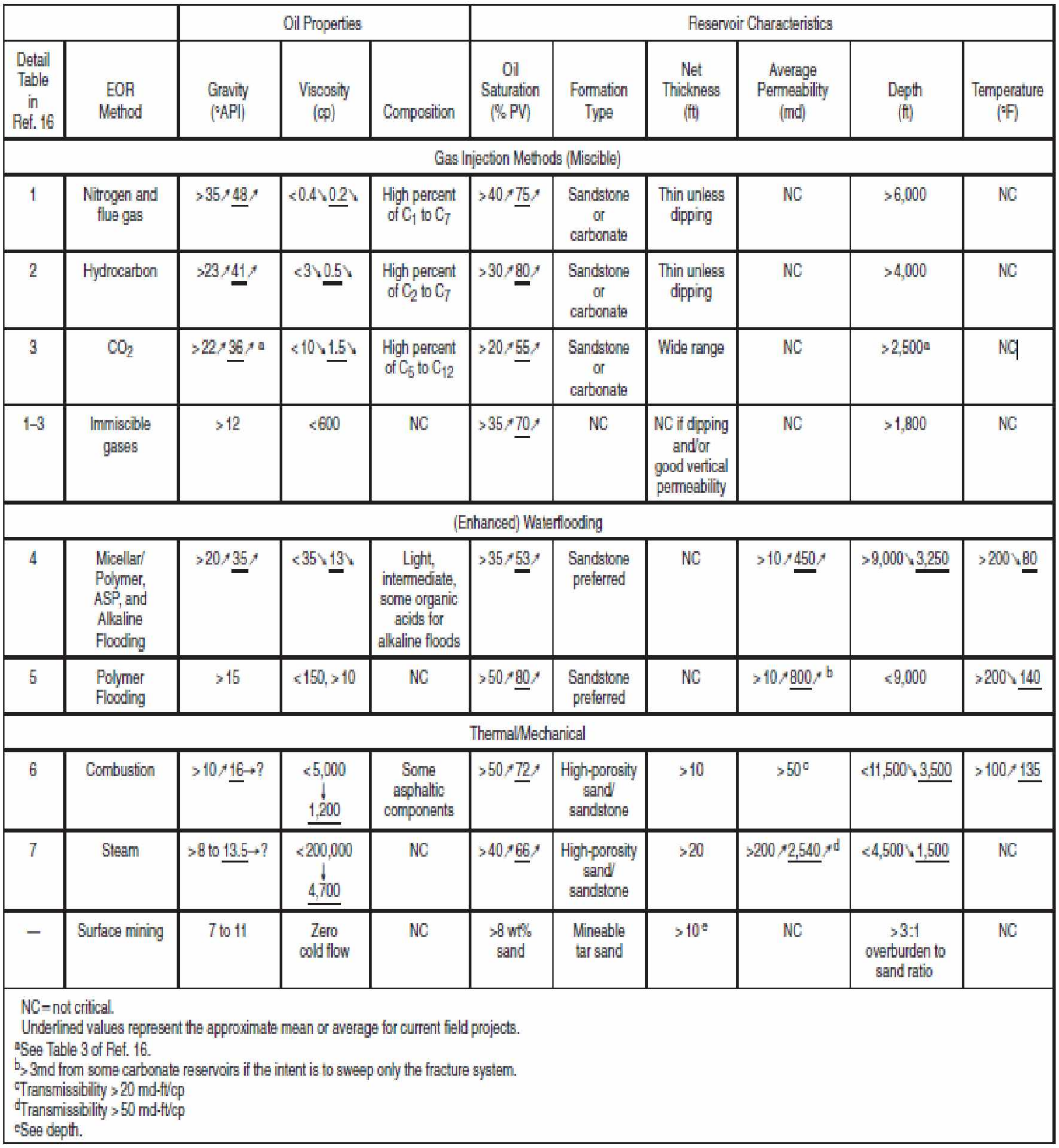
According to reservoir data obtained (Table 5-1), a reservoir with 25-31 API and 2 cp oil at a relatively shallow depth of 6000’ was selected as a candidate for chemical flooding. In order to effectively recover bypassed oil, chemical flooding was selected as the EOR mechanism on the basis of screening criteria provided by Table 5-2, (Taber *et al.*, 1997). However, the objective of this project is to check the feasibility of chemical EOR, and utilize gas for other purposes. The permeability range for this reservoir is low (10-50 md), however, (Delamaide *et al.*, 2014, Fletcher & Morrison, 2008) suggests that even in low permeability reservoirs, chemical EOR can be implemented economically.

Summary of WNS 1 properties

Table 5-1 Summary of WNS 1 properties for screening criteria

Gravity	Viscosity (cp)	Composition	Oil Saturation (%)	Formation type	Average Permeability	Depth (ft)	Temperature (F)
25-31	2	Light components and intermediate	65	Sandstone	10-50 md	6000	89

Table 5-2 Screening criteria for reservoirs (Taber *et al.*, 1997)



		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	$>35 \nearrow \underline{48} \nearrow$	$<0.4 \searrow \underline{0.2} \searrow$	High percent of C_1 to C_7	$>40 \nearrow \underline{75} \nearrow$	Sandstone or carbonate	Thin unless dipping	NC	>6,000	NC
2	Hydrocarbon	$>23 \nearrow \underline{41} \nearrow$	$<3 \searrow \underline{0.5} \searrow$	High percent of C_2 to C_7	$>30 \nearrow \underline{80} \nearrow$	Sandstone or carbonate	Thin unless dipping	NC	>4,000	NC
3	CO_2	$>22 \nearrow \underline{36} \nearrow$ [a]	$<10 \searrow \underline{1.5} \searrow$	High percent of C_5 to C_{12}	$>20 \nearrow \underline{55} \nearrow$	Sandstone or carbonate	Wide range	NC	>2,500[a]	NC
1–3	Immiscible gases	>12	<600	NC	$>35 \nearrow \underline{70} \nearrow$	NC	NC if dipping and/or good vertical permeability	NC	>1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	$>20 \nearrow \underline{35} \nearrow$	$<35 \searrow \underline{13} \searrow$	Light, intermediate, some organic acids for alkaline floods	$>35 \nearrow \underline{53} \nearrow$	Sandstone preferred	NC	$>10 \nearrow \underline{450} \nearrow$	$>9{,}000 \searrow \underline{3{,}250}$	$>200 \searrow \underline{80}$
5	Polymer Flooding	>15	<150, >10	NC	$>50 \nearrow \underline{80} \nearrow$	Sandstone preferred	NC	$>10 \nearrow \underline{800} \nearrow$ [b]	<9,000	$>200 \searrow \underline{140}$
Thermal/Mechanical										
6	Combustion	$>10 \nearrow \underline{16} \rightarrow ?$	$<5{,}000 \downarrow \underline{1{,}200}$	Some asphaltic components	$>50 \nearrow \underline{72} \nearrow$	High-porosity sand/ sandstone	>10	>50 [c]	$<11{,}500 \searrow \underline{3{,}500}$	$>100 \nearrow \underline{135}$
7	Steam	>8 to $\underline{13.5} \rightarrow ?$	$<200{,}000 \downarrow \underline{4{,}700}$	NC	$>40 \nearrow \underline{66} \nearrow$	High-porosity sand/ sandstone	>20	$>200 \nearrow \underline{2{,}540} \nearrow$ [d]	$<4{,}500 \searrow \underline{1{,}500}$	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.

[c] Transmissibility > 20 md-ft/cp

[d] Transmissibility > 50 md-ft/cp

[e] See depth.

4.4 WNS 1 Reservoir Properties

The following data and reservoir properties were used for model development.

Table 5-3: WNS Reservoir Properties (AOGCC, 2010)

Parameter	WNS1
Production started	2008
Reference Datum - ft. below sea level	4000
Temperature - ° F	89
Porosity - %	21
Permeability - md	13
Swi - %	35
Oil Viscosity @ original reservoir pressure - Cp	2
Original Reservoir Pressure. - psi	1850
Bubble Point Pressure – psi	1850
Current Reservoir Press. – psi	1850
Oil Gravity - ° API	25
Net Pay - ft.	12
Orig. FVF - RB/STB	1.19

4.5 WNS 1 Reservoir fluid composition

Table 5-4: Mole composition for reservoir fluid (Joshi, 2012)

Component	Mole %	MW	Density (lb/ft3)
H2S	1.04	34.08	0
N2	0.4	28.013	7.626
CO2	4.6	44.01	17.029
C1	24.23	16.043	4.817
C2	9.25	30.07	13.093
C3	7.52	44.097	24.67
IC4	0.98	58.124	32.01
NC4	3.79	58.124	32.01
IC5	1.27	72.151	38.5
NC5	2.33	72.151	38.8
C6	3.54	86.178	41.5
C7	3.65	100.205	44.6
C8	3.78	128.259	45.6
C9	3.48	114.232	46.5
C10	2.74	142.286	48.3
C11	1.64	151.42	48.3
C12+	25.7	320	54.5

Table 5-5: Molecular weight and bubble point pressure (Joshi, 2012)

Molecular Weight	122.191255	lb/lb-mole
Bubble Point	1850	psia

Table 5-6 Well specific and reservoir properties for WNS reservoir (AOGCC, 2010)

Reservoir Type	Fine grained sandstone
Depth of CD2 -11 well	6086’-6249’
Well spacing	2700’-3200’
Net pay	22’
Porosity	20-25 %
Permeability (k)	10-50 md
Reservoir pressure	1850 psia
Reservoir temperature	89 F
API gravity	27-32
Bubble point pressure	1850 psia
Oil viscosity at bubble point pressure	2 cp
Solution gas oil ratio (Rs)	404 scf/stb

Relative permeability curve obtained using Corey equations:

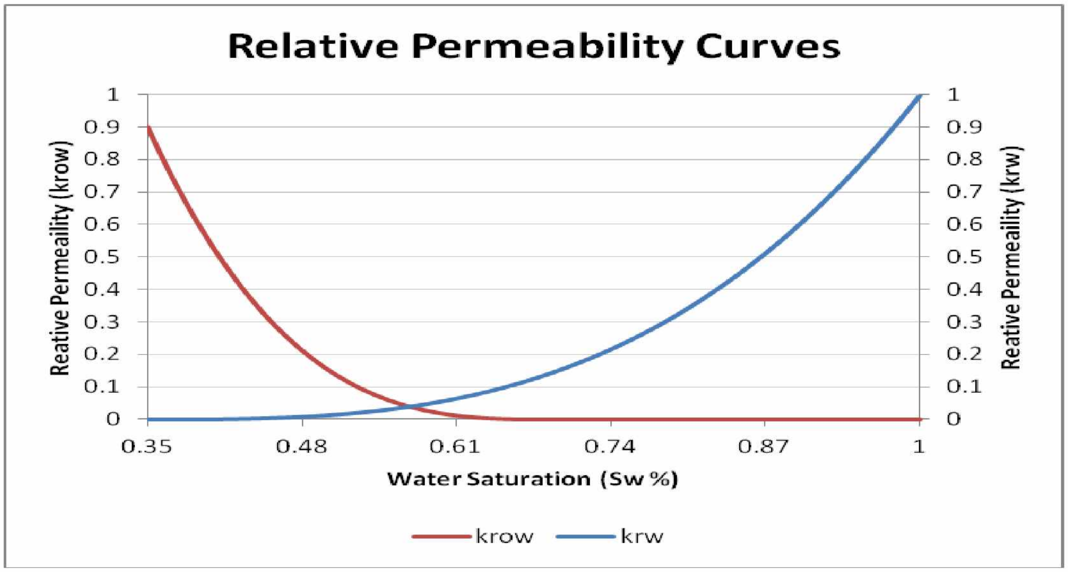


Figure 18 Relative Permeability Curve

CHAPTER 6. DUMMY SIMULATION MODEL

Simulation study guides and template files, provided by CMG, were performed to gain understanding of the model preparation process, and results were obtained to study incremental recovery for the ASP process. The simulation model generated consisted of a homogeneous core with one producer and one injector well. The reservoir parameters used for the simulation are shown below (Table 6-1) and Fig 19:

Coreflood Properties	
Grid Top	1000 ft
I,J,K Permeability	2591 md
Porosity	0.2494
Pressure	89 kPa
Temperature	31 C
Alkali Conc.	0.1
Surfactant	0.11
Polymer	500 ppm

Table 6-1: Dummy model reservoir properties

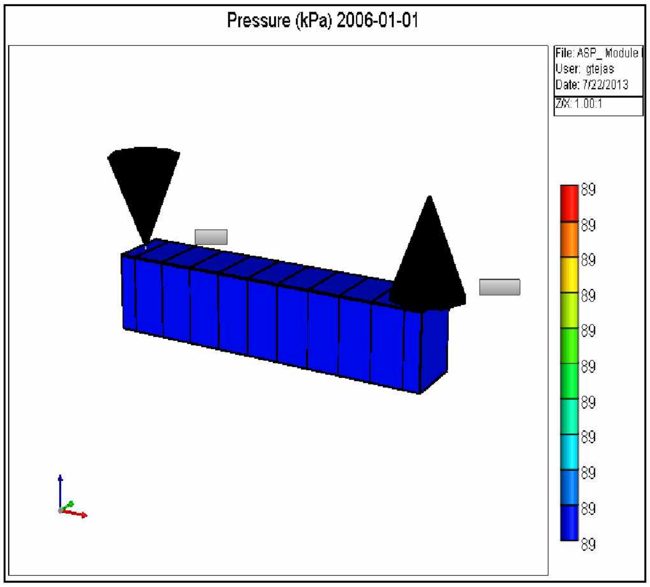


Figure 19 Dummy simulation model

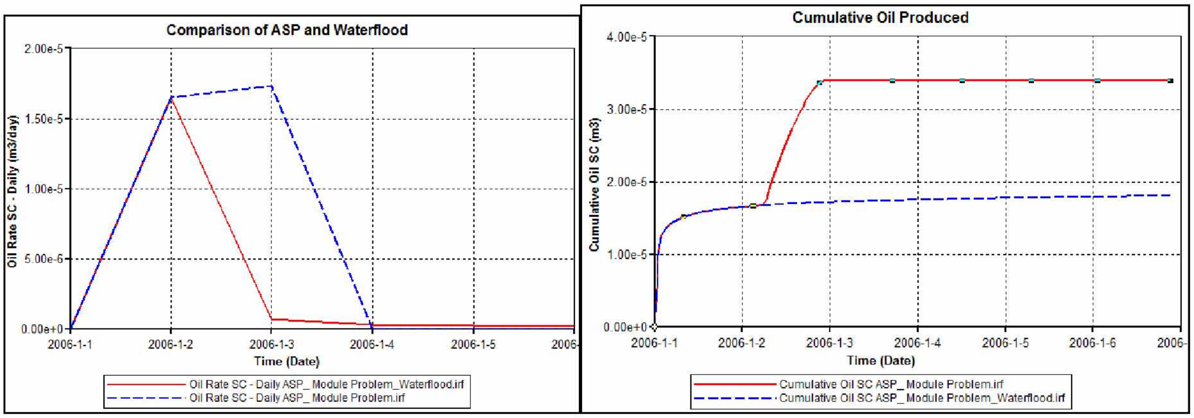


Figure 20: Comparison of ASP flood in practice model

The first run was conducted with waterflood (for 6 days), and in the second run, ASP was injected at 2006-1-2 (2^{nd} Day). The results obtained show increased oil recovery for ASP flooding over waterflood. Figure 20, a graph of oil rate vs. time, shows an increase in oil production (from 1.52*E-05 m3/day to 1.70 *E-05 m3/day) with ASP injection (2006-1-12). Also, the graph of cumulative oil vs. time shows an increase in cumulative oil produced (from 1.9*E-05 m3 to 3.10*E-05 m3). The objective of this exercise was to gain understanding of simulation basics for the waterflooding and ASP flooding processes.

The dummy simulation runs helped in understanding:

a. EOR processes in STARS
b. Modeling of the ASP process in CMG
c. The effect of interfacial tension (IFT) on capillary number to modify relative permeability curves.

CHAPTER 7. WINPROP FLUID MODEL

The WinProp fluid model was prepared on the basis of fluid properties and composition, provided on the AOGCC website, and reservoir parameters developed with standard correlation. Standing correlation (Standing, 1951) was used to obtain values for Bo and used in regression as experimental values.

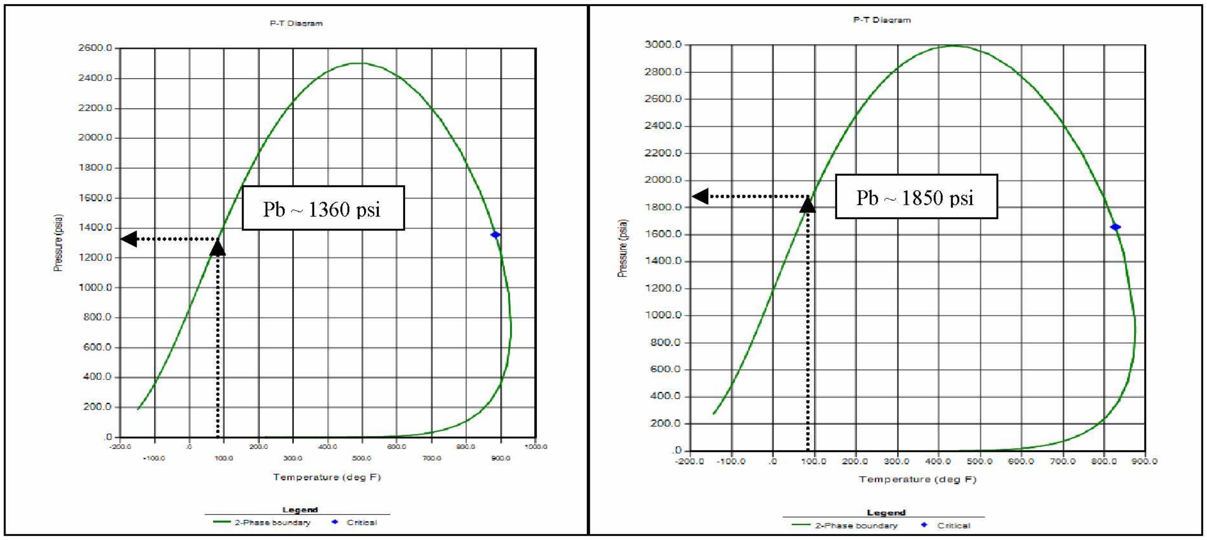


Figure 21: Phase diagram for reservoir fluid before and after regression (Winprop model)

The WinProp-generated post regression model and Fig 21, shows a critical point at 1656 psi and 830° F, and bubble point pressure of ~1850 psi at 89 deg F which is in agreement of field values. (AOGCC, 2010) Regression was conducted by changing C_{12}+ properties including Pc,Tc, acentric factor, MW. Fluid properties such as solution gas oil ratio, oil formation volume factor and viscosity at bubble point pressure were also used for regression as experimental values.

