SIMULATION AND ECONOMIC SCREENING OF IMPROVED OIL RECOVERY METHODS WITH EMPHASIS ON INJECTION PROFILE CONTROL INCLUDING WATERFLOODING, POLYMER FLOODING AND A THERMALLY ACTIVATED DEEP DIVERTING GEL

A Thesis

by

TOBENNA DANIEL OKEKE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2012

Major Subject: Petroleum Engineering

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Committee Members,	Hisham A. Nasr-El-Din
	Yuefeng Sun
Head of Department,	Stephen A. Holditch

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ABSTRACT

Simulation and Economic Screening of Improved Oil Recovery Methods with Emphasis on Injection Profile Control Including Waterflooding, Polymer Flooding and a Thermally Activated Deep Diverting Gel.

(May 2012)

Tobenna Daniel Okeke, B.S., Drexel University

Chair of Advisory Committee: Dr. Robert H. Lane

The large volume of water produced during the extraction of oil presents a significant problem due to the high cost of disposal in an environmentally friendly manner. On average, an estimated seven barrels of water is produced per barrel of oil in the US alone and the associated treatment and disposal cost is an estimated $5-10 billion. Besides making oil-water separation more complex, produced water also causes problems such as corrosion in the wellbore, decline in production rate and ultimate recovery of hydrocarbons and premature well or field abandonment.

Water production can be more problematic during waterflooding in a highly heterogeneous reservoir with vertical communication between layers leading to unevenness in the flood front, cross-flow between high and low permeability layers and early water breakthrough from high permeability layers. Some of the different technologies that can be used to counteract this involve reducing the mobility of water or using a permeability block in the higher permeability, swept zones.

This research was initiated to evaluate the potential effectiveness of the latter method, known as deep diverting gels (DDG) to plug thief zones deep within the reservoir and far from the injection well. To evaluate the performance of DDG, its injection was modeled, sensitivities run for a range of reservoir characteristics and conditions and an economic analysis was also performed. The performance of the DDG was then compared to other recovery methods, specifically waterflooding and polymer flooding from a technical and economic perspective.

A literature review was performed on the background of injection profile control methods, their respective designs and technical capabilities. For the methods selected, Schlumberger's Eclipse software was used to simulate their behavior in a reservoir using realistic and simplified assumptions of reservoir characteristics and fluid properties. The simulation results obtained were then used to carry out economic analyses upon which conclusions and recommendations are based. These results show that the factor with the largest impact on the economic success of this method versus a polymer flood was the amount of incremental oil produced. By comparing net present values of the different methods, it was found that the polymer flood was the most successful with the highest NPV for each configuration followed by DDG.

DEDICATION

I would like to take the opportunity to express my heartfelt gratitude to my research advisor, Dr. Robert Lane, for giving me the opportunity to work on this project with him and without whose constant encouragement and motivation this research would not have been completed.

I would also like to thank the members of my committee, Dr. Hisham Nasr-El-Din and Dr. Yuefeng Sun for their contribution of time and knowledge.

Special appreciation also to the faculty and staff of the Harold Vance Department of Petroleum Engineering at Texas A&M University for providing the necessary facilities to complete this work as well as making my stay in Aggieland a very pleasurable one.

This work is dedicated to Ubanagu, Emeka, Ossie, Laura and Paul; my family here in the United States and back home in Nigeria for their continued love and support.

Gig ‘em!

NOMENCLATURE

dM, mass per unit surface density accumulated during the current time step, dt;

F, net flow rate into neighboring grid blocks;

Q, net flow rate into wells during the current time step;

R_{fl}, non-linear residual error for each fluid component

$q_{p,j}$, volumetric flow rate of phase p in grid block, j,

$T_{w,j}$, transmissibility factor of the grid block which is a function of the wellbore radius, skin, and the x- and y- dimensions and directional permeabilities of the grid block,

$M_{p,j}$, the mobility of the phase and is a function of its relative permeability, viscosity and formation volume factor in the grid block,

P_j, nodal pressure in the grid block,

P_w, bottom hole pressure of the well, and

H_{wj}, wellbore pressure head between the grid block and the bottomhole datum depth

V is the block pore volume

S_w, water saturation

S_o, water saturation

B_r, B_w, are the rock and water formation volumes

ρ_r, ρ_w, rock formation and water densities

k_{rw}, water relative permeability

$k_{ro,}$ oil relative permeability

$\mu_{a,eff}$ is the effective viscosity of the water or polymer when a = w or a = p

R_k, relative permeability reduction factor for the aqueous phase due to polymer retention

P_w, water pressure

g, acceleration due to gravity

D_z, the cell center depth

Q_w, water production rate

Q_l, liquid production rate

C_p, polymer concentration in the aqueous phase and,

C_p^a, polymer adsorption concentration

φ, porosity

S_{dpv}, dead pore space within each grid cell

$\mu_m\left(C_p\right)$, mixture polymer concentration in solution

μ_p, polymer concentration in solution

ω, Todd-Longstaff mixing parameter

HL, High Perm Layer on top of Low Perm Layer

LH, Low Perm Layer on top of High Perm Layer

TABLE OF CONTENTS

Page

LIST OF FIGURES

Page

Page

Page

LIST OF TABLES

Page

I INTRODUCTION

1.1 Problem Description

Highly permeable layers within a heterogeneous reservoir can distort the flood front of a waterflood. These layers, often referred to as thief zones, essentially divert injection water causing early breakthrough at the production well and reducing the effectiveness of the waterflood project with regards to oil recovery. The high volumes of water produced present an expensive challenge in light of the need for environmentally friendly methods of disposal, cost of equipment needed for separation and treatment and reduction in oil production, ultimate recovery and field life. On average, an estimated seven barrels of water is produced per barrel of oil in the US (three barrels of water per barrel of oil worldwide) with the annual cost of its treatment and disposal estimated at between $5 – 10 billion (Seright et al. 2003).

Currently, waterflooding is responsible for over 50% of all oil recoveries in the world oil fields, for instance 60% of BP's oil production in 2007 came from water floods and this was set to increase to 80% by 2010. (Morgan 2007) Typically by the time this method reaches its economic limit, which usually occurs at some predetermined water-cut, roughly half to two-third of the original oil in place is still left in the ground (Brown et al. 2003).

This thesis follows the SPE Style Guide.

Some of the methods used to address this problem have included the use of mechanical plugs, cement squeezes and polymer gels at the injection and production wells to shut off the thief zones. These methods are limited though because their effectiveness is restricted to the near-wellbore region with little or no effect on the injection profile deep within the reservoir in those reservoirs where cross-flow is possible. One promising method that has yielded consistent sound results has been the use of polymer floods.

Polymer floods work by increasing the viscosity of the injected water and reducing its mobility with respect to the oil it is displacing. This in turn reduces the effect of highly permeable zones on the flood front and allows for a more efficient sweep. While this method is technically sound, its cost-effectiveness is often an issue due to the quantities of polymer needed, capital costs of polymer blending equipment and decreased injectivity (thereby decreasing drive fluid throughput and reservoir pressure support).

An alternative approach that requires much less chemical and equipment investment was developed based on the concept of forming a permeability block in the thief zones at some distance from the injection wellbore. The block would then divert flow into lower permeability unswept areas to mobilize previously bypassed oil. The early technology to form the block was through the use of a low viscosity polymer solution containing aluminum citrate as cross-linker which was designed to set and form a diverting gel far from the injection well.

This class of gel was called a Deep Diverting Gel (DDG), and the specific system just described was called the Colloidal Dispersion Gel. (Mack et al. 1994) More recently, a different approach to applying DDG has been developed as evidenced by patents and work done by the referenced authors. (Chang 2006, 2007; Frampton et al. 2004; Pritchett et al. 2003) This system is an internally cross-linked polymer consisting of sub-micron sized particles. Some of the internal cross-links are relatively permanent, while others contain ester groups that can hydrolyze. This arrangement allows the particles to swell to many times their initial size when the ester cross-linking groups hydrolyze. The expansion is triggered over time and accelerated by increased temperature.

A number of articles have been published on the successful application of this type of DDG (Fethi et al. 2010; Husband et al. 2010; Mustoni et al. 2010; Ohms et al. 2009; Yanez et al. 2007) but to our knowledge, it has as yet not been comprehensively compared with polymer flooding and waterflooding in terms of recovery and economics in any open literature.

1.2 Research Objectives

The primary question being addressed by this research is to determine whether in-depth profile modification using a thermally activated deep diverting gel is a better alternative to polymer flooding both technically and economically when faced with excess water production. This was done by modeling the DDG injection process as well as a polymer flood using a reservoir simulator, Schlumberger's Eclipse (Schlumberger 2010).

An outline of the objectives of this research is listed below:

- Model the injection and application of thermally activated Deep Diverting Gels (DDG) in a heterogeneous reservoir to predict performance using Schlumberger's Eclipse simulation software.
- Build simulation models of water and polymer flooding methods using the same base conditions as in the DDG model to compare performance.
- Run sensitivities for a range of conditions such as permeability contrast between layers, varying fluid viscosities and permeability drop at DDG activation site.
- Perform an analysis comparing economics and recoveries due to the use of DDG versus continued water flood and polymer flood.

II LITERATURE REVIEW

This chapter examines the existing methods of reservoir sweep improvement during waterflooding and reduced water production through the use of polymer floods and gel placement with a view of giving the reader a better understanding of the processes.

2.1 Water Production

The reasons for reduced sweep efficiency and increased water production will be presented and typically include mechanical problems usually as a result of casing integrity issues, completion problems – most commonly channels behind the casing, coning and poor frac jobs – and finally reservoir heterogeneity-related problems. This last includes dual porosity problems such as naturally fractured and karstified reservoirs, and heterogeneous matrix problems (the subject of this study).

In reservoirs with permeability variations between contacting layers, channeling can occur between an injector and a producer when hydrocarbons are swept faster from the high permeability layer and subsequently, injected water gets preferentially transported through it without sweeping the layers with lower permeability.

Other factors such as depleted hydrocarbon reserves and coning due to vertical pressure gradients near the wellbore drawing water from lower zones toward the well can contribute to excessive water production (Seright et al. 2003).

2.2 Injection Profile Modification Methods

As mentioned in the introduction, various methods have been employed to address the thief zone problem in waterfloods, with the focus here being on the use of polymers to modify flow profiles.

Attempts have been made to control the injection profile in the near wellbore region with mechanical plugs, cement squeezes and injecting polymer gels but because their area of influence is fairly limited, typically no more than 15 feet (5 meters), these methods are unable to exert much control over reservoir flow.

2.2.1 Gel Placement

Research has also been done on the use of polymer gels to reduce flow through high permeability zones while diverting injected fluids into the lower permeability hydrocarbon-bearing layer(s). The low-viscosity gels are added to the injected water at some point after early breakthrough and designed such that gelation occurs farther in the layer with higher permeability than in the lower permeability zone thereby improving areal and vertical sweep efficiencies. This way the injected water gets diverted to the lower permeability layer. This of course depends on the presence of vertical communication, that is, cross-flow between the layers. (Sorbie et al. 1992) Where such communication does not exist, the gels may be successfully placed closer to the injection well and in only the high permeability layer (Bai et al. 2004).

These gels are often referred to as deep diverting gels due to their ability to go deep into the reservoirs in highly permeable zones and only a shallow distance into the lower permeability zones before gelling and creating resistance to flow. In the past, they have generally consisted of a polymer solution cross-linked with chromium acetate or aluminum citrate. In one of the early forms of this gel, the Colloidal Dispersion Gels (CDG), the concentrations of both components are kept low by design to retard their reaction kinetics enough that they gel *in-situ* at some distance from the point of injection.

However, this process has been controversial with the accuracy of presented lab and field results called into question. Claims of successful application of CDG by Tiorco in the Daqing Field in China (Chang et al. 2006) and Argentina's Loma Alto Sur Field (Muruaga et al. 2008) among others, have been refuted and found inconclusive. In his work, Seright concluded that the benefits attributed to CDG could be explained by other more plausible concepts and that the claims by Tiorco and other supporters of this process are untenable. (Sorbie et al. 1992) Further lab studies on the propagation and gelation of CDG were also ambiguous with findings suggesting results similar to those obtained by polymer floods. (Ranganathan et al. 1998) Variables like gelling time, gel strength and depth of penetration are too easily influenced by factors such as shear stresses, the geochemical characteristics of the reservoir as well as adsorption and the subsequent dilution of the gel during placement. Some other limitations are the limited range of effectiveness whereby sweep efficiency is restricted to the region penetrated by the gel and no further. The applicable viscosity and resistance factors must also be small enough for the gelant to stay within the highly permeable zones without penetrating the lower permeability layers.

One misconception about these gels and blocking agent was that they exclusively targeted and penetrated highly permeable zones in a reservoir. More research has however shown that penetration does occur in the lower permeability layers with an accompanying permeability reduction that may sometimes be even greater than in the highly permeable layers. (Seright et al. 2011) Viscous fingering in the high perm zone has also been shown to occur when water is injected after the gel has formed. This is because as the gel penetrates the less permeable layers, it hardens and creates a barrier to flow thus forcing injected water to create pathways through the gelant bank in the highly permeable layer.

A proposed correction involves reducing the viscosity and resistance factor of the gelant being used and adding a water injection step between its injection and when gelation occurs. This intermediate step is to ensure that there is room between the rear of the gelant bank being formed in the high permeability layer and the front of the bank formed in the adjacent lower permeability zones. The lowered viscosity and resistance factors minimizes gel penetration from the high permeability zone into the adjacent layers while the spacing created by the water post-flush creates a pathway for water to flow into the less permeable zones. This process is shown below in Figures 1 – 4 in which the higher permeability layer is above the low permeability layer.

Figure 1: Injection of a low viscosity gel

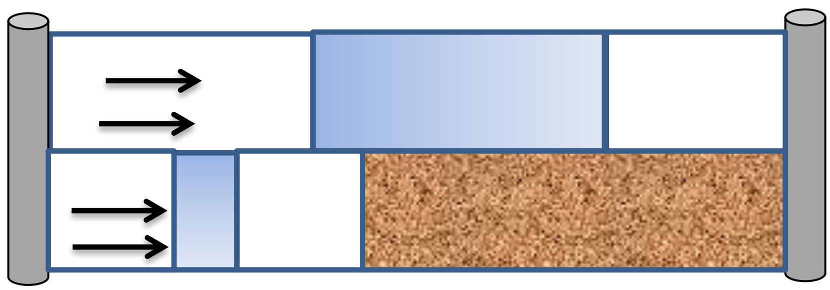

Figure 2: Injection of water post-flush to create pathways

Figure 3: Gelation

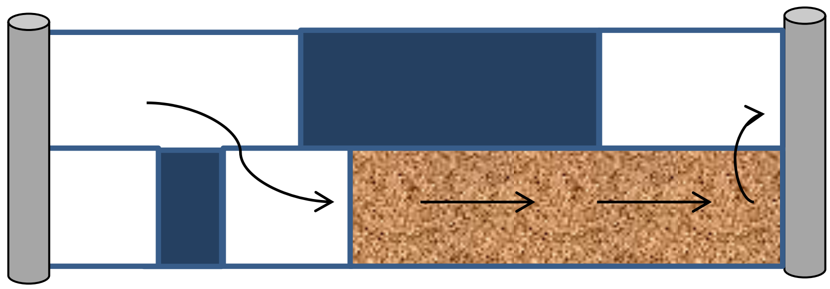

Figure 4: Water Injection after gelation

2.2.2 Polymer Flooding

Polymer flooding is another process designed to provide technical advantages over waterflooding. The advantage which is of particular relevance to this study is its improvement in areal and vertical sweep efficiency and more efficient oil displacement. (Mungan 1970) These can be attributed to two fundamental concepts of polymer flooding which control the effect it has on the mobility ratio of the injected water and recoverable oil and the penetrated depth.

The first effect is that the efficiency of oil displacement increases as the viscosity of the displacing agent (here polymer-treated water) increases leading to the lowering of its mobility ratio. This lowering can be particularly beneficial when the reservoir is highly heterogeneous in the vertical direction with cross-flow between layers (Akanni 2010).

The second is that for a given distance of viscous fluid penetration into a high permeability zone, the distance of penetration into less permeable zones becomes greater with increased viscosity of the injected fluid. With this then, vertical sweep efficiency becomes more uniform across layers with different permeabilities. (Seright 2010) While in-depth permeability reduction is not achieved with polymer flooding, the method does result in greater volumetric sweep efficiency and oil recovery.

Among the limitations of the polymer flooding process are the sensitivity of polymer to salinity, temperature, shear and biological degradations and the high production costs associated with attempts to circumvent these shortcomings. Injectivity issues are also a major concern at high viscosities and it is typical for the maximum usable viscosity to be limited to between three and ten times that of the injected water, with a maximum resistance factor of about 10 (Frampton et al. 2004).

In 1996, the cost of the incremental oil was estimated at between $8 to 10 per barrel with more recent estimates from the Daqing Field in 2002 putting this cost at $9.34 per barrel for polymer flooding versus $9.42 for continued waterflooding. This lower cost was due to the high incremental recovery of 12% OOIP, a production rate that was four times higher than with the waterflood and a five-fold reduction in the water oil ratio (Demin et al. 2003).

2.2.3 Deep Diverting Gels

The deep diverting gel that will be studied and compared to waterflooding and polymer flooding was the result of a research project undertaken in 1997. This was a joint venture between Mobil, BP and ChevronTexaco, also known as MoBPTeCh who agreed to share the costs of the research and development of an effective DDG. Their primary objective was to develop a time-delayed, highly expandable polymer-based gel to improve reservoir sweep efficiency of waterflooding. (Pritchett et al. 2003) Nalco Exxon (later Ondeo Nalco) Energy Services was brought on at some point during the development phase as their associate manufacturing company.

The gel is characterized as a specially designed, long-chain, temperature-sensitive polymer that is formulated by its manufacturers to produce sub-micron size particles made up of tightly-bound tangles of polymer. Its behavior has been likened to that of popcorn in that it would move freely through the rock matrix along with the injection water until a reservoir trigger causes some of the particles' internal crosslink bonds to break, thus allowing the particles to absorb water and swell in size to block the thief zone pore throats.

This material, with the commercial product name Bright Water™, is a highly cross-linked, sulfonate-containing poly-acrylamide micro-particle whose conformation is constrained by labile and stable internal cross-links. The particles, called kernels, are applied in the constrained state but at a designed temperature, de-crosslinking occurs and they expand. These kernels are prepared using an inverse emulsion polymerization process and have diameters ranging from about 0.1 to 3 microns. The temperature required for activation depends on the chemical structure of the cross-linker, and its stability gives the particles conformational integrity even after expansion. These polymer particles can also be prepared by the cross-linking achieved during the ester formation between the polymer's pendant carboxylic acid and hydroxyl groups. The esterification process could be through azeotropic distillation or thin film evaporation. After preparation, these particles can then be individually dispersed into the injection water in a high shear environment and using surfactants (Frampton et al. 2004).

The thermal front caused by the temperature differences between injected water and the reservoir is the basis of this DDG's activation. The thermal front generally lags behind the waterflood injection front; the characteristics and location of this front can be computed from heat transfer equations or modeled with a computer simulator that contains a thermal function. In addition to the thermally-triggered particles, systems that rely primarily on time without major temperature changes were also developed although these are not the focus of this research. Figures 5 and 6 below illustrate the DDG treatment process.

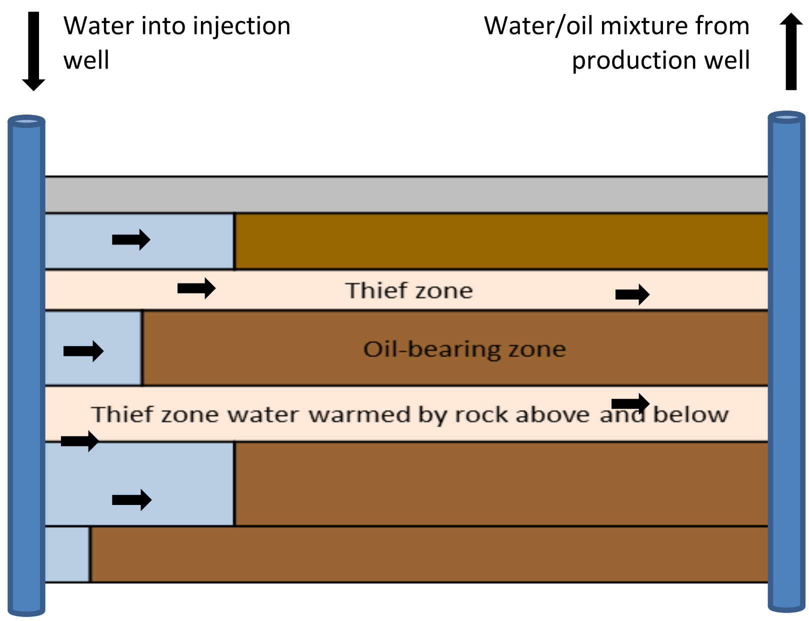

Figure 5: Reservoir before DDG Treatment

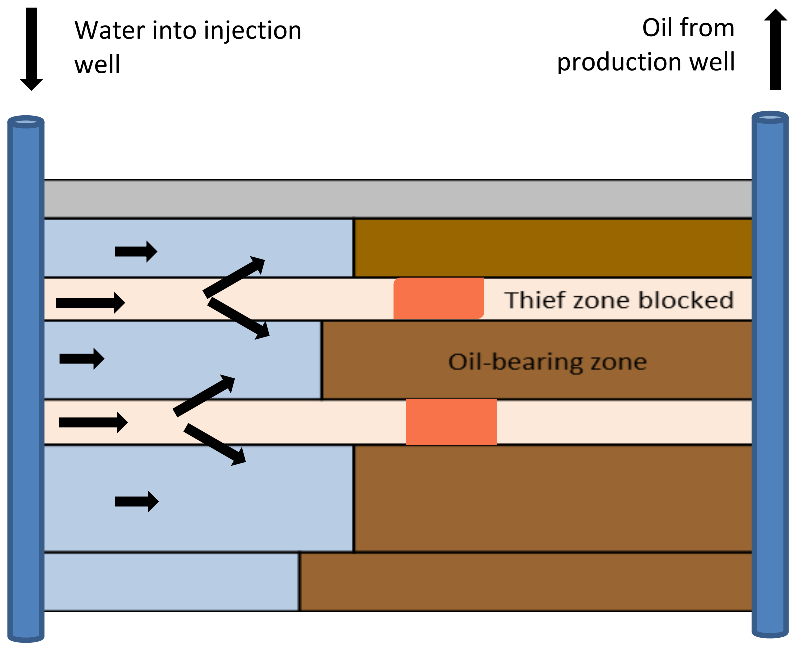

Figure 6: DDG Activation showing diversion of water

After the laboratory stage of preparation was completed, a series of field trials were carried out with the first being in Chevron's Minas Field in Indonesia. This field trial was run with the objectives being to assess the application of the DDG and verify that significant volumes could be injected at a viscosity close to that of water and penetrate deep within the reservoir before expanding at a pre-designed interval. (Pritchett et al. 2003) This was done by conducting injection tracer studies before and after treatment as well as bottom hole pressure fall off tests. These objectives were satisfied without raising the injection pressure or blocking the injection well bore.

Other trials have been completed both offshore and onshore, and in reservoirs with different permeabilities, porosities and temperatures, proving the versatility of this material. The trials have yielded varying levels of technical and economic success (Husband et al. 2010; Ohms et al. 2009).

While it can be concluded that this DDG can be successful in some cases, it has not been conclusively compared to polymer flooding. This research will try to find out which of the methods is the better alternative, either in terms of recovery or economics and how reservoir characteristics such as permeability contrast between layers, viscosity of fluids or cost of materials used affects the outcome.

III RESERVOIR MODELING

3.1 Simulator

Schlumberger's Eclipse 100 was used for all simulations in this research. This choice was in part due to its use in previous attempts to address this topic (Akanni 2010; Seright et al. 2011) and the desire to ensure that a similar approach with regards to software used was taken. In this way, any differences in results would be due to the assumptions made by the user and not the underlying algorithms and calculations employed by the software. Eclipse 100 is described as "a fully-implicit, three phase, three dimensional, general purpose black oil simulator" which uses non-linear equations in material balance equations during simulation runs. The underlying equations used in the software are presented in the relevant sections below with the purpose being to aid in understanding how the results were derived.

3.1.1 Black Oil Fully Implicit Solutions

In this method, the non-linear residual error for each fluid component, R_{fl} in the mass balance equations is computed in each grid block as a function of pressure and saturations at each time step and is given as;

$$R_{fl} = \frac{dM}{dt} + F + Q$$

where,

dM is the mass per unit surface density accumulated during the current time step, dt;

F is the net flow rate into neighboring grid blocks;

Q is the net flow rate into wells during the current time step;

and $R_{fl} \rightarrow 0$

3.1.2 Well Inflow Performance

The inflow performance relationship used by Eclipse is given in terms of volumetric flow rate of each phase in the production fluid, i.e. oil, water, polymer etc. at stock tank conditions. It is written as:

$$q_{p,j} = T_{w,j} * M_{p,j} * (P_j - P_w - H_{wj})$$

where

$q_{p,j}$ is volumetric flow rate of phase p in grid block, j,

$T_{w,j}$ is the transmissibility factor of the grid block which is a function of the wellbore radius, skin, and the x- and y- dimensions and directional permeabilities of the grid block,

$M_{p,j}$ is the mobility of the phase and is a function of its relative permeability, viscosity and formation volume factor in the grid block,

P_j is the nodal pressure in the grid block,

P_w is the bottom hole pressure of the well, and

H_{wj} is the well bore pressure head between the grid block and the bottom hole datum depth

3.1.3 Polymer Flood Model

The polymer option was enabled in Eclipse for polymer flood simulations and implements a fully implicit, five component model that includes, oil, water, gas, polymer and brine. In this model, there is no gas as mentioned above and brine was assumed to be absent as well. The equations for the flow of a standard waterflood with polymer added are given below as:

$$Water \rightarrow \frac{d}{dt}\left(\frac{VS_w}{B_r B_w}\right) = \sum\left[\frac{Tk_{rw}}{B_w \mu_{w,eff} R_k}(\delta P_w - \rho_w g D_z)\right] + Q_w$$

$$Polymer \rightarrow \frac{d}{dt}\left(\frac{V^* S_w C_p}{B_r B_w}\right) + \frac{d}{dt}\left(V\rho_r C_p^a \frac{1-\varphi}{\varphi}\right)$$

$$= \sum\left[\frac{Tk_{rw}}{B_w \mu_{p,eff} R_k}(\delta P_w - \rho_w g D_z)\right] C_p + Q_w C_p$$

$$with\; V^* = V(1 - S_{dpv})$$

where

V is the block pore volume

S_w is the water saturation

B_r, B_w are the rock and water formation volumes

ρ_r, ρ_w are the rock formation and water densities

T is the transmissibility

k_{rw} is the water relative permeability

$\mu_{a,eff}$ is the effective viscosity of the water or polymer when a = w or a = p

R_k is the relative permeability reduction factor for the aqueous phase due to polymer retention

P_w is the water pressure

g is the acceleration due to gravity

D_z is the cell center depth

Q_w is the water production rate

C_p is the polymer concentration in the aqueous phase and,

C_p^a is the polymer adsorption concentration

φ is the porosity and

S_{dpv} denotes the dead pore space within each grid cell

This model includes representations of increases in the viscosity of the injectant upon addition of polymer as well as the losses in polymer solution viscosity that occurs as a result of non-Newtonian shear at high flood velocities. The effective viscosity of a fully mixed polymer solution is given as a function of mixture polymer concentration in solution, $\mu_m(C_p)$, the Todd-Longstaff mixing parameter, ω and the polymer concentration in solution, μ_p and is written as:

$$\mu_{p,eff} = \mu_m(C_p)^{\omega} * \mu_p{}^{1-\omega}$$

The effective water viscosity is also calculated in an analogous manner.

