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Abstract

Excessive water production in hydrocarbon exploration is a worldwide problem. The water produced is considered to be the largest waste stream by volume in during hydrocarbon production. Gelant/polymers have been known to reduce this problem. The gelant solution once injected in the reservoir reduces the water relative permeability while impacting the oil relative permeability to lesser extent. This phenomenon is called disproportionate permeability reduction (DPR). The DPR treatment is considered as an importance means of controlling the excessive water production. DPR treatment reduces the water production and can sometimes improve the oil production. But the argument exists on under what conditions and where should the DPR treatment be employed.

The numerical simulation was carried out on a 3D, radial, multilayered reservoir model to simulate the pilot performance of the reservoir for different cases. This project aims at quantifying the impact of DPR treatment and its designing factors on a multilayered, radial reservoir subjected to water flooding. Results suggested improved pilot performance in terms of better water control and improvement in oil production. But the impact on oil recovery was insignificant. DPR treatment affects significantly the fluid flow performance not only in the reservoir but also the fluid flow in tubing. But skin introduced due to DPR can have a significant negative effect in low permeability layer performance.

Acknowledgement

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I have learned and discovered a great deal of knowledge within these six months of study. I hope you find it this thesis interesting and it will contribute towards the better understanding of the Disproportionate Permeability Reduction treatment. It was an interesting and exciting experience to work on this project.

Paritosh Doshi,

Stavanger

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1. Introduction

Water injection is widely used in many reservoirs for pressure maintenance and to improve oil and gas production and recovery. Produced water in these reservoirs is normally the same as injected water. This produced water is chemically complex and can potentially damage the equipments that are handling reservoir fluid production and can also have an impact on environment in which it will be disposed. Therefore this water needs to be treated. Also some of the chemicals in the water can act as surfactant which imposes the need for separators at the surface to separate water from hydrocarbons.

Produced water is considered as largest waste stream by volume in oil and gas production (Reynolds, 2003). Sometimes this water can be used beneficially such as for the purpose of reinjection in the reservoir to maintain reservoir pressure and sweep oil and gas or treating produced water and use for domestic purposes such as irrigation, cattle and animal consumption etc. Whether beneficial or not this water needs to be treated to be environmentally protective. This treatment includes separation of water from oil and gas, removal of hazardous chemicals from the water, removal of dispersed oil in the water etc. These treatments increase the cost of oil and gas production. To avoid this, water shutoff treatments are used to reduce water production. This thesis is concerned with one of these water shutoff methods, Disproportionate Permeability Reduction (DPR) by gelant injection.

1.1 Objective

This project will focus on quantifying the effect of polymer injection on oil production and overall pilot performance of the treated well.

- **Significance of time of polymer injection:** - This treatment should be employed at an appropriate time during the life of the well. Injecting polymer too early may damage zones near the wellbore introducing skin and in turn extra pressure drop. On the other hand if the treatment is carried out too late then the damage caused by the water production may be irreparable and DPR treatment may not be useful or economical.
- **Quantify effects of different depths of invasions and find optimum depth of invasion: -** For a water producing layer, deeper the polymer invasion is more will be the resistance to water production. But too deep polymer injection may not be very beneficial as this treatment also reduces oil relative permeability and damages reservoir. So it is necessary to investigate optimum depth of invasion.
- **Bullheading or selective injection:-** In a heterogeneous reservoir, there are different layers with different permeability, which means that in some of the layers water breaks through earlier than in other layers. By using bullheading method we inject polymer in low and high permeability layers, which can cause severe damage to layers that do not face water production problems. For low depth of invasion this damage may not be considerable as normally water breakthrough occurs in high permeability layers that have high injectivity. But for high depth of invasion other zones can be damaged and in this case selective injection is more beneficial. In this project we will investigate for given reservoir, the difference in pilot performance for bullheading and selective injection.
- **Sensitivity analysis of relative permeability reduction:** - An ideal DPR polymer would be the one that will reduce the productivity of water without significant impact on productivity of oil. Most of the polymers used in DPR reduce the permeability of water more than permeability of hydrocarbon. But the amount of permeability reduction is not very certain. To address this uncertainty in this thesis we will do sensitivity analysis of relative permeability reduction after DPR treatment. for water and oil
- **Find characteristic of right candidate for DPR treatment: -** DPR treatment, like most of stimulation treatments for water production, is not a panacea (Stavaland et al, 1998). In this project we will try to find under which reservoir conditions we should implement DPR treatment.

2. Literature review

This section provides an insight into the problems related to excessive water production. Further we will discuss Disproportionate permeability reduction (DPR) treatment to reduce water production, mechanism involved in the DPR, the gelant solutions used in the DPR treatment and their properties and finally the major factors that dictates treatment design and post-treatment effects on reservoir.

2.1 Excess water production:-

Almost every reservoir in the world starts producing water during its production life. When oil is produced from the reservoir, other fluids replace the pore volume. Usually this fluid is water. So as oil and gas are produced normally water saturation in reservoir increases. Now this fluid flow in the reservoir is mainly dictated by pressure drop, capillary pressure and viscosity of reservoir fluids. Water has lower viscosity and in turn higher mobility than oil, therefore it tends to bypass the oil flow to reach the well. Also as the oil is produced, the water saturation in the reservoir increases, which in turn increases relative permeability of water and reduces relative permeability of oil causing higher water production and lower oil and gas production at later production life of the reservoir.

The flow of the water towards the well can occur through two types of paths (Aminian):

- Water flow through different pathways than oil and gas production.
- Water flow together with hydrocarbons through different part of the reservoir production.

In the first mechanism, water production competes with oil and gas production, therefore conventional stimulation jobs, like water shut off with high strength material not only reduce water production but increase gas and oil production. On the other hand if water production mechanism is of the second kind, conventional water treatment will reduce water production as well as hydrocarbon production. But gel treatments like DPR can selectively reduce water production without affecting the oil production. For this reason, wells with second kind of water production mechanism are the candidates for gel treatments.

2.2 Problems related to water production:-

As discussed earlier, the water production causes the extra pressure drop. In simple words, the pressure that could have been used for producing oil and gas is used by the water during water production. Apart from that, pressure drop in the well is mainly affected by density of fluids that are being lifted to the surface and water has higher density than oil and gas. Therefore, while lifting the fluids in the well if fluid contains water then the pressure drop in the well increases.

The produced water is chemically very complex. This adds to complexities involved in separating this produced water from oil and gas and this separated water must be treated before it is disposed. This requires specific pressure and temperature conditions and also addition of chemicals. It increases the production cost.

The water production competes with oil production. So higher will be the water production rate, lower will be the oil production rate for given pressure drop which increases the production time and in turn operation time.

Produced water can cause corrosion of the pipelines and other equipment either handling or facilitating the flow of reservoir fluid. This can damage these equipments permanently. Also wax precipitation is another problem associated with produced water. Precipitated wax can block the tubing in the well and also sometimes force to shutoff the well.

2.3 Disproportionate Permeability Reduction (DPR) / Relative Permeability Modification (RPM):

DPR is the phenomenon which causes reduction in the relative water permeability while keeping the effect on oil relative permeability minimum as a result of water soluble gelant/polymer injection. DPR treatment has been successfully used on production wells facing problems related to excessive water production. Literature claims that some of the polymer and gels reduce relative permeability of water more than oil. This allows reduction of water production without losing the oil and gas production. Therefore the DPR treatment is gaining popularity in oil and gas industry as the excessive water production during oil and gas exploration is becoming a worldwide problem.

2.3.1 Mechanism involved in Permeability reduction:

Reasons behind water permeability reduction are not fully understood but few mechanisms have been suggested over the period of time and it has been proposed that DPR is the result of combination of these mechanisms and is dependent on properties of reservoir, reservoir fluids, reservoir fluid saturations and gelant injected.

Some of the frequently suggested mechanisms are:

- Gelant adsorption at the pore surface causing wettability alteration in water-wet system: Experiments carried out to study this mechanism suggest that if water is the wetting phase and oil is non-wetting phase then the effective permeability of water decreases due to polymer adsorption, while the effective permeability of oil remains mostly unaffected. (Zaltoun et al, 1966)
  One of the explanations provided to this phenomenon by Al-Sharji et al (2001), is the adsorption entanglement. Adsorption entanglement is the process of polymer adhering to the surface of the pores which is constantly replenished from flowing

polymer solution. This polymer entanglement takes place in the locations of low dragging forces. These locations are normally in the water flow region as the water has low viscosity. Therefore this phenomenon obstructs the water flow but due to its location it does not obstruct oil flow.

- Selective shrinking and swelling of polymer and cross-linked agents: Sparlin and Hagen (1984) proposed that gels swell in the water while shrink in oil. Due to this selective swelling and shrinking, these gels provide more resistance for water pathways than hydrocarbon pathways.

- Segregated flow of oil and water: - According to White et al (1973), oil and water flow through separate open channels. The polymers used for DPR treatment contains highly polar carboxyl and amyl groups which makes them hydrophilic. Due to this attraction of water, polymer gels are mainly formed in the channels open for water providing more resistance to water flow compared to oil flow. (SPE 71510)

2.3.2 Gelant/Polymer:

The utility of polymers to reduce the water relative permeability was recognized as early as 1970's by White et al (1973). White et al found that the injection of the partially hydrolysed polyacrylamide reduces the water production without sacrificing overall oil recovery. There has been further study about the gelant/polymers that can reduce the water relative permeability by numerous researchers which showed that many other gelants/polymers show similar behaviour.

Common gelants/polymers used for the DPR treatment are in situ polymers and Preformed Particle Gels (PPG). Even though these two types of gels are used for the same cause of reducing the water permeability the chemical composition of these two polymers is different therefore they give different results.

PPG is an improved super adsorbent polymer (SAP). SAP can absorb over the hundred times their weight in liquid. But their properties like fast swelling, low strength and instability at high temperature restricts their use as conformance control material. (Bai et al, 2008)

According to Bai et al (2008), PPG are preferred over the in situ gels due to their properties like more controlled gelation time, adjustable and high strength, salt resistance that resists changes induced by the reservoir minerals and fluids and they are environmentally friendly. Also these gels have only one component during injection therefore PPG injection requires less injection facility.