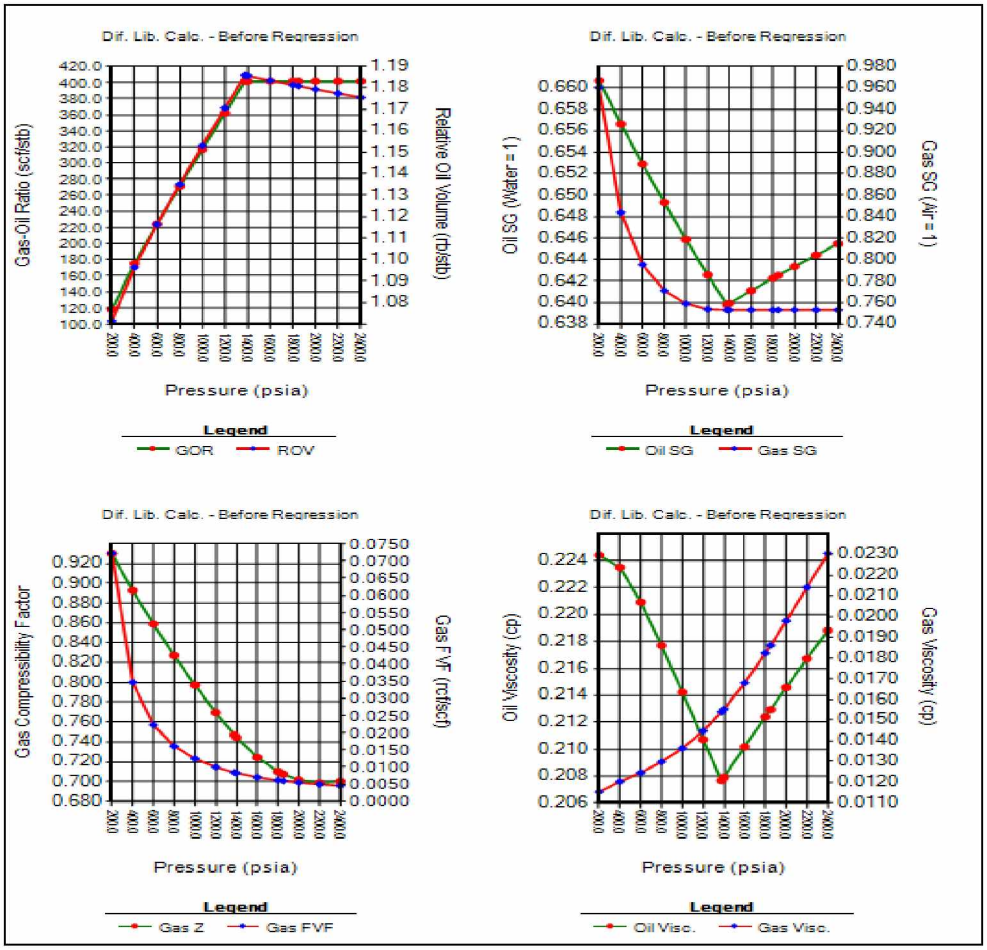


Figure 22: Rs, Bo, Bg values for a reservoir before regression (WinProp model)

As seen from Fig 22, the simulation model generated by WinProp gave an Rs value of 400 scf/bbl and an oil viscosity of 0.2 cp at the given molar composition at bubble point pressure of 1400 psi. However, this data did not match with actual field data, so a regression was conducted. The values obtained for Rs and Bo from fluid analysis data were used for the simulation.

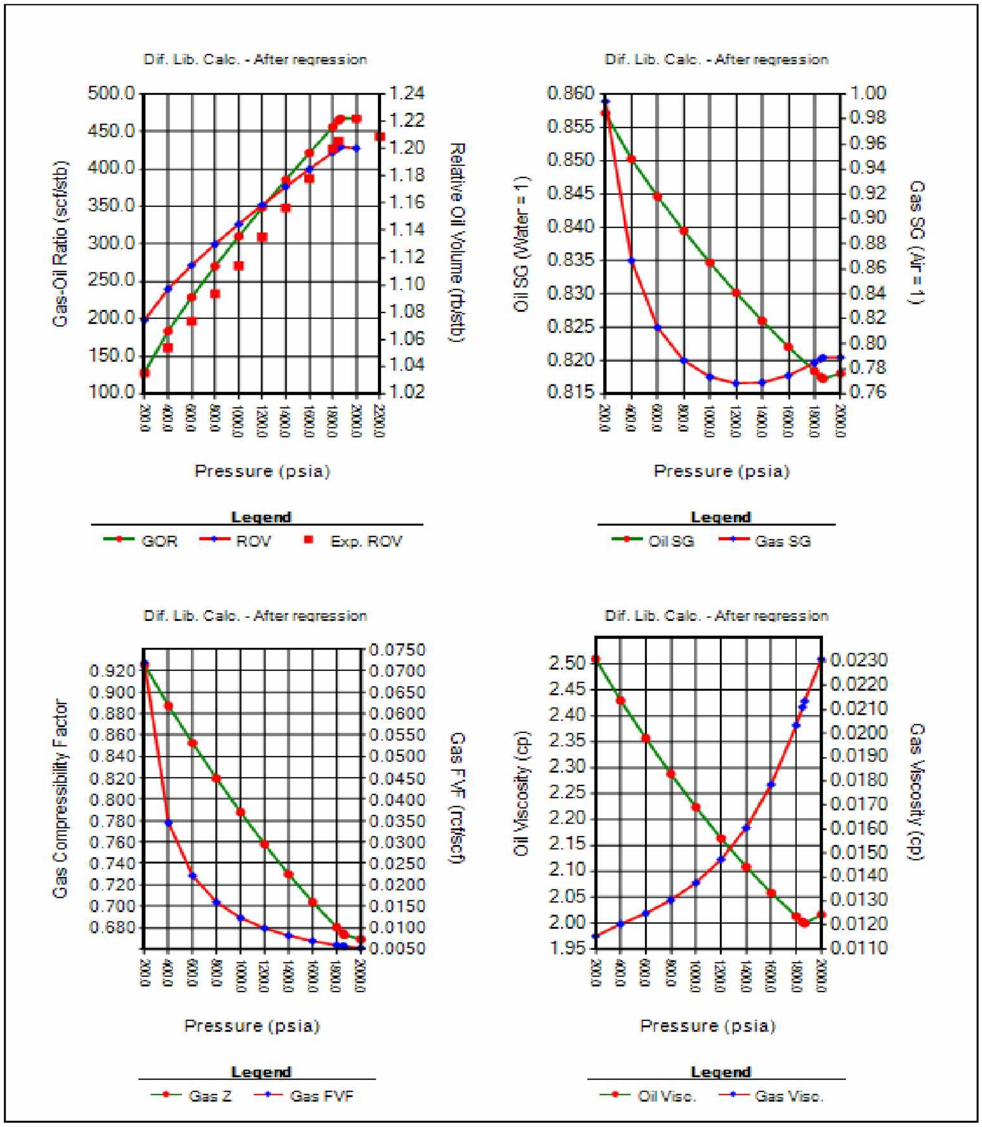


Figure 23: Rs, Bo, Bg values for reservoir after regression

As seen from Fig 23, after regressing properties of C_{12}+ bubble point pressure changed from 1400 psi to 1850 psi and values of solution gas oil ratio (Rs), oil formation volume factor (Bo) and viscosity were close to fluid properties obtained. (AOGCC, 2010)

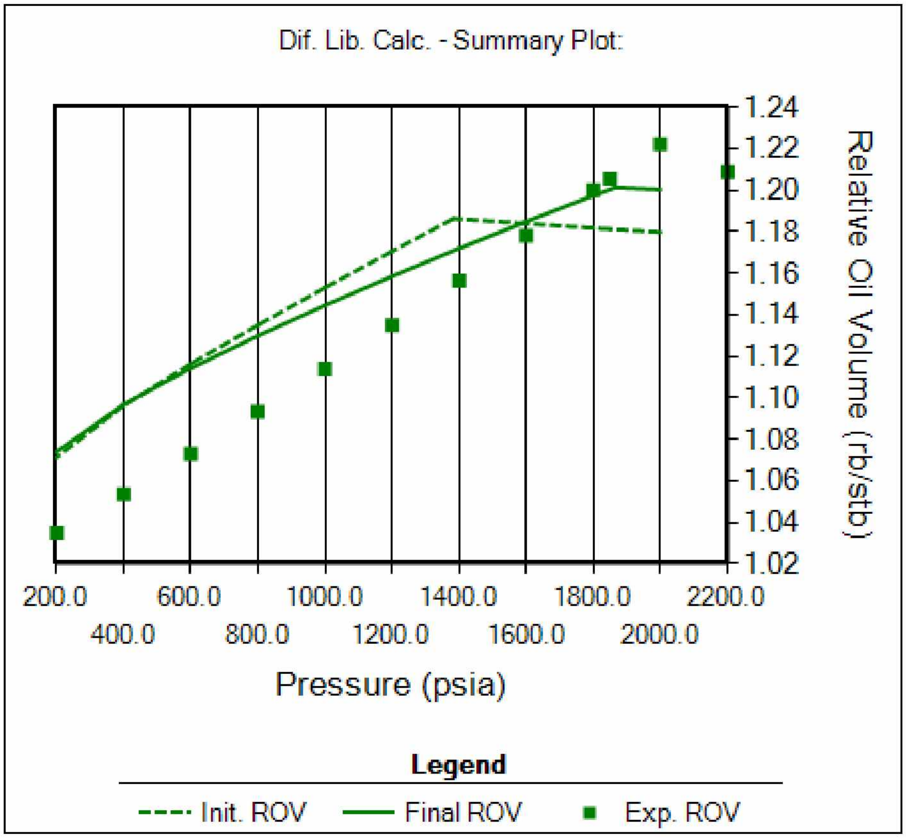


Figure 24: Relative oil volume after regression

The actual field data from the AOGCC website, shown in Table 5-3, 5-4, 5-5 was used in the regression. Bubble point pressure, oil viscosity, solution gas oil ratio, and oil formation volume factor at bubble point were used as inputs in the regression model, and a new match model was generated using them. Results obtained from the regression model shown above in Fig 23, 24 were close to actual field data. This regression model was used to design the reservoir simulation model.

CHAPTER 8. SIMULATION MODEL AND WNS 1 PROPERTIES

Following properties were used to prepare simulation model. Injector producer spacing of ~2800 ft was used in simulation to reduce number of simulation grid blocks for faster simulation. (Table 7-1)

Grid parameters:

Table 8-1: Simulation grid properties

Injector producer spacing	2800 ft
Pattern	5 spot
Grid type	Cartesian
Total number of blocks	27*27*8 = 5832
Block thickness	20 ft

Production history:

The simulation model was prepared on the basis of data provided in the above tables. Primary recovery was obtained for bottomhole flowing pressure of (P_{wf}) 1300 psi, (reservoir pressure = 1850 psi). It was observed that the reservoir is declining at a faster rate, due to less reservoir permeability and decrease in reservoir pressure at a faster rate allowing less fluid to move towards the wellbore.

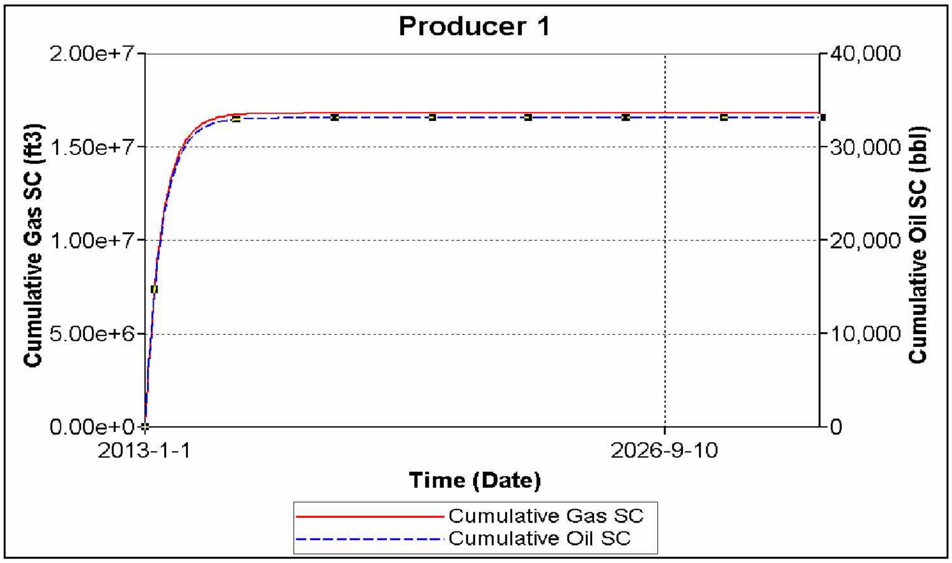


Figure 25: Cumulative Production - Primary recovery

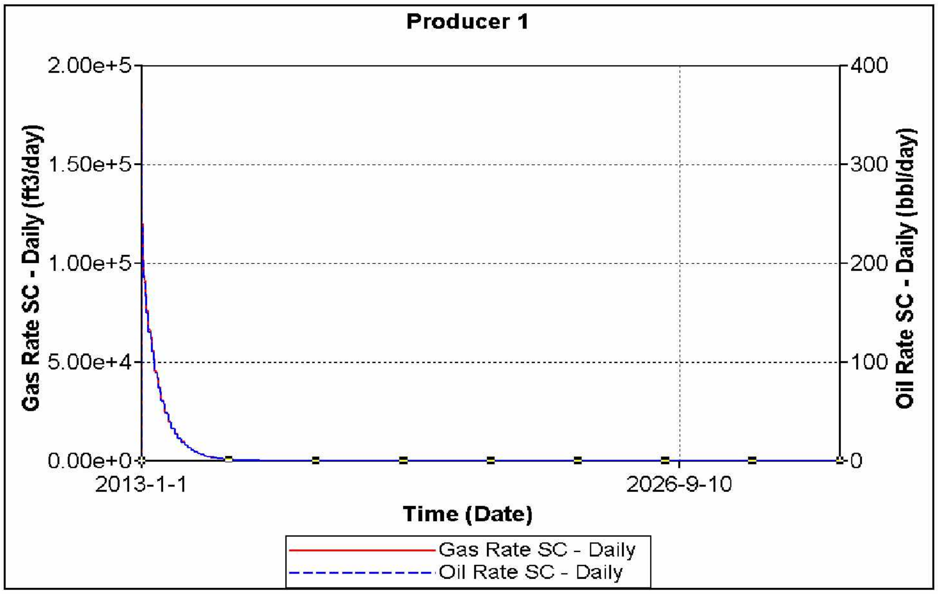


Figure 26: Gas and oil rate - Primary recovery

As it can be seen from Fig 25 and 26, oil and gas rates were declining at faster rate as production starts. Also, as reservoir pressure decreases rapidly, reservoir fluid falls in undersaturated region, hence fails to maintain sustained production and results in rapid decline.Cumulative oil produced in this case is ~32000 bbls and cumulative gas produced is ~1.75 E07, and recovery factor of ~6%.