3.2 Reservoir Description

The reservoir conditions used in generating the base case model are listed below. Some of these assumptions such as well spacing are based on commonly observed practice while others are to reduce complexity such as the use of two layers instead of three or more.

- The field under study is fictitious. A base case model was developed first and used in the waterflooding component of this research. Changes were then made to this model and used in modeling the DDG and the polymer flood.
- A quarter of a 5-spot well spacing, as is commonly used with waterflooding, was used with one producer and one injector placed diagonally on opposite corners of the square.
- The reservoir has two layers of equal thickness and porosity penetrated completely by both wells and with vertical communication between layers. The layers have different permeabilities.
- The only fluids present are oil and water with no aquifer support.
- The effects of capillary pressure are negligible.
- Each layer as modeled is homogeneous.

3.2.1 Base Reservoir Model

The Black-Oil, fully implicit solution method was used in Eclipse 100 to model the performance predictions and solve the governing equations for the simulation's results of the three recovery methods. The grid blocks describing the XYZ-directions were 44 x 44 x 16 and described a 10-acre area of dimensions 660 ft x 660 ft by 60 ft. This grid configuration was chosen to accurately represent the regions under consideration while keeping resource allocation of time and processor requirement manageable.

The injection well was placed in the cell (1, 44, 1) and the producer in cell (44, 1, 1) with both perforated in all grid blocks in the vertical (Z) direction to ensure direct contact with the entire thickness of the reservoir as shown in the figure below. Both wells are controlled by assigned liquid rate and bottomhole pressure limits.

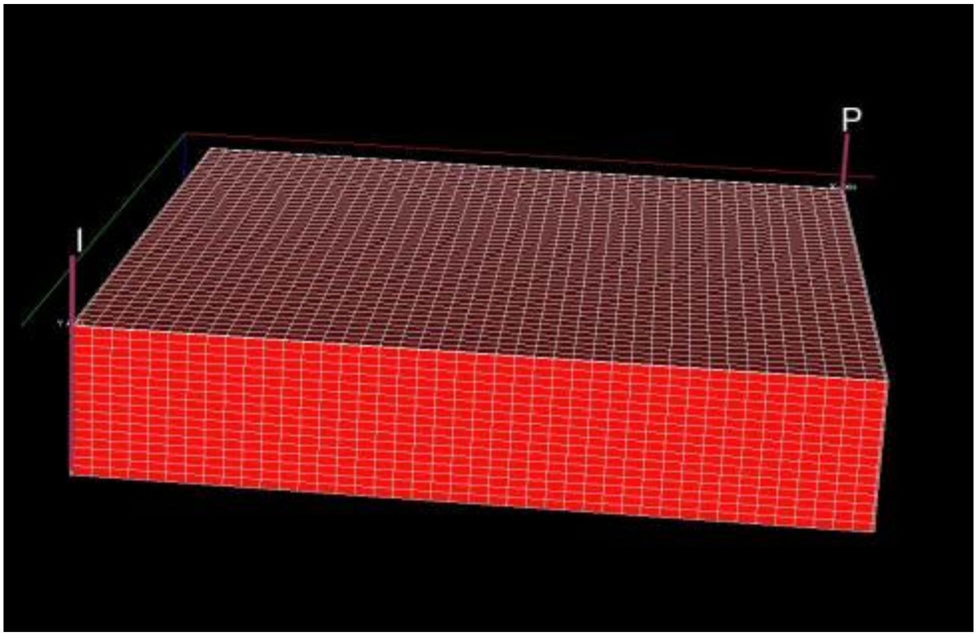

Figure 7: Reservoir model grid

Table 1 below shows the input data used to describe the base case reservoir model's initial conditions and PVT properties. This base model will be modified for both the polymer flood and the DDG cases with any changes stated when made.

Table 1: Reservoir Model Input Data

Start Date	1/1/2000
Reservoir thickness, ft	60
Reservoir length, ft	660
Depth, ft	8000
Areal extent, acres	10
XY High Permeability, md	1200
XY Low Permeability, md	100

Table 1 Continued

Z High Permeability, md	100
Z Low Permeability, md	10
XYZ Porosity, fraction	0.25
Oil API	34.2
Oil viscosity, cp	2.0
Oil formation volume factor, rb/stb	1.01
Oil saturation, fraction	0.8
Water viscosity, cp	0.7
Water formation volume factor, rb/stb	1.0
Connate water saturation, fraction	0.2
Rock Compressibility, psi^{-1}	5.00E-06
Water Compressibility, psi^{-1}	3.03E-06
Water injection rate, bbl/day	500
Liquid production rate, bbl/day	500
Number of grid blocks	44 x 44 x 16
Production well location	44, 1, 1-16
Injection well location	1, 44, 1-16
Economic limit	0.95 WCT
Reservoir Temperature, F	210
Injected water temperature, F	70
Rock specific heat, $btu/ft^3.F$	25

Table 1 Continued

Oil specific heat, btu/lbm.F	0.5
Water specific heat, btu/lbm.F	0.95

3.2.2 Polymer Flood Model

The polymer viscosity was specified as a function of polymer concentrations in the injected water by applying a multiplier to the water viscosity that ranged from 1 to 100 for concentrations from 0 to 0.70 pounds per barrel. Polymer adsorption was kept low to maximize effectiveness of the flood. A Todd-Longstaff mixing parameter was used to model the degree of segregation of the polymer solution and the injection water at the trailing edges of the slug with 1.0 being used to indicate that the polymer and water in the relevant grid cells are fully mixed. This also helps minimize polymer loss which typically occurs at the leading edges of the polymer slug where stripped water banks are created when there is poor mixing.

The polymer flood was timed to commence when the base case water flood reached a water-cut of 85%. Polymer injection was performed for a period of time that closely approximated breakthrough time and its injection rates were calculated by applying an upper limit on the allowable bottom-hole pressure at the injection well. This was done to accommodate the drop in injectivity during the period the polymer is being injected due to the increased viscosity of the drive fluid (Seright 2010).

At low flow rates, polymer floods typically exhibit Newtonian or near-Newtonian characteristics and viscosity remains relatively constant and depends only on polymer concentration. This behavior has been supported by Seright's findings in the paper above. As flow rates increase however, polymer molecules begin to break up and viscosity reduces, first reversibly and then irreversibly as rates further increase. The default model Eclipse uses focuses on the shear thinning of polymer and calculates polymer viscosity based on shear rates which it assumes is proportional to flow viscosity.

3.2.3 DDG Model

The development of the model used to simulate the performance of the DDG was based on the mechanism of its treatment which can be separated into three different steps:

1. The particles are injected into the formation with the injection water. As with the polymer flood, this was set to commence when a watercut of 85% was reached in the base case waterflood. In this step, the particles are inert and still sub-micron sized. This was the basis for assigning the same viscosity and injectivity as water.
2. The sub-micron sized particles are transported through the reservoir in the waterflood. Since the particle slurry has the same viscosity as the water, most of it is also diverted to the thief zones. To avoid loss of particles during this propagation and maximize efficiency, the adsorption and retention of the particles onto the rock pore walls was designed to be negligible.
3. The particles reach the design temperature and 'pop', i.e. the internal crosslinks break and the particles expand and absorb water, effectively blocking the throats of the pores they are travelling through. At this point, the permeability of the

cells predetermined to be occupied by the DDG slug are reduced from 1200 to 40md in the X and Y direction and from 100 to 10 md in the Z-direction. The slug was set to form only in the watered out high permeability zone again assuming ideal behavior and maximum utility.

Eclipse does not currently have the functionality to model the application of the DDG in one simulation, i.e. by coupling running the base case simulation to a designated water-cut or time-step and seamlessly reducing the permeabilities of specified grid blocks then continuing to the project's economic limit. It does however allow the above described scenario to be broken into two steps whereby the DDG simulation can import the reservoir conditions such as saturations and pressure as well as the results of the previously run base case waterflood from time zero up to a predetermined time-step using Eclipse's RESTART function. In the second step, the modified properties (permeability) replace the original values and the run continues to the economic limit.

The time-step at which this occurs is determined by first modeling the thermal front in the base case waterflood using the simulator's TEMP keyword. The temperatures of the cells are then calculated and outputted as a function of time. Energy balance equations are solved after the flow equations at each time-step to calculate the temperature in each grid block. The results of these are then used to modify fluid viscosities as functions of temperature for subsequent time steps.

In practice, the transit time and temperature profile between the wells would be determined to identify the location the bulk of the DDG would go then it would be designed to activate at that temperature. This transit time is then added to the time-step at which 85% water-cut occurs to get the actual time-step at which reservoir parameters from the base case are to be imported. For instance, if a water-cut of 85% occurs after 1000 days of production and it takes 400 days for the waterflood to travel from the injection well to the zone of interest, the time step at which the DDG simulation begins would be after 1400 days. This approach is of importance in accurately comparing the technical performance and economic value of DDG to those of waterflood and polymer flood.

IV RESULTS AND DISCUSSION

The simulation results for the three different methods will be presented and discussed below from the time the water-flood reaches 85% water-cut. This is of particular importance in evaluating the performance of each method from the same starting point. The base case will be described and modifications made to its configuration and relevant properties within each method as well as the effects these changes had on results.

4.1 Water Flooding

This method served as the base case and will be simulated using two configurations; one with the high permeability layer on top (H-L) and the second with it on the bottom (L-H). As expected, the high permeability layer watered out quickly causing injected water to preferentially flow through it and leading to high water production. Figures 8 and 9 below use oil saturation in the reservoir at breakthrough to illustrate this. In both cases, the high permeability layer has very little oil left while the lower permeability layer still contains a considerable amount yet to be recovered.

Table 2: Results from Waterflood Simulation at 85% Watercut

	Oil (MSTB)	Water (MSTB)	Life (Years)	RF
HL	424	398	4.50	43.13%
LH	393	398	4.33	40.06%

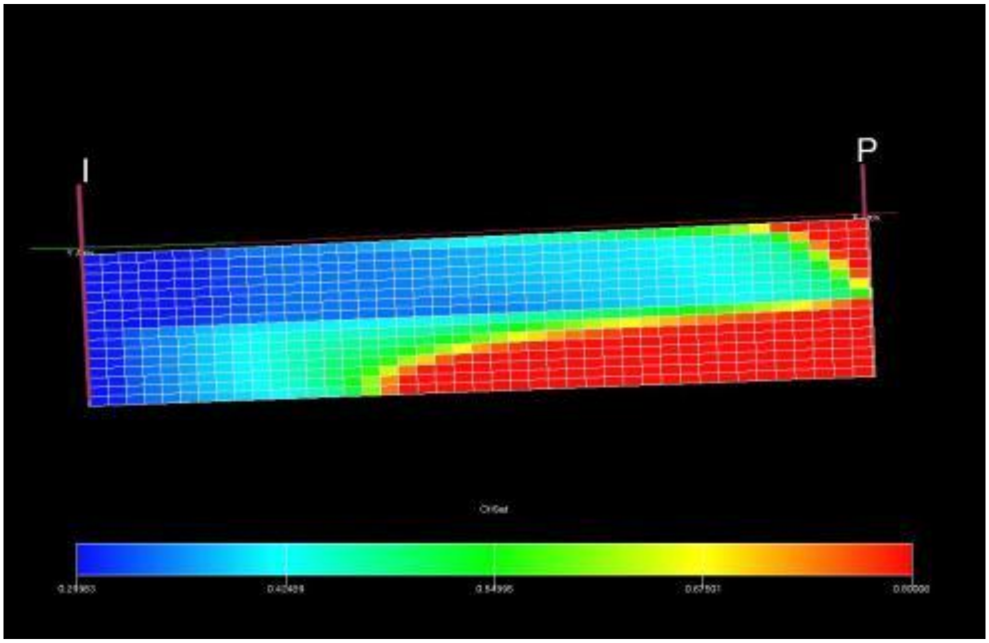

Figure 8: HL Reservoir Oil Saturation at breakthrough

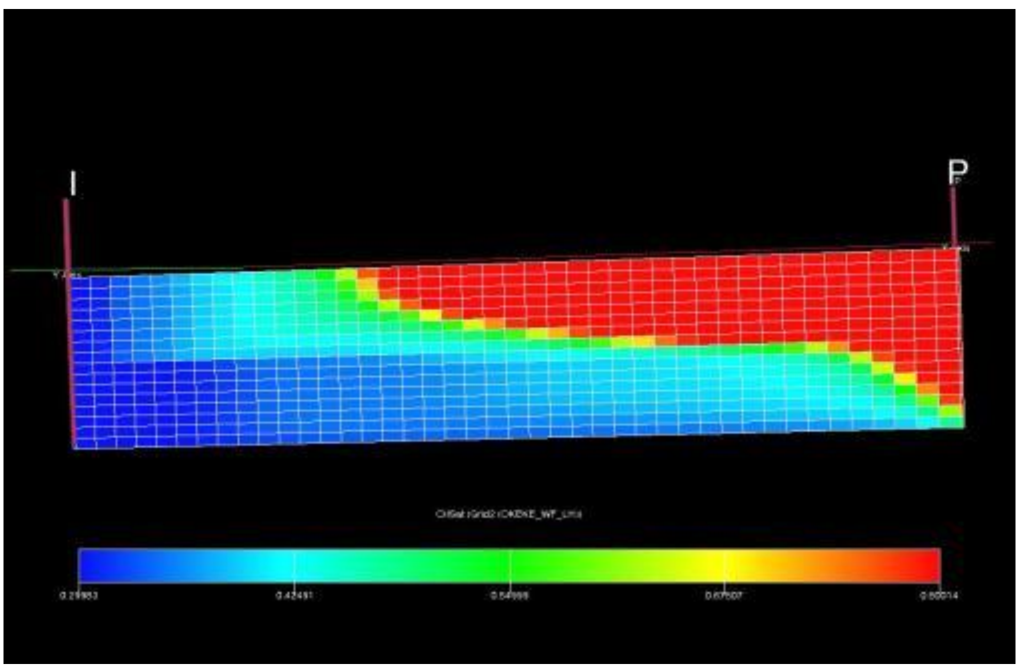

Figure 9: LH Reservoir Oil Saturation at breakthrough

Breakthrough occurs at about the same time in both configurations but as can be seen in Figure 10, the project reaches the economic limit of 95% water-cut about 500 days sooner when the high permeability layer is on top. Table 2 above shows that from the start of the waterflood to 85% watercut, oil recovery is higher in the H-L case due to gravity causing the denser water to slump into the low permeability layer thereby enhancing sweep efficiency. This is also the reason why the watercut in the L-H configuration is steeper than in the H-L.

Incremental oil production is however about 11,000 barrels lower in the H-L run from 85 – 95% watercut due to the fact that there is less oil to recover in its high permeability layer so recovery efficiency drops. On the other hand, about 250,000 barrels more water is produced in the L-H case.

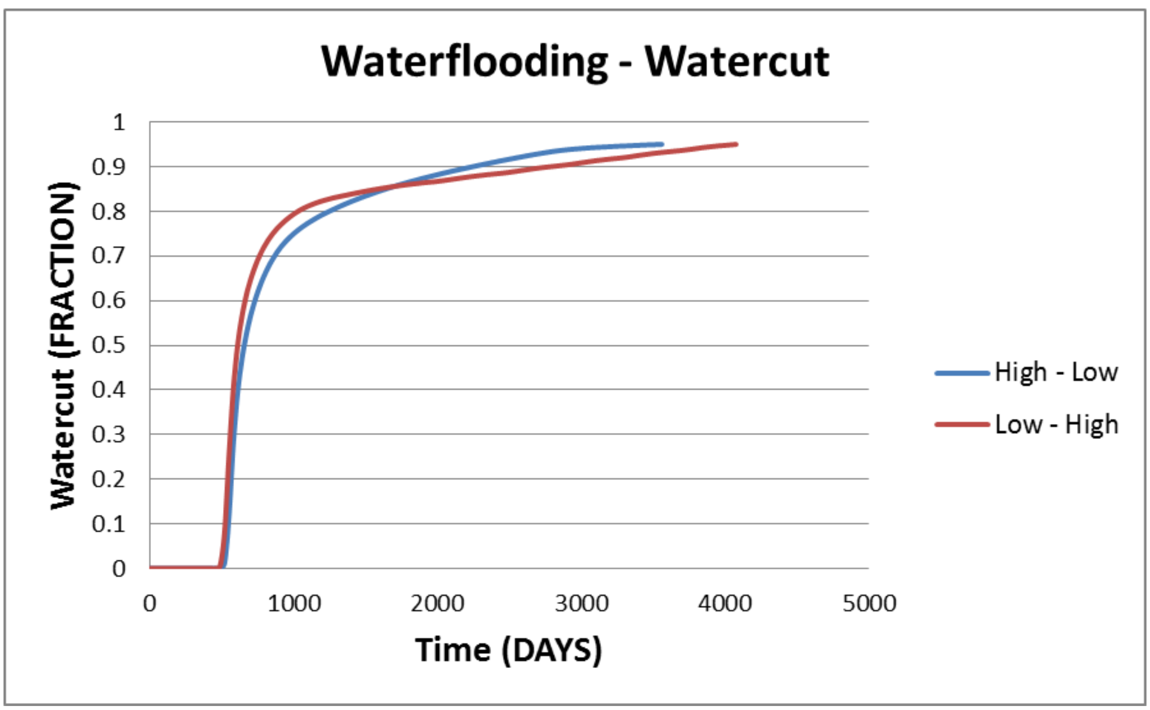

Figure 10: Waterflood – Watercut

4.2 Polymer Flooding

Polymer was injected into the reservoir starting when the corresponding waterflood base cases, i.e. for the H-L and L-H configurations reached 85% water-cut. The polymer concentration used in the base case was 1000 ppm (0.35 lb/stb). Injection went on until breakthrough of polymer was observed at the production well at which point a waterflood post-flush was restarted.

As expected, improving the mobility ratio caused better sweep efficiency which in turn led to increased oil recovery and a reduction in water production. Due to its impact on mobility ratio, an increase in recovery over waterflooding of 121,000 and 112,000 barrels in the H-L and L-H configurations respectively was observed with corresponding reductions in water production of 62,000 and 345,000.

4.3 Deep Diverting Gel

The figures below show the incremental oil and water production rates when the DDG is used as well as the effect this method has on water-cut. These results are compared to those from the other two methods. As can be seen in Figure 11 below, when the DDG 'pops', there is a sharp decline in water-cut resulting in a decrease in water production and an increase in oil recovery. The effect of cross-flow is particularly highlighted by the difference in results for the H-L configuration versus the L-H. Oil recovery is higher than in the waterflood case with the figures below highlighting the increases in recovery of 2.30 % for the HL and 1.80 % for the LH arrangement. Water production is also better controlled as can be seen in Figure 20 where the total water produced with this method is lower than in the other two methods for the HL and LH configurations respectively.

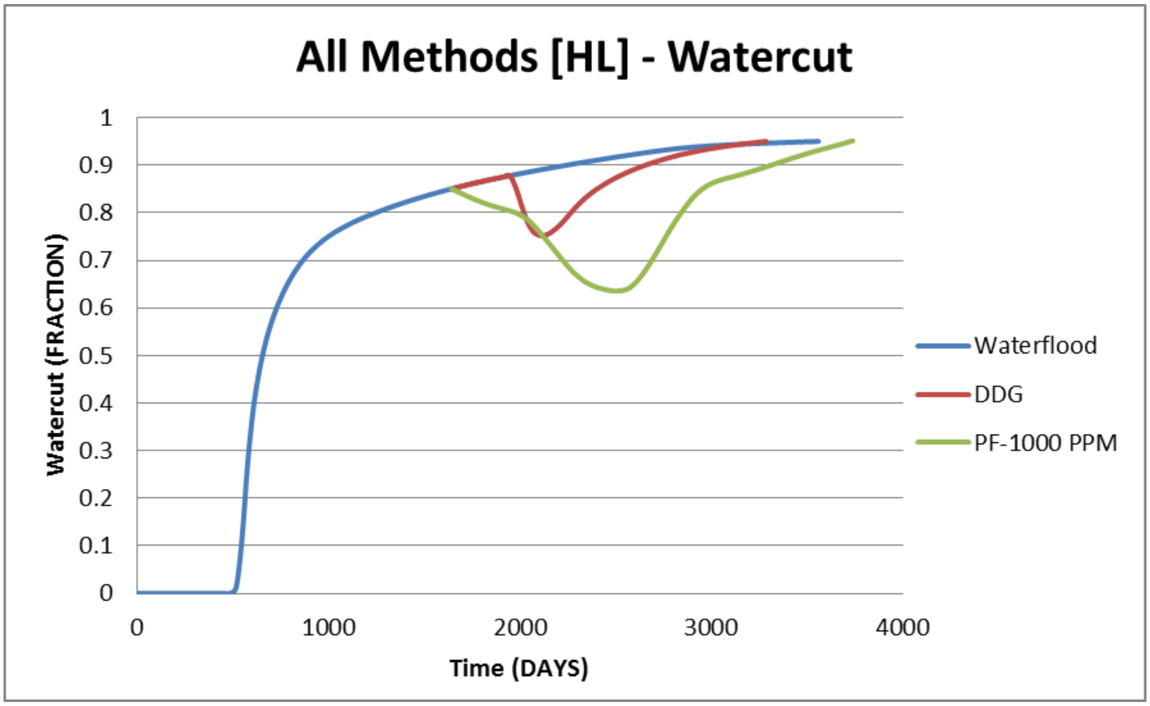

Figure 11: Base Cases – Watercut

The figures below show the oil saturations of the three methods at different watercuts. Figures 13 – 15 show each method at 90% watercut while Figures 16 – 18 shows the oil saturations at 95% water-cut. As we can see, the DDG treatment and polymer flood improve sweep efficiency through the life of the project. Figure 14 shows the water being diverted into the low permeability layer over the plug formed close to the production well. From Figure 18, due to its more effective piston-like displacement of oil, we can conclude that the polymer flood leaves less oil in the less permeable layer than the DDG treatment at the end of the project at 95%.