2.3.3 Gel design:-

For the designing DPR treatment, the study of gel kinematics is very important to avoid the problems related to gel placement. The factors that affect the gelation most are reservoir type, gelation time, reaction time, residence time, retention, dispersion and injection rate (Hatzignatiou, 2014).

Reservoir type – Multilayered reservoir with different permeability for each layer are the good candidates for the gel treatment. In these reservoir high permeability layers experience the water breakthrough first, which then can be treated with gel treatment to shut off water production.

Gel system: The gel system normally comprises three component base material, reactants and accelerator. The base material helps the injection of gelant solution in the reservoir, reactants forms the gel after injection in the reservoir and accelerators dictate the time of gelation.

Gelation time: Knowledge of the gelation time is very important for designing gel treatment. Too early gelation can place the gel at unwanted location and short resident time will result in gel that is not fully formed.

Viscosity: Viscosity dictates injectivity as well as the placement of the polymer in reservoir. The viscosity is measure of drag forces during the injection of the gelant/polymer solution in the reservoir. Therefore higher the viscosity higher is pressure drop required for injecting the polymer in the reservoir. High viscosity has advantages and disadvantages. Higher viscosity polymer cannot enter the small pores. Normally in the reservoir, water and unwanted gas flows through the large pore features while target recovery flows through the small pore features. Therefore if viscosity is high then gel will be placed only in water flow paths and impact on oil flow will be small.

The disadvantage is the solution won't be nearly as invasive, or for some porous media, the operator will have difficulties in injecting solution within gelation time limits (Thomas et al, 2000).

Density: The density can be an important factor, especially when gravitation comes in the equation. The density of the gelant/polymer solution is higher than water. If this difference is too high and if viscosity of the polymer is not high enough then gravity segregation will take place causing the gel to set below the high water saturation zone rather than in high water saturation zone. (Thomas et al, 2000)

3. Numerical Reservoir Model

The Schlumberger's simulation software Eclipse was used for the purpose of numerical modelling as this simulator can run complex reservoir models and gives reliable results.

3.1 Model description:

This is a three dimensional, radial, layered reservoir model with boundary radius of 280 m. There are 4 sandstone layers separated by 3 impermeable shale layers. Gross thickness of the reservoir is 97 m and net pay thickness is 85 m. Size of the reservoir in theta direction is 30°. There are two wells, one production well located at the centre of the reservoir i.e. at radius R=0, and one injection well present at the boundary of the reservoir. Both, production well and injection well are perforated in sandstone layers only. As the shale layers are impermeable, there is no flow between two sandstone layers except through the production and injection wells.

			Permeability	
layers	TOP (DEPTH) (MS)	Thickness (ms)	vertical (mD)	Horizontal (mD)
sandstone 1	3056	30	1200	1200
shale 1	3086	3	0.00001	0.00001
sandstone 2	3089	20	800	800
shale 2	3109	3	0.00001	0.00001
sandstone 3	3112	15	250	250
shale 3	3127	3	0.00001	0.00001
sandstone 4	3130	20	50	50

Table 1 reservoir description and properties

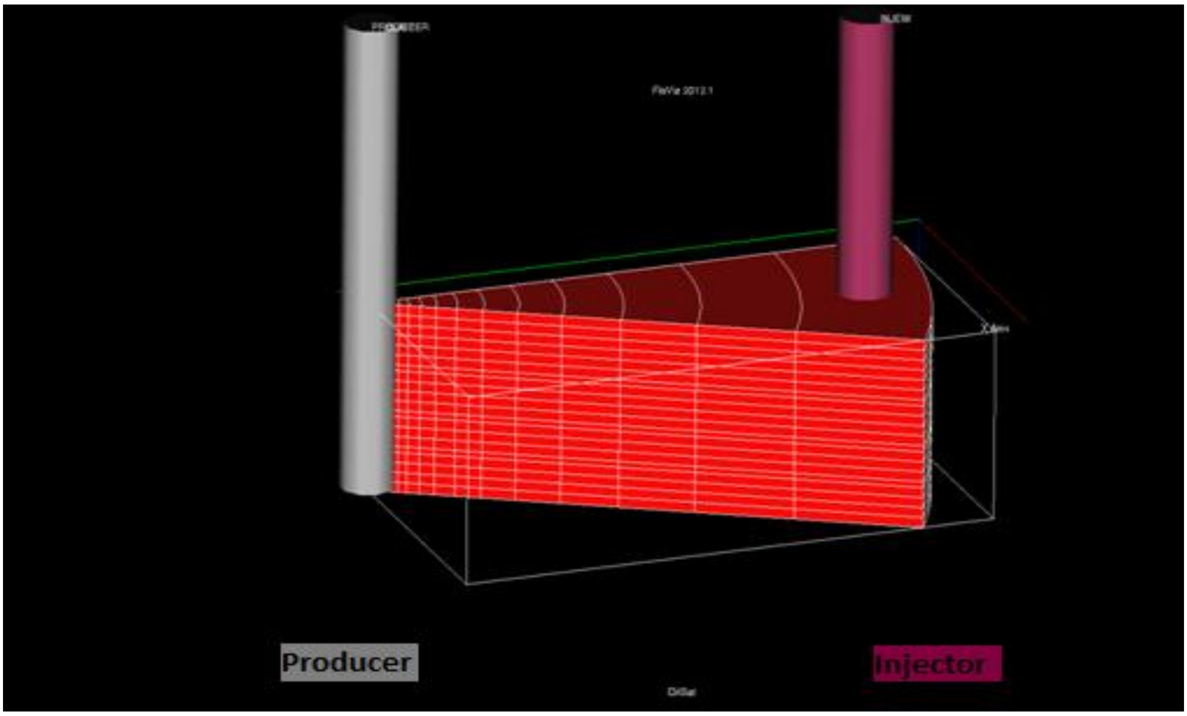

Figure 1 3D view of the reservoir (Schlumberger simulator – FloViz)

3.2 Reservoir fluid properties:-

The reservoir initially contains black oil and no gas. Initially oil saturation is 0.8 and water saturation is 0.2 which is equal to connate water saturation in all blocks of the reservoir.

Reservoir Fluid properties	Value	Unit
Density of Oil (surface conditions)	300	kg/m^3
Density of gas (Surface conditions)	1.1	kg/m^3
Density of water (surface conditions)	1004	kg/m^3
Bubble point pressure (At T_{res}=100°C)	250.410	bars

Table 2 Reservoir fluid properties

Following graph shows the fluid behaviour at reservoir conditions

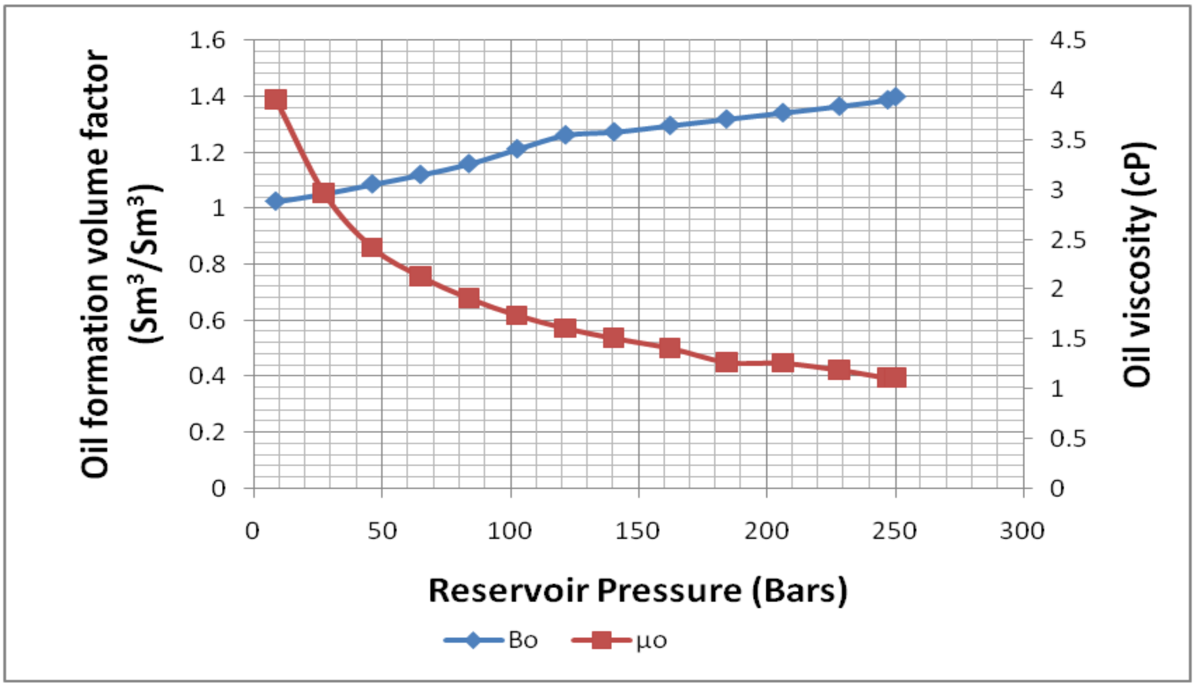

Figure 2 Oil formation volume factor and oil viscosity versus reservoir pressure (at reservoir conditions)