CHAPTER 9. WATERFLOODING:

In the second part of the project, waterflooding was conducted while keeping the reservoir fluid composition and reservoir properties the same. A conventional 5-spot injection pattern was used to evaluate the efficiency of flooding (Fig 27). Injection bottomhole pressure (IBHP) and bottomhole flowing pressure (P_{wf}) were incorporated into the model as mentioned below (Table 9-1):

Table 9-1: Injection and production BHP

Injection bottom hole pressure (IBHP)	5100 psi
Bottomhole flowing pressure (P_{wf})	1300 psi

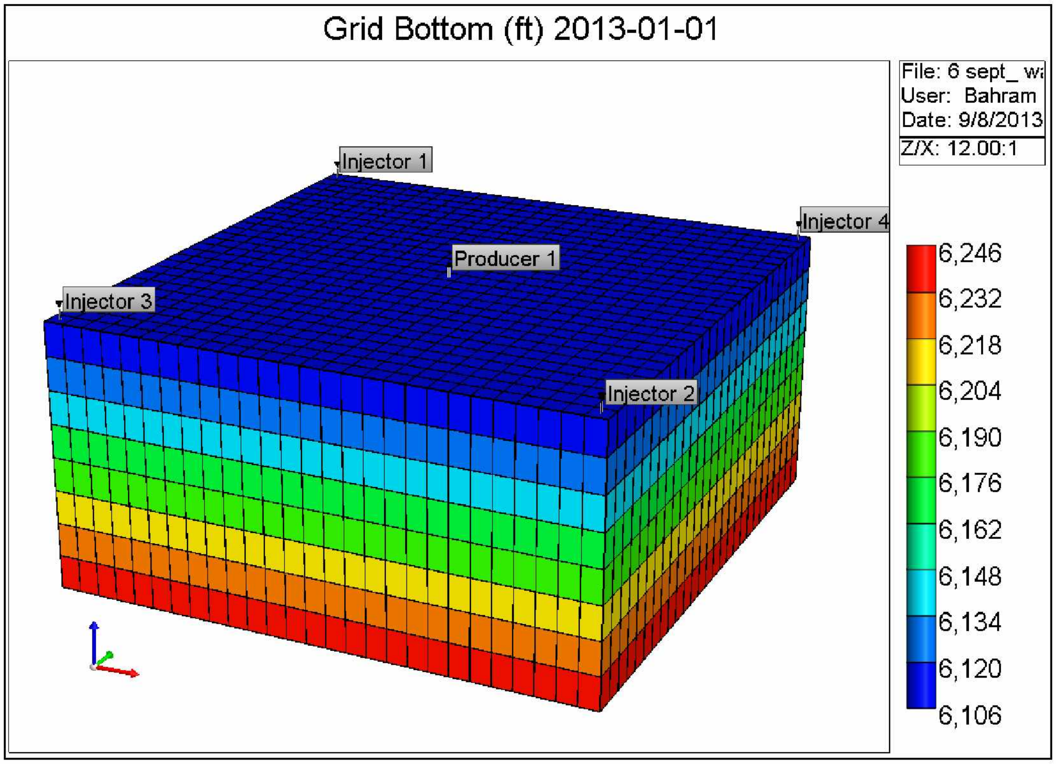


Figure 27: Reservoir simulation model for Waterflooding

8.1 Background

Water flooding was carried out in the field prior to EOR to check recovery factor. According to a report from AOGCC, 2010 water was injected at 5100 psi to maintain reservoir pressure and sustain recovery. Results obtained from the simulation give a significant increase in recovery factor with sustained oil and gas production for almost 60 years. The oil and gas recovery factor increased to 45% with a constant gas-oil ratio.

Water injection, the oldest assisted recovery method, remains the most common (accounting for 80% of the oil produced by enhanced recovery). Oil recovery is increased by improvements in sweep or displacement efficiency. In addition to the enhanced recovery objective, water injection may also be used to:

a. Maintain reservoir pressure when the expansion of the aquifer is insufficient for the purpose. In this instance, the process should be regarded as one of pressure maintenance rather than enhanced recovery.
b. Dispose of brine produced with the oil if surface discharge is impossible. Water may be injected into an underlying or neighboring aquifer.

The effectiveness of secondary recovery processes is depends on the volume of reservoir that will be contacted by the injected fluid. The latter, in turn, is dependent on horizontal and vertical sweep efficiency of the project. The following factors control sweep efficiency:

1. Pattern of injection
2. Off pattern wells
3. Unconfined patterns
4. Fractures
5. Reservoir heterogeneity
6. Continued injection after breakthrough
7. Mobility ratio
8. Position of gas oil and water oil contacts.

8.2 Homogeneous Reservoir

In this project, the reservoir was assumed to be a single homogeneous bed in which fluids moved horizontally. At the start of waterflooding, the project reservoir had already been produced by natural depletion during the first phase of primary production. In the initial reservoir condition, reservoir pressure was lower than the saturation pressure of the original oil in place (Fig 28).

Under the influence of increasing pressure due to injected water, free gas tends to re-dissolve into the oil, with which it is in contact over a large surface area. Consequently, oil production does not increase immediately after water injection. There is an initial filing period during which the volume of free gas initially present in the reservoir is injected. During this filling period, a large amount of gas will be re-dissolved, the remainder being produced at the production wells. The filling can be represented by oil traveling ahead of and much faster than the water front. Behind the oil front, gas saturation is at its residual value. The arrival of the oil front at the producing well marks the end of the filling period. (Fig 29)

When filling has been achieved, the frontal advance continues, but the oil production rate increases, eventually becoming practically equal to the rate of water injection. If initial formation water saturation was lower than required for it to flow, oil production during this second phase will be water-free.

Water production increases rapidly at the expense of oil production. The gradual recovery of oil behind the front is only obtained by the circulation of considerable volumes of water. During the final phase of injection, after breakthrough, the area swept will also be increasing; this may provide sufficient oil production to justify the continuation of injection. The project will come to an end once operating costs exceed the income of the oil produced.

For increase in the efficiency of water flood, different pattern injection methods are used. The relative location of injection and producing wells depends upon the geology of the reservoir, its type, and the volume of hydrocarbon-bearing rock required to be swept in a time limited by economics. It is advantageous, where possible, to make use of any favorable influence of gravity, for example, in inclined reservoirs, reservoirs with a gas cap, or reservoirs with an underlying aquifer.

This leads to two types of injection well locations:

a) Central and peripheral flooding, in which injectors are grouped together

b) Pattern flooding, in which injectors are distributed amongst production wells.

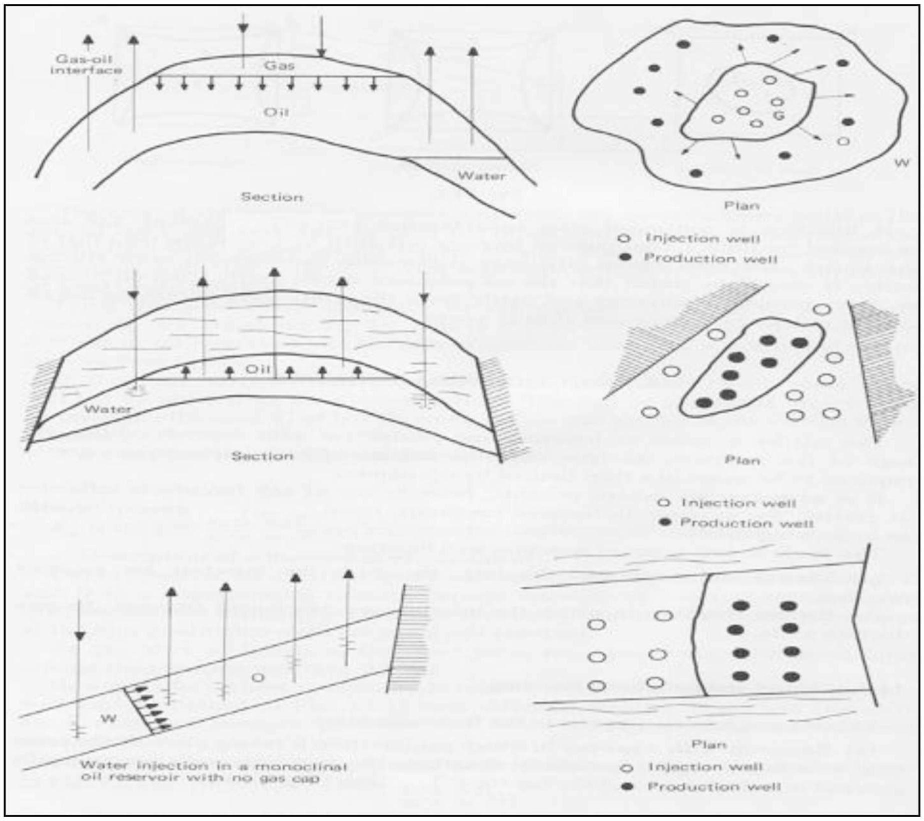


Figure 28: Injection Well Pattern in Anticline Reservoirs, (Latil, 1980)

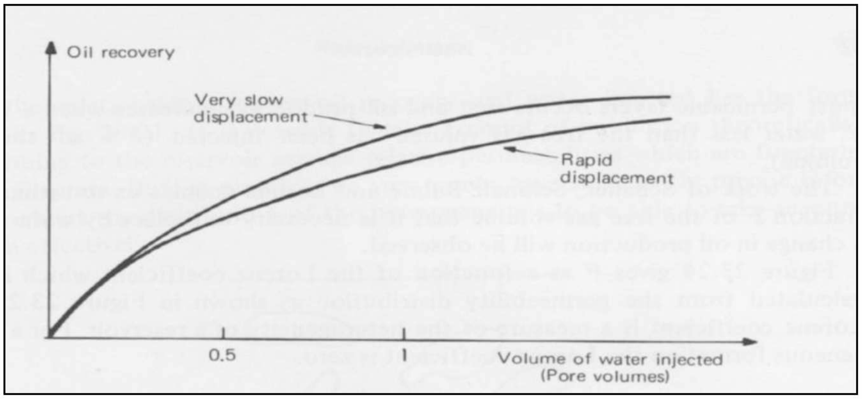


Figure 29: Effect of Waterflooding on Oil Recovery, (Latil, 1980)