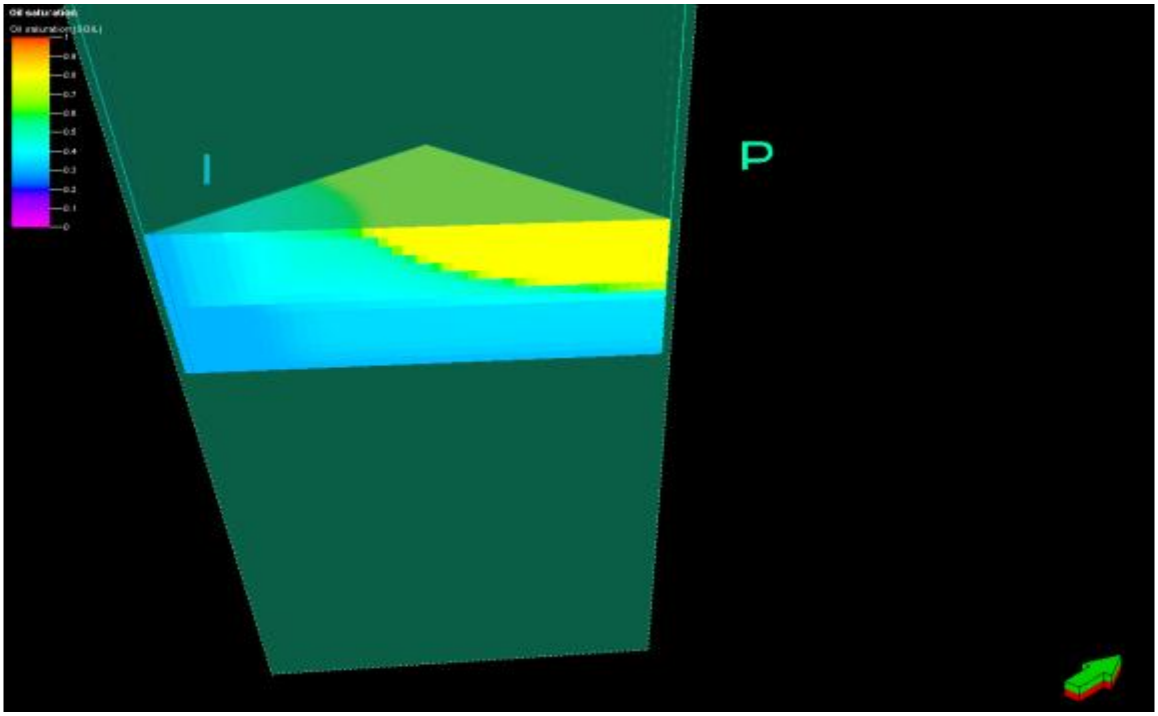

Figure 12: Waterflood [LH] – Oil Saturation at 85% Watercut

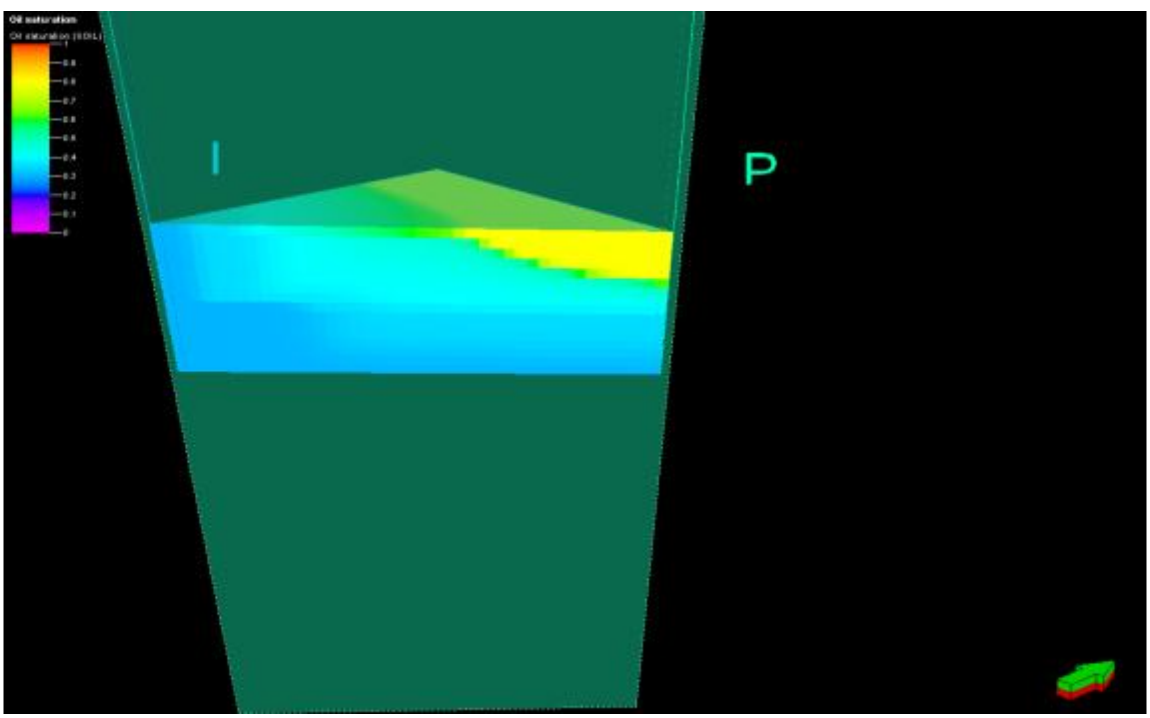

Figure 13: Waterflood [LH] – Oil Saturation at 90% Watercut

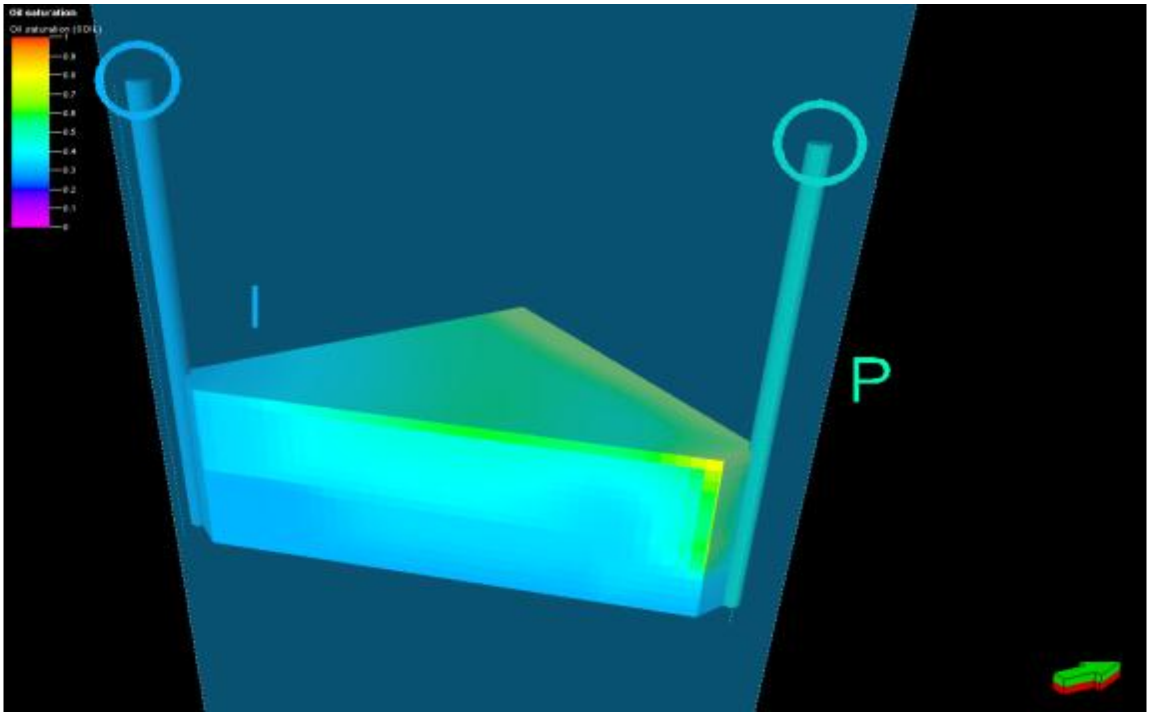

Figure 14: DDG [LH] – Oil Saturation at 90% Watercut

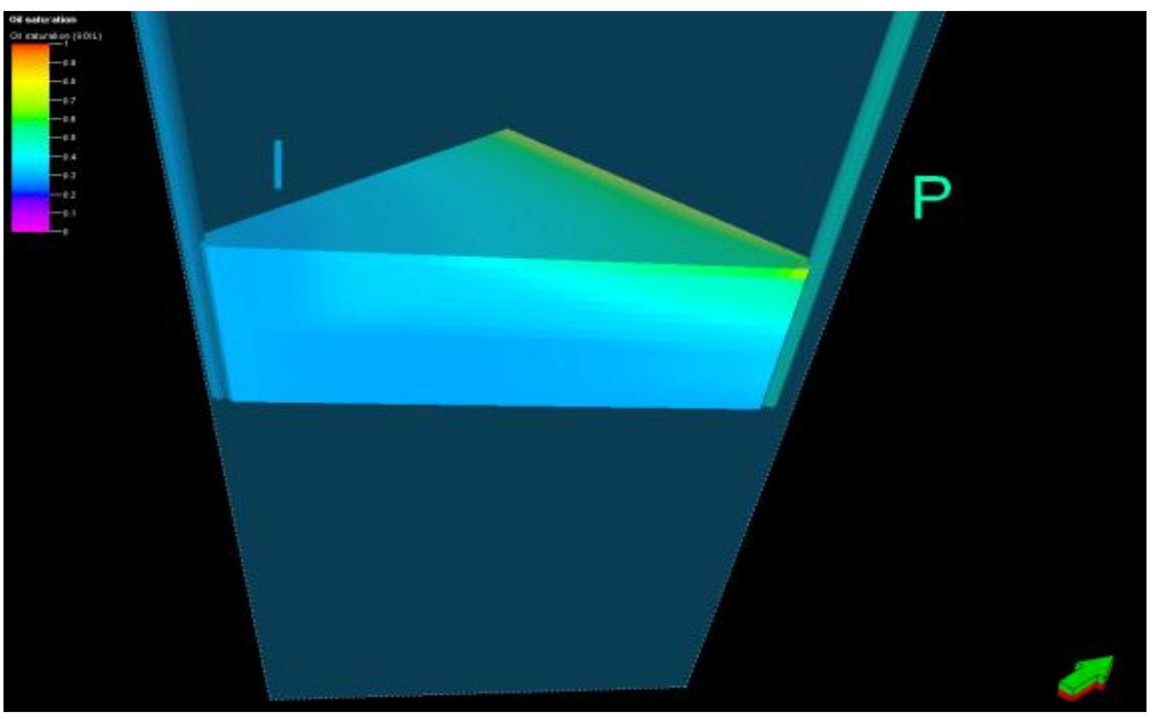

Figure 15: Polymer flood [LH] – Oil Saturation at 90% Watercut

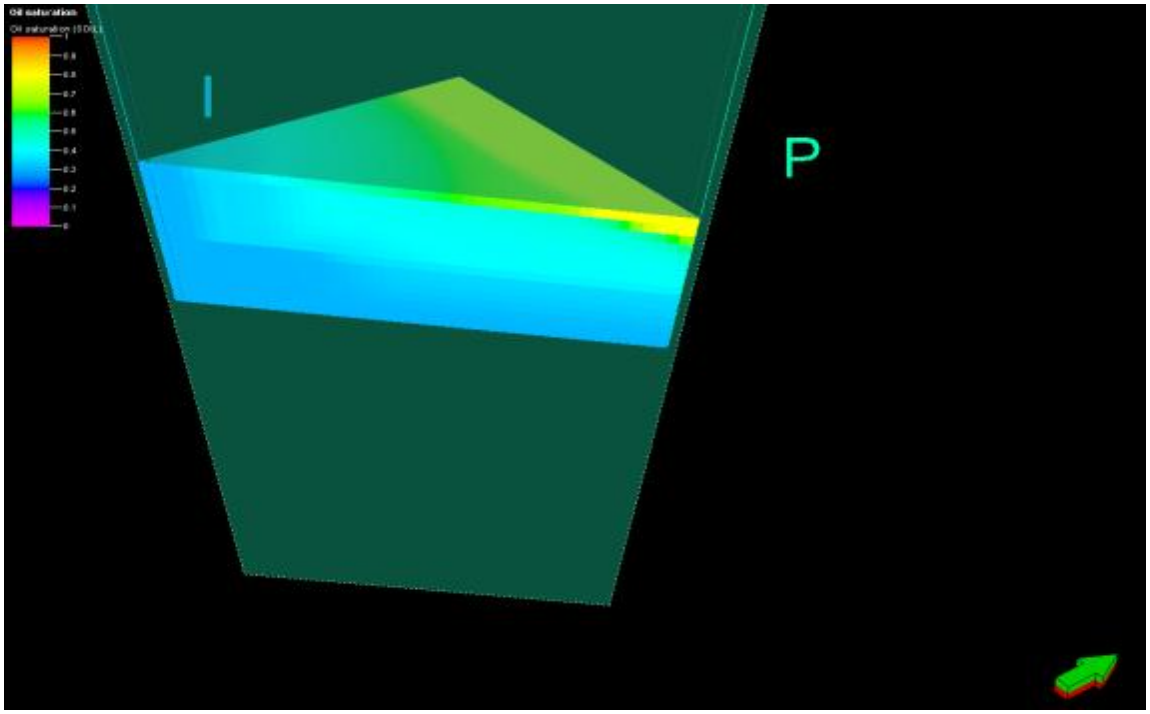

Figure 16: Waterflood [LH] – Oil Saturation at 95% Watercut

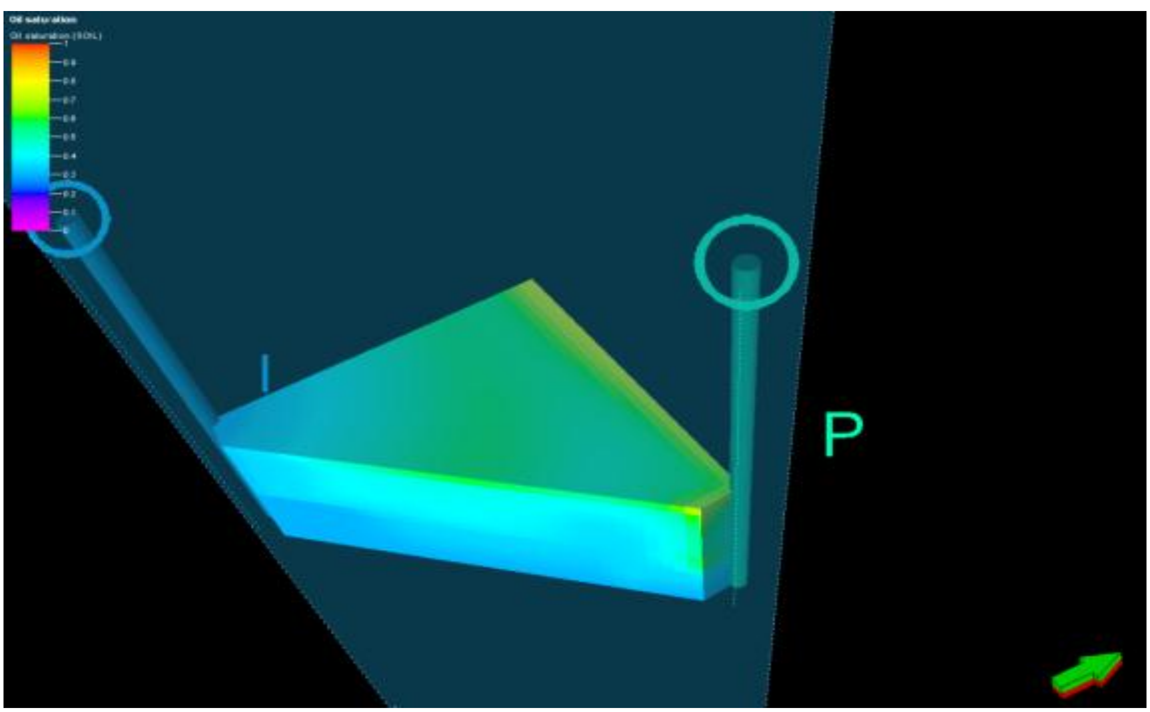

Figure 17: DDG [LH] – Oil Saturation at 95% Watercut

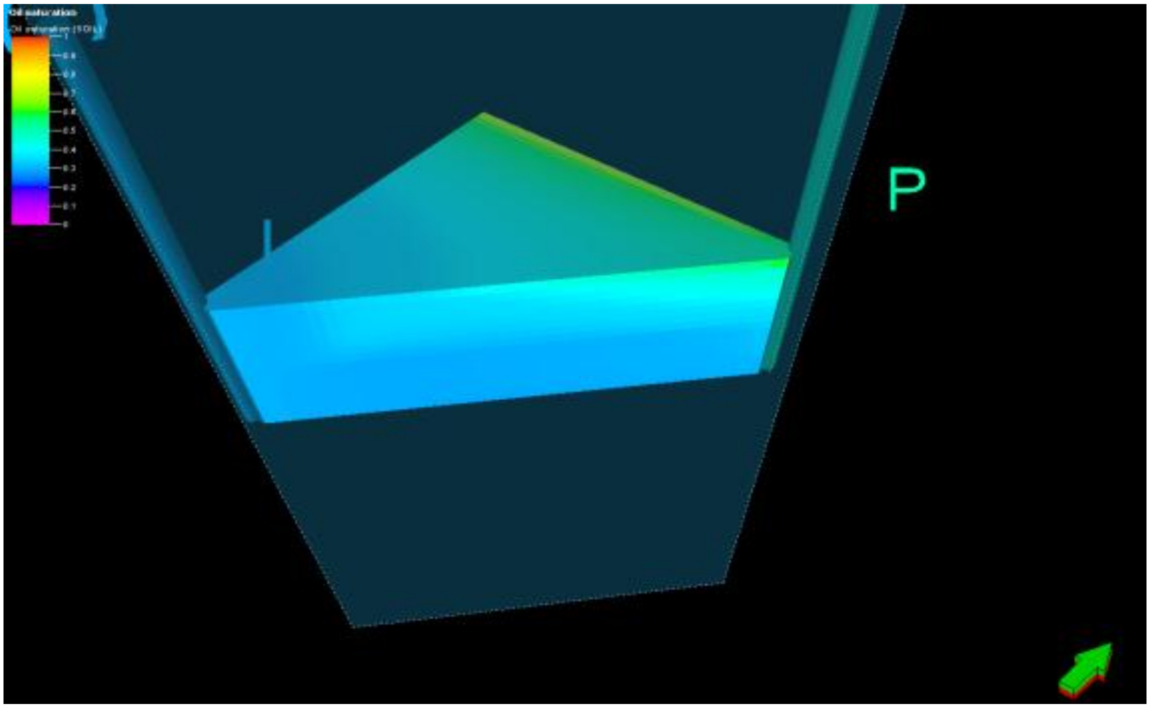

Figure 18: Polymer flood [LH] – Oil Saturation at 95% Watercut

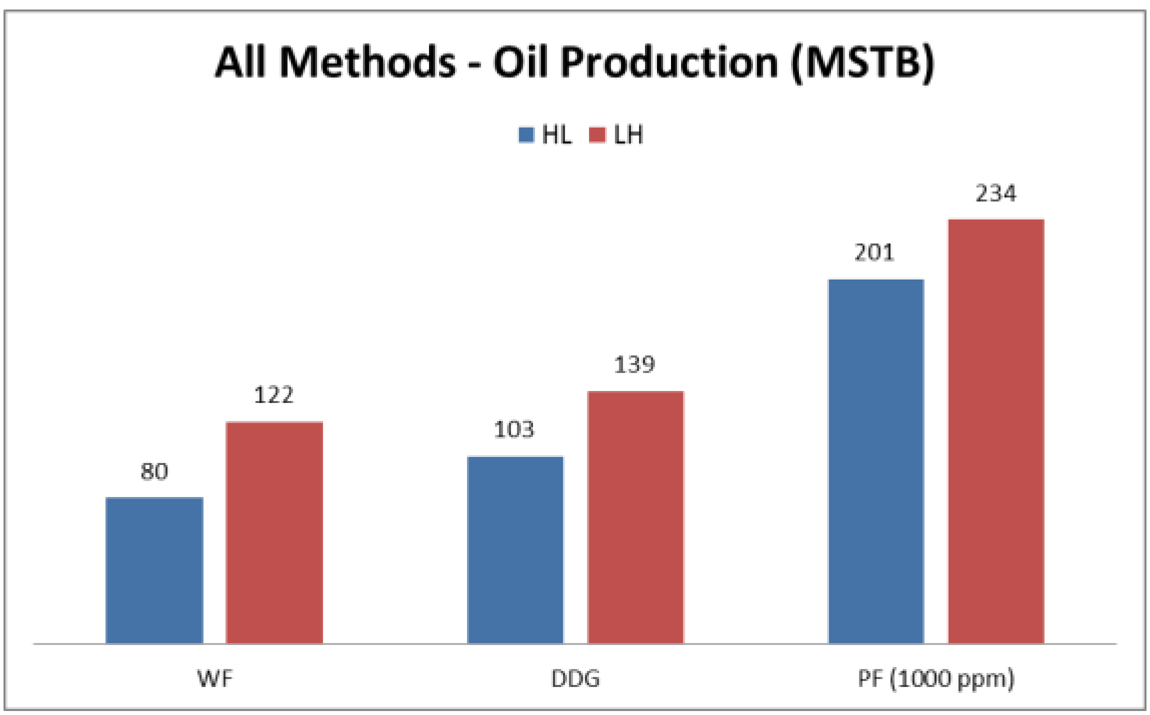

Figure 19: Base Cases – Incremental Oil Production

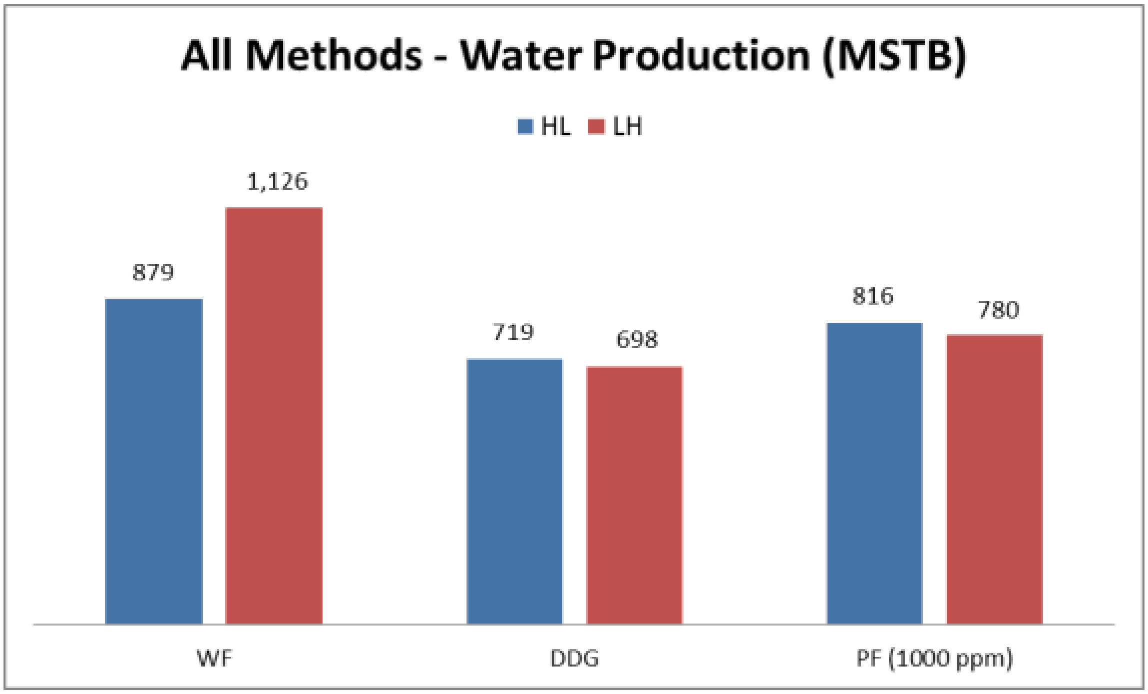

Figure 20: Base Cases – Incremental Water Production

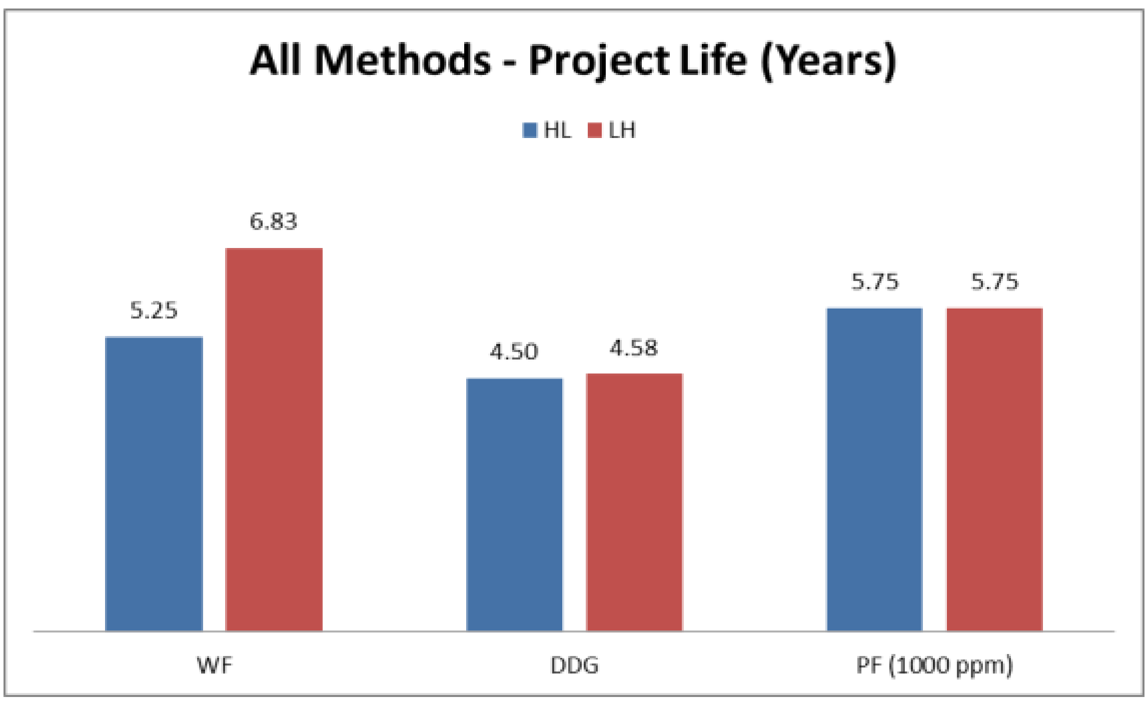

Figure 21: Base Cases – Project Life

4.4 Sensitivity Analysis

In order to assess how polymer flood and DDG performed under different conditions, variables such as permeability reduction at the DDG's activation site, polymer concentration and oil viscosity were modified.

4.4.1 Permeability Reduction

In this run, the permeability at the plugged site was reduced to 0 from 1200 md in the DDG model to simulate an ideal case. Recovery was only slightly improved from the case where the permeability was reduced to 40 md in the plugged cells with an increase of less than 2000 barrels. Water production was however reduced by about 155,000 barrels with production time reduced by about 300 days. It is however unrealistic to expect the permeability to drop completely to 0 md as no literature was found to support this. Work done by Frampton (2004) and Husband (2010) suggests that the reduction can be expected to range between 11 and 350 times that of the original value.

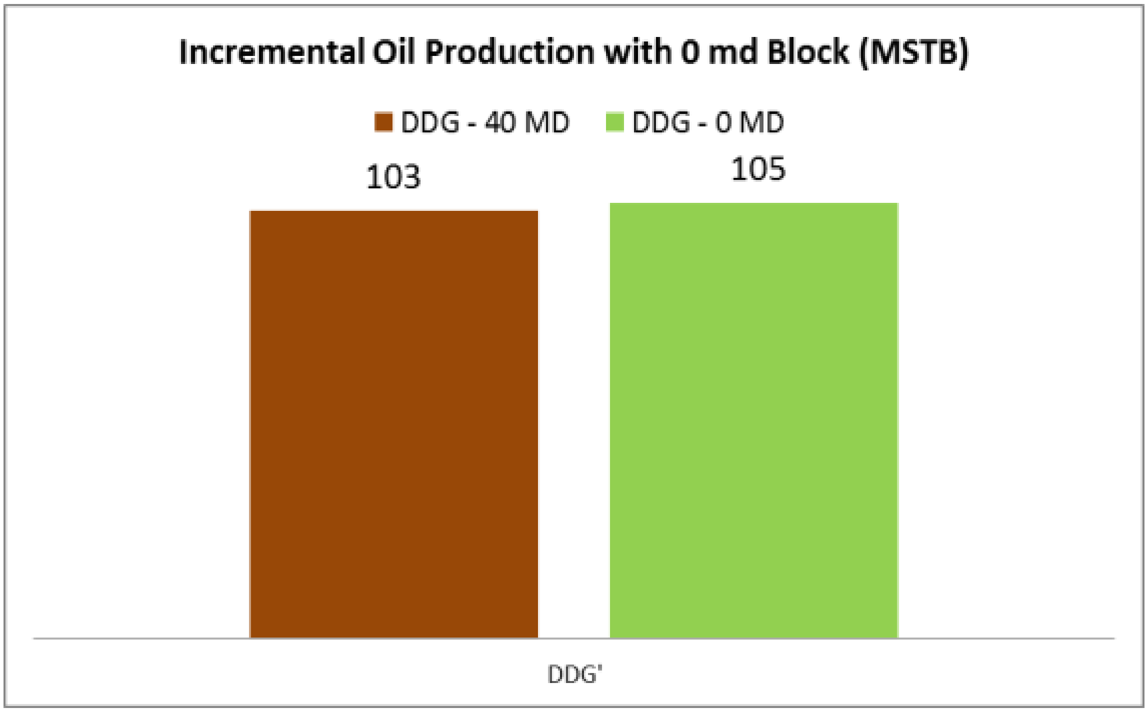

Figure 22: DDG – Incremental Oil Production with 0 md Block

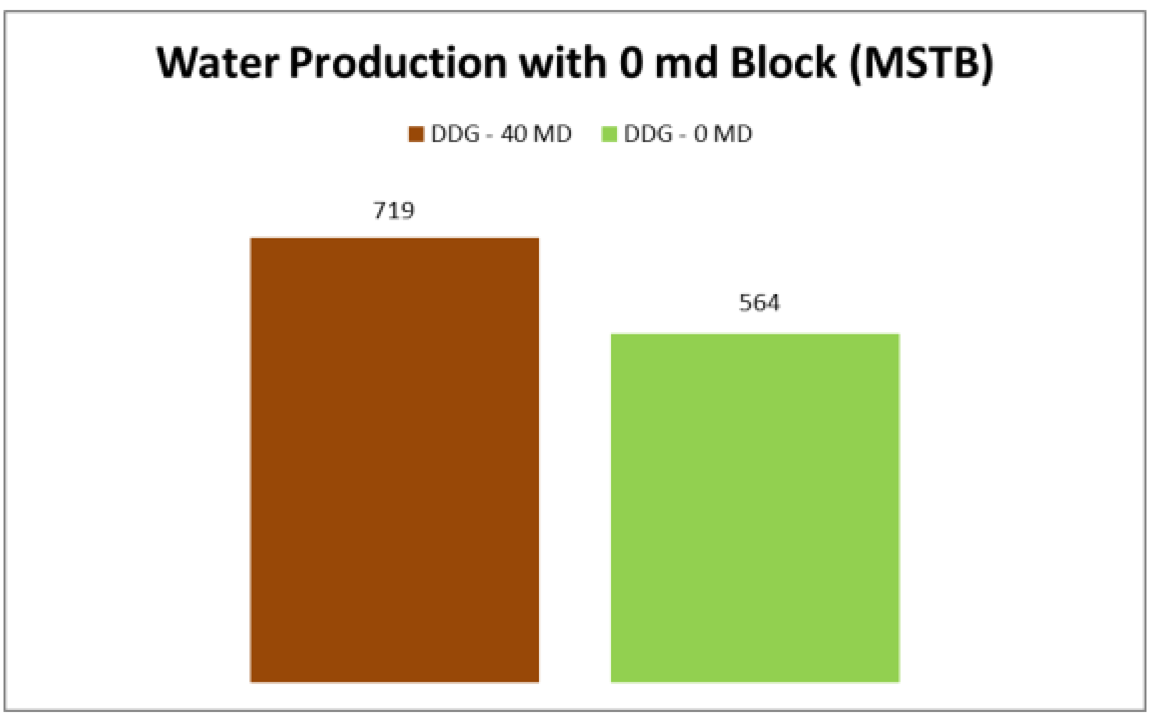

Figure 23: DDG – Incremental Water Production with 0 md Block

4.4.2 Polymer Concentration

To get a better idea of the effect of the concentrations used on polymer floods performance, simulations were performed at concentrations of 285 ppm (0.10 lb/stb), 600 ppm (0.21 lb/stb) and 1500 ppm (0.525 lb/stb). For both H-L and L-H arrangements, oil recovery increased slightly at the higher concentration with more marked reductions observed as concentration was reduced. Water production was however more substantially reduced at 1500 ppm.