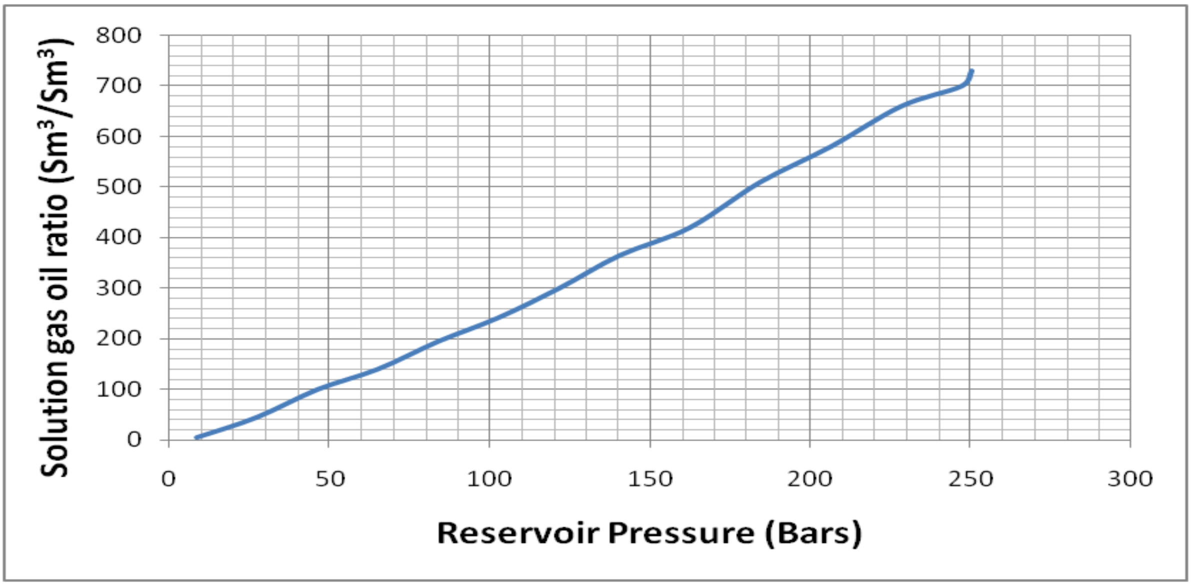

Figure 3 Solution gas oil ratio versus reservoir pressure (at reservoir conditions)

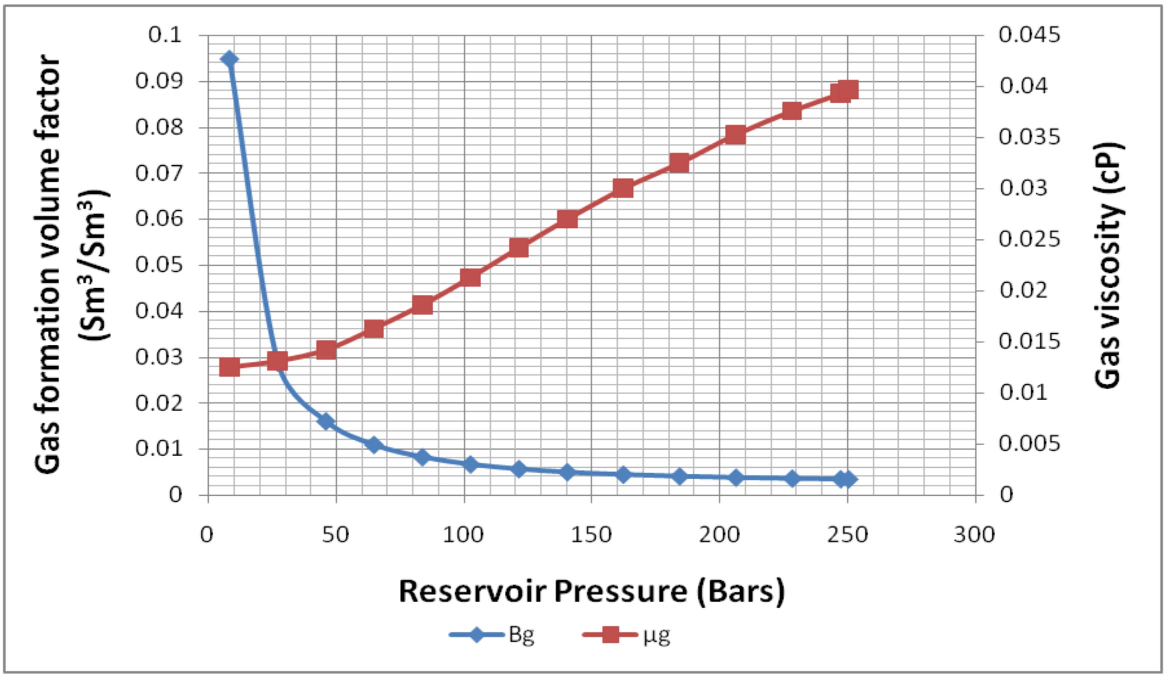

Figure 4 Gas properties versus reservoir pressure (at reservoir conditions)

Oil-water relative permeability curves: The four sandstone layers have different permeability. For this reason, the fluid interaction is different in each layer.

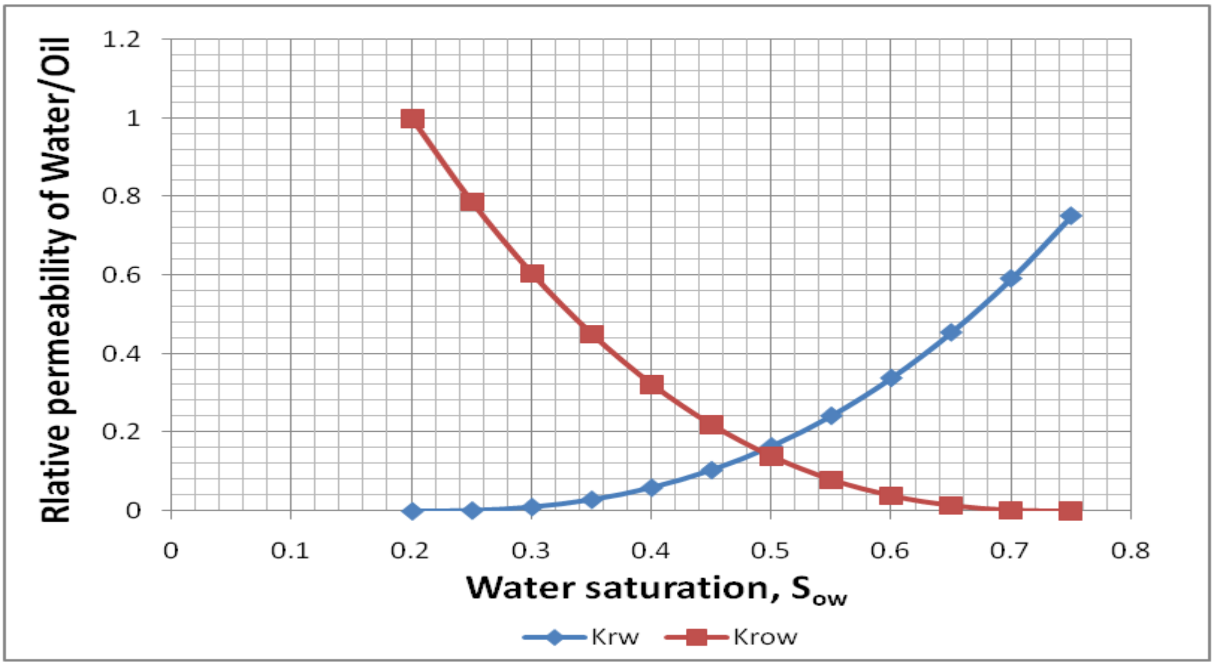

Figure 5 Relative permeability curves for oil and water

As the reservoir is water wet the end point permeability of the water is lower than that of oil.

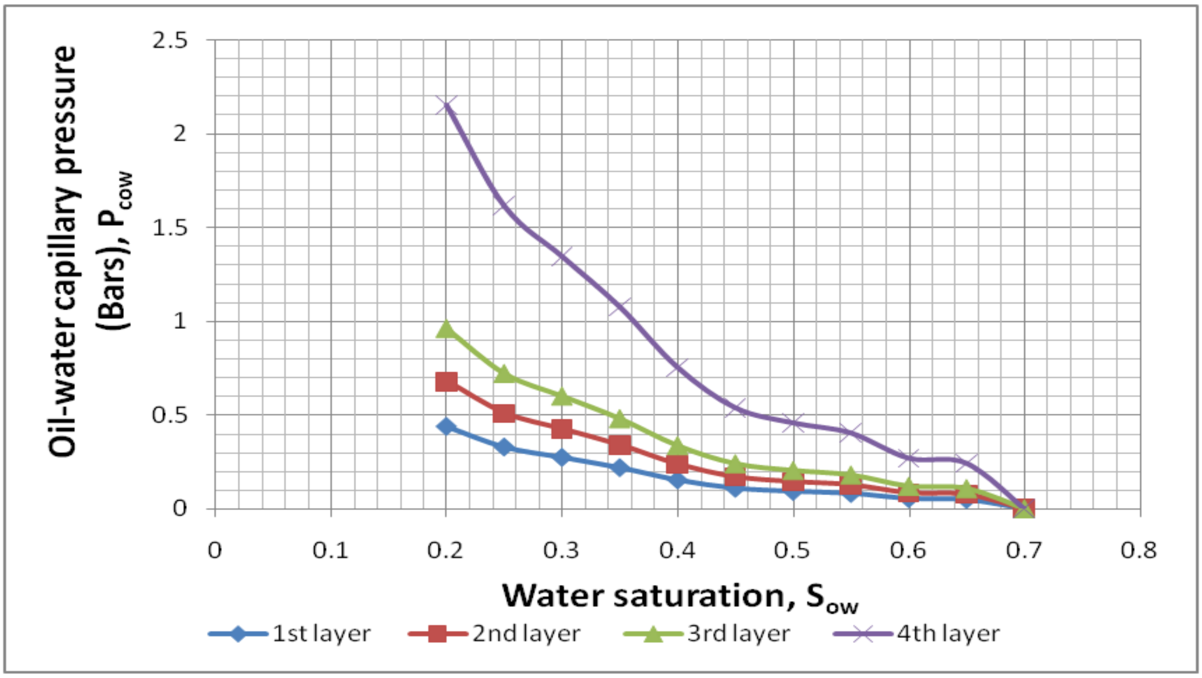

Figure 6 Oil water capillary pressure versus water saturation for each layer

From the fig.5, for the 4th layer, which is lowest permeability layer, capillary pressure between oil and water is higher for the same water saturation value than other layers, while 1st layer, which is the higher permeability layer, has lowest value of capillary pressure between the oil and water compared to other layers. Lower permeability layers cause the higher oil water capillary pressure for the same saturation values of water, mainly because, lower permeability rocks tend to have small pore sizes causing the capillary pressure to rise.

Two phase relative permeability curve for oil and gas is as following.