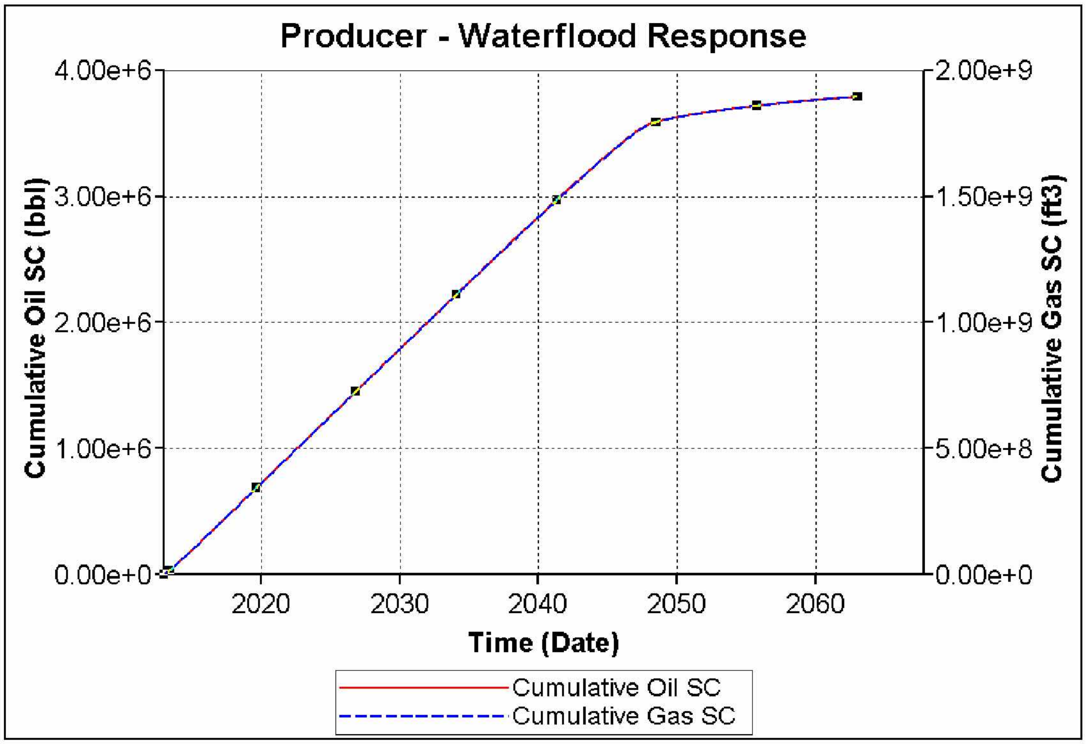


Figure 30: Cumulative oil produced - Waterflood

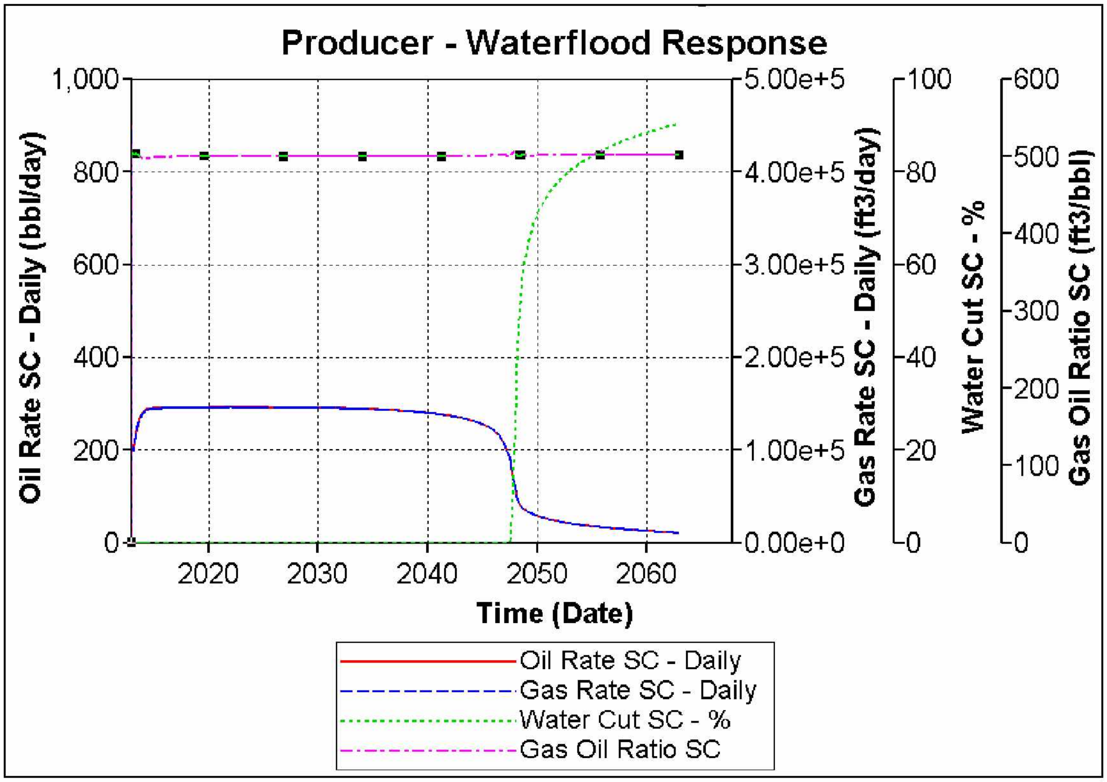


Figure 31: Gas, oil rate and water cut - Waterflooding

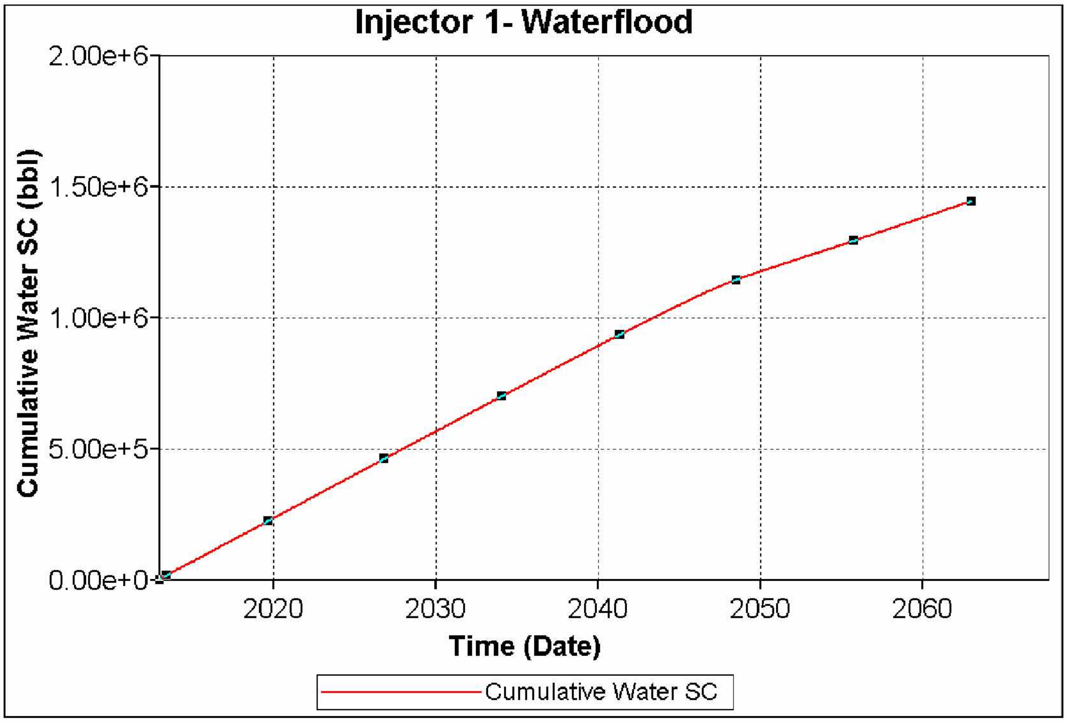


Figure 32: Cumulative water injected - Waterflood

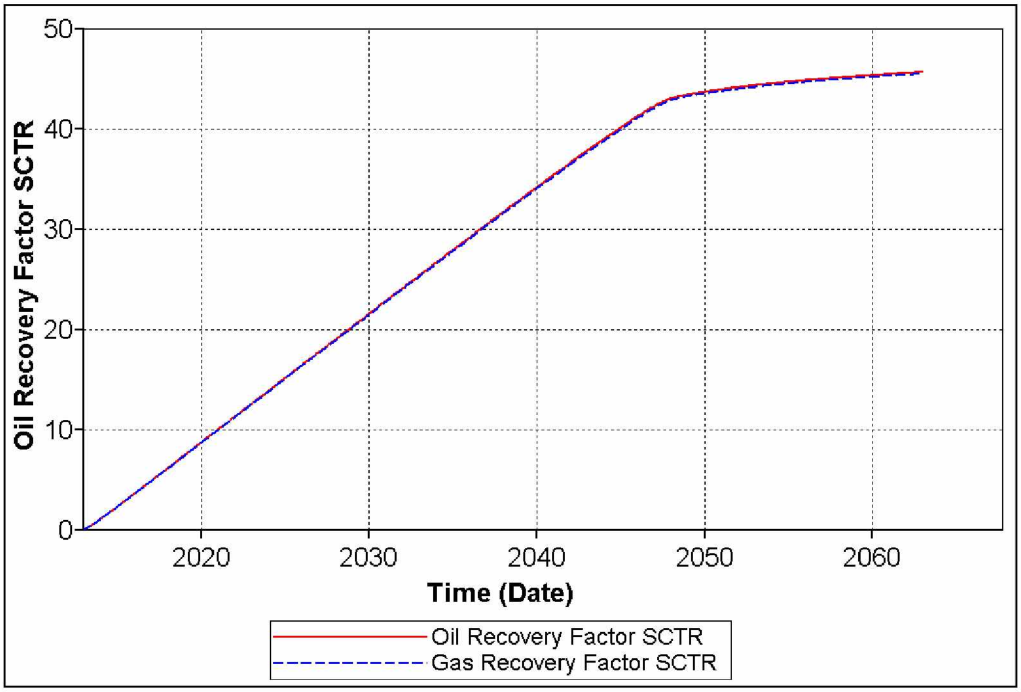


Figure 33: Oil and gas recovery factor

8.3 Comparison of primary and waterflood:

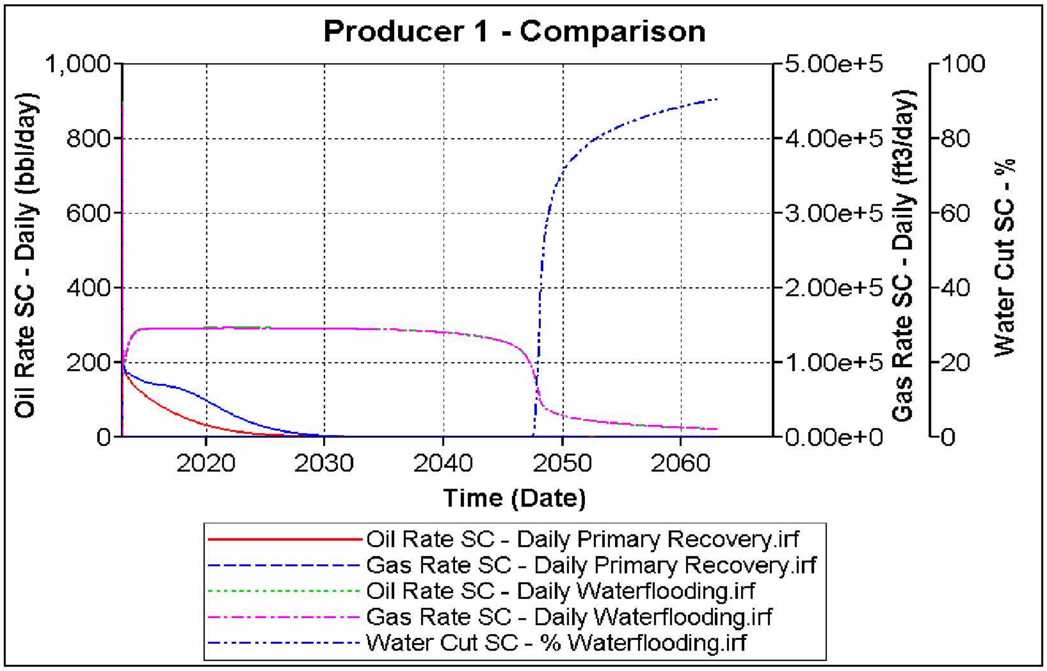


Figure 34: Comparison of primary recovery and waterflooding

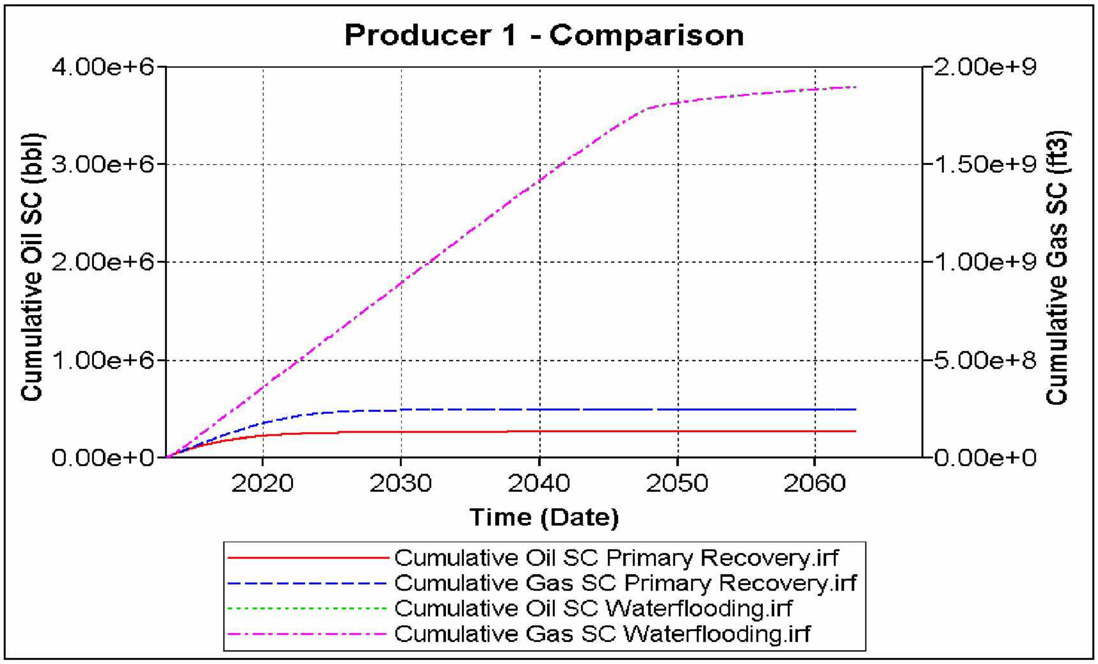


Figure 35: Cumulative oil recovered - Primary and waterflooding

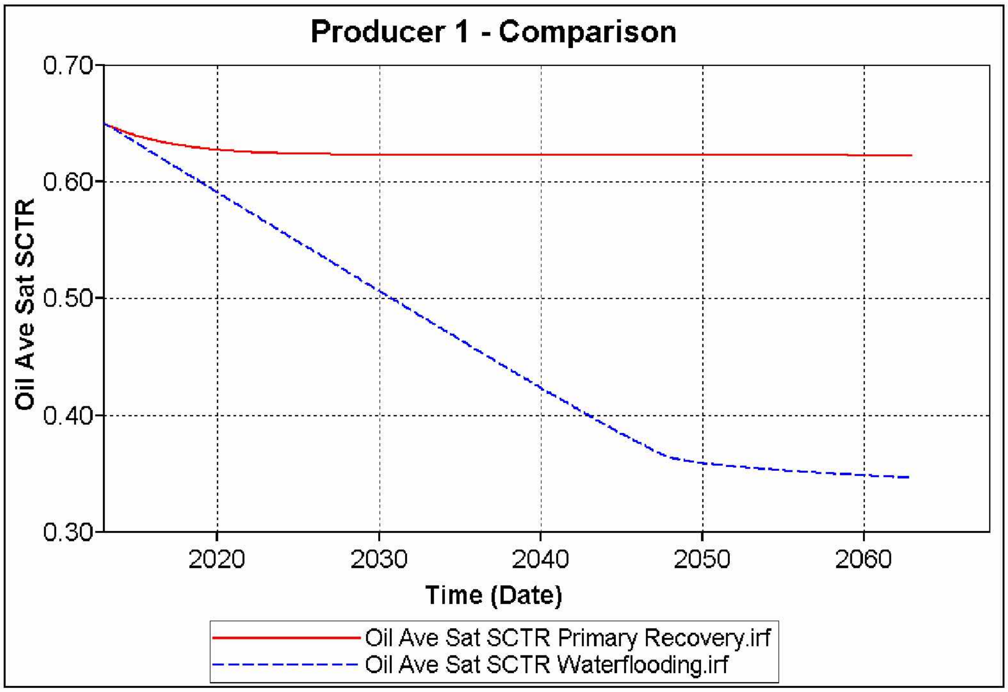


Figure 36: Average oil saturation - primary recovery and waterflooding

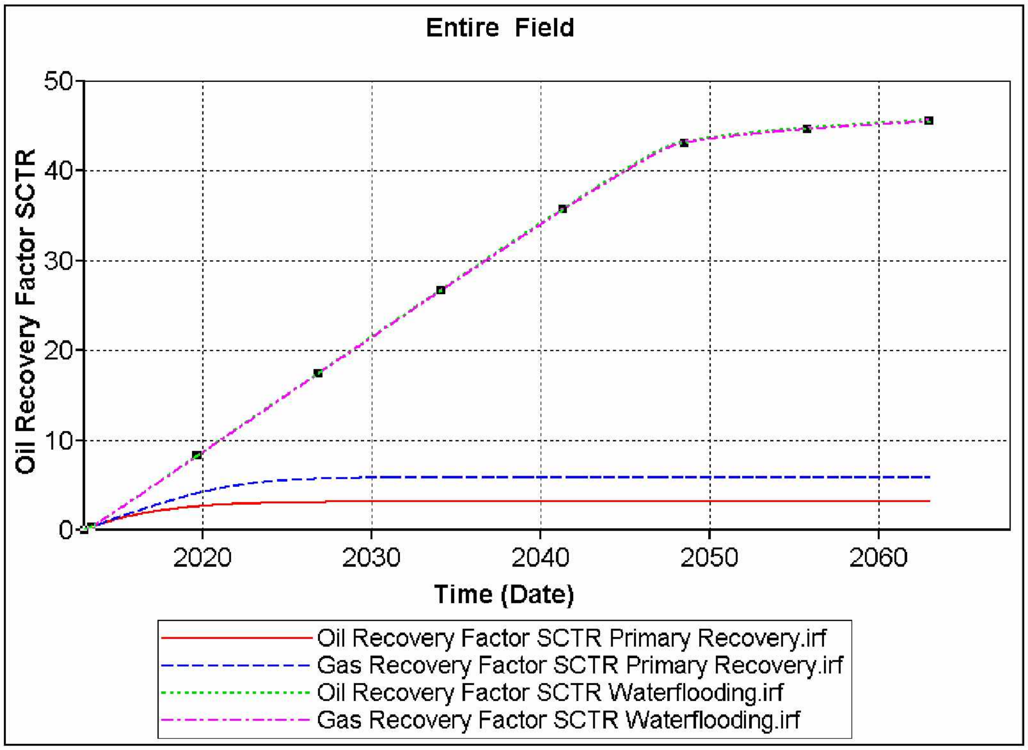


Figure 37: Recovery factor- primary recovery and waterflooding

Comparison of primary recovery and waterflooding suggests:

1. As shown in Figure 31 and Fig 34, high oil and gas production rates are sustained until 2046, at approximately 300 bpd and 1.10 e+5 ft3/day for waterflooding compared to 200 bpd for primary recovery.
2. Water starts invading the production well in 2046, as we can see in Figure 31, increasing to 90% by 2060, decreasing oil and gas production.
3. In waterflooding (Fig 34 and 37), oil and gas rates coincide with each other, indicating a constant-producing gas-oil ratio compared to a varying producing gas-oil ratio GOR in primary recovery.
4. The cumulative oil and gas produced in waterflooding is 3.96 e+06 bbls and 1.80 e+09 ft3, compared to 0.75 e+06 bbls and 0.1 e+06 ft3 in primary production.(Fig 30, 35)
5. The steep increase in the slope of the graph (Fig. 35, 37) for waterflooding suggests rapid displacement due to the homogeneity of the reservoir.
6. The change in slope of the oil recovery graph (Fig. 34) after 2046 was observed due to water invasion of production wells, indicating water breakthrough in the reservoir.
7. Average oil saturation values at end recovery for the primary method barely reached 0.65, while waterflooding reduced this value to 0.34 (residual oil saturation value), suggesting effective displacement.(Fig 36)
8. Due to rapid displacement of displaced phase, the recovery factor for waterflooding was 45%, while primary recovery was ~6% at 1300 psi producing BHP.(Fig 33,37)

CHAPTER 10. ASP FLOODING

The simulation model developed was used to conduct ASP flooding. For a fair comparison between primary recovery and secondary/tertiary recovery, such as water flooding and ASP flooding, the same specific technical parameters were used to design and develop the ASP model. ASP was injected into a reservoir in slugs with water as a chasing medium in order to have a more economical and efficient recovery. The process was conducted in stages. In the first stage, water was injected for a year to act as preflush, conditioning the reservoir for ASP action. Further ASP was injected for two years, followed by water for one year. This cycle of 2 years ASP followed by 1 year of water injection was repeated several times.

Alkali (NaOH) and surfactant leading in ultra low IFT were used in the process. A polymer with a molecular weight (MW) of 8000 lb/mol (CMG chemical module) was used to achieve conformance control. First, liquid with a composition of 100 ppm polymer, 0.11% weight surfactant, and 0.1% weight alkali was injected. The recovery factor was increased to 53%, a 20% increase compared to that obtained from waterflood (45%).

The following table 10-1 shows the sequence of injection:

Table 10-1 Injection sequence for ASP

Chemical	From	To
Water	2013	2014
ASP	2014	2017
Water	2017	2019
ASP	2019	2022
Water	2022	2067

Results were as follows (Table 10-2) (ASP model results with 50 ppm polymer):

Table 10-2 Results of ASP (50 ppm) flood

Cumulative Oil recovered (bbls)	4.37*10E6
Cumulative Gas recovered (ft3)	2.17*10E9
Recovery Factor (%)	52.19
Residual oil average saturation	0.30
Water injection volume	5.7*10E6
Life of project (up to 80% water cut) (years)	16

The cumulative oil recovered in ASP flooding was more than that recovered in waterflooding, making it an effective recovery method.

During the injection of water in the initial phase (2013-2014), the injection rate was high (average: 1500 bbls/day), but dropped as ASP arrived at the wellhead (average: 300 bbls/day). This drop was caused by the increase in injection water viscosity due to the addition of polymer at constant IBHP (5100 psi).

Interpolation sets for the logarithm of the capillary number for ASP recovery in CMG were set between -2 and -10. These were used to calculate saturation and subsequent oil recovery during flooding. However, to study sensitivity and its effect on recovery, various interpolations, from -2 to -25, were used. Recovery was observed to be almost the same (only varying by 2% w.r.t. oil recovery for 50 ppm polymer) with the logarithmic interpolation method.

The observed increase in recovery was due to:

a. Decrease in IFT due to surfactants and in situ surfactant formation due to alkali
b. Increase in capillary number (N_{ca})
c. Emulsion formation due to alkali and surfactant interaction with oil
d. Improved sweep efficiency due to conformance control.

The gas-oil ratio remained constant during the process, but changed when water cut was 100%. Water cut was observed earlier (in 2036) in this recovery method due to higher injection rates and an increase in sweep of oil over a short span of time. However, the observed amount of PV swept by displacing fluid was less, because of less injection volume due to injection at IBHP (5100 psi). It can be increased in future simulations by increasing well injectivity, which will ultimately increase well productivity.

Sensitivity of polymer concentration:

The alkaline-surfactant-polymer process has two mechanisms. First, the viscosity of the displacing fluid is increased in order to improve macroscopic sweep efficiency. Second, oil-water interfacial tension is reduced to improve microscopic sweep efficiency. This results in improved overall volumetric sweep efficiency. In this project, the viscosity of the injection fluid was changed by varying polymer concentration, and its effect on recovery was observed.

Observations and results obtained from runs are given below:

1. Polymer concentration was varied from 50 ppm to 2000 ppm and compared for the same injected volume and surfactant-alkali concentration. However, recovery observed was the same for all scenarios but time, in which the amount of oil recovered was different. (Fig 38,39,42) The time at which 80% water cut was observed in the well increased as polymer concentration increased. This was due to the increase in viscosity as constant injection bottom hole pressure decreased injection rate.

2. At 50 ppm polymer concentration, the same amount (52.19%) of oil was recovered at a faster rate (23 years) compared to recoveries at other polymer concentrations (2000 ppm - 29 years).(Fig 41,43) From an economic point of view, an equal amount of oil recovered in a shorter span of time gives more net revenue with less taxes and operating costs.

3. A 50 ppm polymer concentration produces low viscosity injection fluid, resulting in an equal amount of water injected over a short span of time (23 years), decreasing operating expenditure (OPEX) and maintenance costs of injection plants.(Fig 40, 43)

4. The trend of water cut remained the same for all polymer concentrations, but the time at which it occurred in the production well changed (23 years for 50 ppm and 29 years for 2000 ppm). (Fig 42)

5. The average reservoir pressure increased to a maximum of 4000 psi at the end of the injection process, when compressibility was at a minimum. However, when a water channel encroached into the production well, water cut increased continuously.

6. Effect of capillary curves on residual saturation of oil is described by Fig 44, 45. As polymer concentration decreases from 2000 ppm to 50 ppm, capillary number increases for same residual saturation, resulting in effective displacement. When compared it with standard graph of residual saturation, it showed that, reservoir is homogeneous and composed of well sorted sand, which is in agreement of simulation inputs.