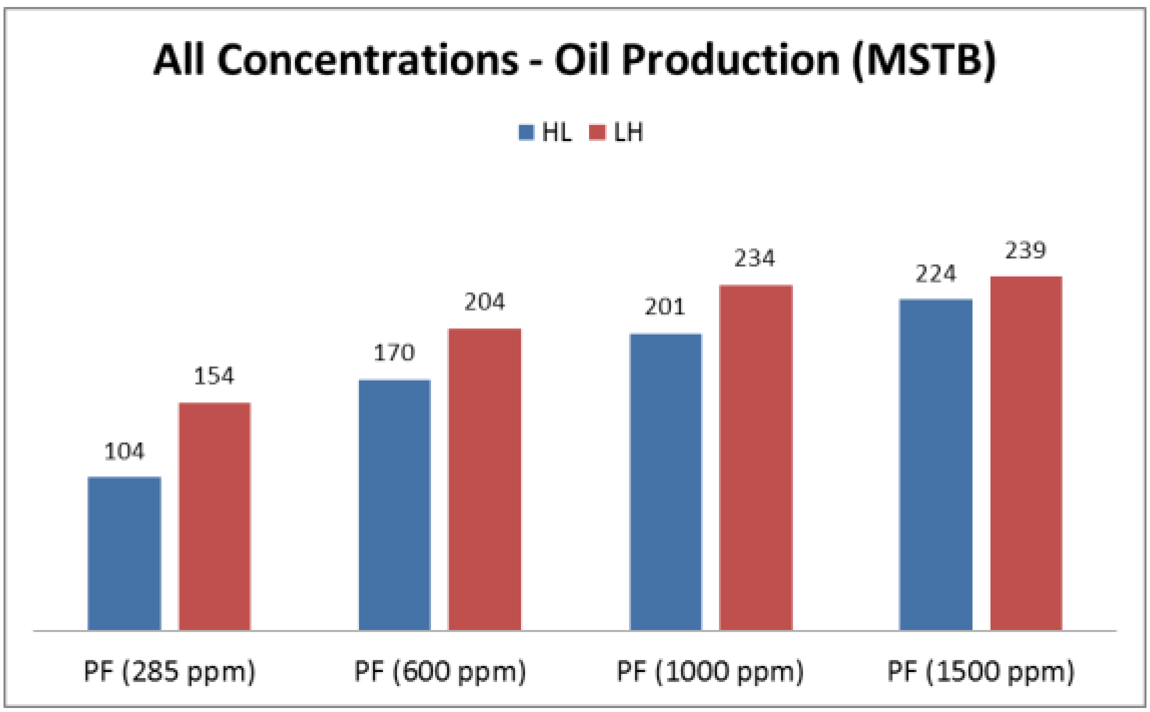

Figure 24: Polymer Flood – Oil Production at Different Concentrations

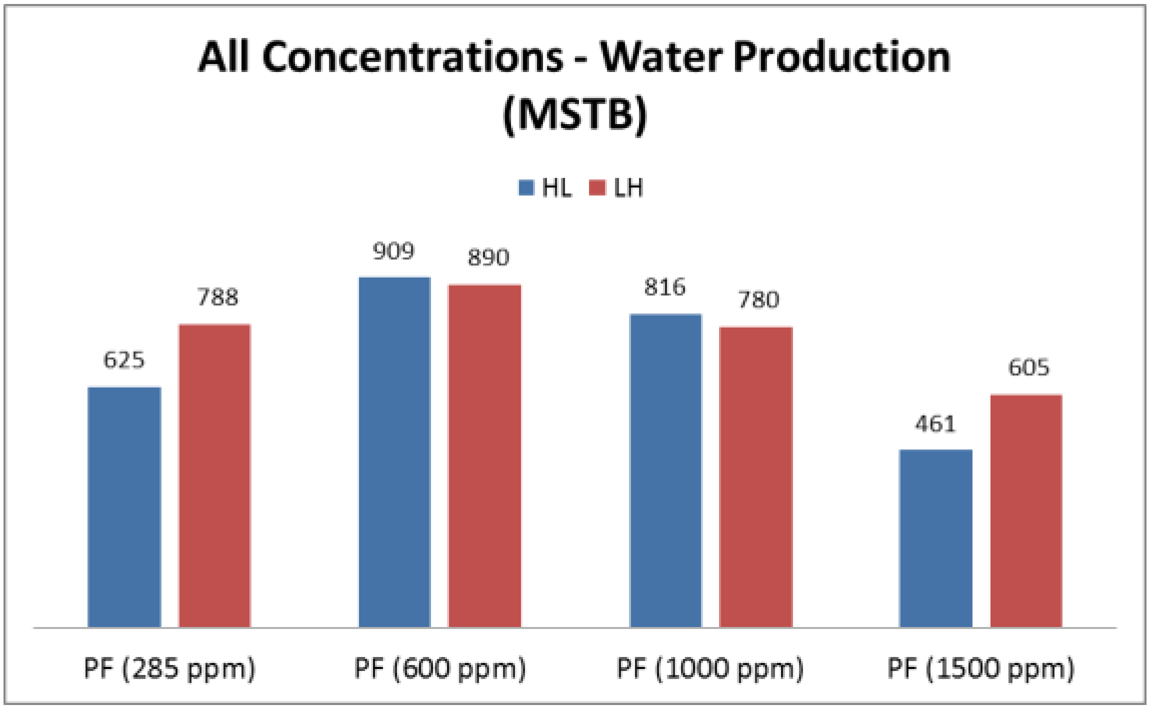

Figure 25: Polymer Flood – Water Production at Different Concentrations

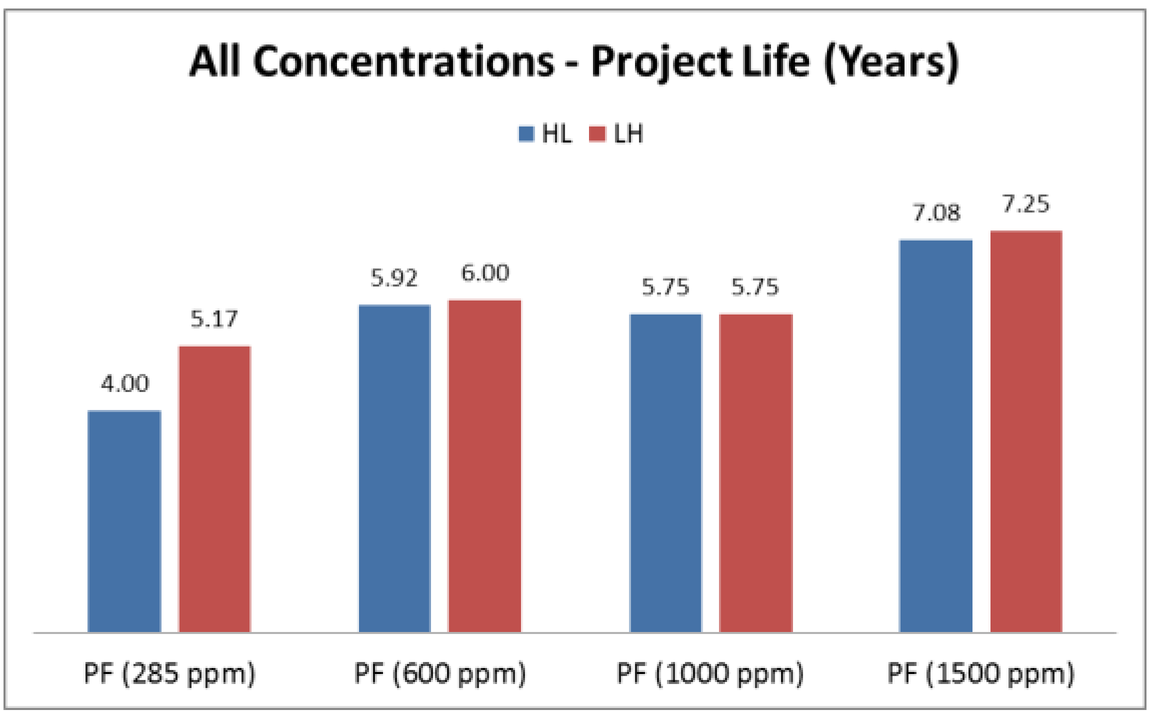

Figure 26: Polymer Flood – Project Life at Different Concentrations

4.4.3 DDG Production Pressure

One of the assumptions made in the DDG process is that the viscosity of the added slurry be as close to that of water as possible. As such the pressure responses at the injection and production wells are only slightly different from the base case waterflood. To better compare this method to the polymer flood, it was decided to artificially increase the pressure drop at the production well in the DDG runs to simulate the drop observed during polymer flood. This was done by reducing the injection rate in one set of simulations by 100 barrels per day while keeping production rate constant and increasing the liquid production rate by the same amount in a second with injection rate held constant.

Oil recovery increased 90 – 96 % in the H-L configuration and by 60 % in the L-H arrangement compared to the DDG base case results. This was however followed by increases in project life of 3 to 4 years and in water production ranging from 60 – 90 % for both configurations.

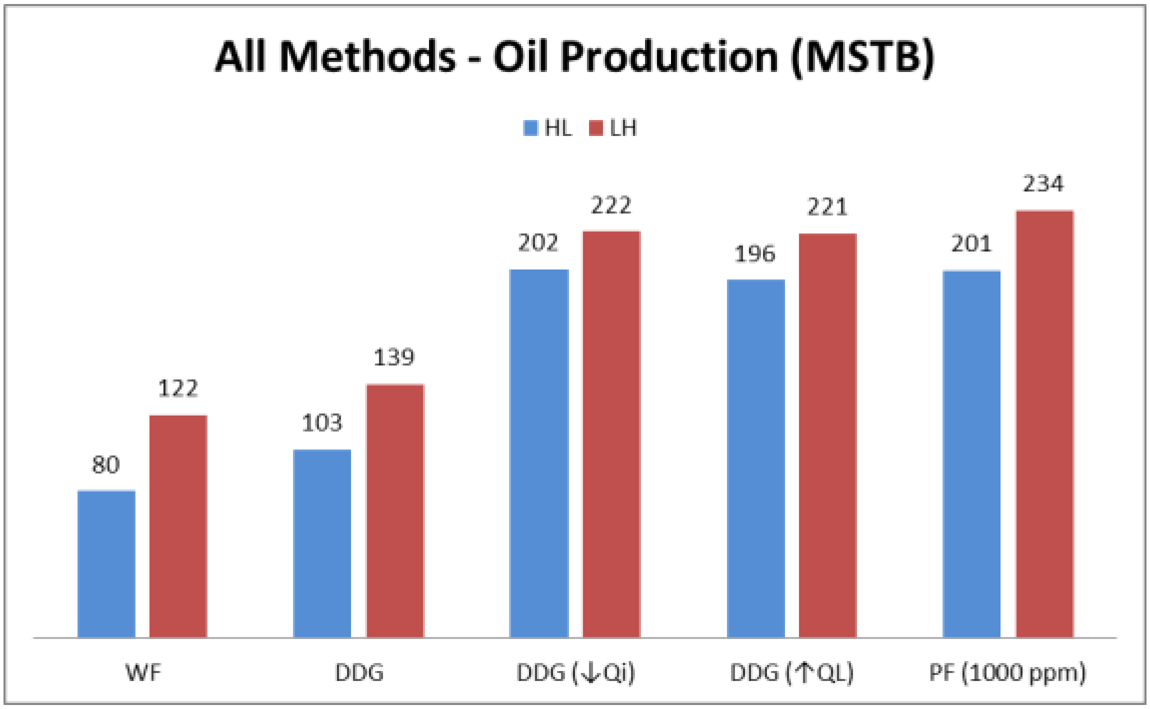

Figure 27: DDG – Oil Production with lowered Production Pressure

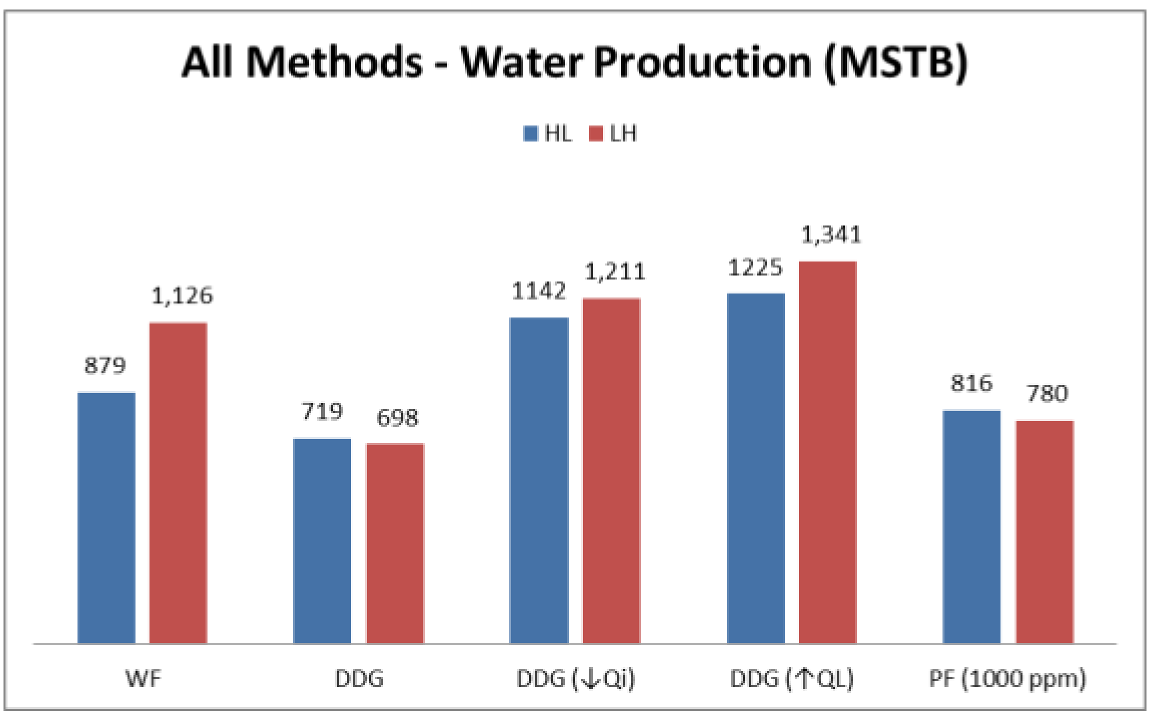

Figure 28: DDG – Water Production with lowered Production Pressure

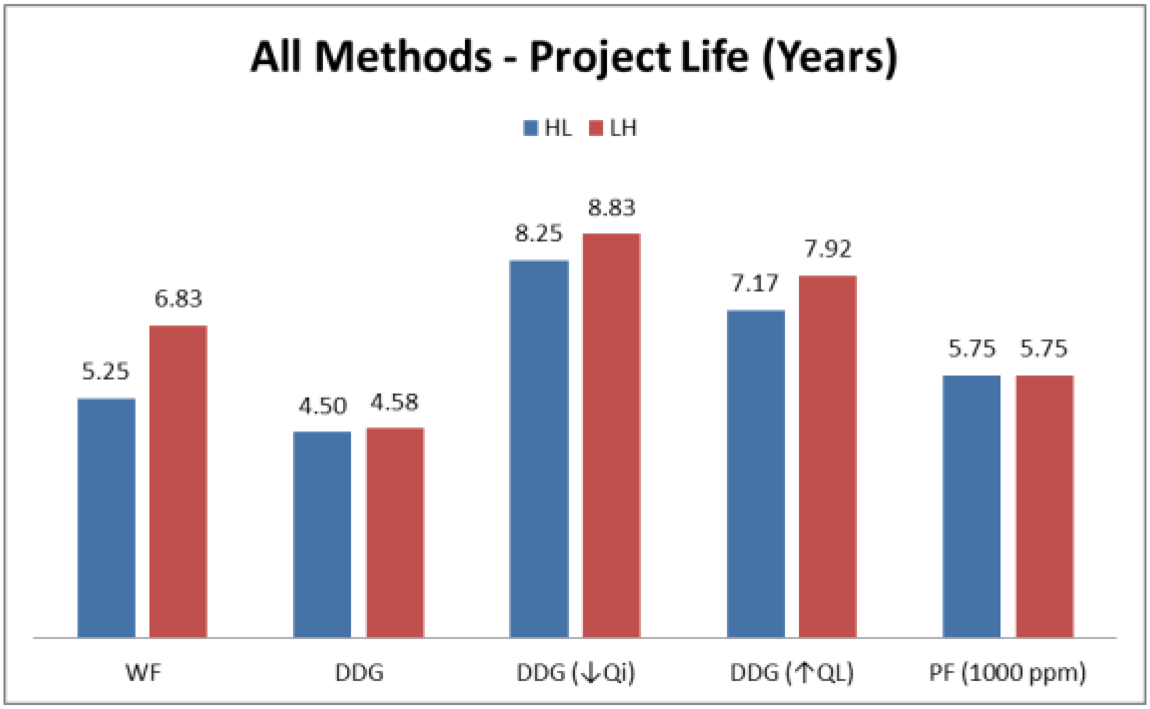

Figure 29: DDG – Project Life with lowered Production Pressure

4.4.4 Oil Viscosity

The oil viscosity in the H-L layer configuration was increased from 2 cp to 10 cp and 100 cp in all three methods. The waterflooding model was run first to obtain the time at which 85% water-cut was reached. As expected, with an even worse mobility ratio, sweep efficiency was poorer and water production started earlier with the water-cut increasing faster than in the base case. These new times were used to determine the new time it would take the DDG to reach the activation site and to begin injection in the Polymer flood for the 600 ppm, 1000 ppm and 1500 ppm models. Figures 30 – 32 show the results of these runs.

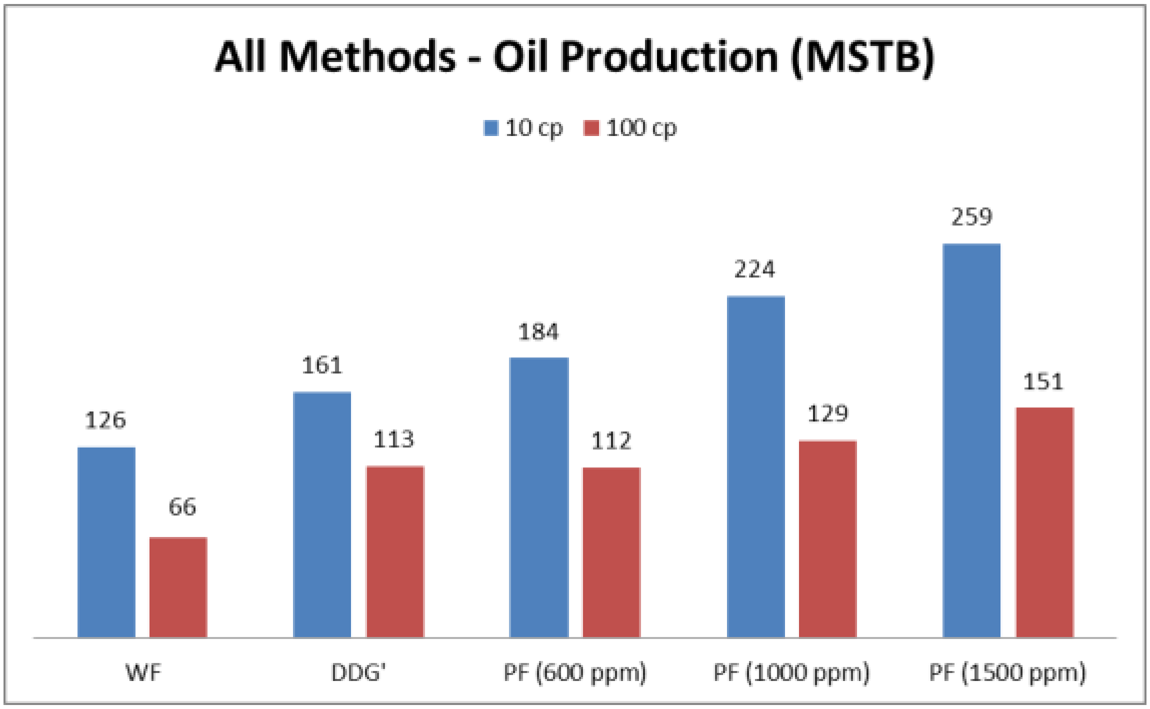

Figure 30: Incremental Oil Production for 10 and 100 cp Oil

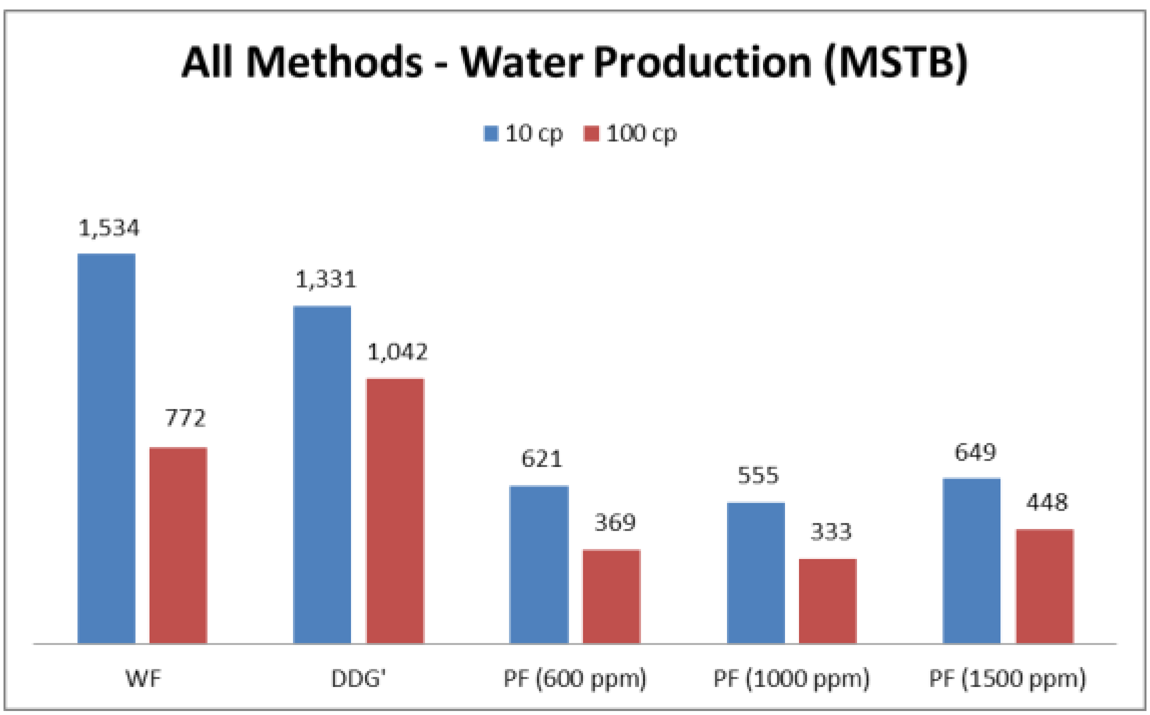

Figure 31: Incremental Water Production for 10 and 100 cp Oil

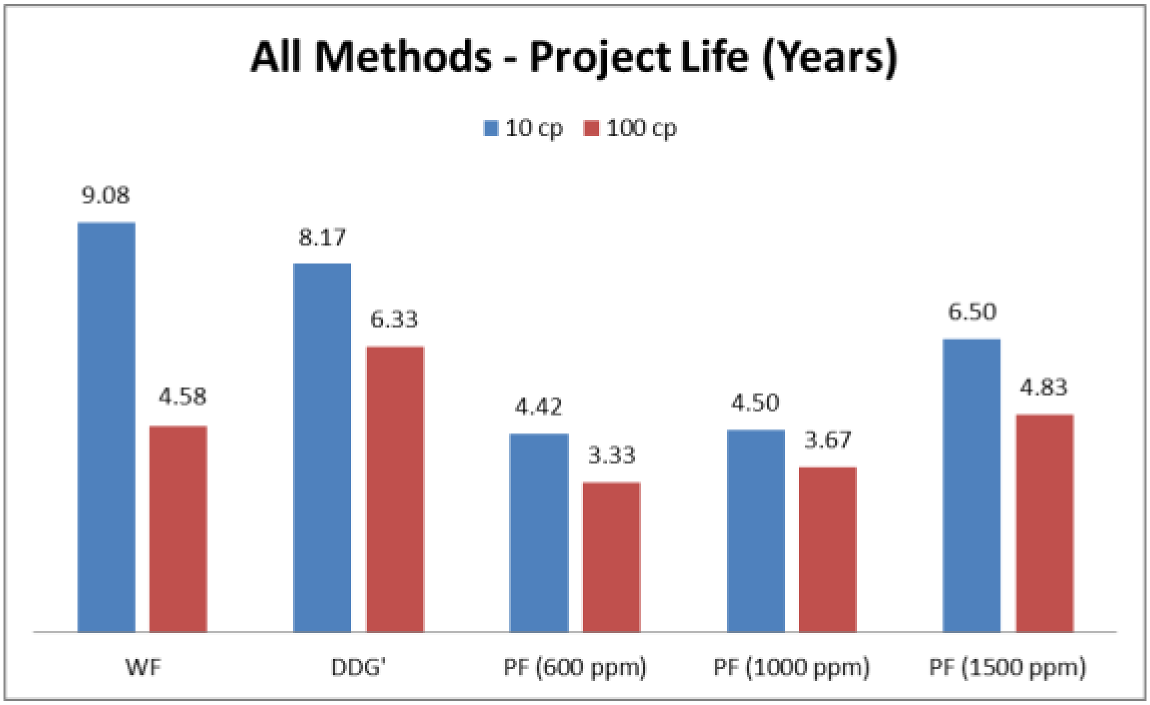

Figure 32: Project Life for 10 and 100 cp Oil

As can be seen in the figures above, DDG performed better in terms of oil recovery at higher viscosities when compared to polymer flood than in the base case. This however came at the cost of much higher water production relative to polymer production.