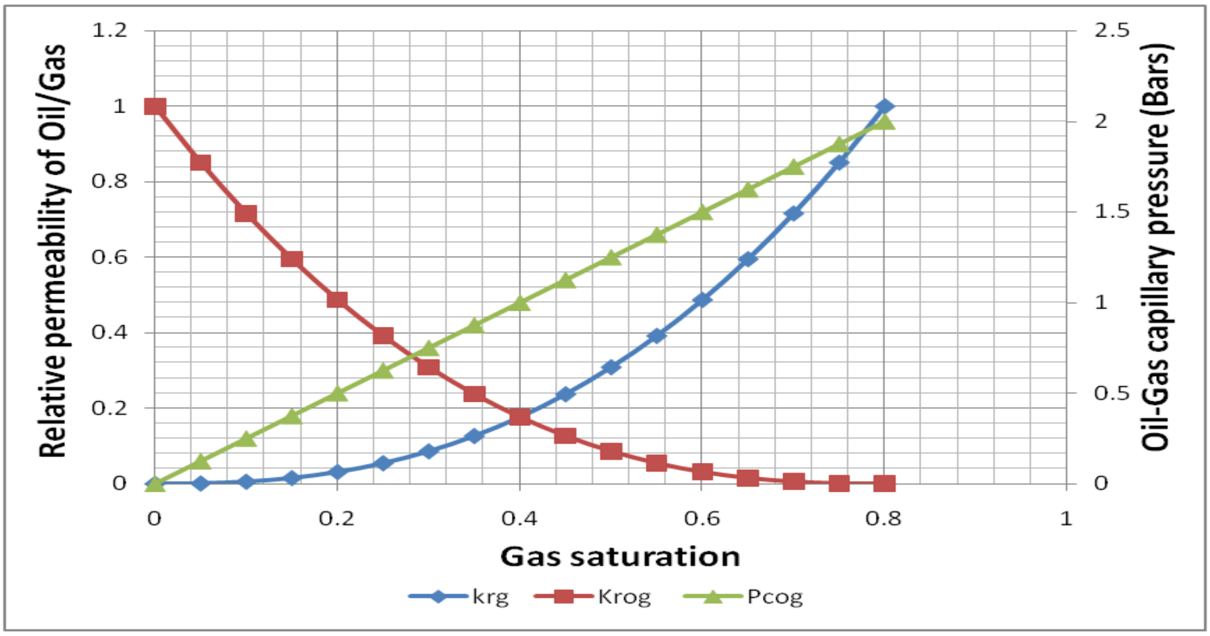

Figure 7 Relative permeability curves and capillary pressure behaviour of oil and gas

3.3 DPR treatment design:

The properties of the gelant solutions dictate the DPR treatment design. This subsection discusses rheological properties of the gelant solution.

3.3.1 Rheological properties of the gelant solution:-

The rheological properties determine the viscosity behaviour and as we have seen before, the understanding of the viscosity behaviour is of great importance in order to predict the gel placement in the reservoir.

The DPR gelant solution used in the modelling shows shear thinning behaviour which means the viscosity of the solution decreases with increase in shear rate. Now shear rate increases when the fluid flows with higher velocity and when an injected fluid enters the reservoir it has highest velocity at the wellbore and as invasion increases the velocity decreases. Therefore for constant injection rate, the gelant once injected in the reservoir will have lowest viscosity at the well bore and will decrease as it progresses deeper in the reservoir. Now even though the same gelant solution has been injected in all the layers the viscosity-velocity behaviour of polymer will be different in each layer. This is because the shear rate induced by the velocity of the fluid depends also on the resistance to fluid flow, which can be measured by permeability of the reservoir rock and as the reservoir rock has different permeability the shear rate induced by the same velocity of the gelant solution for each layer will be different and as the shear rate dictates the viscosity of the polymer solution the viscosity-velocity behaviour of gelant solution will be different in each layer.

The viscosity-velocity relation for gelant solution for each layer is as follows

Layer 1 - $\ddot{\Upsilon} = -2.5 * \ln(v) - 9.1961$

Layer 2 - $\ddot{\Upsilon} = -2.5 * \ln(v) - 9.8221$

Layer 3 - $\ddot{\Upsilon} = -2.5 * \ln(v) - 11.616$

Layer 4 - $\ddot{\Upsilon} = -2.5 * \ln(v) - 14.098$

Where $\ddot{\Upsilon}$ - Viscosity of gelant solution

And v – Velocity of gelant solution

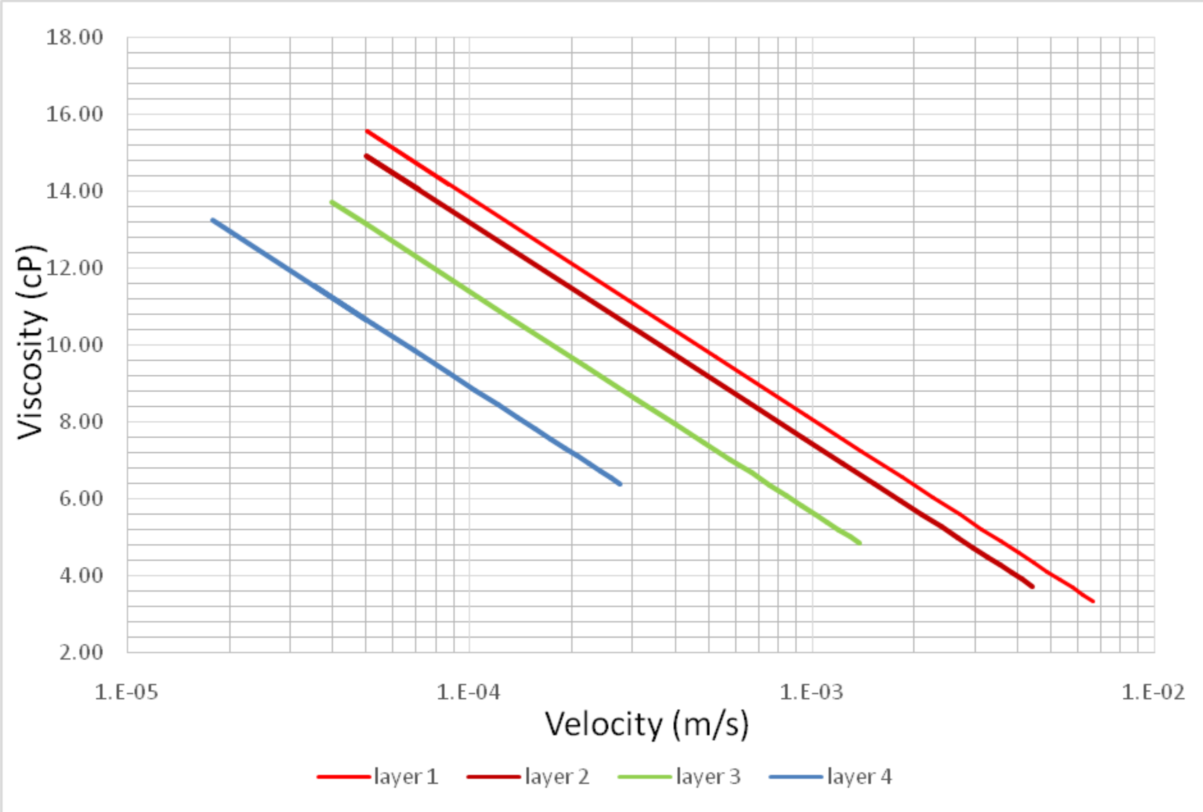

Figure 8 Semi-log plot of velocity versus viscosity for each layer

The plot in fig 8 show that for the gelant solution moving with same velocity will have higher viscosity in the high permeability layer compared to low permeability layer. This is one of disadvantage of shear thinning behaviour as our target is high permeability layers and higher viscosity means higher resistance to flow. Therefore higher viscosity can cause reduction in injectivity of high permeability layers.

3.3.2 Injection of the gelant solution and effects on the reservoir:-

The idea here is that, after the producer starts producing water, to block this water production DPR treatment would be employed on producer well. After the treatment, following factors will dictate the effect of the DPR on the reservoir.

Depth of invasion:- The depth of invasion in each layer is decided by the volume of injection and injectivity of each layer. Normally the high permeability layers have high injectivity therefore depth of invasion would be high in those layers. The depth of invasion is a measure of affected volume of the reservoir by DPR treatment. Higher the depth of invasion higher is volume of reservoir around the well bore in which relative permeability curves would be modified.

Water relative permeability reduction:- The aim of the DPR treatment is to reduce the water relative permeability as much as possible. This reduction in the water relative permeability is given by residual resistance factor for water (RRF_w). RRF_w is the ratio of relative permeability of water prior to DPR treatment to relative water permeability post-treatment.

Oil permeability reduction:- DPR treatment not only causes reduction in the water permeability but also in the oil relative permeability. The reduction in oil relative permeability is given by the residual resistance factor for oil (RRF_o). RRF_o is the ratio of relative permeability of oil prior to DPR treatment to relative permeability of oil post-treatment.

Absolute permeability reduction:- DPR treatment introduces the gel in the reservoir which causes the reduction in absolute permeability in the invaded zone. The measure of this reduction is given by residual resistance factor (RRF). The RRF is given by ratio of the permeability of invaded zone prior the treatment to the permeability post treatment.

All the case studies in this thesis will be concerned with study of impact of the variation in above four factors and time of treatment.

3.4 Case studies - numerical model details:

This thesis studies 13 different cases. These case studies can be subdivided in three sections.

First section, which contains case 1 is comparison of pilot performance of two scenarios. Scenario 1 is when DPR treatment was carried out and base scenario when no DPR treatment was carried out. Further in every section base scenarios will be addressed to the scenarios when no DPR treatment was carried out.

The section 2 contains six case studies, case 2 to case 7. In these cases effect of designing factors like depth of invasion, time of treatment, RRFw value, RRF value, the injection process on the reservoir performance will be studied. In order to study only reservoir performance, the vertical lift performance calculations are not taken into consideration. In both sections, section 1 and section 2, only fluid flow in reservoir is considered and therefore no vertical lift performance calculations are carried out. For this reason the constraints for the producer well for all cases in section 1 and section 2 are same.

In the third section which contains case 8 to case 13, the aim is to understand the effect of DPR treatment on both, inflow and outflow performance of the well. Therefore the vertical lift performance calculations for producer well are added in the simulation. Due to this difference in the model some of constraints applied to the production well are different for sections 1, 2 and section 3 which will be discussed further in next subsection. The tubing diameter used for vertical lift performance calculation is 0.2 m and tubing roughness is 1.524e-02.