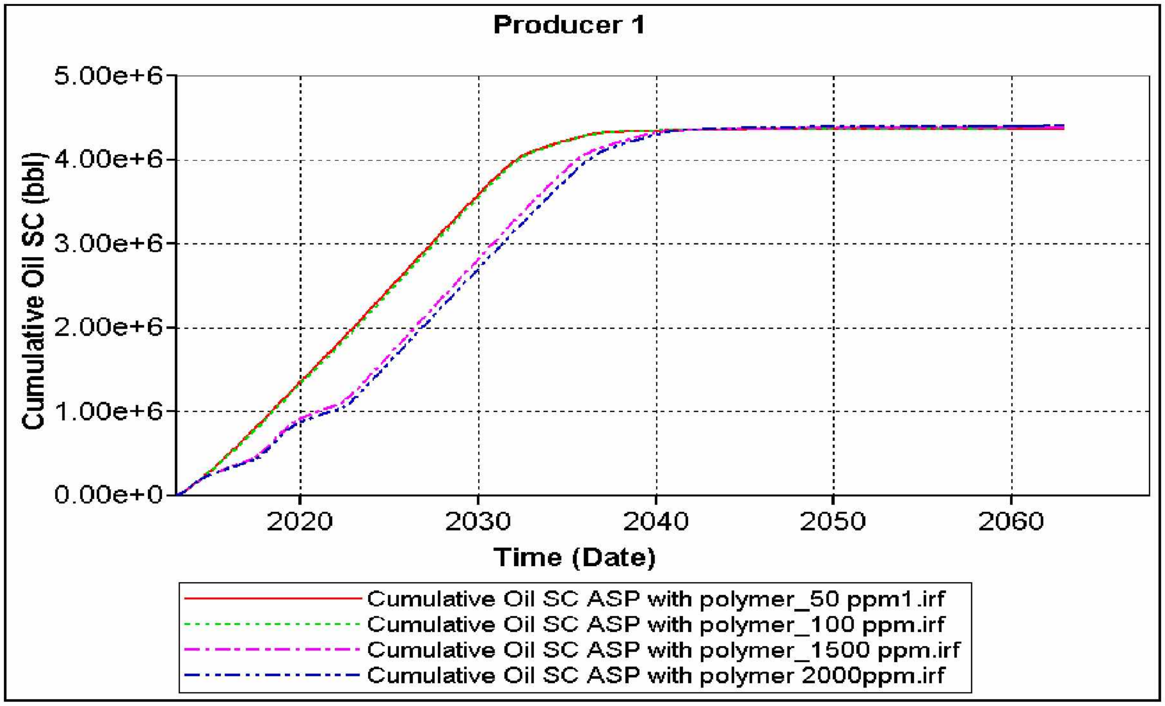


Figure 38 Cumulative oil recovery at different polymer concentration

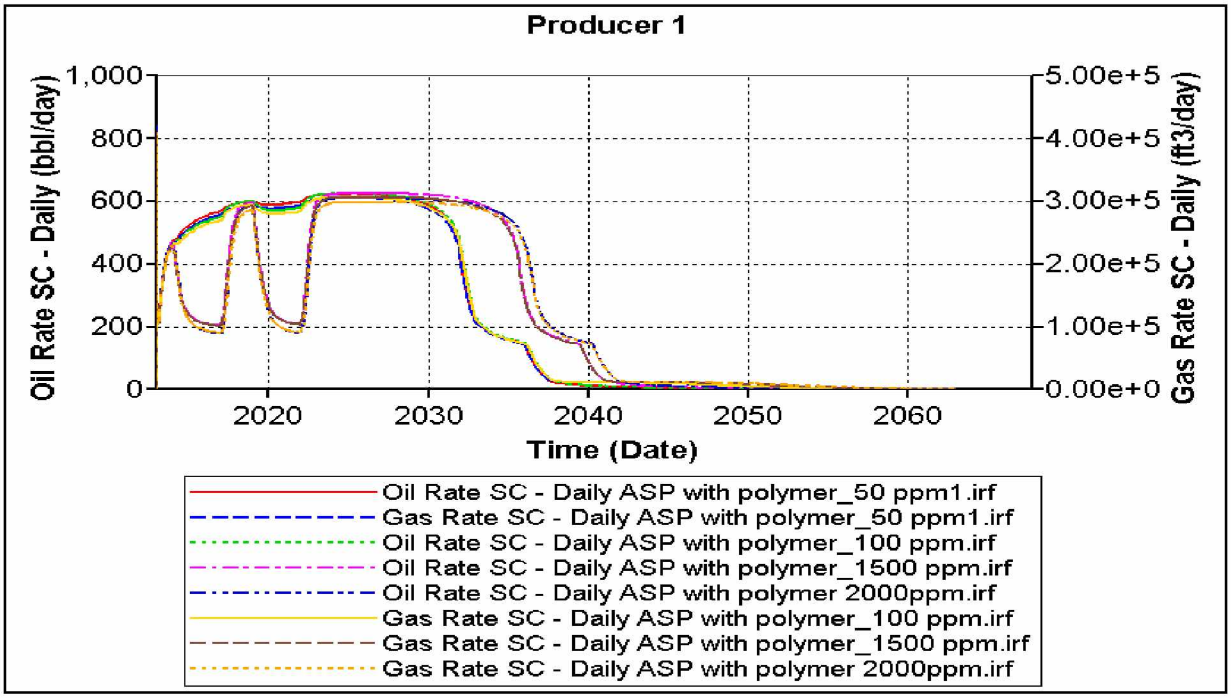


Figure 39 Daily oil and gas rates at different polymer concentrations

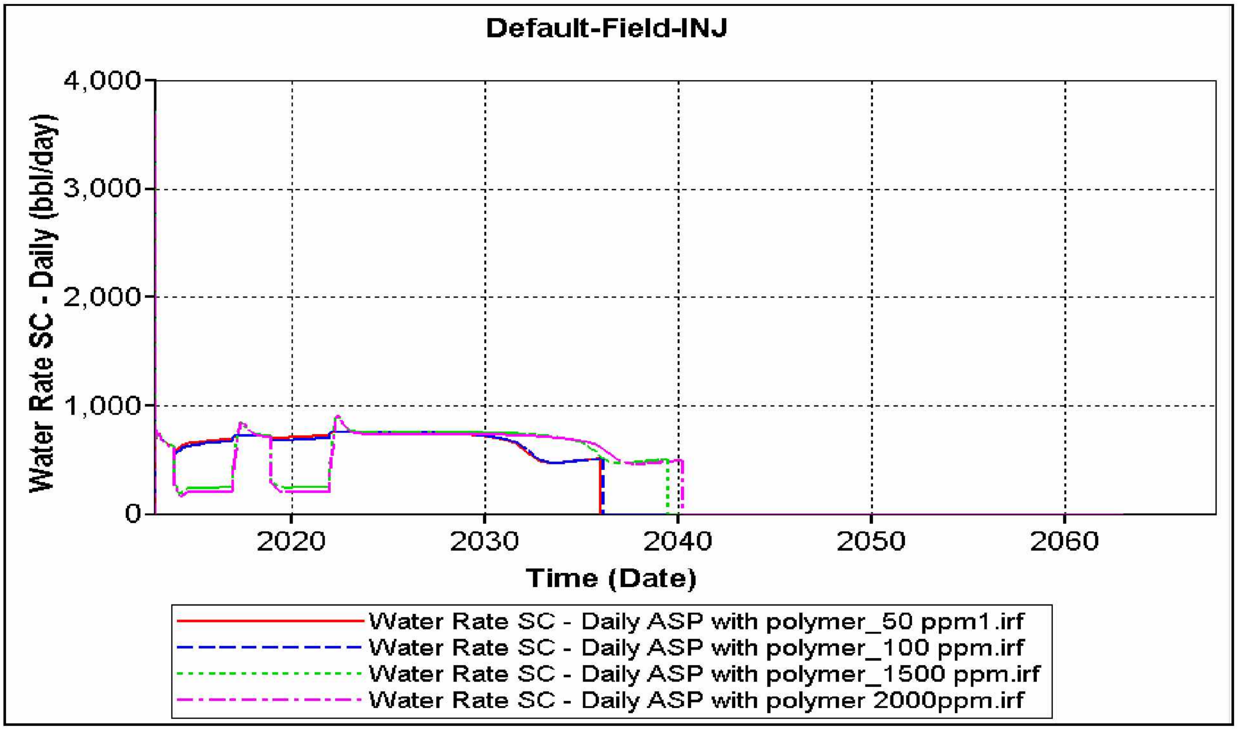


Figure 40 Daily field water injection rate at different polymer concentrations

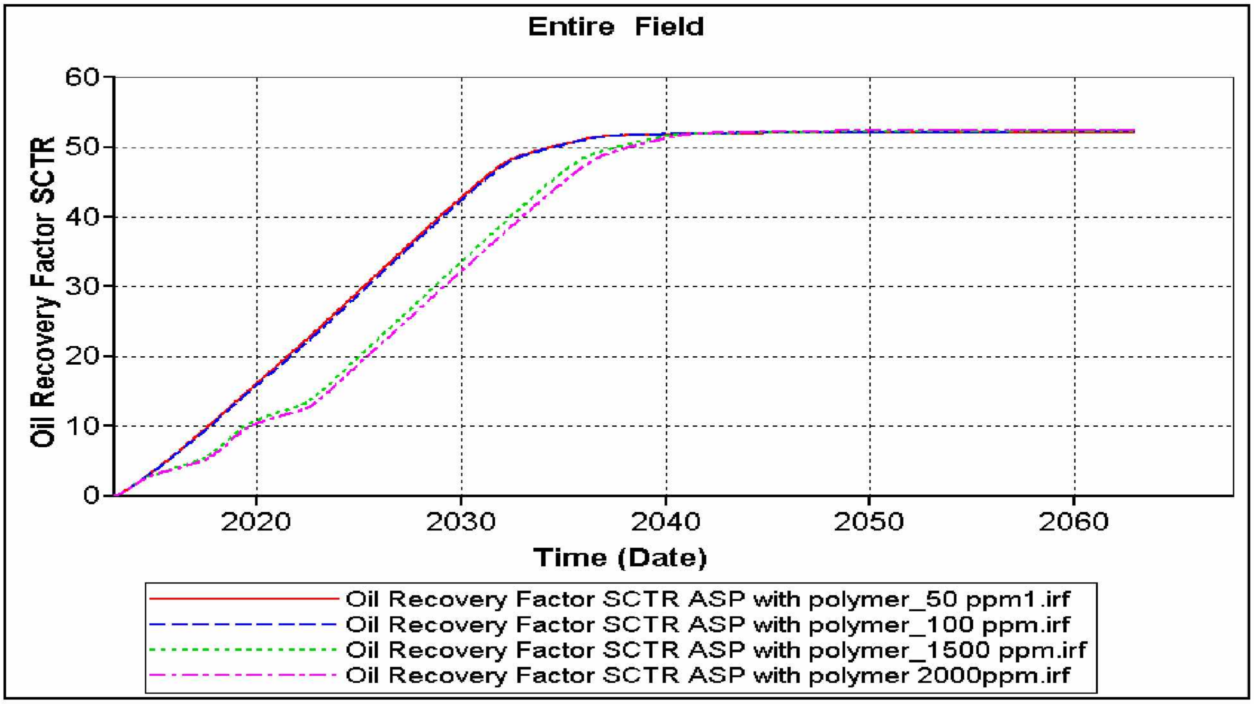


Figure 41 Oil recovery factor at different polymer concentrations

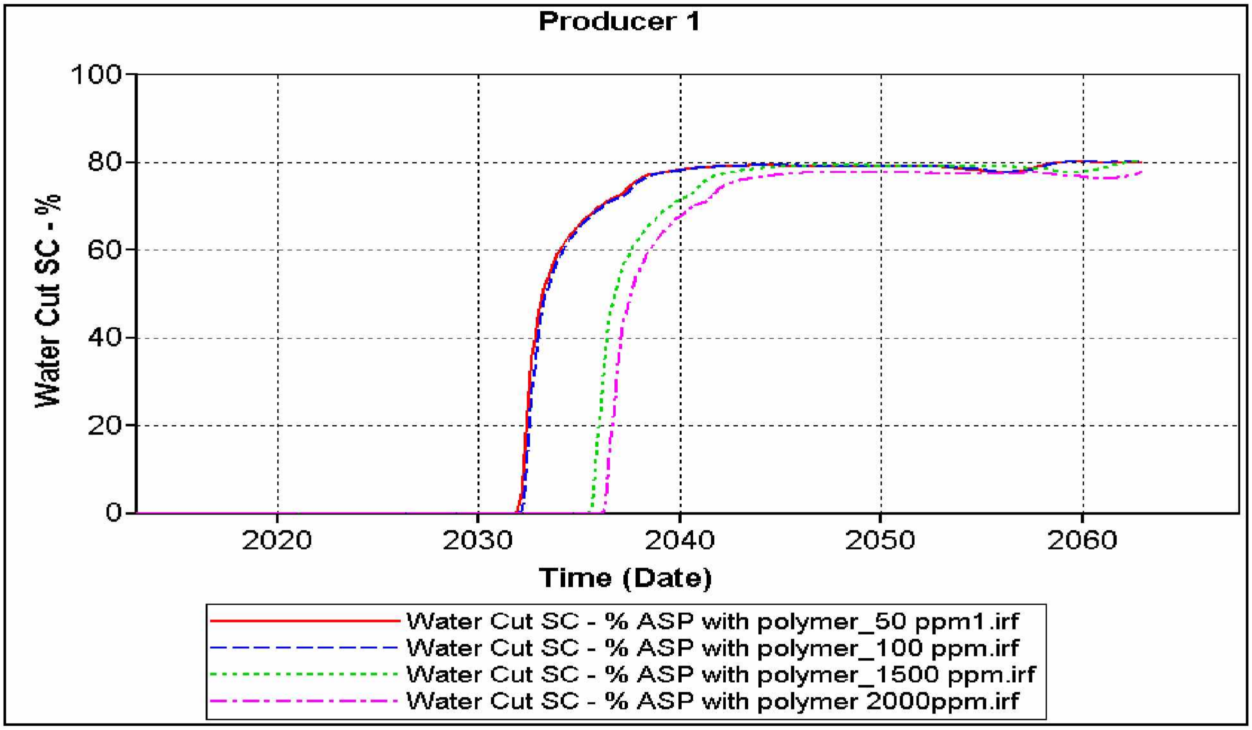


Figure 42 Water cut at different polymer concentrations

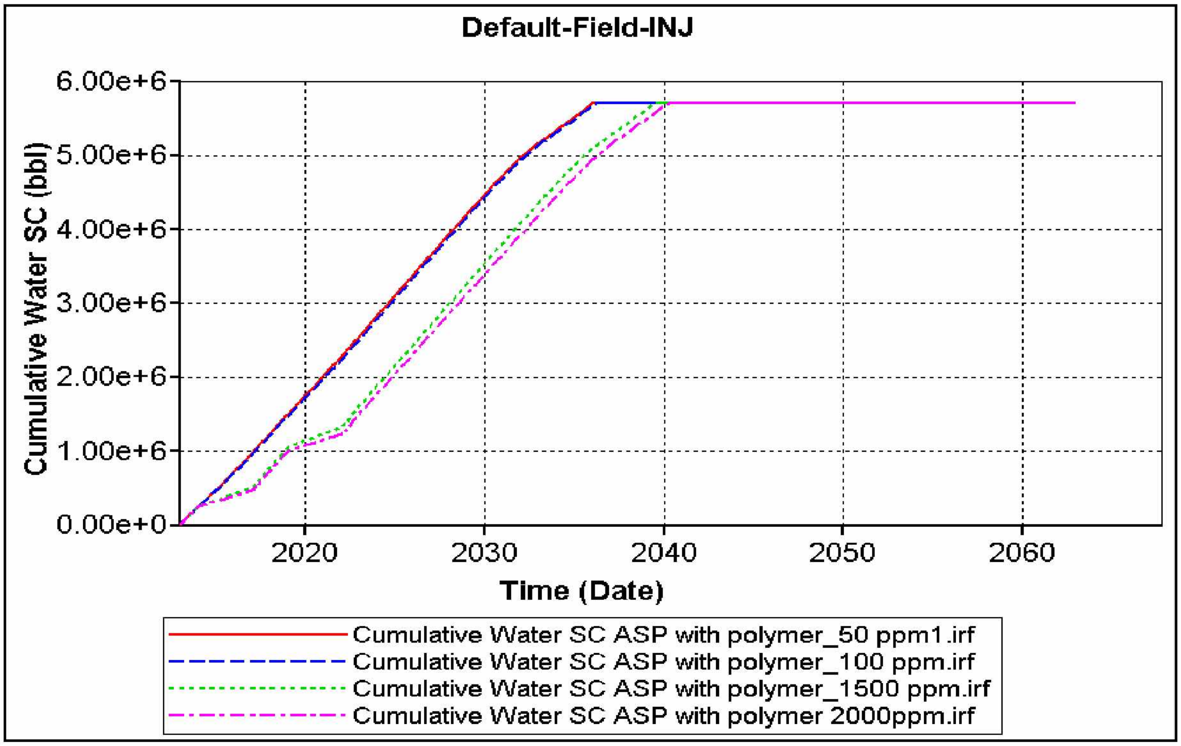


Figure 43 Cumulative Water injected at different polymer concentrations

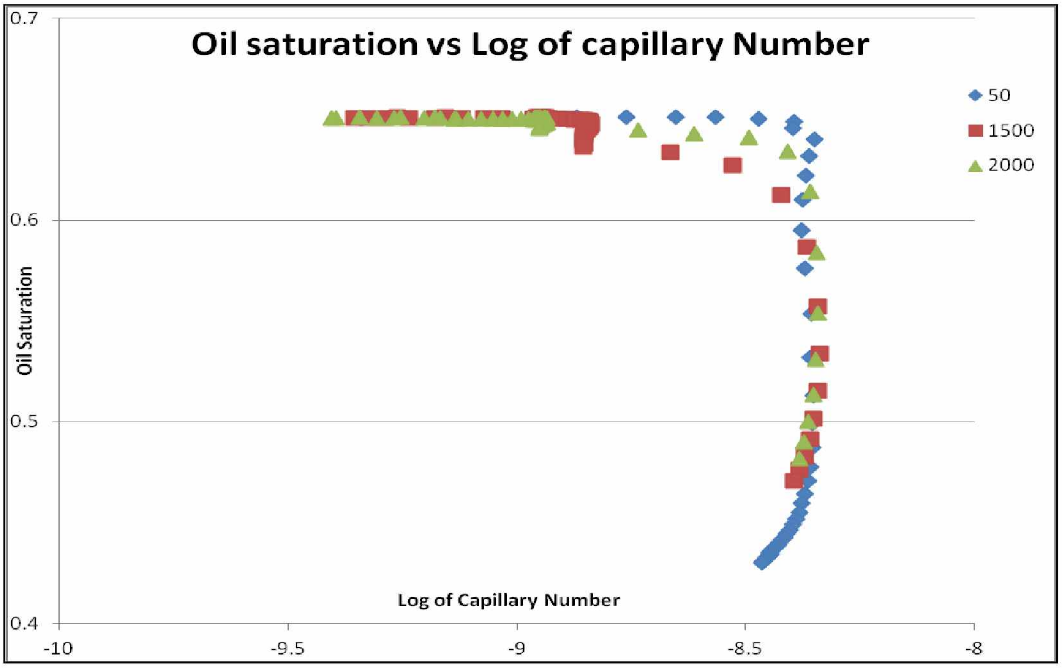


Figure 44 Oil saturation vs. Log of Capillary number

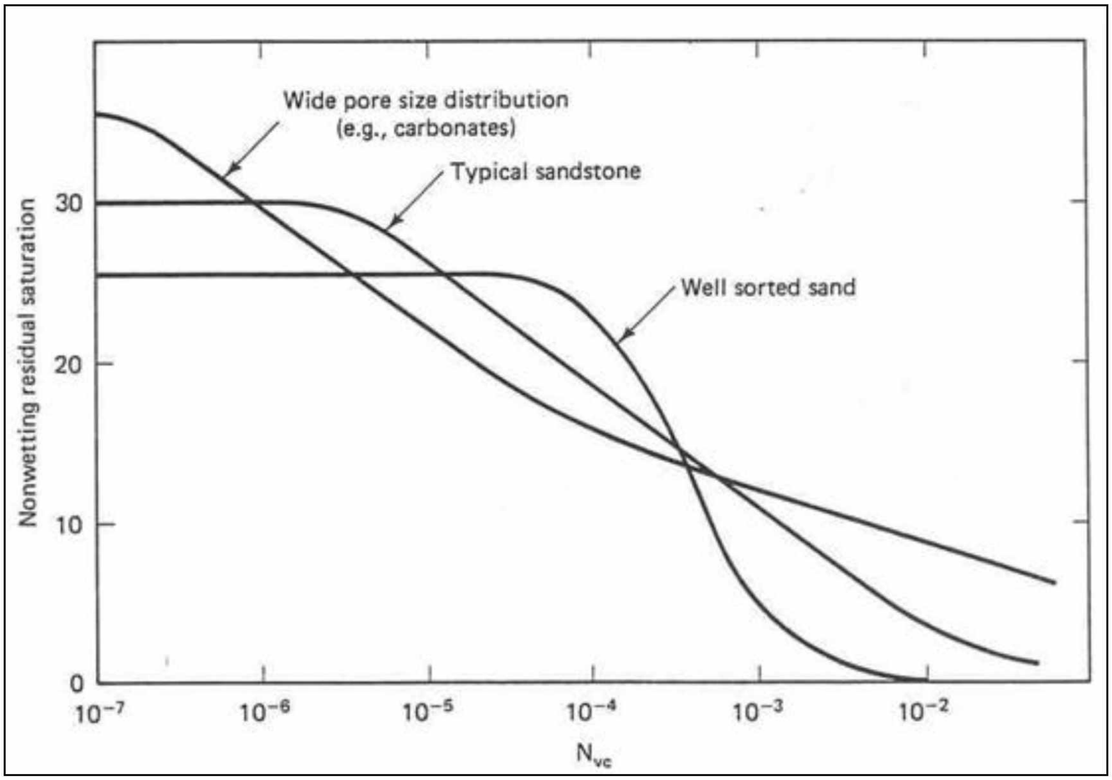


Figure 45 Pore size distribution and capillary number (Lake, 1989)

Comparison for Primary, waterflood and ASP (50 ppm -Polymer)

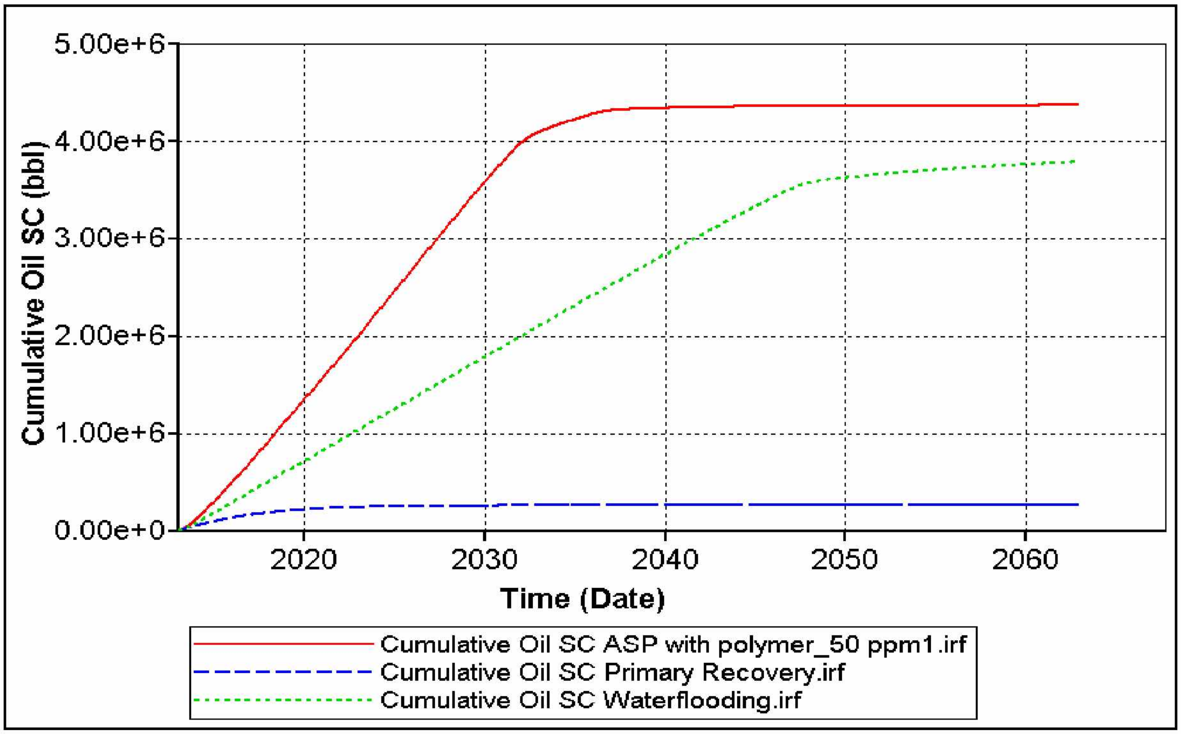


Figure 46 Cumulative oil recovered for different recovery methods

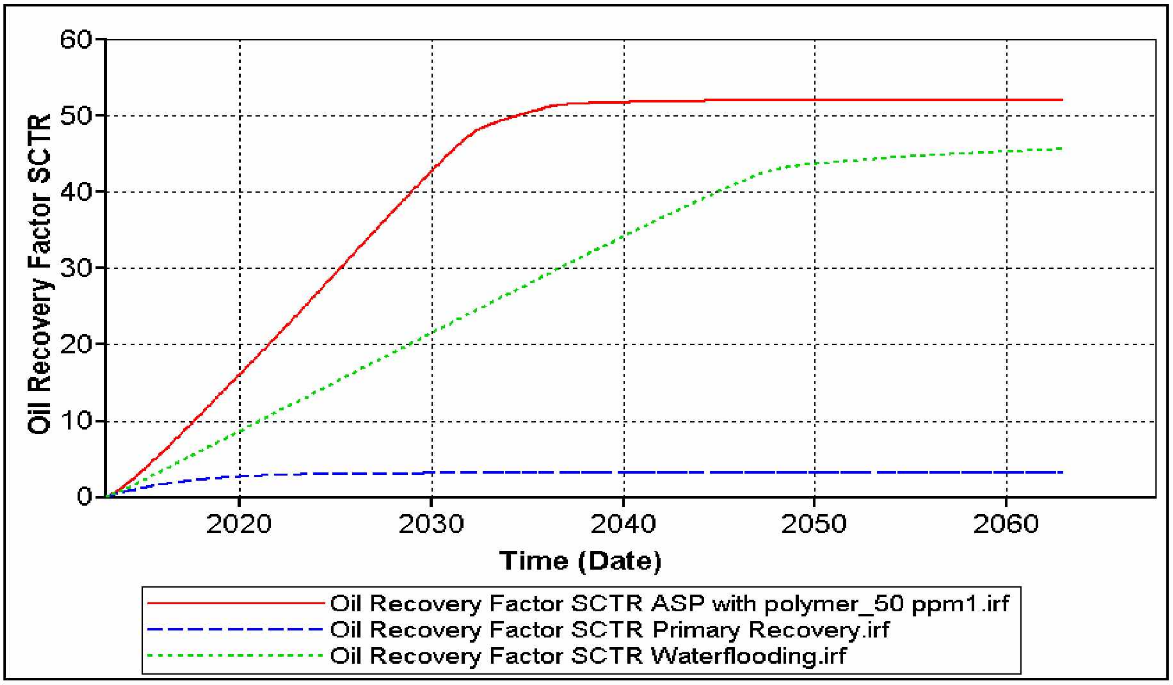


Figure 47 Oil Recovery factor for different recoveries

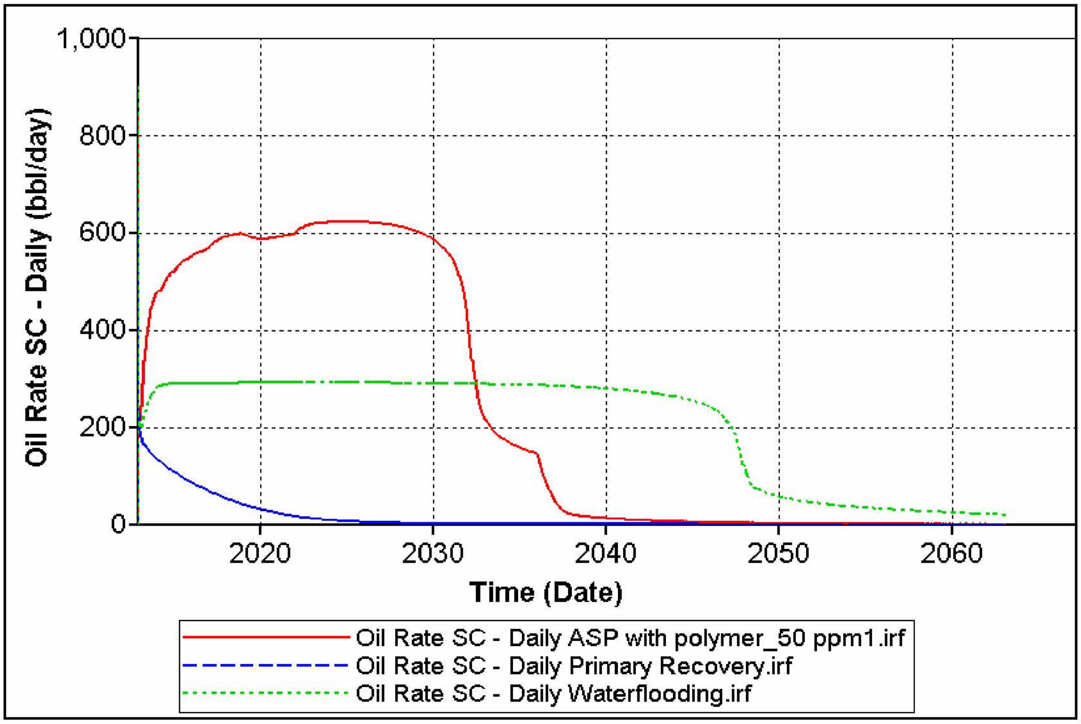


Figure 48 Daily oil rate for different recovery methods

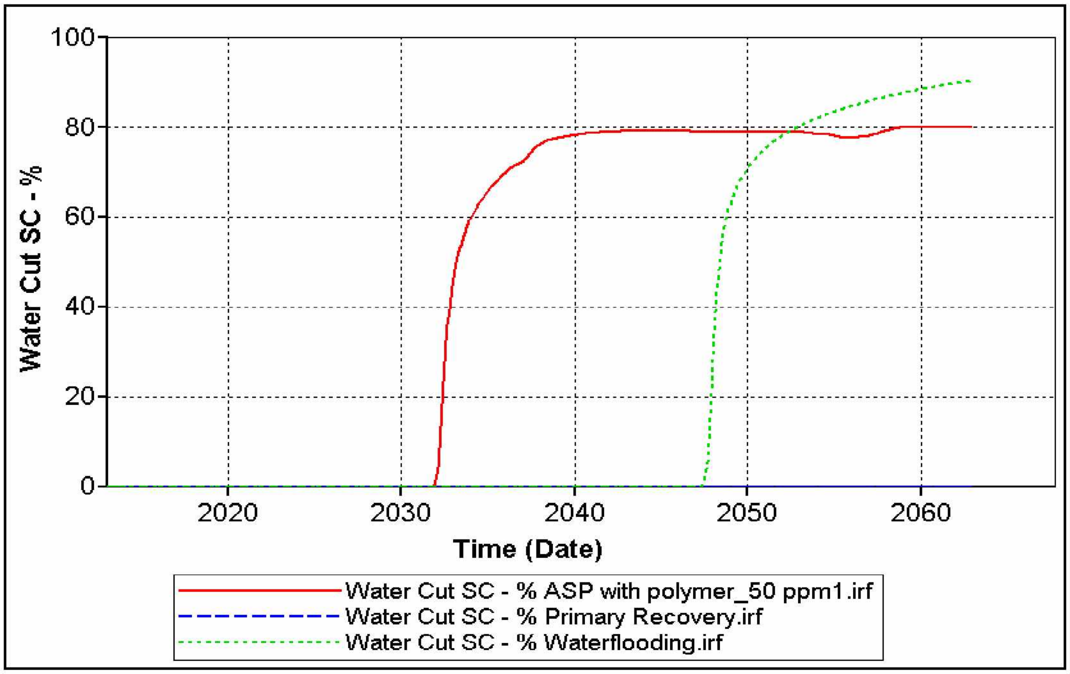


Figure 49 Water cut at different recoveries

Comparison of ASP, Waterflood, and Primary recovery

Results for these recovery methods are given below (Fig 46, 47, 48, 49) and (Table 10-3):