4.4.5 Polymer Flood Pressure Control

Two approaches to polymer flooding are commonly recognized with the first, and approach taken here, being to inject and produce at the maximum allowable rates. (Wang et al. 2008) The second approach is one involving a strategy of long term sustainable development whereby production rate is controlled by reducing injection rates to prolong the oil production period.

With this in mind, simulations were carried out where the production rate was kept equal to, or as close to the injection rate. This approach also reduces the pressure drop observed at the producer well and across the reservoir to more closely simulate the pressure profile observed during the DDG treatment.

The results show that for this reservoir, matching injection rates to production rate besides extending the field life leads to reduced oil production and NPV both of which, while lower than the results from the approach that favors maximizing production, are still higher than those from the DDG treatment.

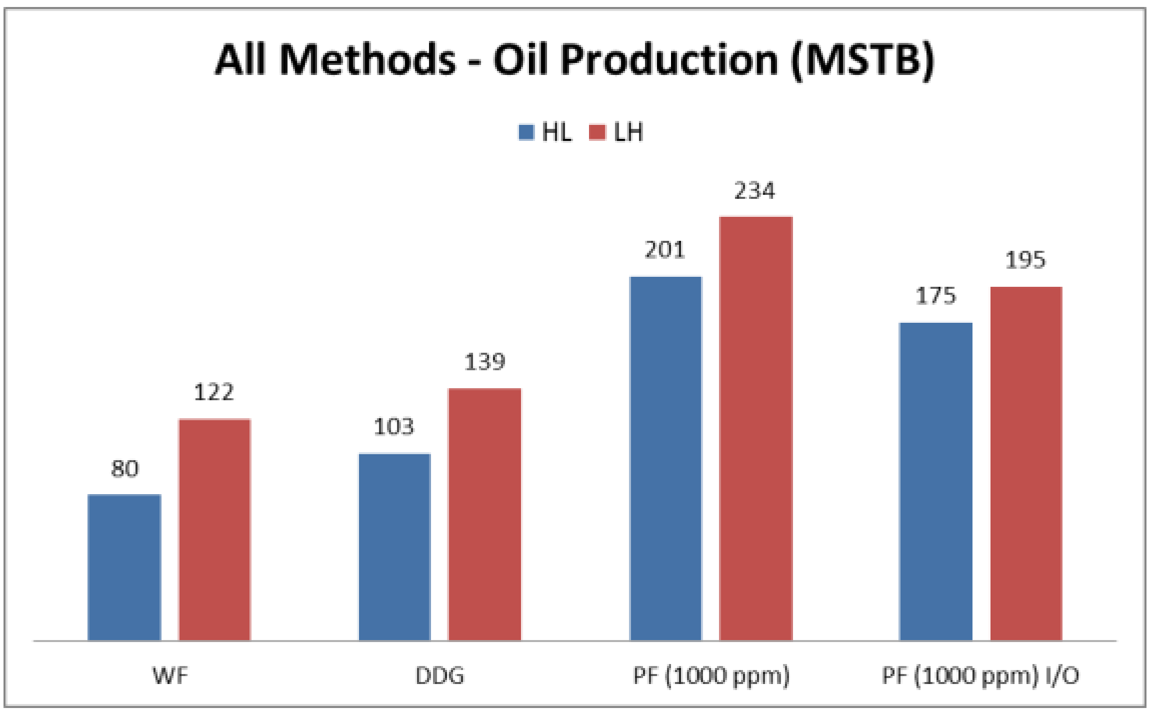

Figure 33: Oil Production when $Q_L = Q_i$

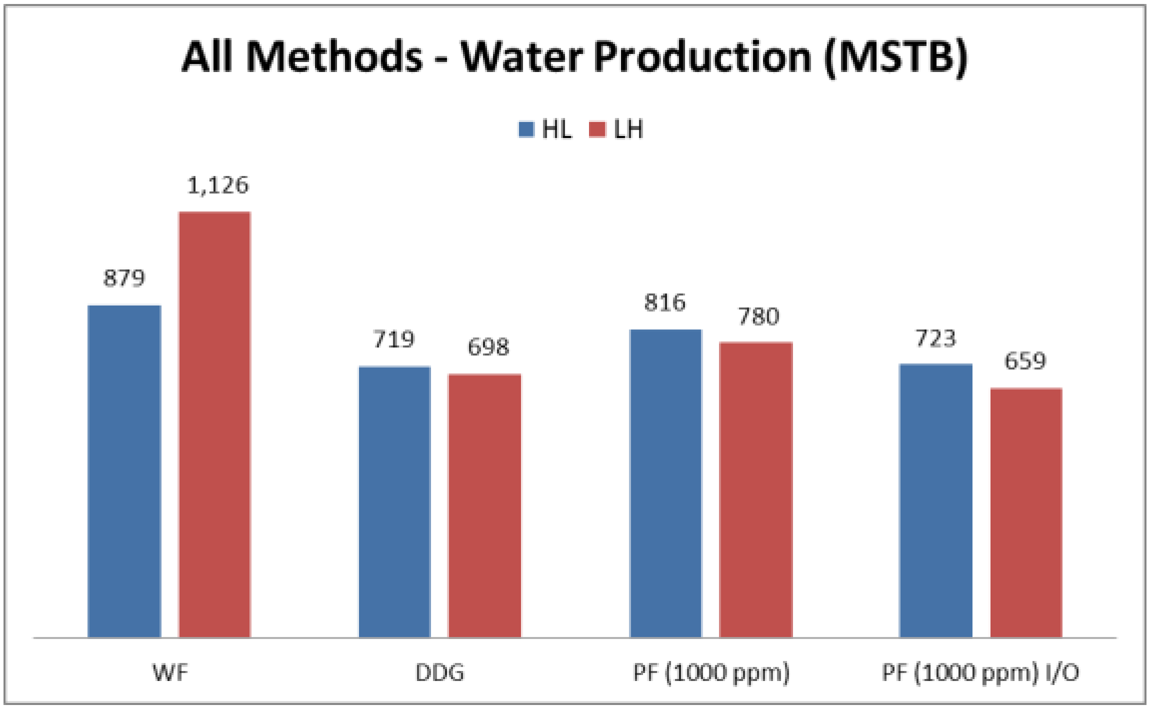

Figure 34: Water Production when $Q_L = Q_i$

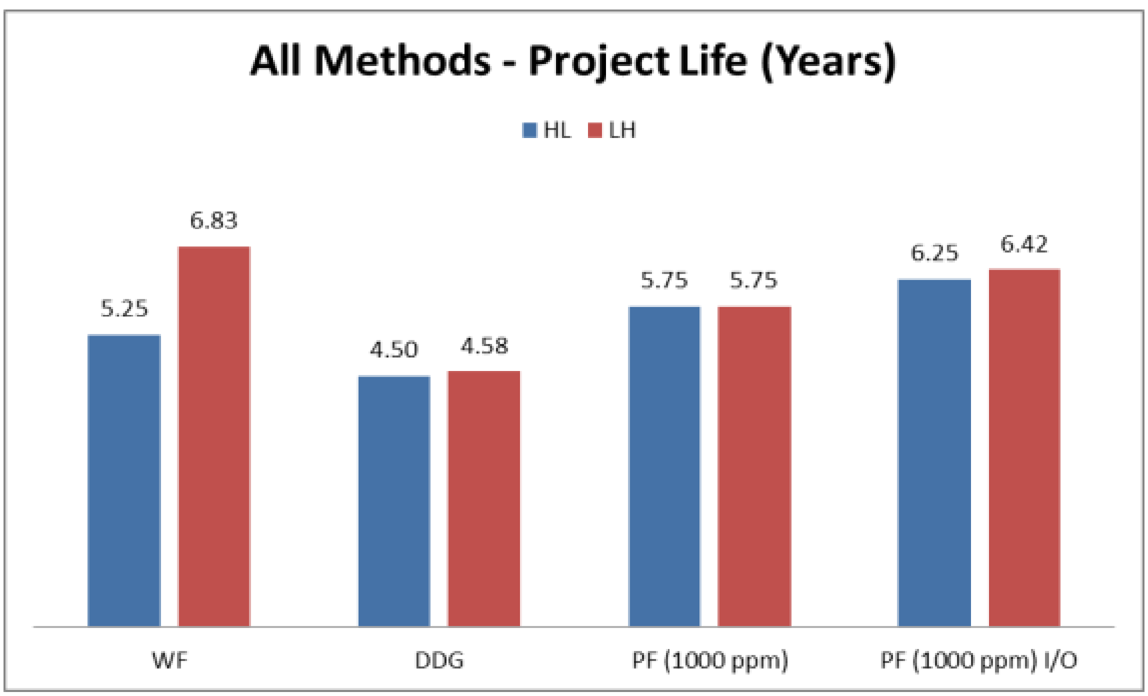

Figure 35: Project Life when $Q_L = Q_i$

4.4.6 Calculation of Polymer Viscosity

As previously stated, the default model in Eclipse used to calculate polymer viscosity in the base case focuses on the shear thinning behavior of polymers. The assumption may prove to be invalid in heterogeneous reservoirs such as ours with regions of different permeability in that shear rate would be higher in low permeability rock than in high permeability rock. Seright also stated that an overly optimistic injectivity may be calculated if shear thinning is assumed for HPAM polymer. Results were therefore verified using the Herschel-Bulkley model which calculates viscosity as a function of rheology, flow rate, pressure drop along a given length, and rock properties such as permeability and porosity.

The figures below show the results using both models for the LH configuration of the polymer flood. Figure 36 shows the calculated polymer viscosities in the low and high perm layers at the midpoint between the injection and production well for the base case polymer flood. The difference between the viscosities calculated using the two methods is negligible and this is also reflected in the production rates and field life with slightly higher differences observed with the highest viscosity polymer.

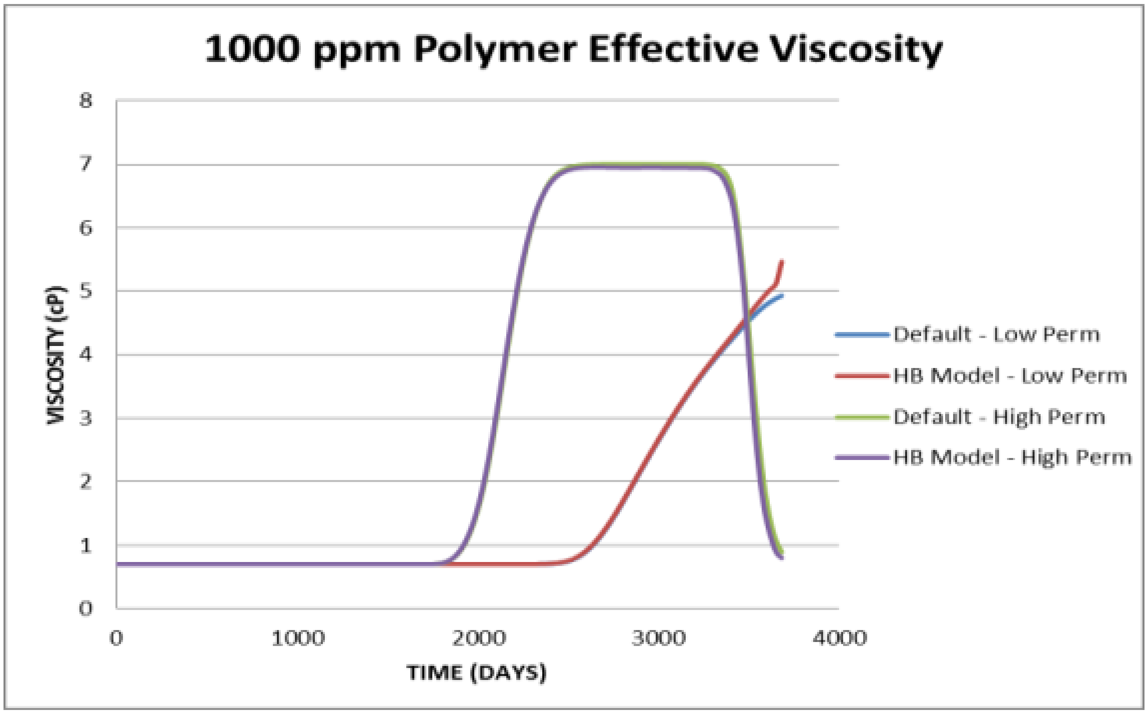

Figure 36: 1000 ppm PF Viscosity using Default & Herschel-Bulkley Models

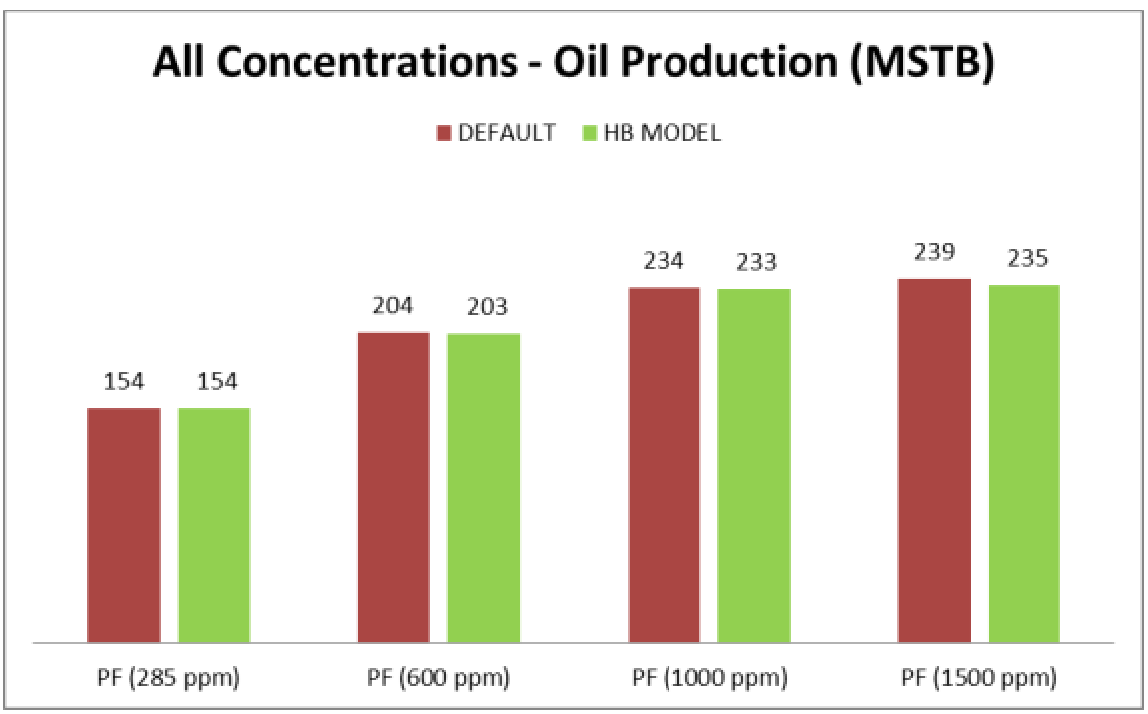

Figure 37: PF [LH] Oil Production using Default & Herschel-Bulkley Models

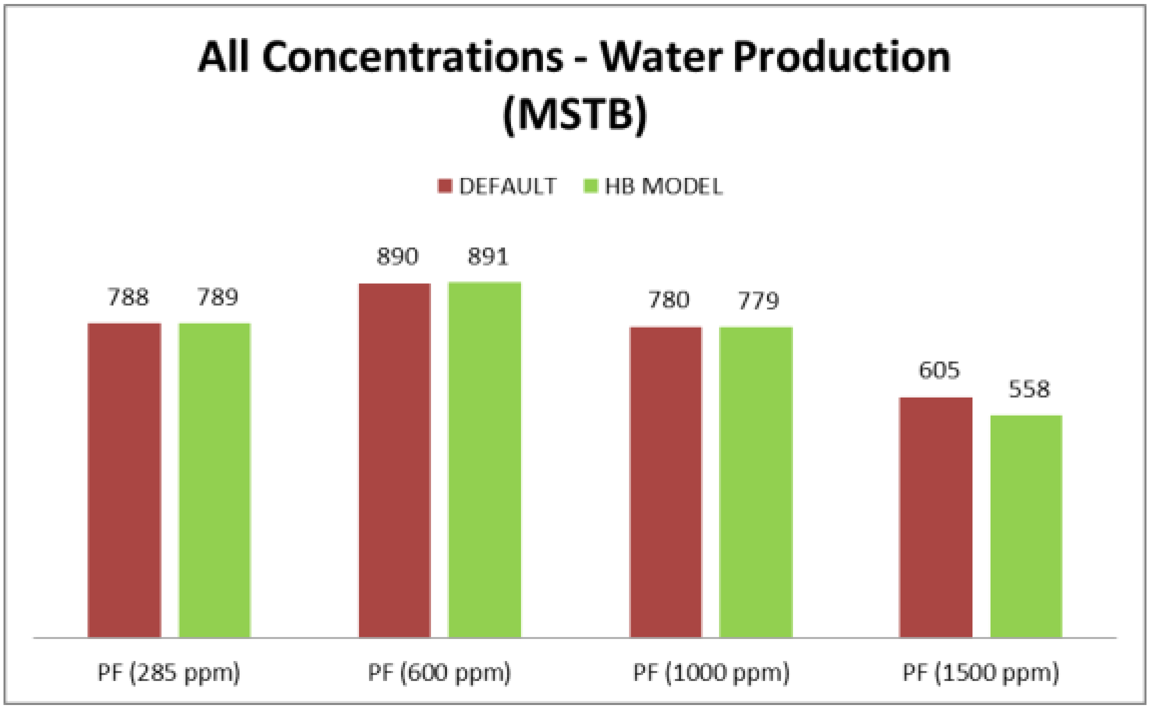

Figure 38: PF [LH] Water Production using Default & Herschel-Bulkley Models

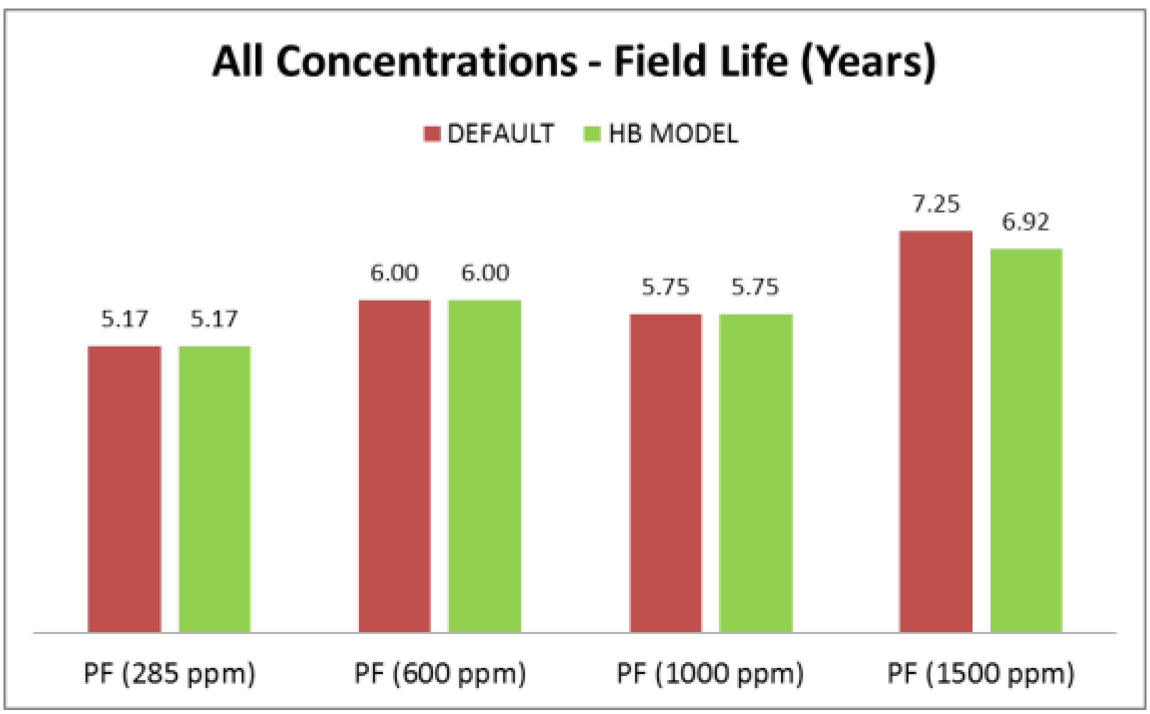

Figure 39: PF [LH] Field Life using Default & Herschel-Bulkley Models

The tables below shows the results, i.e. oil and water production rates, the project life and recovery factors of simulations performed.

Table 3: Results from H-L Simulations

	Oil (MSTB)	Water (MSTB)	Life (Years)	RF
WF	80	879	5.25	51.3%
DDG	103	719	4.50	53.6%
DDG' (0 md)	105	564	3.67	53.8%
DDG (↓Q_i)	201	1,142	8.25	63.7%
DDG (↑Q_L)	195	1,225	7.17	63.0%
PF (285 ppm)	104	625	4.00	53.7%
PF (600 ppm)	170	909	5.92	60.4%
PF (1000 ppm)	201	816	5.75	63.6%
PF (1500 ppm)	224	461	7.08	65.9%
PF (1000 ppm) $Q_L = Q_i$	175	723	6.25	61.0%

Table 4: Results from L-H Simulations

	Oil (MSTB)	Water (MSTB)	Life (Years)	RF
WF	122	1,126	6.83	52.5%
DDG	139	698	4.58	54.3%
DDG (↓Q_i)	222	1,211	8.83	62.7%
DDG (↑Q_L)	221	1,341	7.92	62.6%
PF (285 ppm)	154	788	5.17	55.7%
PF (600 ppm)	204	890	6.00	60.8%
PF (1000 ppm)	234	780	5.75	63.8%
PF (1500 ppm)	239	605	7.25	65.4%
PF (1000 ppm) $Q_L = Q_i$	195	659	6.42	59.9%

Table 5: Results from 10 cp Oil Simulations

	Oil (MSTB)	Water (MSTB)	Life (Years)	RF
WF	126	1,534	9.08	41.2%
DDG	161	1,331	8.17	44.9%
PF (600 ppm)	184	621	4.42	47.1%
PF (1000 ppm)	224	555	4.50	51.3%
PF (1500 ppm)	259	649	6.50	54.8%

Table 6: Results from 100 cp Oil Simulations

	Oil (MSTB)	Water (MSTB)	Life (Years)	RF
WF	66	772	4.58	21.5%
DDG	113	1,042	6.33	26.5%
PF (600 ppm)	112	369	3.33	26.2%
PF (1000 ppm)	129	333	3.67	27.9%
PF (1500 ppm)	151	448	4.83	30.1%

V ECONOMICS

In this section, the primary objective is to compare the polymer flood to the DDG treatment method in terms of value and economic feasibility using the Net Present Value of each configuration as a yardstick. The model used to perform this analysis was developed using Microsoft Excel® and kept simple and flexible to allow for any modifications that needed to be made.

The input data, i.e. oil and water production, water injection and quantities of DDG and polymer used will be imported starting from the time-step immediately after the base case reaches 85% water cut. This assumes then that all activity up to that point is a sunk cost.

To measure the profitability of each method required taking the cost of capital into consideration by calculating the Present Value of future cash flows at each monthly time-step. This was done by applying a discount factor derived from the annual interest rate for the cost of capital to the net cash flow per period after operating costs and taxes had been deducted.

NPV is therefore given by

$$NPV = \sum \left\{ Cash\ Flow * \left[\frac{1}{\left(1 + \frac{i}{12}\right)^{n}} \right] \right\}$$

where $Cash\ Flow = Revenue - Operating\ Costs - Taxes$

$$i = Annual\ Interest\ Rate$$

$$n = Number\ of\ months$$

Revenue was calculated by multiplying the oil produced by the assumed price of crude oil. The operating costs included assumed values for a monthly fixed cost, the costs associated with injecting water and its disposal, the cost of polymer; here Hydrolyzed Polyacrylamide HPAM and the DDG. Table 6 below includes the values used for these calculations. The operating costs, except the cost of the DDG, were taken from a recent economic analysis on polymer flooding and data from polymer flooding operations in the Daqing Oil Field in China. (Alusta et al. 2011; Demin et al. 2003) The price of the DDG is a conservative estimate based on industry prices for other similar complex polymers. The economics of both methods will be impacted by the price of chemicals and water handling costs which, while reasonable estimates based on market prices, are still assumptions. Two additional scenarios were considered where the prices of polymer and the DDG were changed and these will be discussed below.

Table 7: Economic Analysis Input Data

Effective Starting Date	January 2000
Oil Price ($/bbl)	50
CAPEX ($) at 85% WCT - Waterflooding - Polymer Flood - DDG	 - 0 - 250,000 - 25,000
Production Tax Rate (%)	12.50
Fixed Operating Costs ($/month)	1750
Abandonment ($)	50,000
Water Injection ($/bbl)	2.00
Water Disposal ($/bbl)	2.00
Discount Rates (%)	10
Variable Oil Cost ($/bbl)	0.05
Polymer Cost ($/lb)	1.50
DDG Cost ($/lb)	3.00

5.1 Waterflooding

These results are for the two different layer arrangements and constitute the base case for each of these configurations as used in the DDG treatment and polymer flooding. The monthly incomes and annualized economic variables are presented below. The steady decline in cash flow reflects the decreasing production of oil and steady high water production.