In all the case studies, for the scenarios with DPR treatment the RRF_o value is 1.33, while the RRFw value is 10 unless the change in RRFw values is the subject of investigation. Also in all cases, the RRF value is 1, unless the subject of investigation is effect of RRF values on the pilot performance.

3.4.1 Producer well and injector well constraints

Producer well and water injection well constraint for the section 1 and section 2:

There are three constraints for the producer for cases in this section, maximum liquid production rate is 200 Sm^3/day, minimum bottom hole pressure is 250 bars and maximum water cut is 0.95. The minimum bottom hole pressure of 250 bars is used to ensure that no gas is formed in the reservoir as bubble point pressure for black oil used is 250 bars. The only constraint for injector is water injection rate of 200 Sm3/day and maximum bottom hole pressure of 800 bars to prevent fracturing of the reservoir.

Producer well and injector well constraint for section 3:

Three constraints for the producer well are maximum liquid production rate is 200 Sm3/day, minimum tubing head pressure is 20 bars and maximum allowable water cut at surface is 0.95. The injector well constraints are same as that for the other section.

3.5 Results and discussions:

3.5.1 Section 1

3.5.1.1 Case 1 Comparison between treated and untreated reservoir:-

This subsection considers two scenarios, scenario 1 when the DPR treatment was carried out on the producer well and base scenario when no DPR treatment was carried out.

The aim of this subsection is to investigate the difference between the pilot performances of the producer for scenario 1 and base scenario. Further we will try to understand the effect of DPR treatment on the fluid flow in the reservoir on the field level. Table below shows the result of simulation.

		Cases	
		Scenario 1	Base scenario
Polymer volume injected during treatment (Sm^3)		300	-
Time of treatment after start of production (days)		740	-
Depth of invasion (m)	1st layer	11.65	-
	2nd layer	11.65	-
	3rd layer	6.87	-
	4th layer	4.084	-
Oil production total (Sm^3)	1st layer	91904	94629
	2nd layer	60913	63081
	3rd layer	43346	45158
	4th layer	53912	53042
	Total	250077	255550
Oil Recovery (%)		63.0039	64.38
water production total (PV)	1st layer	0.2126	0.9246
	2nd layer	0.0893	0.3866
	3rd layer	0.0187	0.0663
	4th layer	0.0005	2.43E-06
	Total	0.3211	1.3774
water injection total (PV)	1st layer	0.524	1.2374
	2nd layer	0.2911	0.5935
	3rd layer	0.1612	0.2148
	4th layer	0.1893	0.1813
	Total	1.1656	2.227
Corresponding time of production (Days)		1792	3420

Table 3 Case 1 Treatment design details and pilot performance comparison

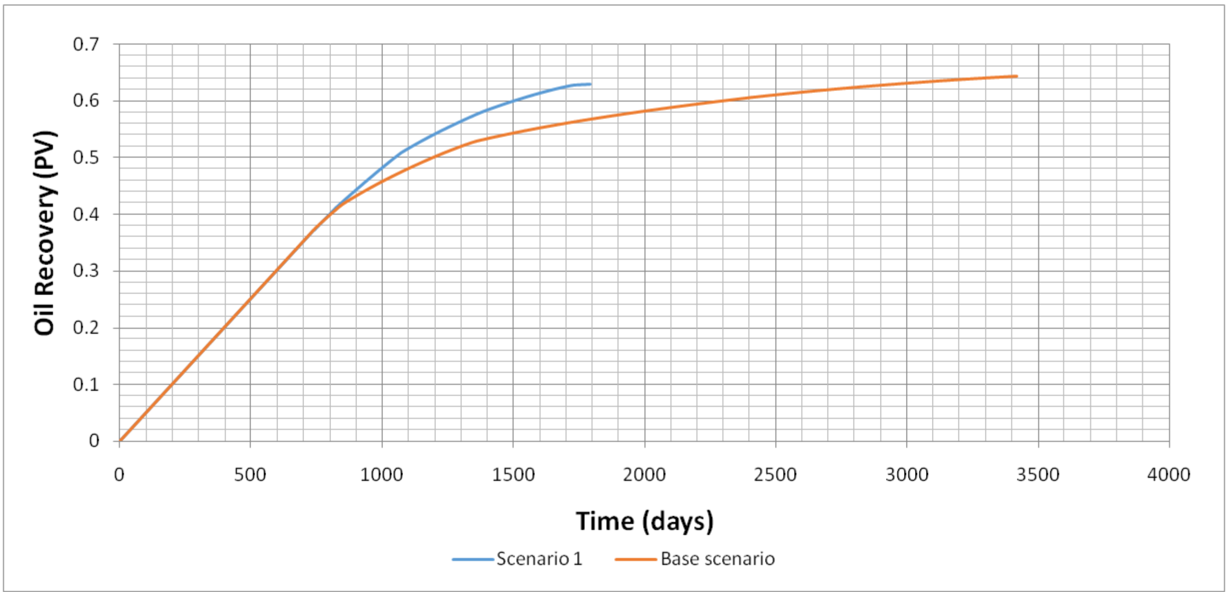

Figure 9 Case 1 Oil recovery versus time

Oil recovery plots show that oil recovery for scenario 1 is lower than that of the recovery for base scenario by 1.4 %. But the production time in the scenario 1 is around 1900 which is approximately 47% lower than production time of 3400 days for untreated reservoir. Also from the table above we can see that the total water production has been decreased by almost four and quarter fold.

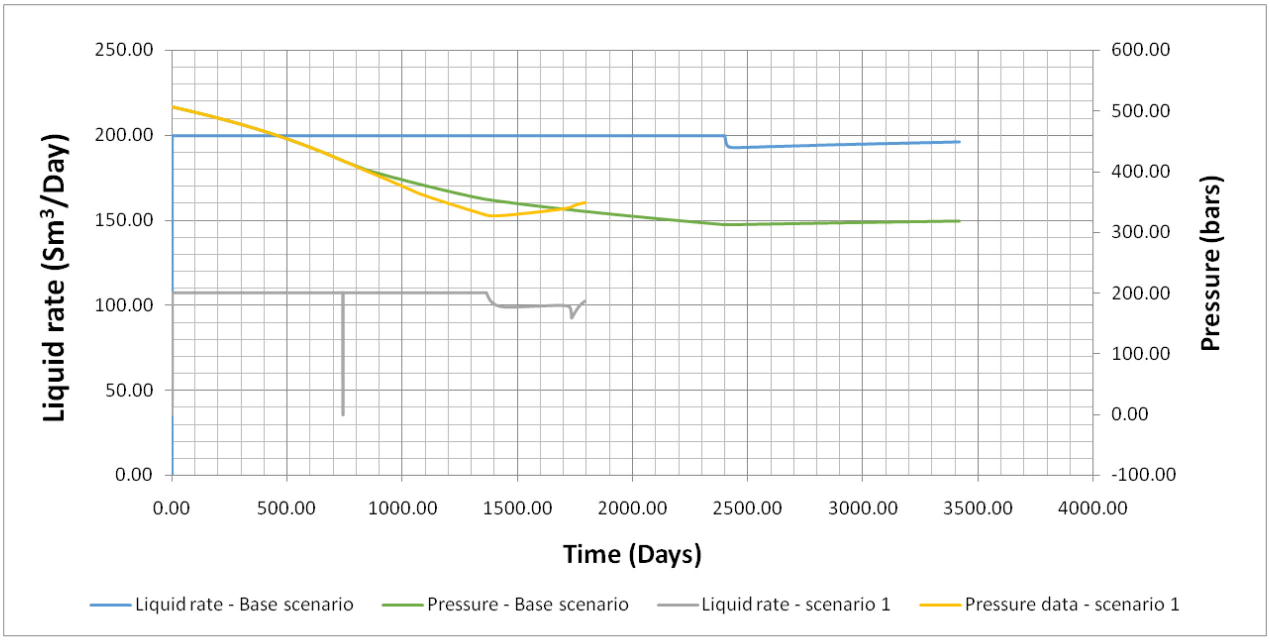

Figure 10 Case 1 Liquid rate and average reservoir pressure behavior

After the water breaks through the 2^{nd} layer, the reservoir pressure drops more drastically in scenario 1 than in Base scenario. This is an indication of higher oil production rate and lower water production rate for the production period after the treatment for scenario 1 compared to base scenario. The well producer produces with constant liquid rate at 200 Sm^3/day. This liquid production rate is the addition of water production rate and oil production rate. Water has higher mobility due to lower viscosity value compared to oil. So if liquid produces more oil then there will be higher pressure drop. This observation can be supported by oil recovery behaviour in fig. 9.

Also approximately after 1400 days, in scenario 1 the liquid rate of 200 Sm3/Day was not sustainable and dropped due to low reservoir pressure. But at the same time, injection rate was 200 Sm^3/Day. This imbalance in scenario 1 caused the reservoir pressure to increase after 1400 days.

(Note - The figures that show water injection rate versus time for each layers in this case, some of the irregular peaks are caused due to convergence problems that were faced while simulation of numerical model.)