Table 10-3 Summary of different recoveries

Recovery	Primary	Waterflood	ASP (50 ppm)
Cumulative Oil recovered (bbls)	268186	3.78*10E6	4.37*10E6
Cumulative Gas recovered (ft^3)	2.45*10E8	1.89*10E9	2.17*10E9
Oil Recovery Factor (%)	4	45	53
Injection volume (bbls)	NA	5.7*10E6	
Life of project (oil rate ~10 bpd)	10	50	30
Observed time of water cut in production well	NA	2047	2032

As discussed above,(Table 10-3) the oil recovery factor was greatest for the ASP flooding process for the same injection volume. This suggests that ASP flooding is beneficial even in reservoir fluids with low viscosities (2 cp). However, increasing polymer concentrations reduces the injection rate at constant BHP, decreasing sweep and recovery factor.

The sensitivity analysis done in the simulation shows that the polymer concentration in an ASP flood does not contribute much to the oil recovery. From a theoretical/simulation point of view, the flooding can be only done with ASP without polymer, thus improving overall project economics without compromising recovery. However, these findings must be backed up by strong lab results before being implemented at a field level.

CHAPTER 11. ASP OPTIMIZATION

Further to check effect of each component on recovery, alkali, surfactant and polymer was injected in reservoir individually to optimize and understand effect on recovery. It was observed that effect of 0.1% alkali was more prominent in accelerated recovery followed by 0.11% surfactant and 50 ppm polymer concentration.