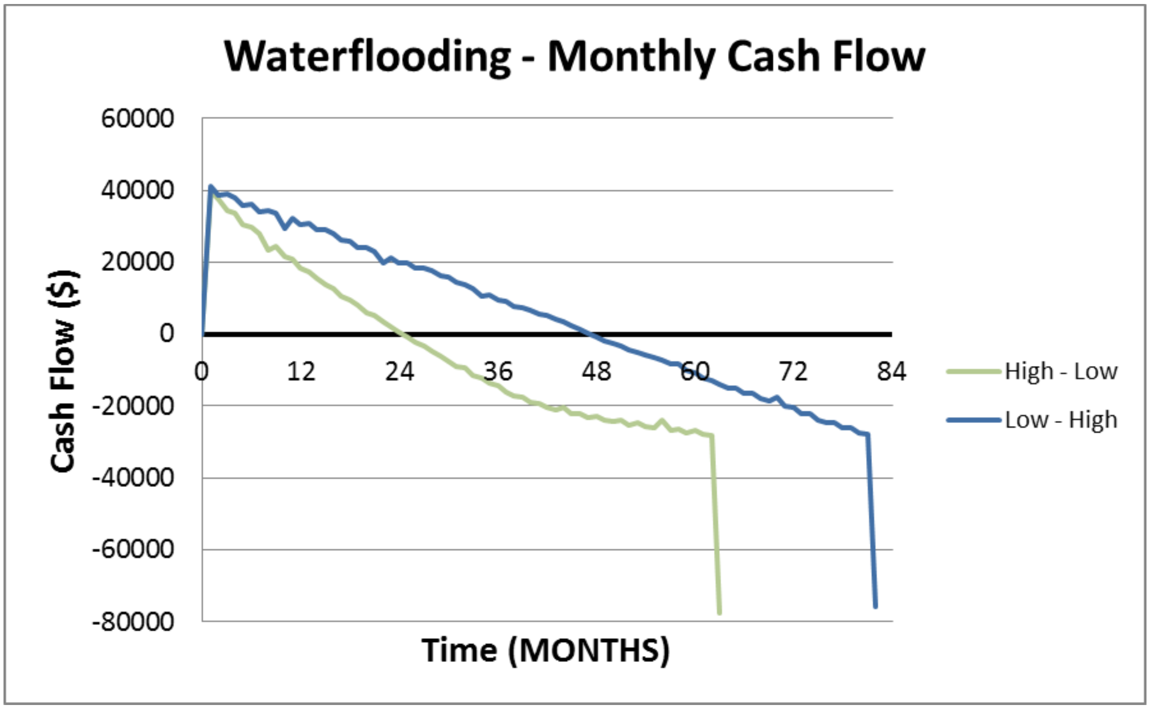

Figure 40: Waterflooding – Monthly Income

5.2 Polymer Flooding

The results for the polymer simulations in both the H-L and the L-H arrangement are given below for the concentrations under study. These results are compared to those obtained from the waterflooding simulations at the end of this section. It should be pointed out that the amount of polymer injected is constrained by the polymer concentration in the injected solution, given in pounds per barrel of water injected. The price of the polymer remained the same at different concentrations because it was assumed that the type of polymer being used remained the same with the only change being in the concentrations and amount used.

Injection only starts after a water-cut of 85% is reached with an initial negative cash flow when the CAPEX for the polymer flood facilities and equipment are added. Income begins to increase as the improvement in sweep efficiency leads to improved oil recovery. The accompanying reductions in water injection and production also help to increase cash flow. The loss incurred by the cost of the polymer needed was however offset by the returns obtained as oil production increased.

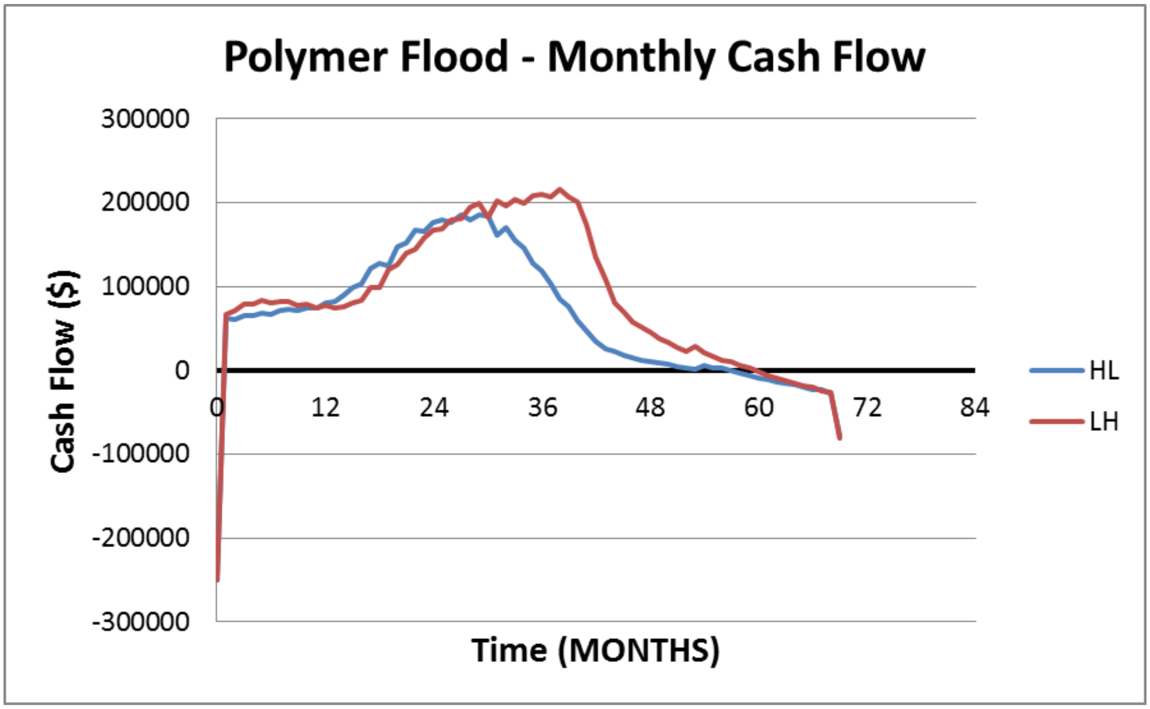

Figure 41: 1000 ppm Polymer Flood – Monthly Income

5.3 Deep Diverting Gel

One of the key steps in performing an economic analysis on the DDG treatment was estimating the amount of the polymer to be used. This was performed using a rule of thumb proposed by the DDG supplier which relates the amount of DDG to the effective pore volume of the thief zone to be blocked. A treatment size of 3% of this pore volume was recommended and a supply concentration of polymer between 1.5 – 1.7 % (Roussennac et al. 2010).

Therefore in our case where by the time 85% water-cut has been reached, the high permeability layer is considered the thief zone with a pore volume of 621,000 barrels, the amount of treated water to be injected was 18,600 barrels with about 317 barrels of the DDG mixed in. A weight conversion factor also from work done by Roussennac et al (2010) was used to obtain the mass of this volume in pounds. Care was taken to ensure that the cost of this treatment was applied to the economic analysis starting from the month injection began and not from the beginning of the project at Month 0. Using this cost at the beginning of the project depressed the value of the project's NPV since there was no discounting and it was assumed to be a part of the initial sunk cost and capital expenditure. The figures below show the results from these runs.

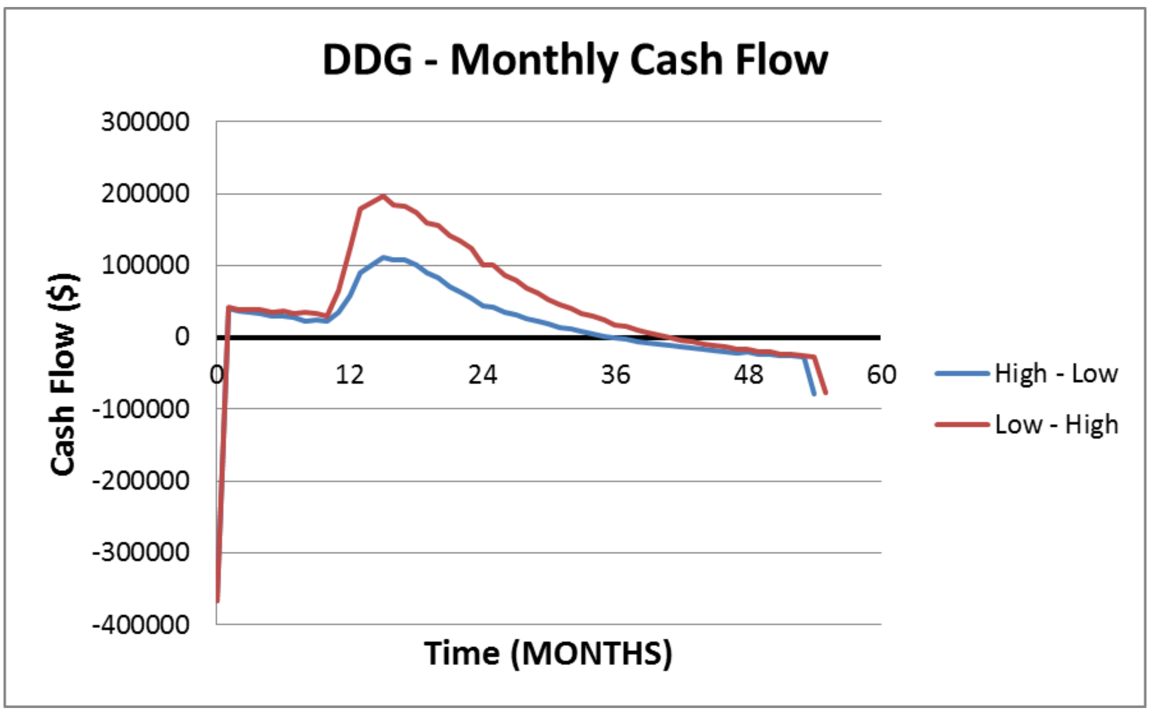

Figure 42: Deep Diverting Gel – Monthly Income

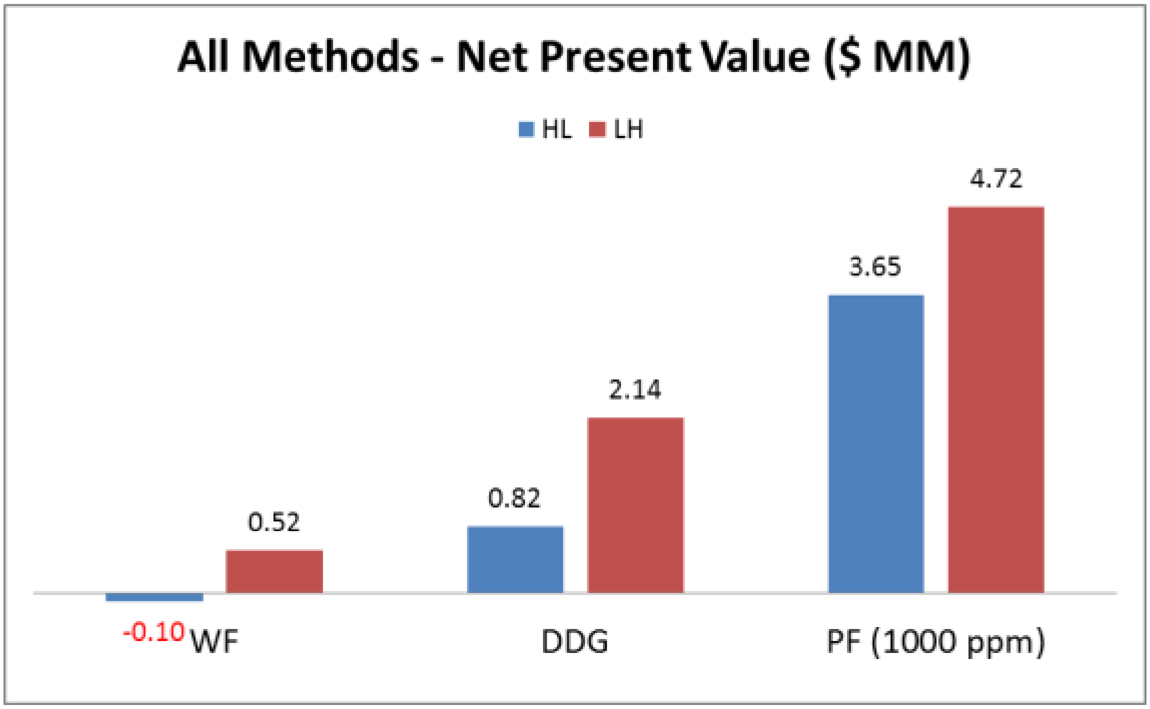

Figure 43: Base Cases – NPV

Table 8: Base Case (HL) – Economic Results Summary

	Cash Flow ($)	NPV ($)
WF	329,000	98,000
DDG	905,000	821,000
PF (1000 ppm)	4,408,000	3,650,000

Table 9: Base Case (LH) – Economic Results Summary

	Cash Flow ($)	NPV ($)
WF	384,000	522,000
DDG	2,487,000	2,144,000
PF (1000 ppm)	5,927,000	4,723,000

5.4 Sensitivity Analysis

The results from the runs in the sensitivity analyses performed in the section above are also shown below.

5.4.1 Permeability Reduction

Due to the increase in oil recovery and reduced water production observed when the permeability at the plugged site was dropped to 0 md, there is a higher return after the activation of the DDG in this scenario than in the base case as can be seen in the figure below.

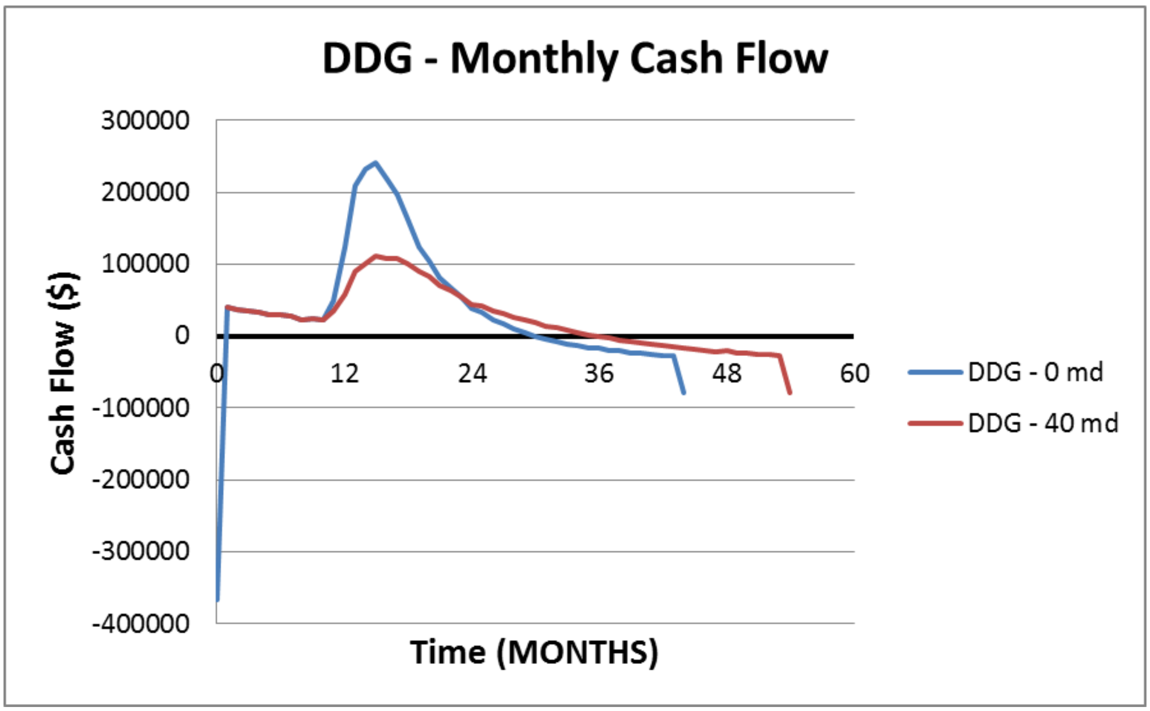

Figure 44: Deep Diverting Gel – Monthly Income

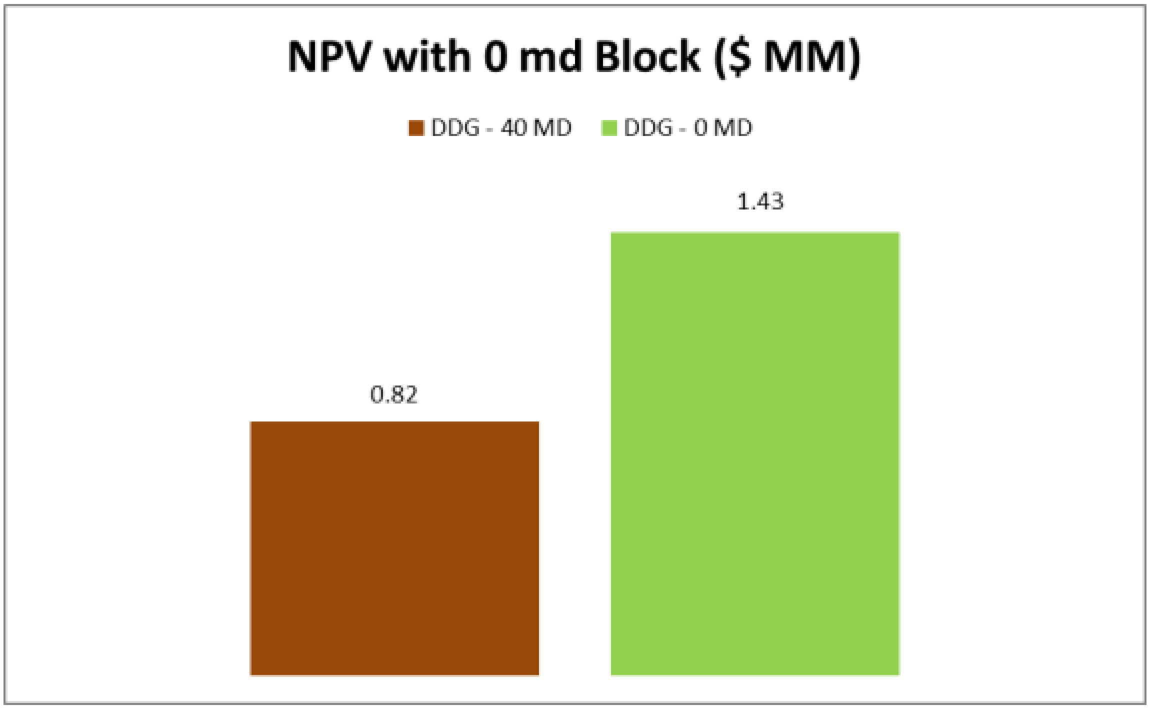

Figure 45: DDG – NPV with 0 md Block

Table 10: DDG (0 & 40 md) – Economic Results Summary

	Cash Flow ($)	NPV ($)
DDG (40 md)	905,000	821,000
DDG (0 md)	1,617,000	1,434,000

5.4.2 Polymer Concentration

The same behavior as in the base case was observed at lower polymer concentrations although returns were lower due to the lower volumes of oil produced. When a polymer concentration of 1500 ppm is used, a period of steady cash flow is observed that corresponds to the time it takes for the injected polymer slug to flow through the reservoir. It remains steady because although both wells are flowing at their maximum rates, these rates are much lower than the design rates due to the reduction in injectivity that occurs because of the increased viscosity of the polymer solution.

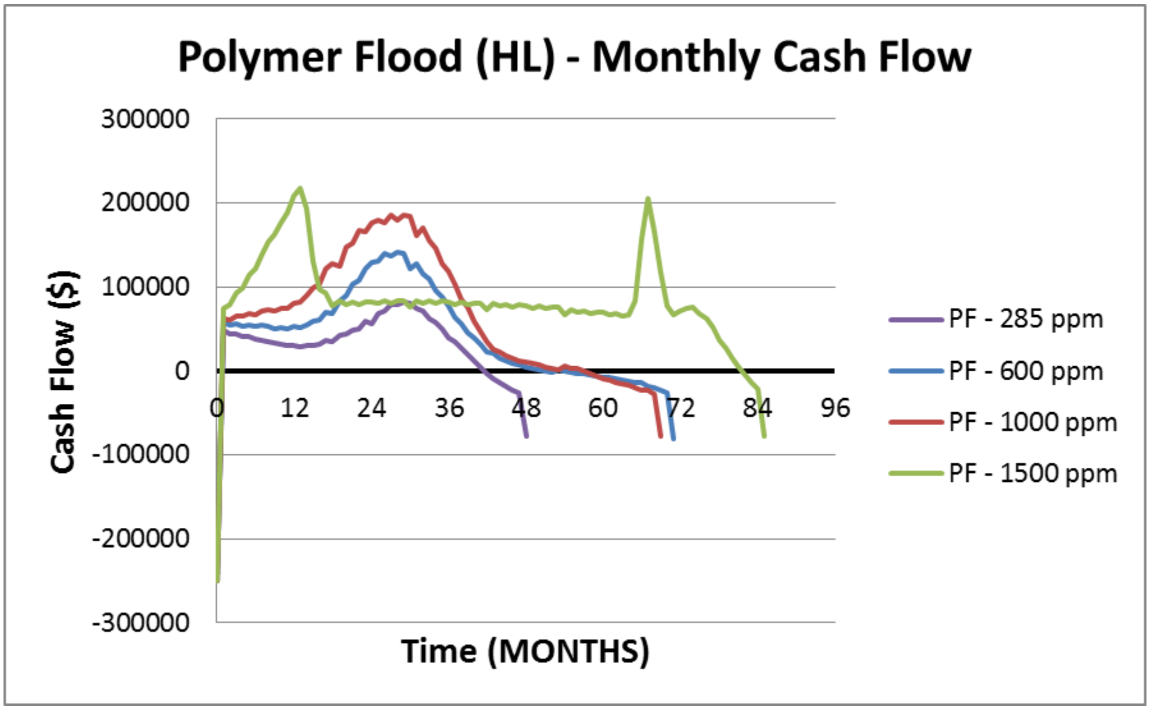

Figure 46: Polymer Flood (HL) – Monthly Income

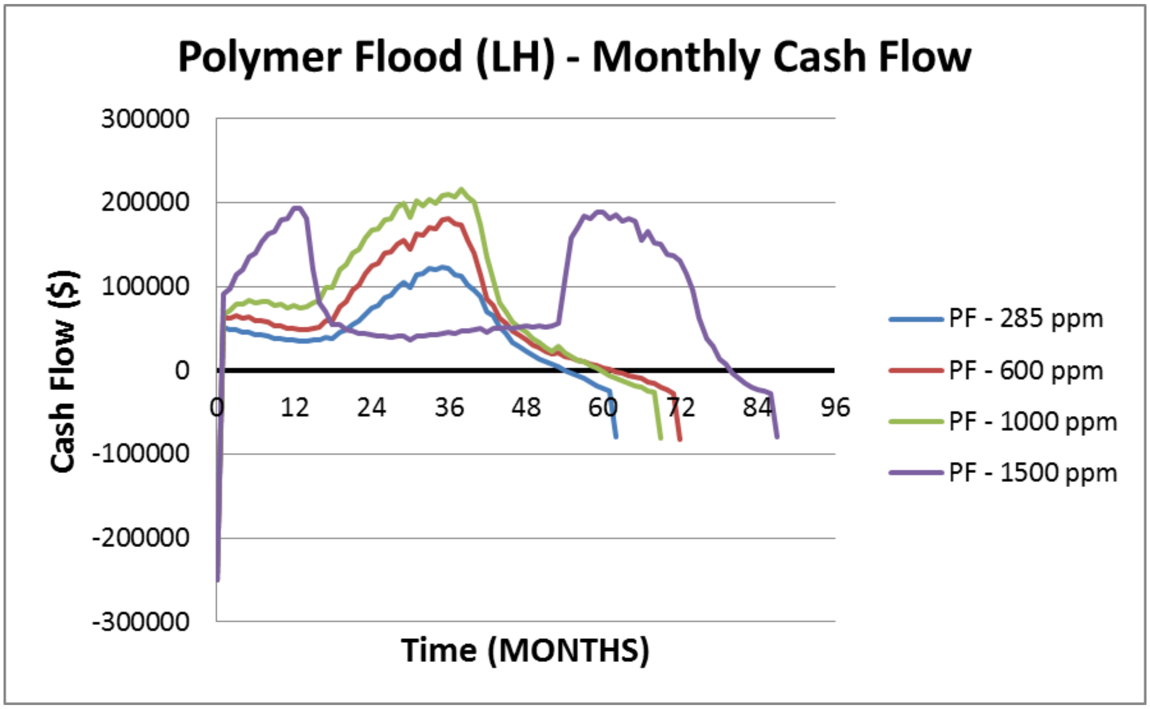

Figure 47: Polymer Flood (LH) – Monthly Income

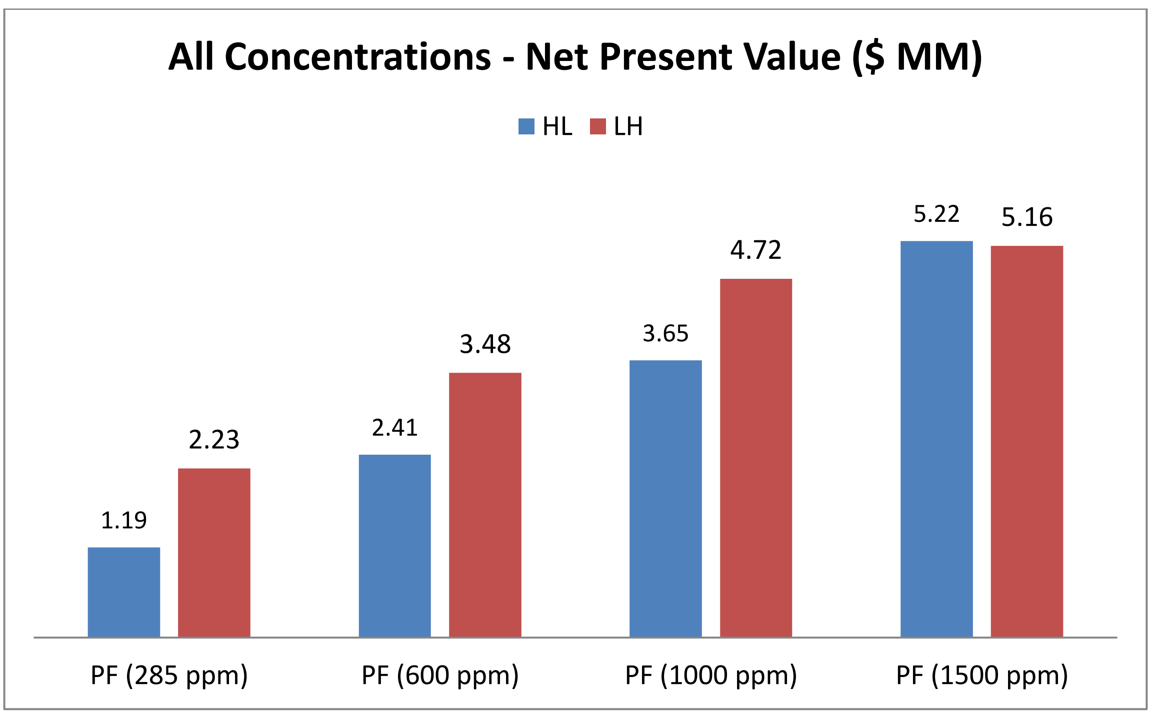

Figure 48: Polymer Flood – NPV at Different Concentrations

Table 11: Polymer Flood (HL) – Economic Results Summary

	Cash Flow ($)	NPV ($)
PF (285 ppm)	1,430,000	1,186,000
PF (600 ppm)	2,881,000	2,406,000
PF (1000 ppm)	4,409,000	3,646,000
PF (1500 ppm)	6,954,000	5,220,000

Table 12: Polymer Flood (LH) – Economic Results Summary

	Cash Flow ($)	NPV ($)
PF (285 ppm)	2,812,000	2,227,000
PF (600 ppm)	4,388,000	3,484,000
PF (1000 ppm)	5,927,000	4,723,000
PF (1500 ppm)	7,088,000	5,157,000

5.4.3 DDG Production Pressure

The figures below illustrate the increased cash flow of the DDG project when the production pressure is forced to reduce. In the first simulation, where the injection rate is reduced by 100 barrels per day, the increase in cash flow is due to the reduced operating expenses as less water is injected. The second simulations results closely mirror those of the first although in this instance the cash flow increases as oil production is ramped up by an extra 100 barrels a day.