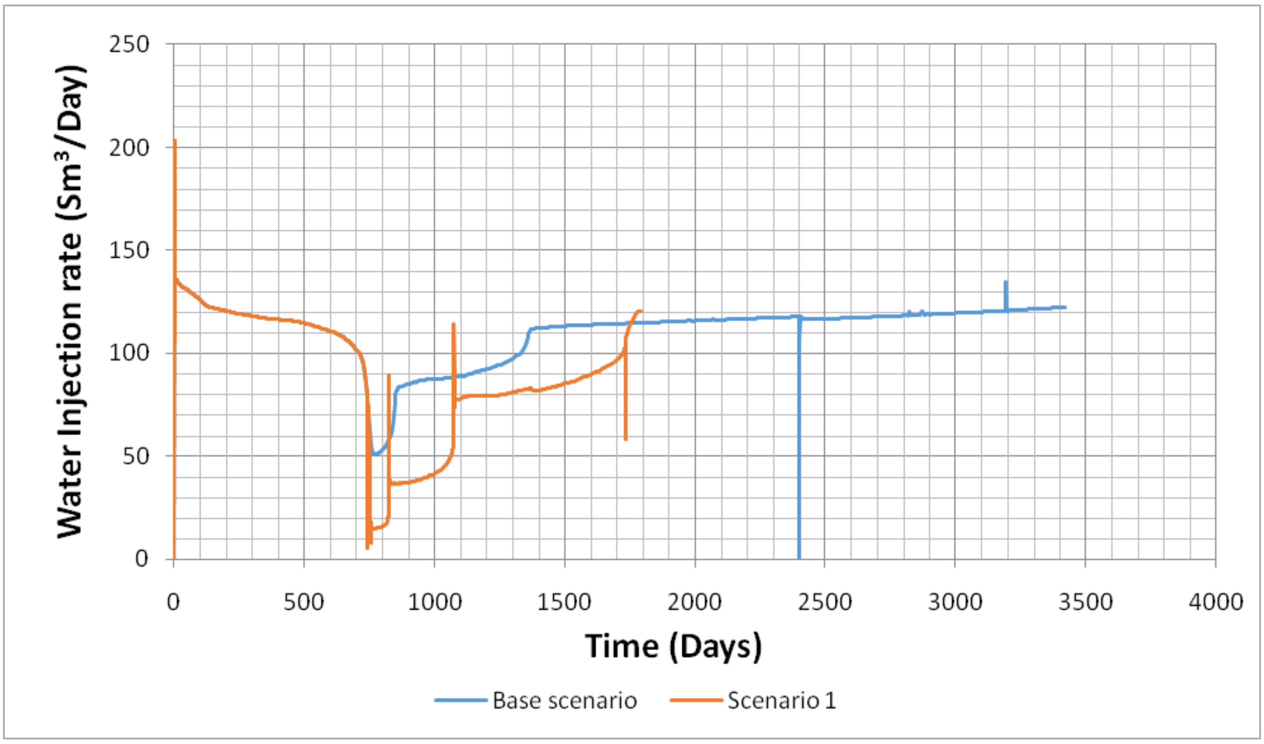

Figure 11 Case 1, 1st layer, Water injection rate versus time

The water injection rate graph shows that, initially water injection rate for 1st layer is lower for the scenario 1 than base scenario from the time of treatment. But in scenario 1, this water injection rises drastically rises three times at around after 820 days of production, 1080 days of production and finally at around 1720 days of production. This happens because DPR treatment was carried out after the water has broken through 1st layer. Due to DPR treatment, resistance to flow of the water increases and as water saturation is highest for the 1st layer, flow resistance affects most in 1st layer. But we see increase three times because the injectivity in 1st layer is competing with three other layers and when water breaks through any of these layers the resistance to flow in those layers increases and injectivity in those layers decrease resulting in increase in the 1st layer injectivity.

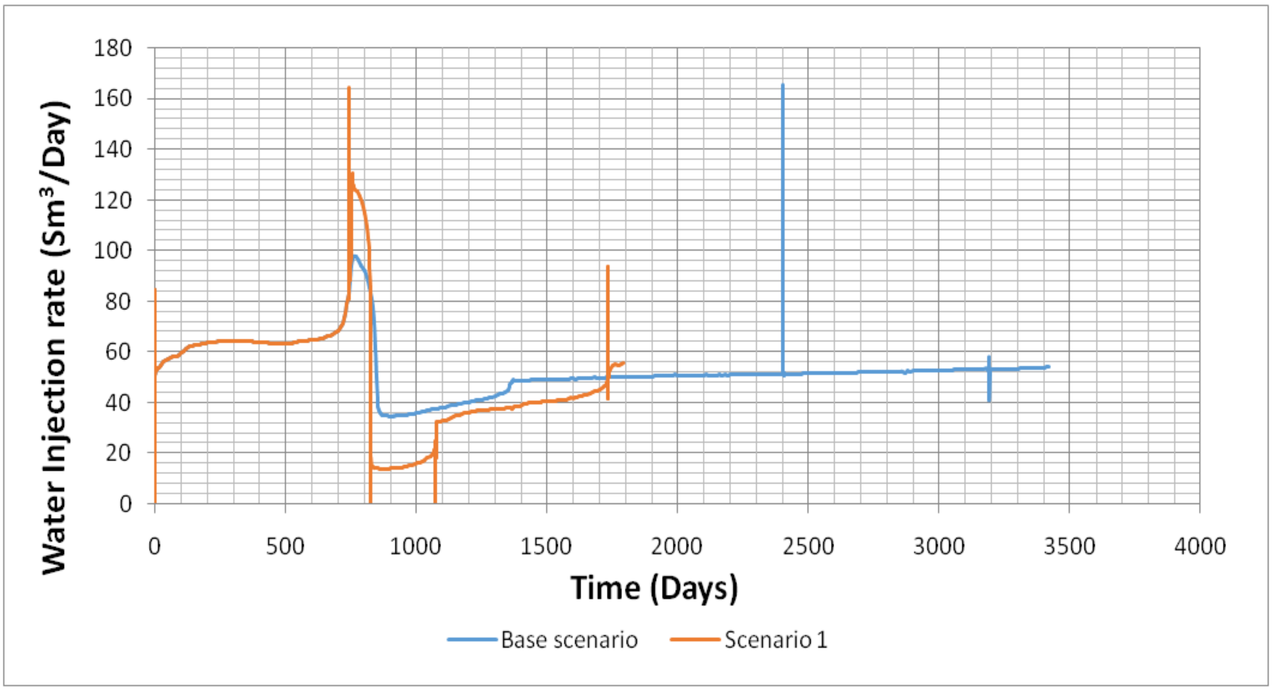

Figure 12 Case 1, 2nd layer, Water injection rate versus time

Water injection rate behaviour for this layer is different than previous layer. For some period after the treatment, water injection rate is higher for scenario 1 than base scenario. This happens because at the time of treatment water front hasn't been reached to the well for 2nd layer. So the initially mobility contrast between 1st and 2nd layer is lesser for scenario 1 than base scenario. But after around 820 days of production water breakthrough occurs, the injection rate drops and water injection behaviour their after is similar to 1st sandstone layer.

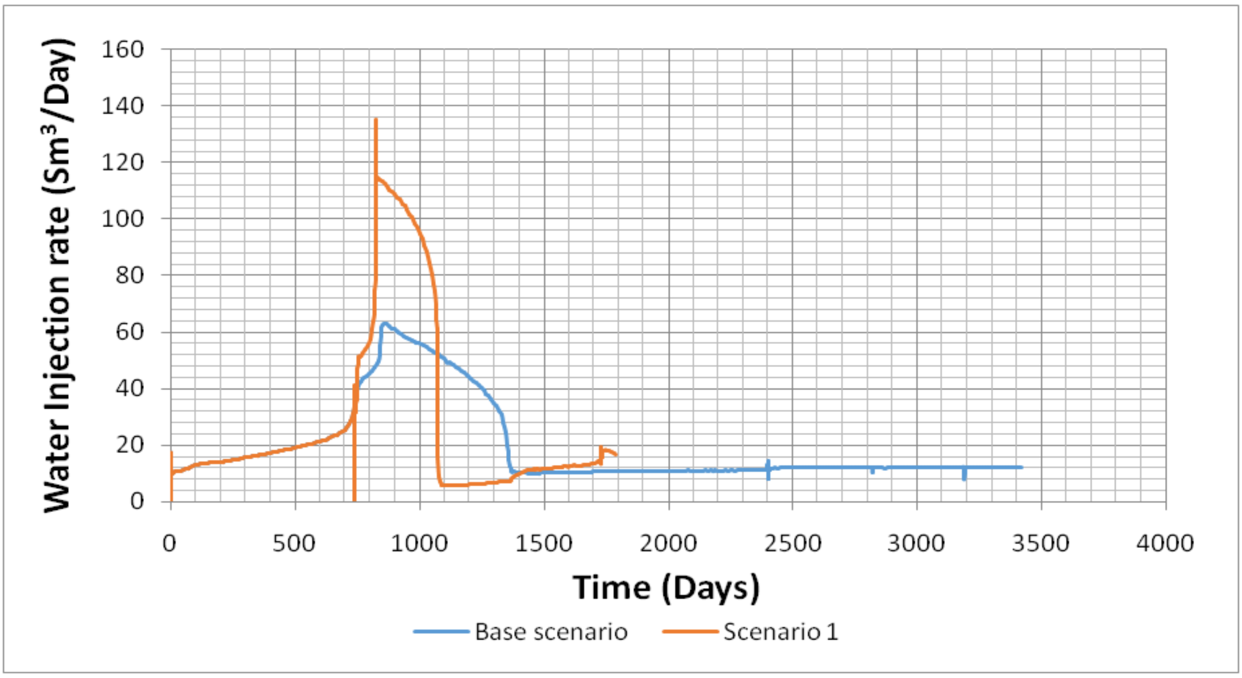

Figure 13 Case 1, 3rd layer, Water injection versus time

In scenario 1, water injection behaviour for 3rd layer is similar to 2nd layer except that initial drop in water injection occurs after around 1080 days while in previous case it was much earlier. This happen because permeability in 3rd layer is less than permeability in 2nd layer and so the water front in this layer takes more time to reach the well but after the water front has reached the well, the injection rate drops and then slightly rises at the end at around 1720 days when the 4th layer experience water breaks through.