Alkali concentration produces insitu surfactants which helps to reduce capillary number (Nca) defined as ratio of viscous forces to capillary forces ($Nca = v\mu/\sigma$) (Green & Willhite, 1998), and helps to decrease residual oil saturation and produce oil more effectively. In surfactant and polymer recovery, water injection rate at constant BHP was less, hence displacement and voidage replacement rate was less results in delaying of production. (Fig 50)

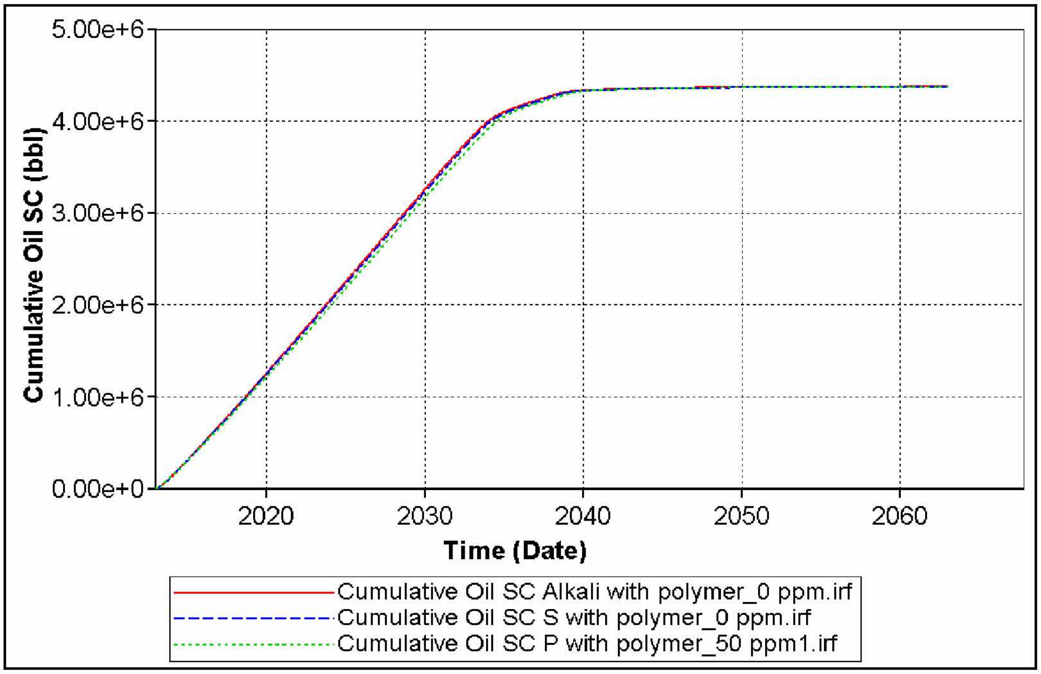


Figure 50 Cumulative Oil Produced

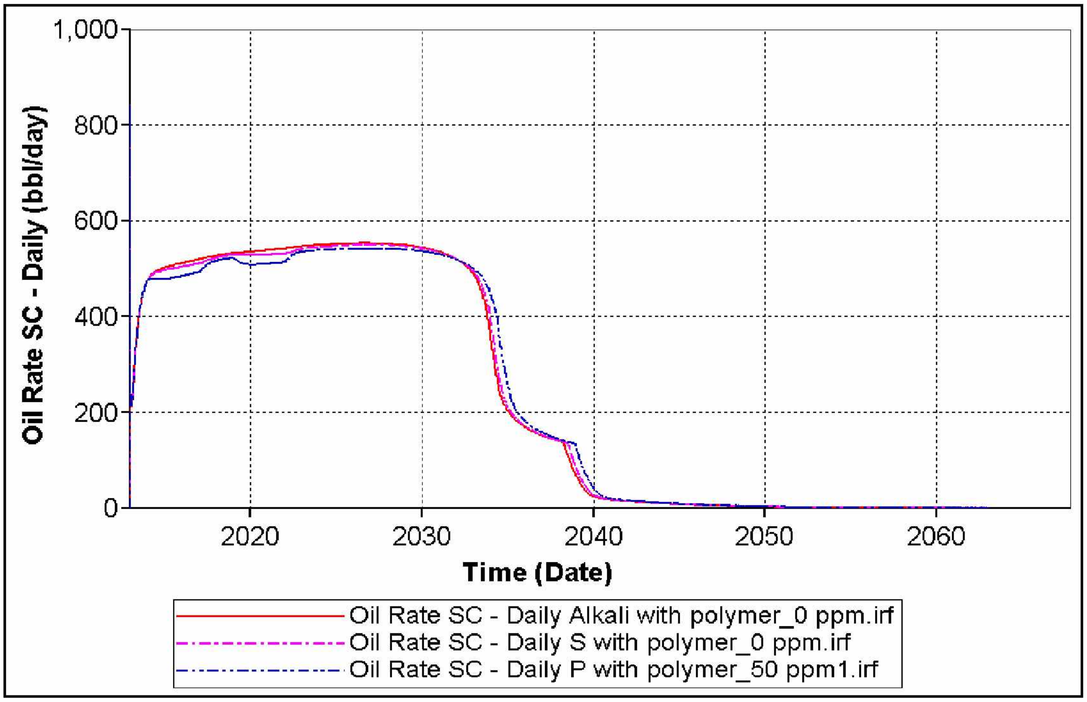


Figure 51 Comparison of Oil and Gas rates for A, S, P flood

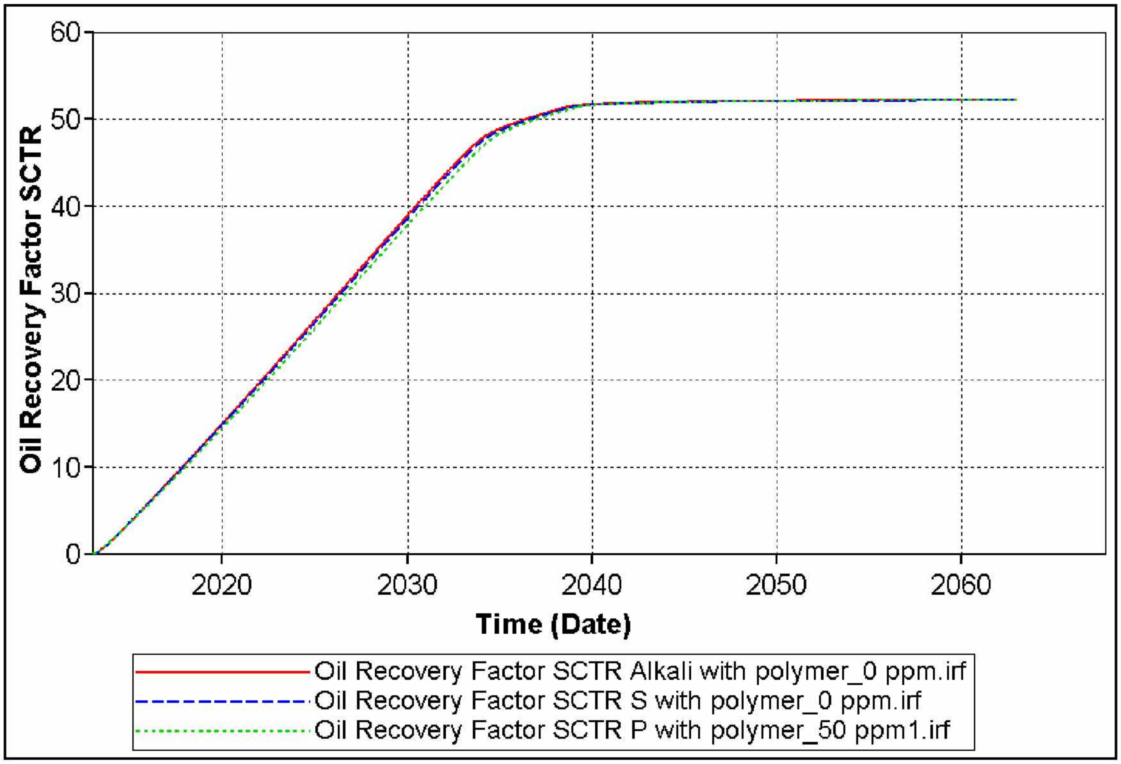


Figure 52 Comparison of oil recovery factor for A, S, P flood

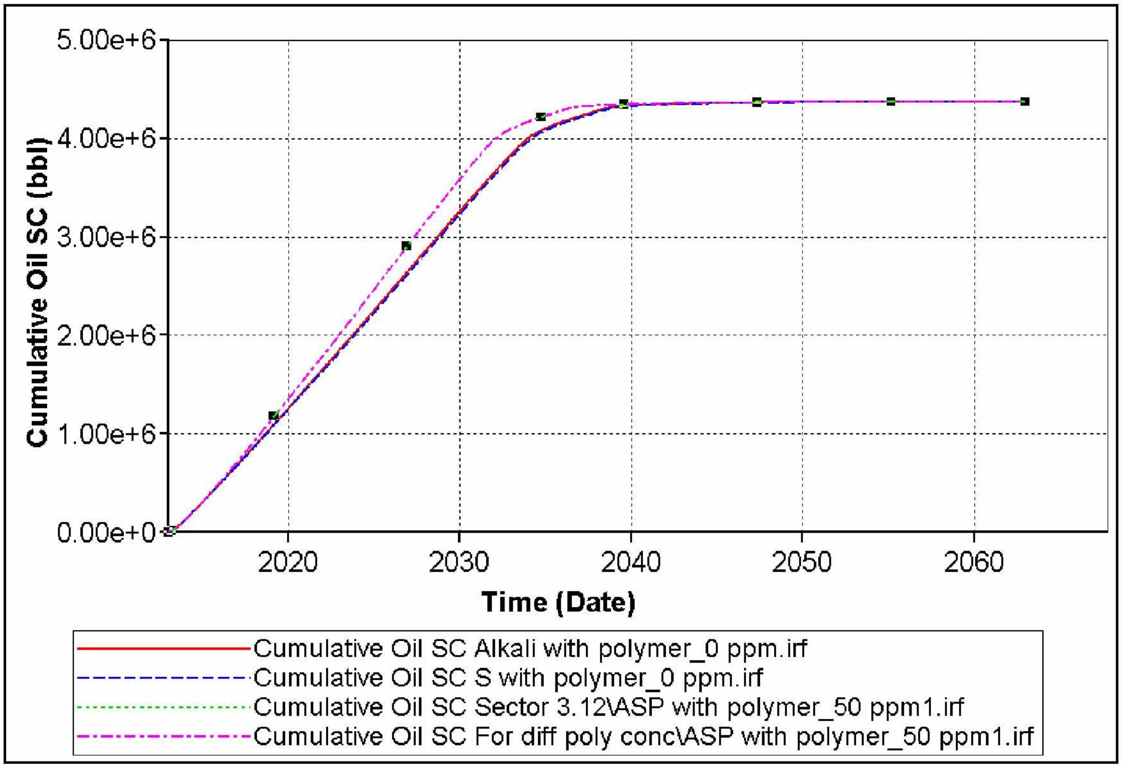


Figure 53 Accelerated recovery for ASP flooding

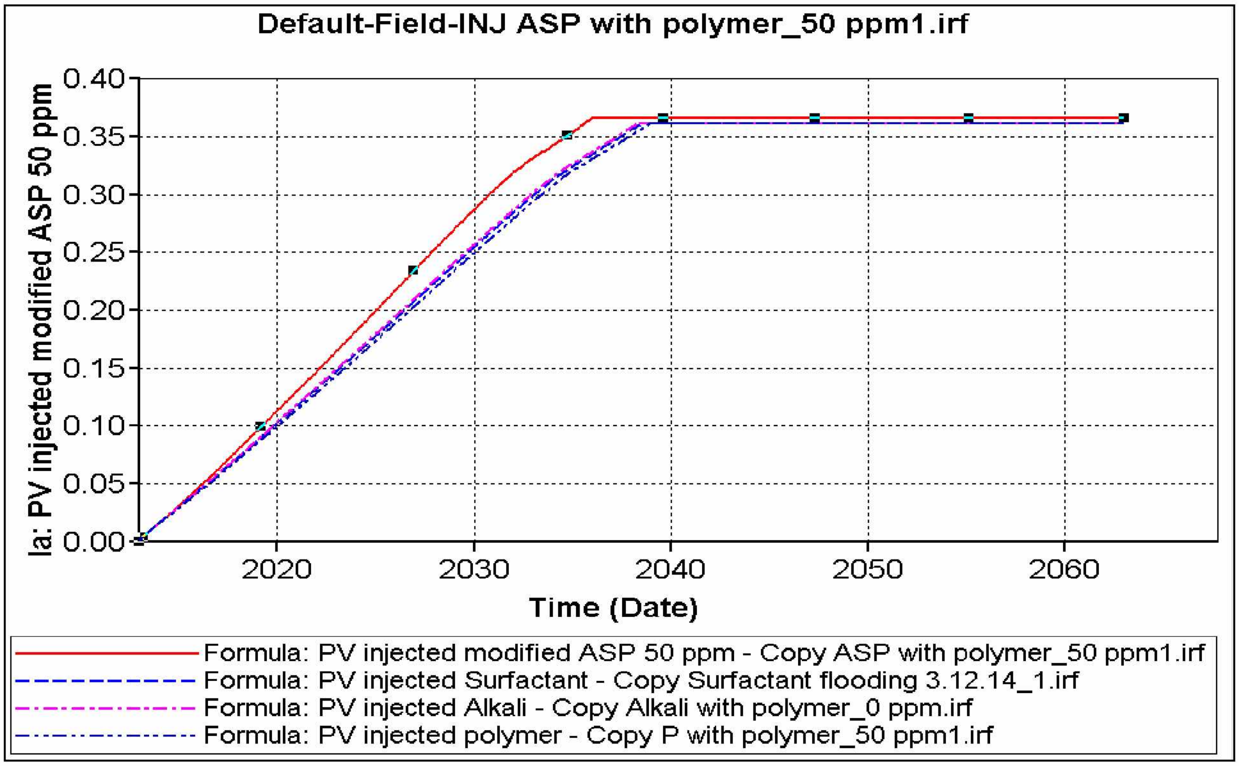


Figure 54 PV injected for A, S, P and ASP flooding

However, interesting fact to be noted here that, when all results were compared to previously selected ASP (0.1% - alkali, 0.11% Surfactant and 500 ppm concentration), alkali flooding was observed to produce more oil by (5000 bbls) at end of recovery but it not significant. It may be due to effect of IFT reduction was observed more prominent to oil recovery than mobility control, but for optimized and accelerated recovery combination of IFT reduction and mobility control is necessary. Hence, accelerated recovery was observed with ASP combination compared to all methods. Comparison was shown as below (Fig 51, 52, 53,54) and (Table 11-1):

Table 11-1 Comparison of values of A,S,P and ASP (50 ppm) flooding

Recovery	Polymer	Alkali	Surfactant	ASP with 50 ppm
Cumulative Oil recovered (bbls)	4372942.5	4374661.5	4370942.5	4371150
Cumulative Gas recovered (ft^3)	2176280320	2177227264	2175365632	2175951104
Oil Recovery Factor (%)	52.1486282	52.16912842	52.12477875	52.123
Injection volume (bbls)	5.7*10E6			
Life of project (oil rate ~10 bpd)	31	30	30	30
Observed time of water cut in production well	2034	2033	2033	2032

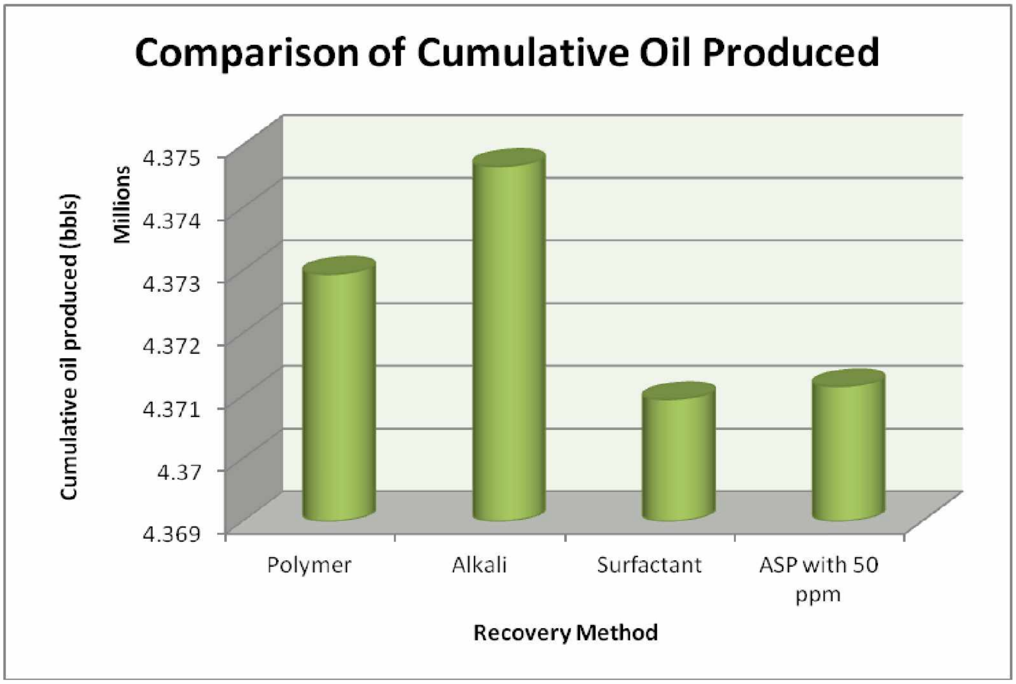


Figure 55 Comparison of cumulative oil recovered for A, S, P, and ASP flooding method

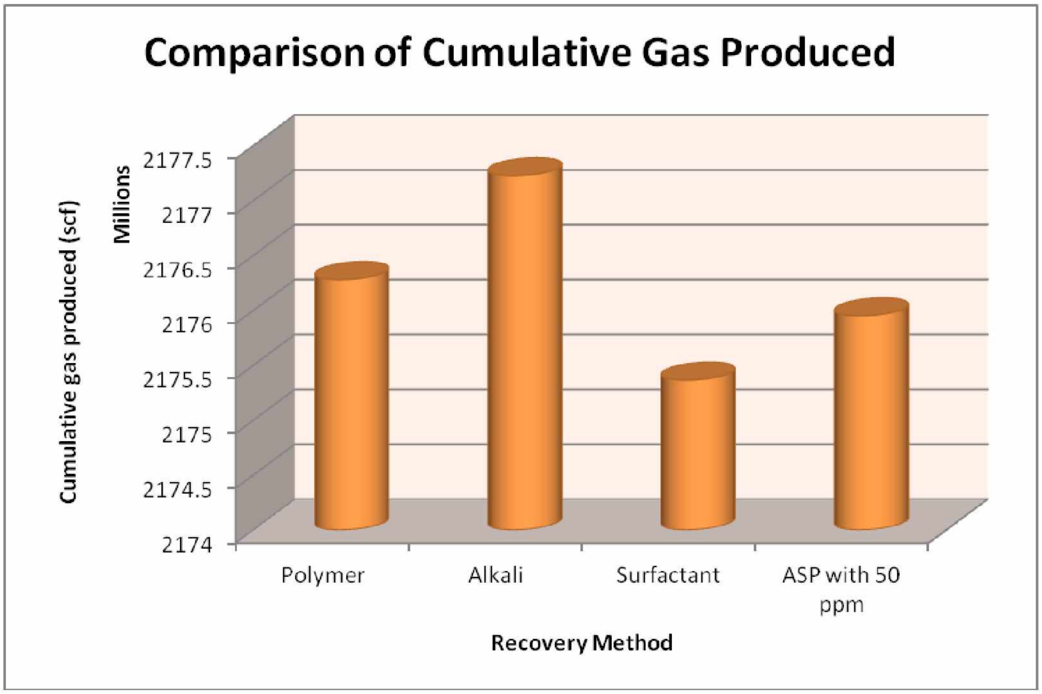


Figure 56 Comparison of cumulative gas recovered for A, S, P and ASP flooding method