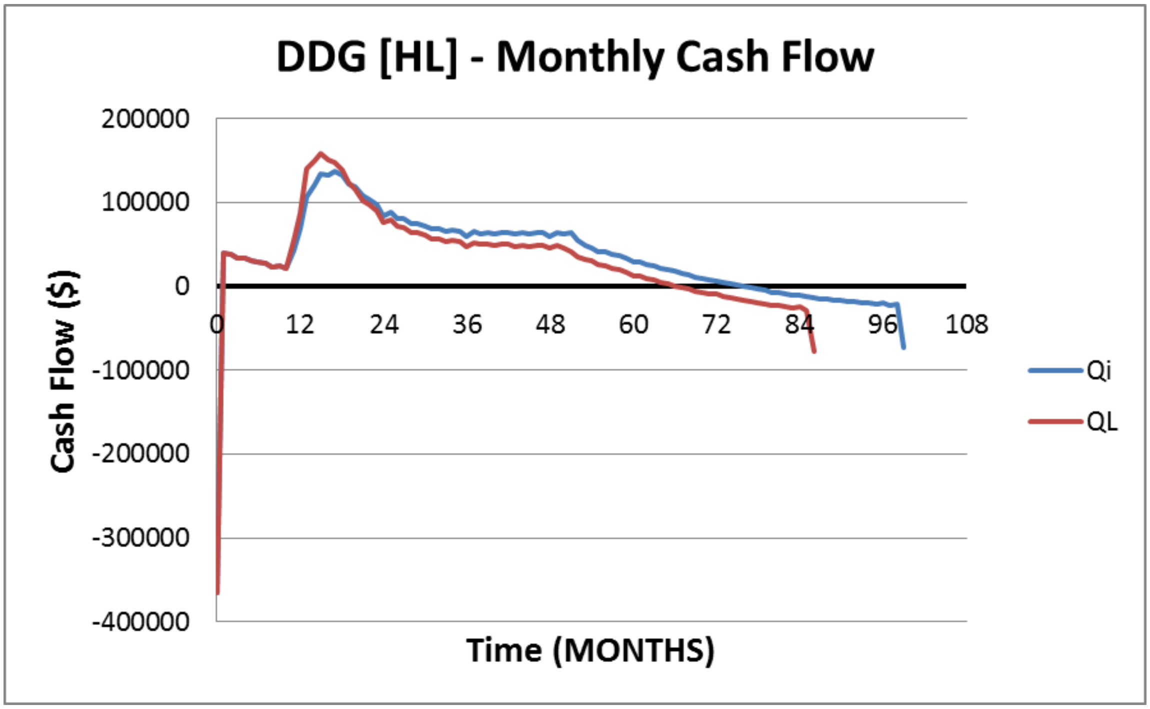

Figure 49: DDG (HL) – Monthly Income with lowered Production Pressure

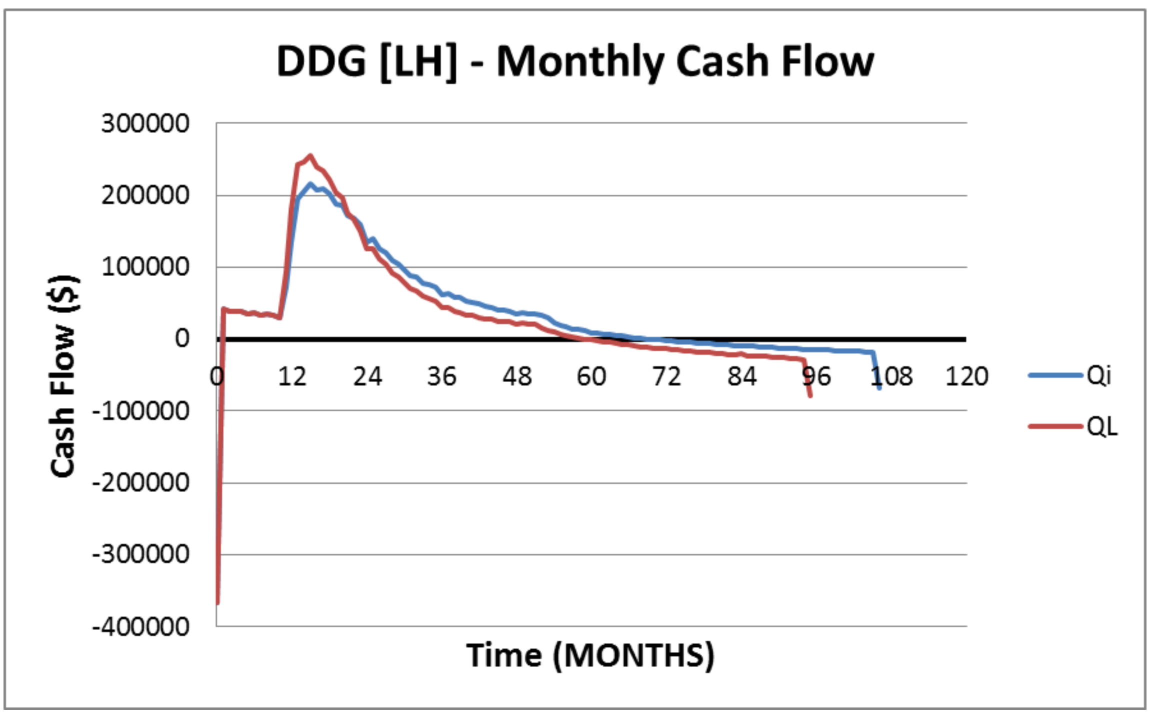

Figure 50: DDG (LH) – Monthly Income with lowered Production Pressure

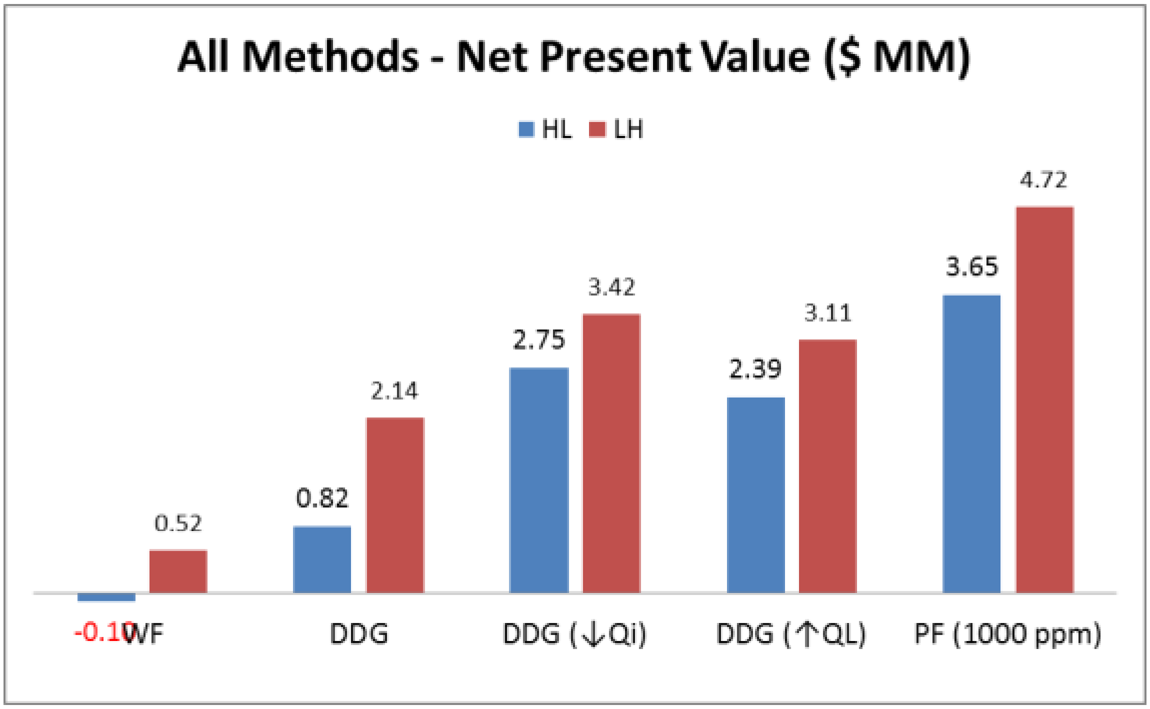

Figure 51: DDG – NPV with lowered Production Pressure

5.4.4 Oil Viscosity

In the case of the oil viscosity being changed from 2 cp to 10 and 100 cp, the effect of well life and incremental water and oil production can be seen in the figures below. The trends shown by the NPV followed those observed in the monthly cash flows in the 10 cp and 100 cp oil simulations with the DDG's NPV lower than those of the polymer floods at all concentrations.

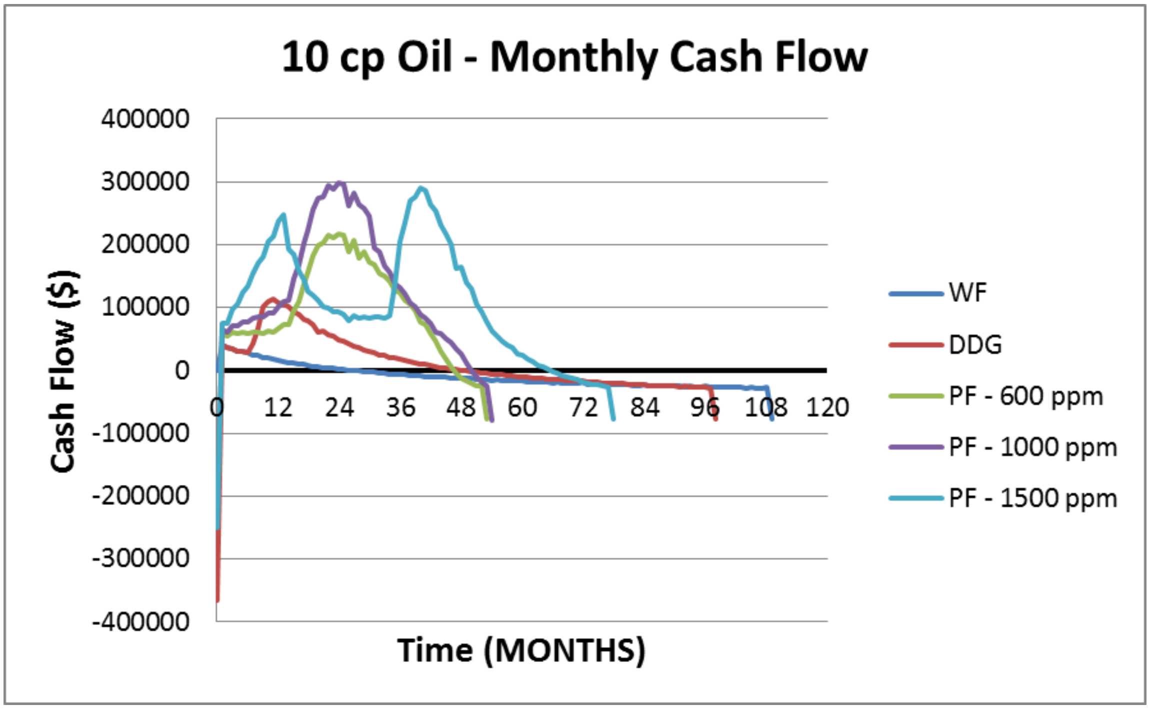

Figure 52: Monthly Income from simulations using 10 cp Oil

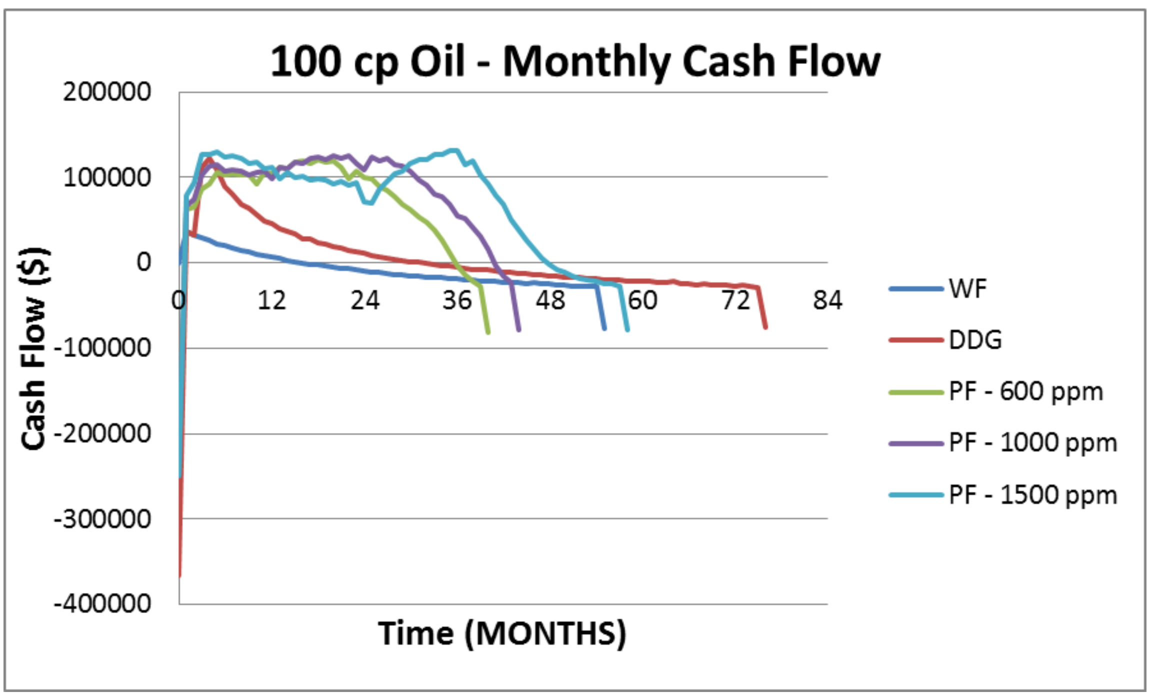

Figure 53: Monthly Income from simulations using 100 cp Oil

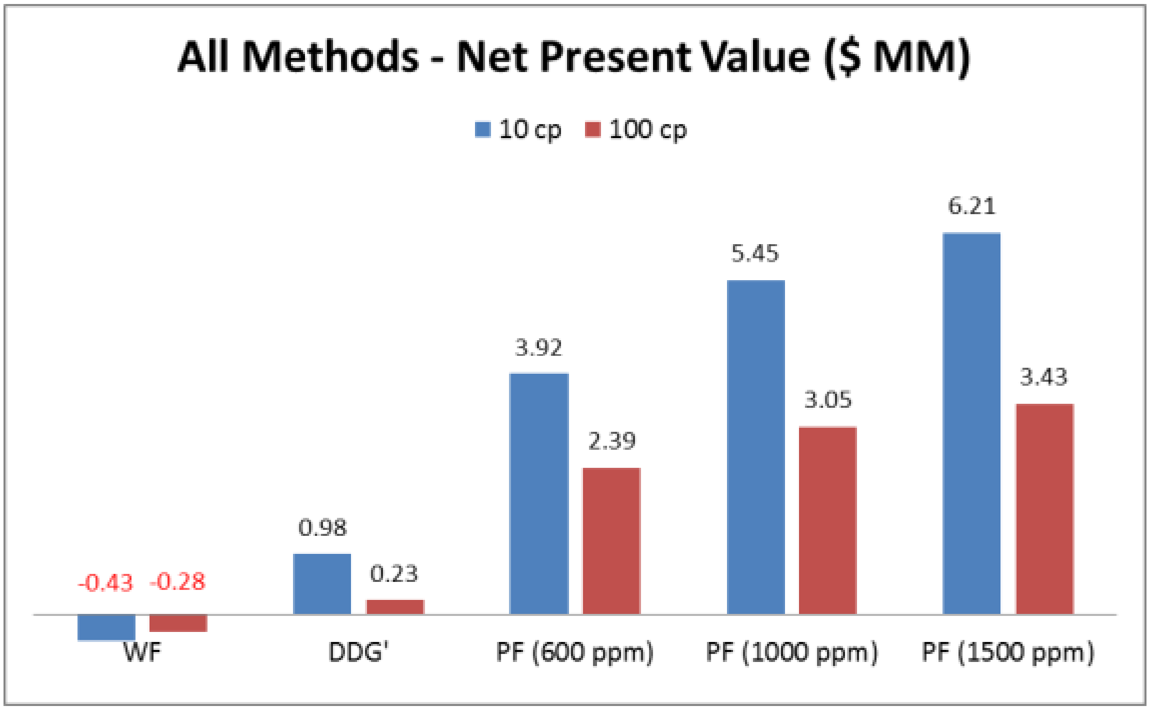

Figure 54: NPV for 10 and 100 cp Oil

Table 13: 10 cp Oil – Economic Results Summary for All Methods

	Cash Flow ($)	NPV ($)
WF	(1,141,000)	(433,000)
DDG'	813,000	981,000
PF (600 ppm)	4,789,000	3,917,000
PF (1000 ppm)	6,665,000	5,451,000
PF (1500 ppm)	7,840,000	6,208,000

Table 14: 100 cp Oil – Economic Results Summary for All Methods

	Cash Flow ($)	NPV ($)
WF	(483,000)	(281,000)
DDG'	(5,000)	233,000
PF (600 ppm)	2,739,000	2,388,000
PF (1000 ppm)	3,572,000	3,047,000
PF (1500 ppm)	4,082,000	3,434,000

5.4.5 Polymer Flood Pressure Control

Although the field life was extended in this run, the choking back of production ultimately led to a lower cumulative oil production than in the base case. This is also reflected in the NPV.

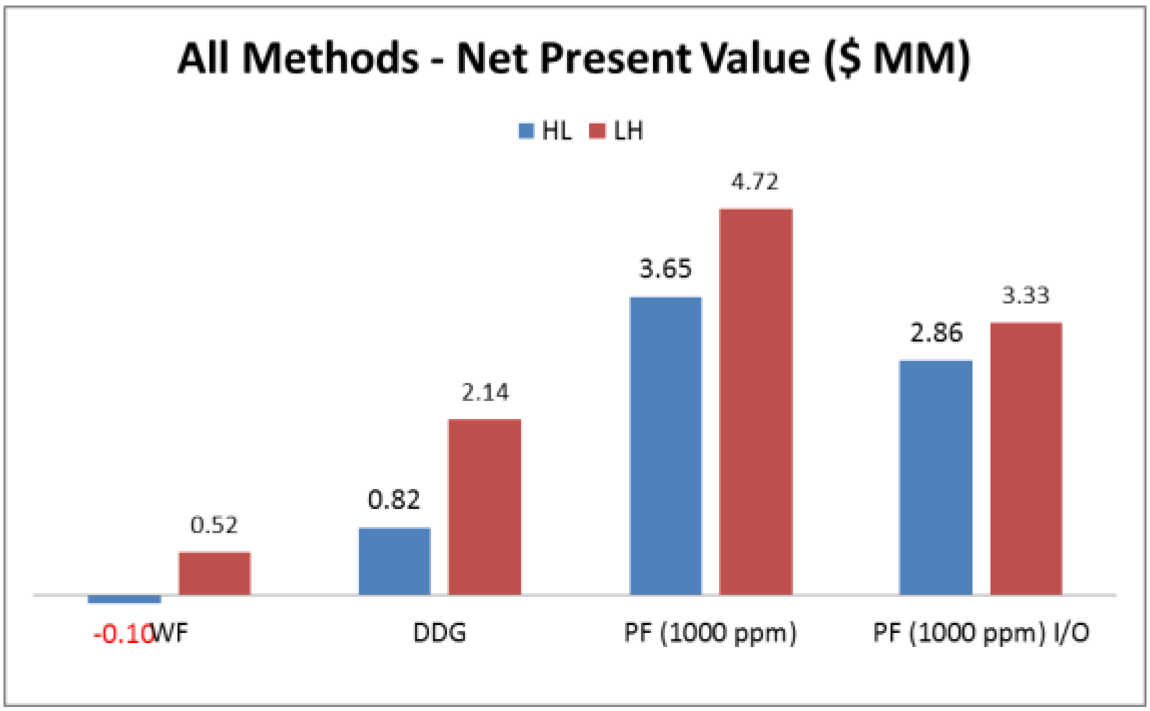

Figure 55: NPV when Q_L = Qi

5.4.6 Cost of Polymers

The effect of the cost of polymer and DDG on cash flow and NPV was examined by reducing the price of DDG to $1.50 per pound and for the scenario where the price of polymer increases to $3.00 per pound with all other variables held constant. Based on the figures below, the cost of polymer would have to be unreasonably high for the economics of both methods to be equal.

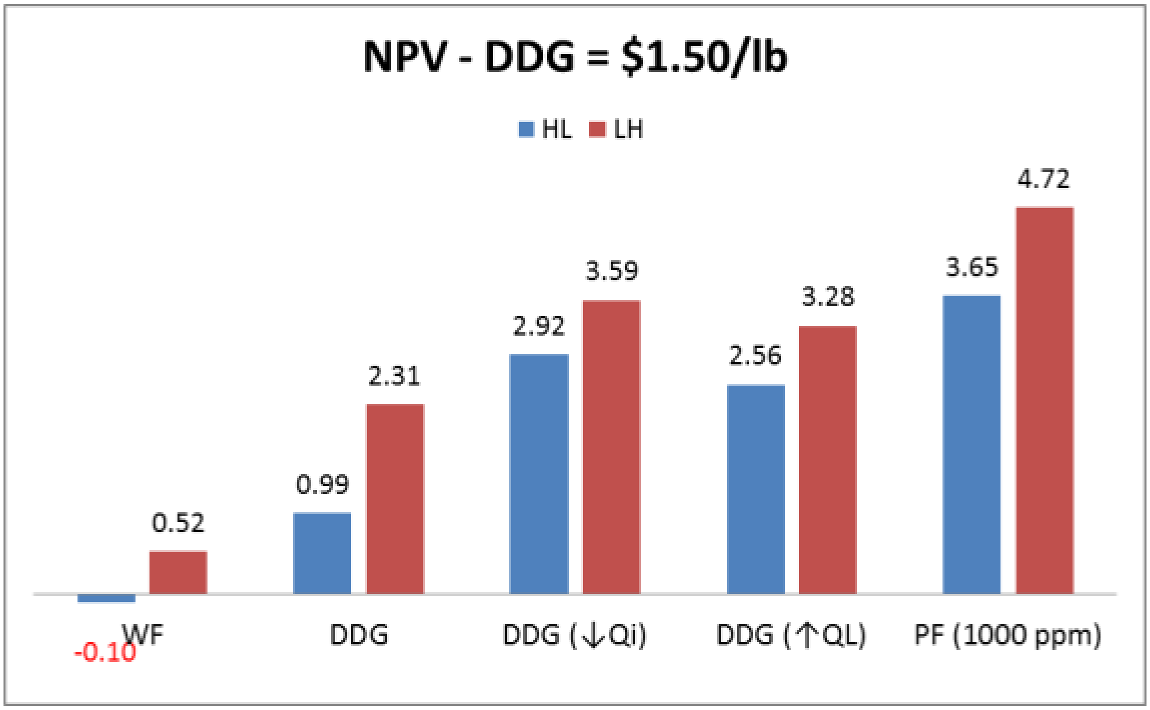

Figure 56: NPV at DDG = $1.50/lb

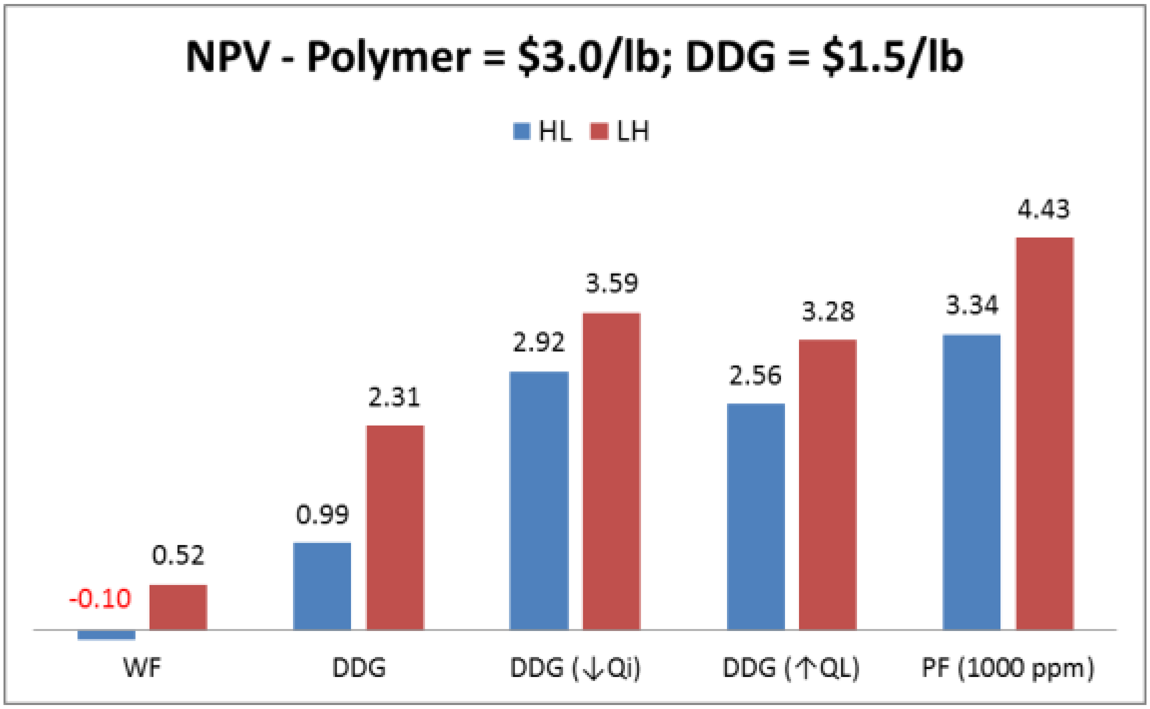

Figure 57: NPV at Polymer = $3.0/lb and DDG = $1.50/lb

VI CONCLUSIONS AND RECOMMENDATIONS

6.1 Conclusions

Both polymer flooding and the DDG have their limitations, some of which have been made obvious in the preceding chapters. The use of deep diverting gels as an effective recovery method is constrained by cost, reservoir characteristics such as permeability, porosity and temperature, minimal reservoir fracturing to prevent loss of the particles, vertical communication between layers, and an injector-producer transit time that needs to be more than thirty days. Polymer floods on the other hand are limited by injectivity concerns due to the possibility of having viscous slugs forming too close to the injection well if improperly designed and the risk of formation damage, maximum allowable viscosities, reservoir properties like temperature and salinity. These factors and more need to be taken into consideration when evaluating either of these two methods as potential candidates for secondary recovery.