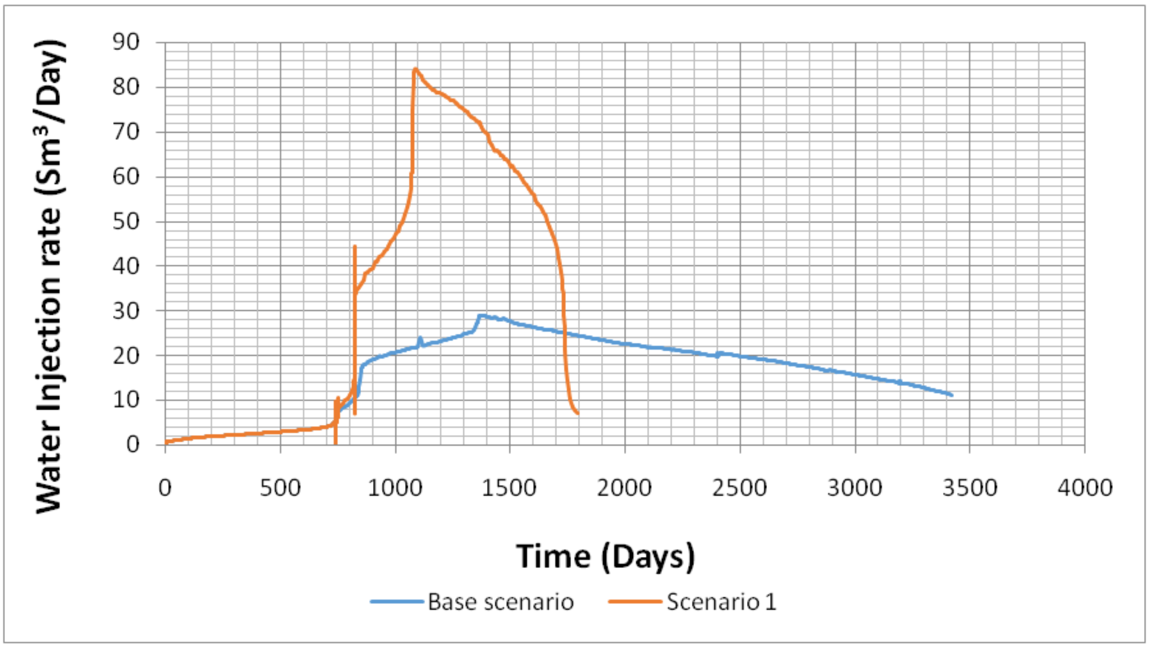

Figure 14 Case 1, 4th layer, Water injection rate versus time

For 4th layer permeability value is smaller than all other sandstone layers. Therefore water front for this layer is last one to reach the production well, which is around 1720 days after production period. Therefore the water injection in this layer is higher for scenario 1 compared to base scenario from the time of treatment but decreases when the water breakthrough occurs.

Observations

DPR treatment

- Reduces the total water production by approximately 75 %.
- Reduces the operation time by 47 %
- Causes only slight decrease in oil recovery
- Improves the sweep efficiency of water flooding

3.5.2 Result and discussions section 2

3.5.2.1 Case 2: Impact of gel treatment volume/radius

This subsection considers the impact of treatment depth on the reservoir performance. The question addressed is the potential existence of an optimum treatment depth that yields the best pilot performance.

The volume of DPR gelant solution dictates the depth of DPR treatment. The larger the injected DPR gelant volume the larger the volume of the treated zones and thus, the larger the radii of reduced fluids (oil and water) relative permeability curves.

In bullheading well treatments, injected gelant will invade all layers and not only the highest permeability one. Therefore, whereas the relative permeability reduction may be beneficial for the highest permeability layer, it may have a negative impact on the productivity of the low permeability layers.

In this case, the volume of injected gelant was ranged from 50 Sm^3 to 900 Sm^3. The following table shows a summary of the simulation results.

		Scenarios					
Polymer Volume Injected		scenario 1	scenario 2	scenario 3	scenario 4	scenario 5	Base scenario
Polymer volume injected during treatment (Sm^3)		50	150	300	500	900	-
Time of treatment after start of production (days)		740					-
Depth of invasion (m)	1st layer	4.05	8.95	11.65	15.18	19.77	-
	2nd layer	4.05	6.87	11.65	15.18	15.18	-
	3rd layer	2.39	5.27	6.87	6.87	11.65	-
	4th layer	1.41	3.1075	4.08	5.27	5.27	-
Oil Recovery (%)		63.21	63.05	63.0039	62.96	62.93	64.38
Total water production (PV)		0.3618	0.3286	0.3211	0.3141	0.3073	1.3774
Corresponding time of production (Days)		1852	1802	1792	1782	1772	3420

Table 4 Case 2 Treatment design details and pilot performance comparison

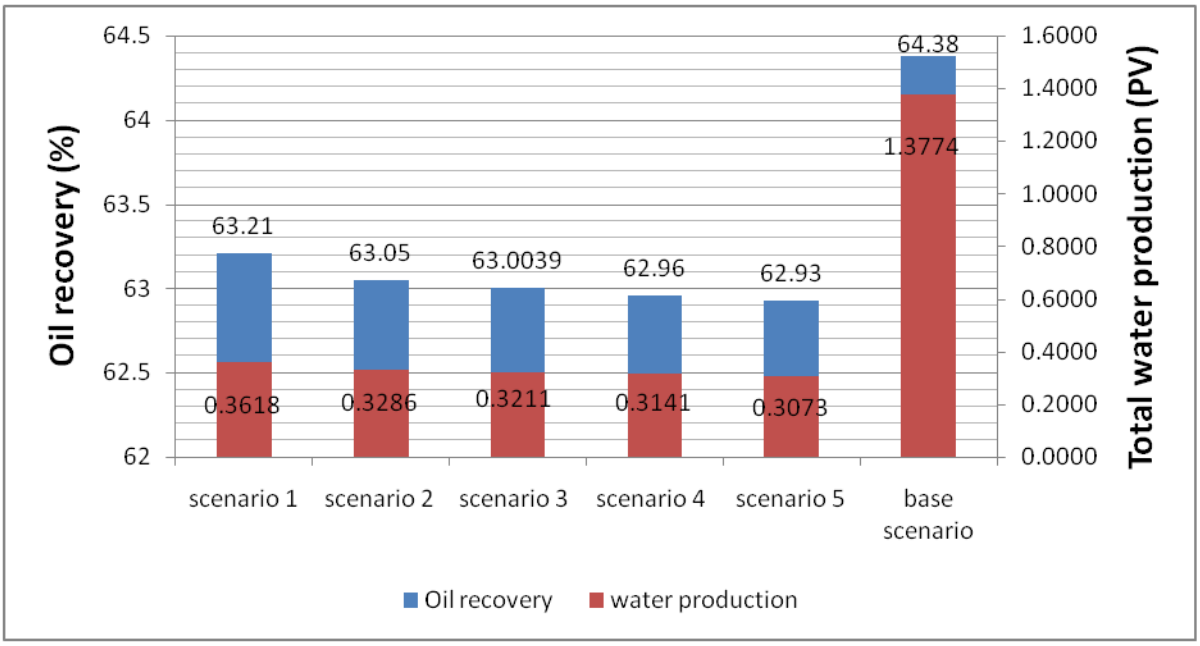

Figure 15 Case 2 Oil recovery and total water production comparison

Results show maximum change in the pilot performance is between scenario 1 and scenario 2 especially the total water production. The total water production in scenario 1 is around 10 % higher than scenario 2 which is result of 3 fold decreases in volume treatment. While in rest of the scenarios the volume treatment has been increased by 2 fold than previous scenario and total water production difference obtained was about 2.2 %. First scenario among all the scenarios considered injects least gelant volume. Therefore, it shows room for improvement in resistance to water flow. But the similarity in simulation results for other scenarios indicates that damage to low permeability layers due to gelant invasion is not significant for scenarios considered.

3.5.2.2 Case 3 –Impact of Water relative permeability reduction

Uncertainty in RRF_w has been one of the reasons that DPR treatment is not widely used. This subsection attempts to compute the reliability of reservoir simulation taking into consideration uncertainties involved in RRF_w values as well as to gauge the lowest RRF_w value below which the DPR treatment would be economically unviable.

The following table contains details and simulation results for four scenarios with different RRF_w values.

	Scenarios				
	RRFw=10	RRFw=5	RRFw=2.5	RRFw=2	No DPR
Polymer volume injected during treatment (Sm^3)	300				-
Time of treatment after start of production (days)	740				-
Depth of invasion (m) — 1st layer	11.65				-
Depth of invasion (m) — 2nd layer	11.65				-
Depth of invasion (m) — 3rd layer	6.87				-
Depth of invasion (m) — 4th layer	4.084				-
Oil recovery (%)	63.0039	63.7	64.31	64.43	64.38
Total water production (PV)	0.3211	0.526	0.9	1.0475	1.3774
Corresponding time of production (Days)	1792	2112	2692	2922	3420

Table 5 Case 3 – Treatment design details and pilot performance comparison

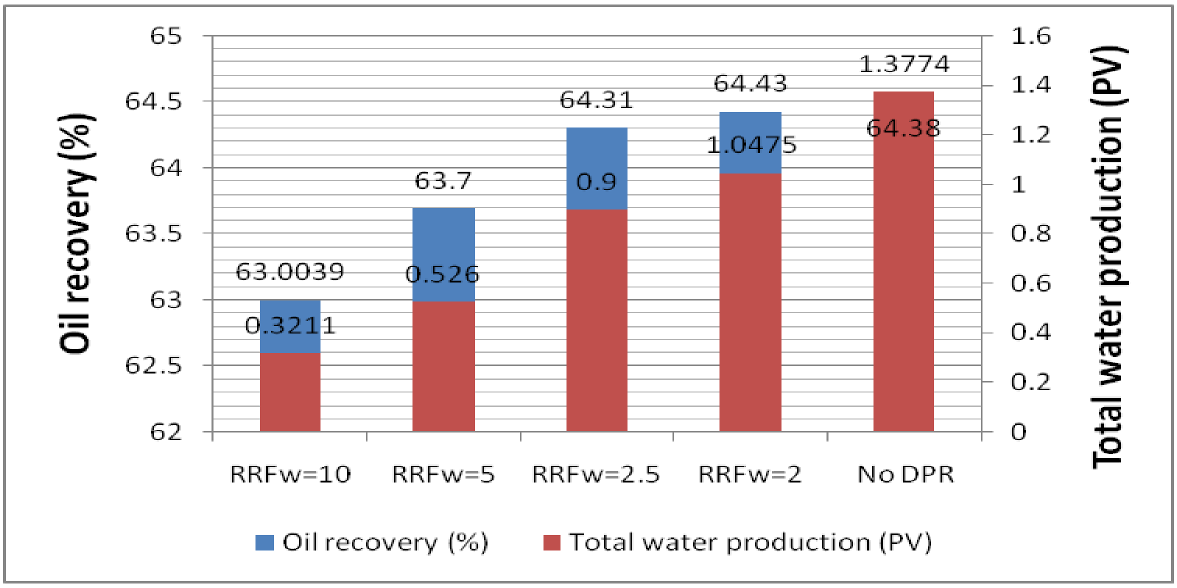

Figure 16 Case 3 Oil recovery and total water production results

The results above show that the relative permeability reduction has a considerable impact on oil recovery. But the major impact is on the total water production and length of production period. Also this impact is very sensitive to the value of relative permeability reduction factor for water.