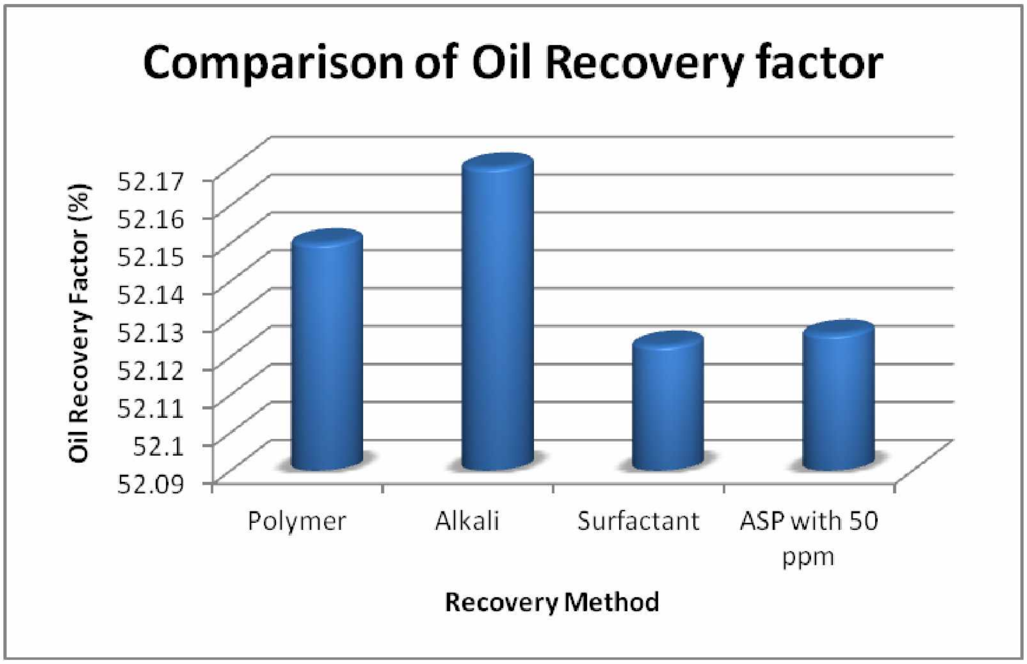


Figure 57 Comparison of oil recovery factor for A, S, P, ASP flooding method

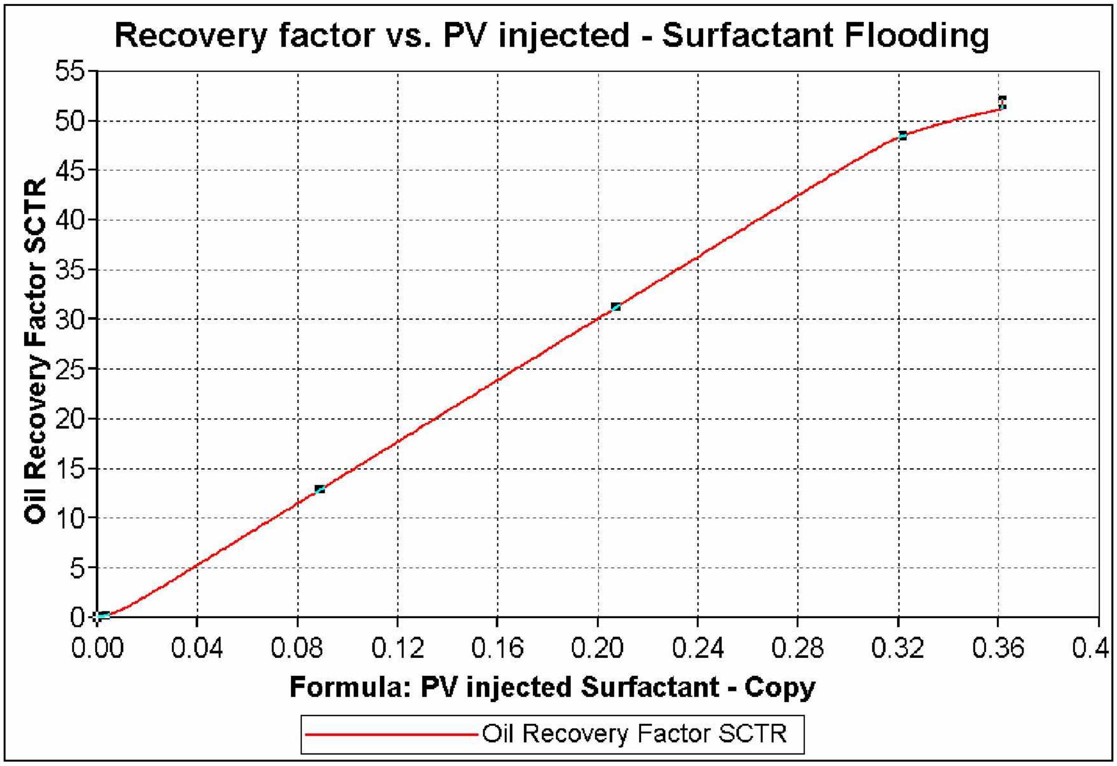


Figure 58 Recovery factor vs. PV injected for Surfactant flooding

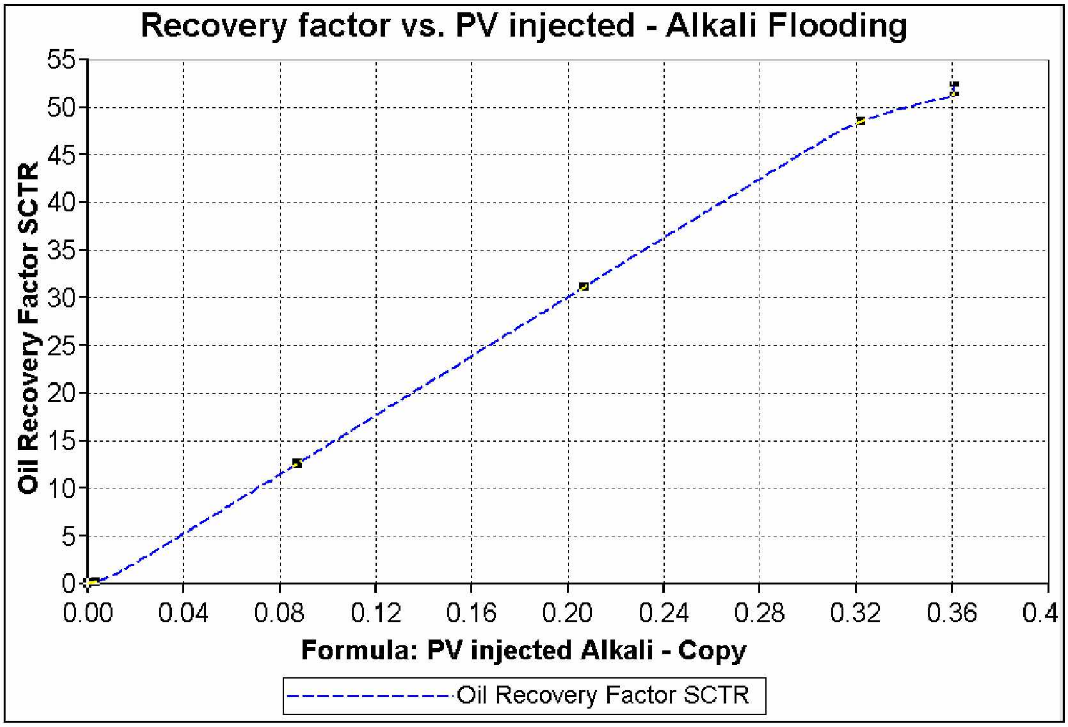


Figure 59 Recovery factor vs. PV injected for Polymer flooding

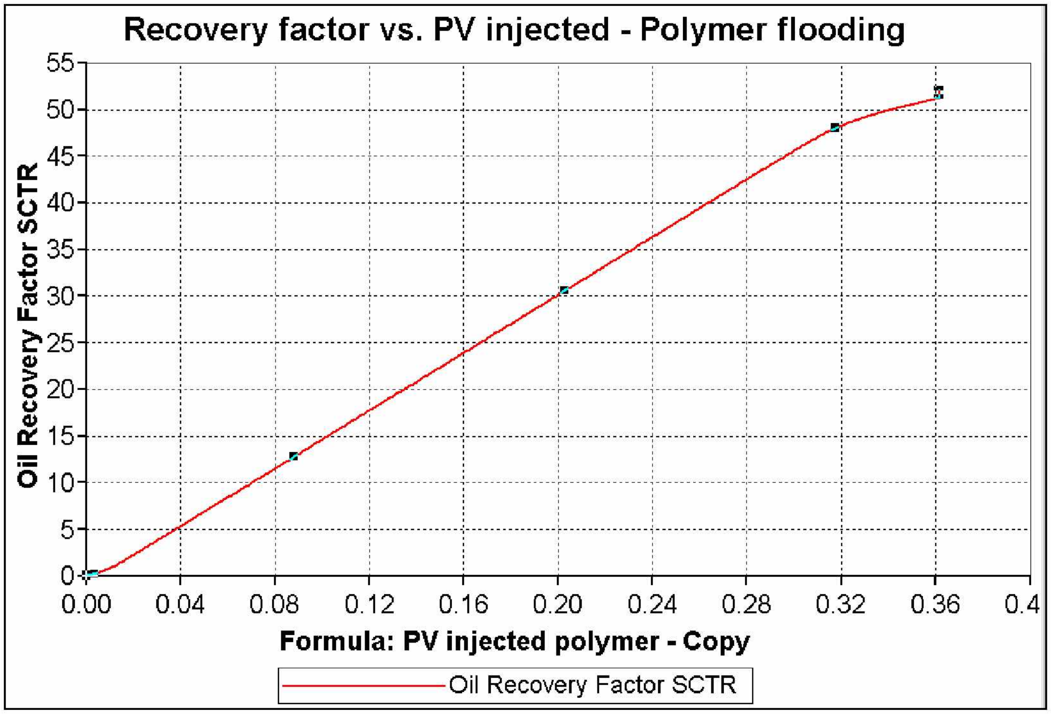


Figure 60 Recovery factor vs. PV injected for polymer flooding

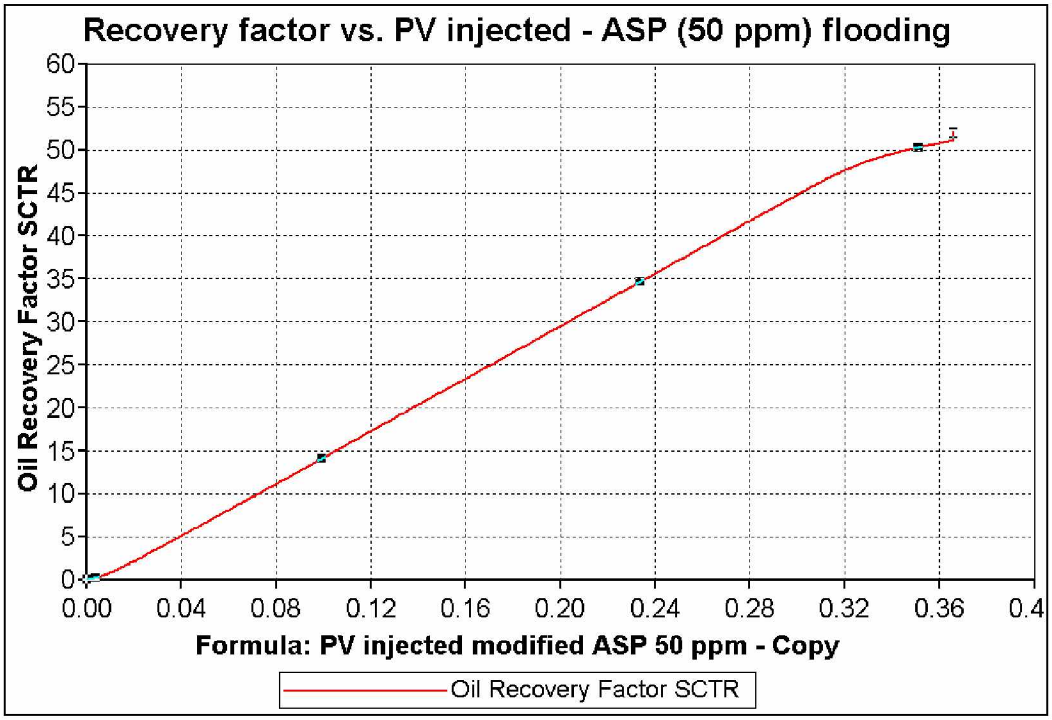


Figure 61 Recovery factor vs. PV injected for ASP (50 ppm) flooding

Hence, even though recovery factor is slightly more for polymer and alkali flooding compared to ASP combination, accelerated recovery makes more difference from economical point of view which suggest to have ASP flooding with 50 ppm concentration can be most suitable chemical combination. (Fig 55, 56, 57)

However, from plot of PV injected vs. time (Fig 54), it can be seen that, amount of PV injected is more for ASP flooding compared to Alkali, Surfactant and Polymer flood at ~2033. Also, Fig 58, 59, 60, 61 shows that there is slight difference in the recoveries (Alkali - 52.17 %, Surfactant - 52.12%, Polymer- 52.15%, ASP with 50 ppm - 52.13%) and values for oil recovery factor were very close. Hence, so as to determine effectivity of accelerated recovery, economics should be evaluated.

CHAPTER 12. CONCLUSIONS AND RECOMMENDATIONS

Screening criteria provided by Taber et al and ASP projects in low permeability and low viscosity fluid, showed that ASP flooding can be possible in WNS 1 reservoir. Fluid model generated with the help of given mol composition gave bubble point of ~1360 psi and viscosity of 0.2 cp. After regressing the properties of $C_{12}+$, like critical pressure (Pc), critical temperature (Tc), acentric factor (ω) and molecular weight (MW) and obtained from AOGCC, 2010 of oil formation volume factor, solution gas oil ratio and viscosity, fluid model with correct values of bubble point pressure as ~1850 psi was generated.

Primary recovery with natural drive mechanism as solution gas drive, gave recovery factor of ~6%. So, as to maintain reservoir pressure above saturation pressure, water was injected in reservoir for ~60 years at 5100 psi, which gave recovery factor of ~45% with water cut observed in 2046, after 33 years of injection.

Alkali, surfactant, polymer flooding was implemented in reservoir with the same injection and production constraints. Water was used as preflush and followed by first ASP slug for 3 years, followed by water and second ASP slug, followed by extended waterflood. So as to find out optimum polymer concentration and study polymer sensitivity, polymer concentration was varied from 50 ppm to 2000 ppm. Results were obtained and showed that, as polymer concentration increases, injection fluid viscosity increases and injection rate decreases at constant injection pressure, which results in delaying of flood response. Accelerated recovery obtained from 50 ppm polymer concentration (~23 years) compared to 2000 ppm concentration (~29 years) for the same PV injected.

Also, further to understand, effects of alkali, surfactant and polymer on recovery, similar injection volume (~5.7E006 bbls) and slugs of alkali , surfactant and polymer was injected in reservoir and compared with ASP with 50 ppm concentration. It showed that, in a reservoir with homogeneous permeability, porosity, and low reservoir fluid viscosity (~2 cp) recovery obtained from alkali injection (~52.17%) was more compared to polymer (~52.15%), surfactant (~52.123) and ASP with 50 ppm flooding (~52.13%).

It showed that, in homogeneous, low permeability, low reservoir fluid viscosity reservoir, effect of interfacial tension (IFT) is dominant compared to mobility control, but so as to get accelerated recovery, combination of IFT reduction and mobility control is necessary, but economics of project should be evaluated.

RECOMMENDATIONS

Following results are required for accurate simulation:

1. Experimental results
    a. Effect of chemicals (Alkali and Surfactants) on reservoir fluid:

       Effect of chemicals on reservoir fluid will result in understanding behavior of reservoir fluids after emulsion formation and give properties of emulsions such as viscosity, interfacial tension and density.

    b. Polymer adsorption study

       Effect of rock properties on polymer consumption will provide adsorption rate of polymer on rock, and can helpful in determining effective concentration of polymers in injection fluid.

    c. Surfactant and alkali consumption

       During chemical flooding, alkali and surfactant are adsorbed on rocks and consumed before production of low IFT emulsion. Consumption study of alkali, surfactants can give us better idea in determining concentrations.

    d. Resistance factor

       Resistance factor for varying polymer concentration should be evaluated and injectivity of displacing fluid should be analyzed for effective injection.

2. Core flooding experiments

    a. Waterflooding

    Waterflooding experiments of core, will give values for recovery factor, permeability, residual oil saturation, production data for history matching.

    b. Chemical flooding

    Chemical flooding such as alkali, surfactant, polymer flooding, can help in determining residual saturation after chemical flooding, viscosity of displacing phase, mobility ratio and hence capillary number.

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