The results and economic analysis presented above however show that a properly designed polymer flood program has a decided advantage over the use of the DDG both in terms of oil recovery and monetary value. Incremental oil recovery for the DDG treatment over waterflooding was 2.3% in the HL configuration and 1.8% in the LH configuration while the polymer flood resulted in increments of 12.3 and 11.4% respectively. The factors with the largest impact on the economics were the amount of oil produced and the extent of reduction in water production and are the main reason polymer flooding is more attractive than the DDG treatment.

The economic limit of a project is typically determined by excessive water production. 95% water-cut was chosen arbitrarily and in reality would depend on project specifics. Based on the monthly cash flows for all three methods, it can be deduced that a water-cut of 95% which was picked as the economic limit in the simulations may be a poor choice because cash flow is negative in the last two years or more in all configurations. This has the effect of reducing the Net Present Value of the projects from their ideal values if each project was terminated when monthly cash flow became 0.

6.2 Recommendations

One of the major shortcomings of previous work done on comparing the DDG's performance to that of Polymer flooding has been in the accuracy of the assumptions used. This is particularly obvious in the areas of estimating the amount of DDG used in any treatment, in pinpointing the exact location of its activation and estimating the area and volume plugged.

In this work it was assumed that the DDG treatment had the same viscosity as water to provide an optimal environment although based on work by Pritchett et al (2003), the slurry viscosity could actually be two to seven times higher than that of the injection water. Akanni (2010) also reported discrepancies between the results obtained using a commercial simulator and those based on analytical calculations and attributed it to the possible effect of gravity although the reasons for this are still open to investigation.

More precise work could be performed on these areas to more accurately simulate the DDG's performance.

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APPENDIX

A Waterflooding Data File

-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Two wells, one injector and one producer, on opposite sides of the 10 ac-pattern
-- Grid dimensions are 660 ft by 660 ft by 60 ft
-- Grid represents a 110x110x16 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC

TEMP

-- Specifies the dimensions of the grid: 44x44x16
DIMENS
44 44 16 /

-- Specifies phases present: oil, water

OIL

WATER

-- Field units to be used
FIELD

-- Specifies dimensions of saturation and PVT tables
TABDIMS
1 1 30 30 1 30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
2 16 2 2 /

-- Specifies start of simulation
START
1 'JAN' 2000 /

-- Specifies the size of the stack for Newton iterations
NSTACK
90 /

GRID
==

-- Specifies the length of the cell in the X and Y direction: 10 ft

DXV
2 42*15.61905 2 /

DYV
2 42*15.61905 2 /

-- Specifies the length of the cell in the X and Y direction: 4 ft

DZ
30976*4 /

-- Specifies permeabilities in X direction: 100 md on low perm layer and 1200 on high perm layer

BOX
1 44 1 44 1 8 /
PERMX
15488*1200 /

BOX
1 44 1 44 9 16 /
PERMX
15488*100 /

ENDBOX

-- Specifies permeabilities in Y direction: 100 md on low perm layer and 1200 on high perm layer

BOX
1 44 1 44 1 8 /
PERMY
15488*1200 /

BOX
1 44 1 44 9 16 /
PERMY
15488*100 /

ENDBOX

```
-- Specifies permeabilities in Z direction: 10 md on low perm layer and 100 on high
perm layer

BOX
1 44 1 44 1 8 /
PERMZ
15488*100 /

BOX
1 44 1 44 9 16 /
PERMZ
15488*10 /

ENDBOX

-- Specifies Porosity 25%

BOX
1 44 1 44 1 8 /
PORO
15488*0.25 /

BOX
1 44 1 44 9 16 /
PORO
15488*0.25 /

ENDBOX

-- Specifies the depth of the top cells: 8000 ft
TOPS
1936*8000.0 /

-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT
```

```
PROPS
===============================================================

-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil
relative permeability
-- and Oil-Water capillary pressure

SWOF

-- Sw     krw           kro               Pcow

0.2     0               1               0
0.25    0.004346481     0.751314732     0
0.3     0.013763162     0.545761134     0
0.35    0.027010896     0.379858861     0
0.4     0.043581146     0.249999989     0
0.45    0.063161081     0.152424743     0
0.5     0.08553019      0.083187501     0
0.55    0.110520981     0.038106184     0
0.6     0.138000001     0.012679833     0
0.65    0.167857295     0.00193272      0
0.7     0.2             0               0/

-- Specifies PVT properties of water: Bw = 1.063; Cw = 3.03E-06; watervisc = .8. All
values at 3480 psia and 280 DegF
PVTW
3464  1  3.03E-06  .7  0.0 /

-- Specifies PVT properties of the oil: pressure, Bo and oilvisc
PVDO

-- Pressure             Bo      Oil visc
        3480            1.01            2.0
        3600            1.00            2.0/

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07;
GRAVITY
34.2  1.07 /

-- Specifies rock compressibility: 5.0E-06 psi -1 @ 3480 psia
ROCK
3480.0  5.0E-06 /

SPECHEAT
0.0 0.48 0.94 0.5
```

```
300.0 0.52 0.95 0.5/

SPECRock
0.0 25
300 25 /

RTEMP
210 /

REGIONS
============================================================

-- Specifies the number of saturation regions (only one for this case)
SATNUM
30976*1 /

SOLUTION
============================================================

-- Specifies initial equilibration conditions. Datum depth = 8060 ft; Reference pressure at
datum = 3480 psia
-- WOC depth = 15000 ft (out of the reservoir means no initial contact present)
-- GOC depth = 0 ft (out of the reservoir means no initial contact present)

EQUIL
8060  3480  15000  0   0   0   1   0   0  /

-- Specifies parameters to be written in the SOLUTION section of the RESTART file:
pressure, water saturation
-- gas saturation and oil saturation
RPTSOL PRESSURE  SWAT SOIL FIP /

-- Specifies that RESTART files are to written every timestep
RPTRST
BASIC=2 /

SUMMARY
==========================================================

-- Specifies that a SUMMARY file with neat tables is to be written in text format
RUNSUM

BTCNFHEA
1 44 4 /
1 44 12 /
```

```
15 30 4 /
15 30 12 /
30 15 4 /
30 15 12 /
44 1 4 /
44 1 12 /
/

-- Specifies that the SUMMARY file is to be created as a separate file in addition from
the text file with neat tables
SEPARATE

-- Specifies that reports are to be written only at the timesteps sepcified in the DATA
file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

-- Specifies that a group of parameters specific to ECLIPSE are going to be written in
the SUMMARY files.
ALL

EXCEL
separate
ALL

FOE

SCHEDULE
=====================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                              FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /

-- Define well specifications:
WELSPECS
'P'  'G'    44  1  8030  'OIL' 2* SHUT /
'I'  'G'    1  44  8030  'WAT'  /
/

-- Specifies completion data
COMPDAT
'P'    44   1   1   16 'OPEN'   1  0   .27 3* z /
```

```
'I'   1   44   1   16 'OPEN'   1  0   .27 3* z /
/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate
-- The final record specifies target for the control parameter: 530 reservoir barrels

WCONPROD
'P' 'OPEN' 'LRAT' 3* 500 /
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate
-- The final record specifies target for the control parameter: 1200 reservoir barrels

WCONINJ
'I' 'WATER' 'OPEN' 'BHP' 4* 3600 /
/

WECON
'P' 2* 0.95 2* WELL YES/
/

WTEMP
'I' 70 /
/

TUNING
/
/
50  2  100  1  40/

-- Specifies the number and length of the timesteps required: 200 timesteps of 20 days
each

TSTEP
0.1 0.3 0.6 1 3 5 21 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
```

31 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31 /
--0.1 0.3 0.6 1 3 5 29*10 30*30 40*50/

END

B DDG Treatment Data File

-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Two wells, one injector and one producer, on opposite sides of the 10 ac-pattern
-- Grid dimensions are 660 ft by 660 ft by 60 ft
-- Grid represents a 110x110x15 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC

TEMP

-- Specifies the dimensions of the grid
DIMENS
44 44 16 /

-- Specifies phases present: oil, water

OIL

WATER

-- Field units to be used
FIELD

-- Specifies dimensions of saturation and PVT tables
TABDIMS
1 1 30 30 1 30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
2 16 2 2 /

```
-- Specifies start of simulation
START
1 'JAN' 2000  /

-- Specifies the size of the stack for Newton iterations
NSTACK
90 /

GRID
============================================================

-- Specifies the length of the cell in the X and Y direction: 10 ft

DXV
2 42*15.61905 2 /

DYV
2 42*15.61905 2 /

-- Specifies the length of the cell in the X and Y direction: 4 ft

DZ
30976*4 /

-- Specifies permeabilities in X direction: 100 md on low perm layer and 1200 on high
perm layer

BOX
1 29 5 5 1 8 /
PERMX
232*40 /

BOX
1 31 6 6 1 8 /
PERMX
248*40 /

BOX
1 34 7 7 1 8 /
PERMX
272*40 /

BOX
1 36 8 8 1 8 /
```

```
PERMX
288*40 /

BOX
30 37 9 9 1 8 /
PERMX
64*40 /

BOX
32 37 10 10 1 8 /
PERMX
48*40 /

BOX
34 38 11 11 1 8 /
PERMX
40*40 /

BOX
35 38 12 13 1 8 /
PERMX
64*40 /

BOX
36 39 14 15 1 8 /
PERMX
64*40 /

BOX
37 40 16 44 1 8 /
PERMX
928*40 /

BOX
1 44 1 4 1 8 /
PERMX
1408*1200 /

BOX
30 44 5 5 1 8 /
PERMX
120*1200 /

BOX
32 44 6 6 1 8 /
```

```
PERMX
104*1200 /

BOX
35 44 7 7 1 8 /
PERMX
80*1200 /

BOX
37 44 8 8 1 8 /
PERMX
64*1200 /

BOX
38 44 9 10 1 8 /
PERMX
112*1200 /

BOX
39 44 11 13 1 8 /
PERMX
144*1200 /

BOX
40 44 14 15 1 8 /
PERMX
80*1200 /

BOX
41 44 16 44 1 8 /
PERMX
928*1200 /

BOX
1 29 9 9 1 8 /
PERMX
232*1200 /

BOX
1 31 10 10 1 8 /
PERMX
248*1200 /

BOX
1 33 11 11 1 8 /
```

PERMX
264*1200 /

BOX
1 34 12 13 1 8 /
PERMX
544*1200 /

BOX
1 35 14 15 1 8 /
PERMX
560*1200 /

BOX
1 36 16 44 1 8 /
PERMX
8352*1200 /

BOX
1 44 1 44 9 16 /
PERMX
15488*100 /

ENDBOX

-- Specifies permeabilities in Y direction: 100 md on low perm layer and 1200 on high perm layer

BOX
1 29 5 5 1 8 /
PERMY
232*40 /

BOX
1 31 6 6 1 8 /
PERMY
248*40 /

BOX
1 34 7 7 1 8 /
PERMY
272*40 /

BOX
1 36 8 8 1 8 /

```
PERMY
288*40 /

BOX
30 37 9 9 1 8 /
PERMY
64*40 /

BOX
32 37 10 10 1 8 /
PERMY
48*40 /

BOX
34 38 11 11 1 8 /
PERMY
40*40 /

BOX
35 38 12 13 1 8 /
PERMY
64*40 /

BOX
36 39 14 15 1 8 /
PERMY
64*40 /

BOX
37 40 16 44 1 8 /
PERMY
928*40 /

BOX
1 44 1 4 1 8 /
PERMY
1408*1200 /

BOX
30 44 5 5 1 8 /
PERMY
120*1200 /

BOX
32 44 6 6 1 8 /
```

```
PERMY
104*1200 /

BOX
35 44 7 7 1 8 /
PERMY
80*1200 /

BOX
37 44 8 8 1 8 /
PERMY
64*1200 /

BOX
38 44 9 10 1 8 /
PERMY
112*1200 /

BOX
39 44 11 13 1 8 /
PERMY
144*1200 /

BOX
40 44 14 15 1 8 /
PERMY
80*1200 /

BOX
41 44 16 44 1 8 /
PERMY
928*1200 /

BOX
1 29 9 9 1 8 /
PERMY
232*1200 /

BOX
1 31 10 10 1 8 /
PERMY
248*1200 /

BOX
1 33 11 11 1 8 /
```

PERMY
264*1200 /

BOX
1 34 12 13 1 8 /
PERMY
544*1200 /

BOX
1 35 14 15 1 8 /
PERMY
560*1200 /

BOX
1 36 16 44 1 8 /
PERMY
8352*1200 /

BOX
1 44 1 44 9 16 /
PERMY
15488*100 /

ENDBOX

-- Specifies permeabilities in Z direction: 10 md on low perm layer and 100 on high perm layer

BOX
1 29 5 5 1 8 /
PERMZ
232*10 /

BOX
1 31 6 6 1 8 /
PERMZ
248*10 /

BOX
1 34 7 7 1 8 /
PERMZ
272*10 /

BOX
1 36 8 8 1 8 /

PERMZ
288*10 /

BOX
30 37 9 9 1 8 /
PERMZ
64*10 /

BOX
32 37 10 10 1 8 /
PERMZ
48*10 /

BOX
34 38 11 11 1 8 /
PERMZ
40*10 /

BOX
35 38 12 13 1 8 /
PERMZ
64*10 /

BOX
36 39 14 15 1 8 /
PERMZ
64*10 /

BOX
37 40 16 44 1 8 /
PERMZ
928*10 /

BOX
1 44 1 4 1 8 /
PERMZ
1408*100 /

BOX
30 44 5 5 1 8 /
PERMZ
120*100 /

BOX
32 44 6 6 1 8 /

```
PERMZ
104*100 /

BOX
35 44 7 7 1 8 /
PERMZ
80*100 /

BOX
37 44 8 8 1 8 /
PERMZ
64*100 /

BOX
38 44 9 10 1 8 /
PERMZ
112*100 /

BOX
39 44 11 13 1 8 /
PERMZ
144*100 /
BOX
40 44 14 15 1 8 /
PERMZ
80*100 /

BOX
41 44 16 44 1 8 /
PERMZ
928*100 /

BOX
1 29 9 9 1 8 /
PERMZ
232*100 /

BOX
1 31 10 10 1 8 /
PERMZ
248*100 /

BOX
1 33 11 11 1 8 /
PERMZ
```

```
264*100 /

BOX
1 34 12 13 1 8 /
PERMZ
544*100 /

BOX
1 35 14 15 1 8 /
PERMZ
560*100 /

BOX
1 36 16 44 1 8 /
PERMZ
8352*100 /

BOX
1 44 1 44 9 16 /
PERMZ
15488*10 /

ENDBOX

-- Specifies Porosity 25%

BOX
1 44 1 44 1 8 /
PORO
15488*0.25 /

BOX
1 44 1 44 9 16 /
PORO
15488*0.25 /

ENDBOX

-- Specifies the depth of the top cells: 8000 ft
TOPS
1936*8000.0 /

-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /
```

```
-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT



PROPS
==============================================================

-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil relative permeability
-- and Oil-Water capillary pressure

SWOF

-- Sw     krw          kro             Pcow

0.2     0              1               0
0.25    0.004346481    0.751314732     0
0.3     0.013763162    0.545761134     0
0.35    0.027010896    0.379858861     0
0.4     0.043581146    0.249999989     0
0.45    0.063161081    0.152424743     0
0.5     0.08553019     0.083187501     0
0.55    0.110520981    0.038106184     0
0.6     0.138000001    0.012679833     0
0.65    0.167857295    0.00193272      0
0.7     0.2            0               0/

-- Specifies PVT properties of water: Bw = 1.063; Cw = 3.03E-06; watervisc = .8. All values at 3480 psia and 280 DegF
PVTW
3464  1  3.03E-06  .7  0.0 /

-- Specifies PVT properties of the oil: pressure, Bo and oilvisc
PVDO

-- Pressure               Bo     Oil visc
        3480              1.01          2
        3600              1.00          2/
```

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07;
GRAVITY
34.2 1.07 /

-- Specifies rock compressibility: 5.0E-06 psi -1 @ 3480 psia
ROCK
3480.0 5.0E-06 /

SPECHEAT
0.0 0.48 0.94 0.5
300.0 0.52 0.95 0.5/

SPECRock
0.0 25
300 25 /

RTEMP
210 /
REGIONS
===

-- Specifies the number of saturation regions (only one for this case)
SATNUM
30976*1 /

SOLUTION
===

RESTART
'OKEKE_WF_HL_BHP' 69 /

SUMMARY
===

-- Specifies that a SUMMARY file with neat tables is to be written in text format
RUNSUM

-- Specifies that the SUMMARY file is to be created as a separate file in addition from the text file with neat tables
SEPARATE

-- Specifies that reports are to be written only at the timesteps sepcified in the DATA file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

```
-- Specifies that a group of parameters specific to ECLIPSE are going to be written in
the SUMMARY files.
ALL

EXCEL
separate
ALL

FOE

SCHEDULE
============================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                                  FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /


-- Define well specifications:
WELSPECS
'P'  'G'    44  1  8030  'OIL'  /
'I'  'G'    1  44  8030  'WAT'  /
/

-- Specifies completion data
COMPDAT
'P'    44   1   1   16 'OPEN'   1  0   .27 3* z /

'I'    1   44   1   16 'OPEN'   1  0   .27 3* z /
/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate
-- The final record specifies target for the control parameter: 530 reservoir barrels

WCONPROD
'P' 'OPEN' 'LRAT' 3* 500 /
/

-- Specifies well controls for the injector
```

-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate
-- The final record specifies target for the control parameter: 1200 reservoir barrels

```
WCONINJ
'I' 'WATER' 'OPEN' 'BHP' 4* 3600 /
/

WECON
'P' 2* 0.95 2* WELL YES/
/

WTEMP
'I' 70 /
/

TUNING
/
/
2* 100/
```

-- Specifies the number and length of the timesteps required: 200 timesteps of 20 days each

```
TSTEP
0.1 0.3 0.6 1 3 5 21
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31 /


END
```

C Polymer Flood Data File

```
-- Area of the pattern is 40 acres. Quarter of 5-spot represents 10 acres.
-- Two wells, one injector and one producer, on opposite sides of the 10 ac-pattern
-- Grid dimensions are 660 ft by 660 ft by 60 ft
-- Grid represents a 110x110x16 Cartesian model of a quarter of a 40 acre 5-spot

RUNSPEC

TEMP

-- Specifies the dimensions of the grid: 44x44x15
DIMENS
44 44 16 /

-- Specifies phases present: oil, water

OIL

WATER

POLYMER

-- Field units to be used
FIELD

-- Specifies dimensions of saturation and PVT tables
TABDIMS
1    1   30    30    1   30 /

-- Specifies maximum number of well and groups of wells
WELLDIMS
2    16    2    2 /

-- Specifies start of simulation
START
1 'JAN' 2000  /

-- Specifies the size of the stack for Newton iterations
NSTACK
95 /

MESSAGES
2000 200 200 200 20 2 1000000 1000000 1000000 100000 10 1 /
```

```
GRID
=====================================================================

-- Specifies the length of the cell in the X and Y direction: 10 ft

DXV
2 42*15.61905 2 /

DYV
2 42*15.61905 2 /

-- Specifies the length of the cell in the X and Y direction: 4 ft

DZ
30976*4 /

-- Specifies permeabilities in X direction: 100 md on low perm layer and 1200 on high
perm layer

BOX
1 44 1 44 1 8 /
PERMX
15488*1200 /

BOX
1 44 1 44 9 16 /
PERMX
15488*100 /

ENDBOX

-- Specifies permeabilities in Y direction: 100 md on low perm layer and 1200 on high
perm layer

BOX
1 44 1 44 1 8 /
PERMY
15488*1200 /

BOX
1 44 1 44 9 16 /
PERMY
15488*100 /

ENDBOX
```

-- Specifies permeabilities in Z direction: 10 md on low perm layer and 100 on high perm layer

```
BOX
1 44 1 44 1 8 /
PERMZ
15488*100 /

BOX
1 44 1 44 9 16 /
PERMZ
15488*10 /

ENDBOX

-- Specifies Porosity 25%

BOX
1 44 1 44 1 8 /
PORO
15488*0.25 /

BOX
1 44 1 44 9 16 /
PORO
15488*0.25 /

ENDBOX

-- Specifies the depth of the top cells: 8000 ft
TOPS
1936*8000.0 /

-- Specifies what is to be written in the GRID output file
RPTGRID
1 1 1 1 1 0 0 0 /

-- Allows for creating a GRID output file
GRIDFILE
2 1 /

-- Allows for creating an INIT output file
INIT
```

```
PROPS
===============================================================

-- Specifies water saturation tables: Water saturation, Water relative permeability, Oil relative permeability
-- and Oil-Water capillary pressure

SWOF

-- Sw     krw          kro            Pcow

0.2     0              1              0
0.25    0.004346481    0.751314732    0
0.3     0.013763162    0.545761134    0
0.35    0.027010896    0.379858861    0
0.4     0.043581146    0.249999989    0
0.45    0.063161081    0.152424743    0
0.5     0.08553019     0.083187501    0
0.55    0.110520981    0.038106184    0
0.6     0.138000001    0.012679833    0
0.65    0.167857295    0.00193272     0
0.7     0.2            0              0/

-- Specifies PVT properties of water: Bw = 1.063; Cw = 3.03E-06; watervisc = .8. All values at 3480 psia and 280 DegF
PVTW
3464  1  3.03E-06  .7  0.0 /

-- Specifies PVT properties of the oil: pressure, Bo and oilvisc
PVDO

-- Pressure             Bo      Oil visc
        3480            1.01            2.0
        3600            1.00            2.0/

-- Specifies surface densities: Oil API: 34.2; Water spec. gravity: 1.07;
GRAVITY
34.2  1.07 /

-- Specifies rock compressibility: 5.0E-06 psi -1 @ 3480 psia
ROCK
3480.0  5.0E-06 /

-- Specifies polymer viscosity as function of concentration
PLYVISC
```

0.0 1.0
0.35 10.0
0.7 100.0 /

-- Specifies the polymer-rock properties and includes inaccessible pore volume, residual resistance factor, rock mass density, adsorption index and maximum adsorption value
PLYROCK
0 1 620.4 1 0.000003 /

-- Polymer adsorption properties
PLYADS
0.0 0.000
0.25 0.000001
0.50 0.000002
0.75 0.000003 /

-- Mixing Parameter for miscibility between polymer and water between 0.0 and maximum of 1.0
TLMIXPAR
1.0 /

-- Specifies maximum value of polymer concentration in solution
PLYMAX
1.0 0.0 /

SPECHEAT
0.0 0.48 0.94 0.5
300.0 0.52 0.95 0.5/

SPECRock
0.0 25
300 25 /

RTEMP
210 /

REGIONS
===

-- Specifies the number of saturation regions (only one for this case)
SATNUM
30976*1 /
SOLUTION
===

-- Specifies initial equilibration conditions. Datum depth = 8060 ft; Reference pressure at datum = 3480 psia
-- WOC depth = 15000 ft (out of the reservoir means no initial contact present)
-- GOC depth = 0 ft (out of the reservoir means no initial contact present)

```
EQUIL
8060  3480  15000  0   0   0   1   0   0  /
```

-- Specifies parameters to be written in the SOLUTION section of the RESTART file: pressure, water saturation
-- gas saturation and oil saturation

```
RPTSOL PRESSURE  SWAT SOIL FIP PBLK PLYADS 'FIPPLY=2'/
```

-- Specifies that RESTART files are to written every timestep

```
RPTRST
BASIC=2 /

SUMMARY
=====================================================================
```

-- Specifies that a SUMMARY file with neat tables is to be written in text format

```
RUNSUM
FCPR
FCPT
FCPC
FCIR
FCIT
FCIP
FCIC
FCAD
BEPVIS
1 1 4 /
2 1 4 /
3 1 4 /
4 1 4 /
5 1 4 /
6 1 4 /
7 1 4 /
8 1 4 /
9 1 4 /
10 1 4 /
11 1 4 /
12 1 4 /
13 1 4 /
14 1 4 /
```

```
15 1 4 /
16 1 4 /
17 1 4 /
18 1 4 /
/
RPTSMRY
1 /

-- Specifies that the SUMMARY file is to be created as a separate file in addition from
the text file with neat tables
SEPARATE

-- Specifies that reports are to be written only at the timesteps specified in the DATA
file. Avoids reports to
-- be created at chopped timesteps (to avoid excessive data and clutter).
RPTONLY

-- Specifies that a group of parameters specific to ECLIPSE are going to be written in
the SUMMARY files.
ALL

EXCEL
separate
ALL

FOE

SCHEDULE
=====================================================================

-- Specifies what is to written to the SCHEDULE file
RPTSCHED                                FIELD   16:55 18 APR 86
  1  0  1  0  0  0  2  0  0  0  0  2  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0
  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  0  /


-- Define well specifications:
WELSPECS
'P'  'G'    44  1  8030  'OIL' 2* SHUT /
'I'  'G'    1  44  8030  'WAT' 0.0 STD SHUT NO /
/

-- Specifies completion data
COMPDAT
```

```
'P'    44   1   1   16 'OPEN'   1  0   .27 3* z /

'I'    1   44   1   16 'OPEN'   1  0   .27 3* z /
/

-- Specifies well controls for the producer
-- Name of the well: P
-- Status of the well: open to production
-- Well control mode: reservoir voidage rate
-- The final record specifies target for the control parameter: 530 reservoir barrels

WCONPROD
'P' 'OPEN' 'LRAT' 3* 500 /
/

-- Specifies well controls for the injector
-- Name of the well: I
-- Status of the well: open to injection
-- Well control mode: reservoir injection rate
-- The final record specifies target for the control parameter: 1200 reservoir barrels

WCONINJ
'I' 'WATER' 'OPEN' 'BHP' 4* 3600 /
/

WECON
'P' 2* 0.95 2* WELL YES/
/

WTEMP
'I' 70 /
/

TUNING
/
/
2* 100/

-- Specifies polymer viscosity (1000 ppm)
WPOLYMER
'I' 0.35 0.0 /
/
TSTEP
31 28 31 30 31 30 31 31 30 31 30 31
31 30 14 /
```

```
WPOLYMER
'I' 0.0 0.0 /
/
TSTEP
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 28 31 30 31 30 31 31 30 31 30 31
31 29 31 30 31 30 31 31 30 31 30 31/

END
```

VITA

Name: Tobenna Daniel Okeke

Address: Harold Vance Department of Petroleum Engineering

Texas A&M University

3116 TAMU

College Station, TX 77843

Email: tobenna.okeke@pe.tamu.edu

Education: B.S., Chemical Engineering, Drexel University, 2008

M.S., Petroleum Engineering, Texas A&M University, 2012