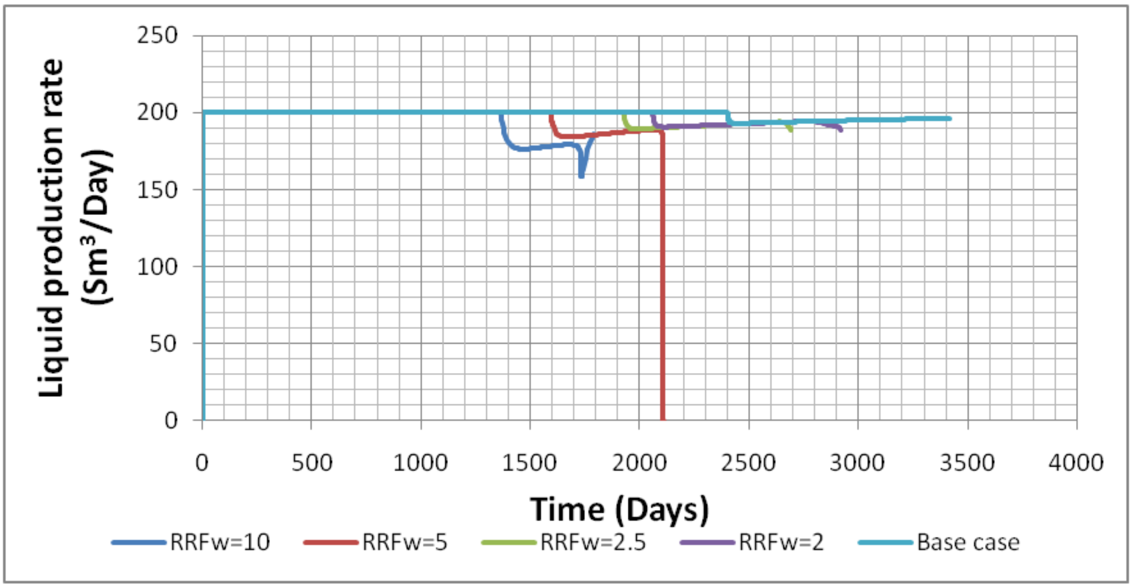

Figure 17 Case 3, Liquid production rate versus time

The maximum liquid production rate of 200 Sm^3/Day is one of the constraints for the producer. Therefore any drop from this value indicates that the reservoir conditions cannot sustain the liquid rate. The plot in Fig.16 demonstrates that higher the RRFw value lower is period for which maximum liquid rate is sustained.

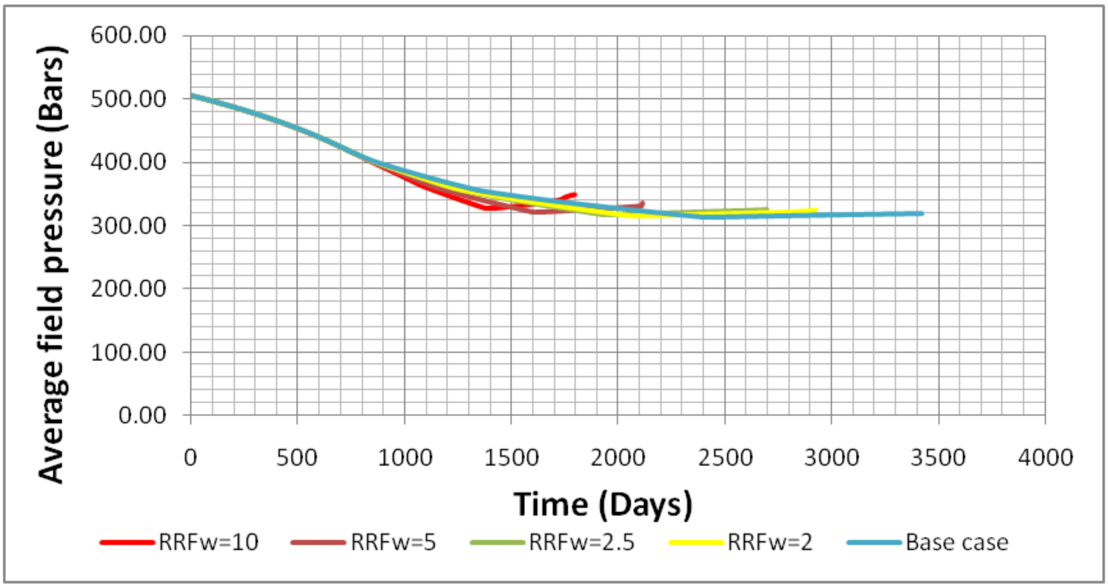

Figure 18 Case 3, Average reservoir pressure versus time

It can be seen that when RRF_w is higher the pressure drops more drastically.

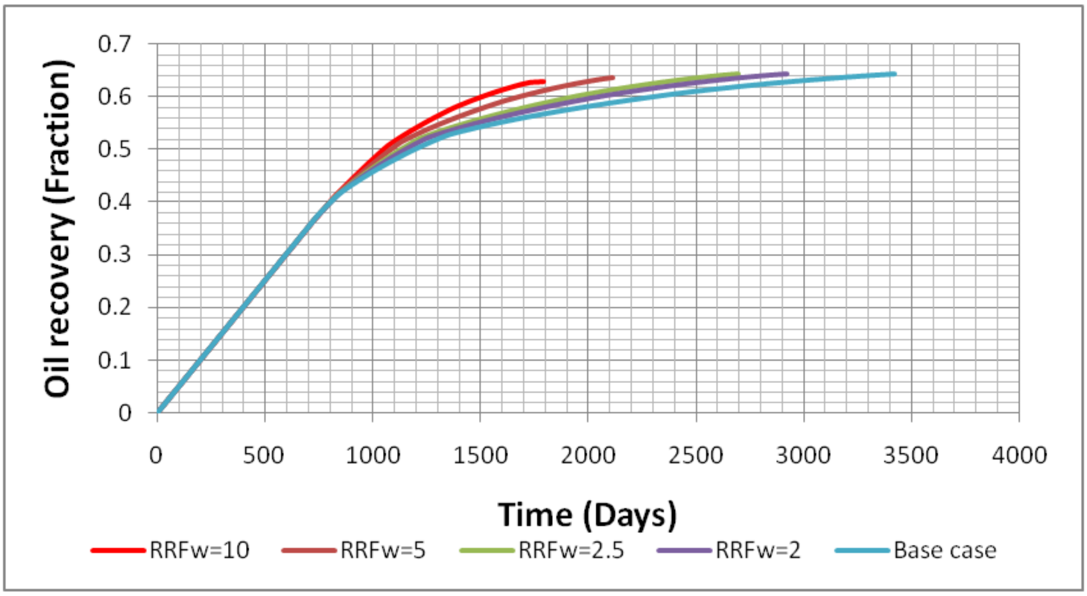

Figure 19 Case 3, Oil recovery versus time

Even though pressure drops more drastically and production time is much shorter when RRFw values are higher, there is not much of an impact on the final oil recovery value.

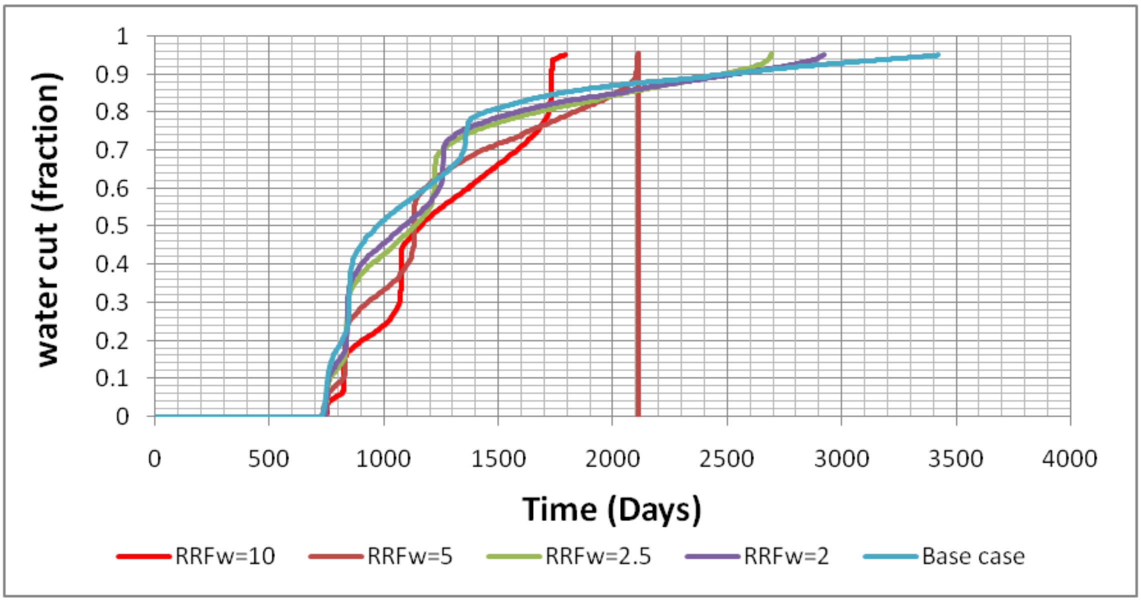

Figure 20 Case 3 Water cut versus Time

Initially the water cut is lower for scenarios with higher RRFw value, but increases more drastically while for scenarios with lower RRFw value, the curve is more gradual. The reason behind this is when water has broken through high permeability layers and lower permeability layers still contains high saturation of hydrocarbons around the well bore, higher RRFw values reduce the permeability contrast by higher resistance to fluid flow in higher permeability layers, improving the overall sweep efficiency of water flooding. But due to high sweep efficiency the water front travels faster in lower permeability layers, causing early water breakthrough. And as the water breaks through these layers, the water cut values increase. Also if the water is injected at high rate then the water front tend to be sharper while if water injection rate is low then the water front will proceed as a smooth curve. For this reason the water cut curves show drastic changes in scenarios with high RRFw values, while they are smoother in scenarios with low RRFw value

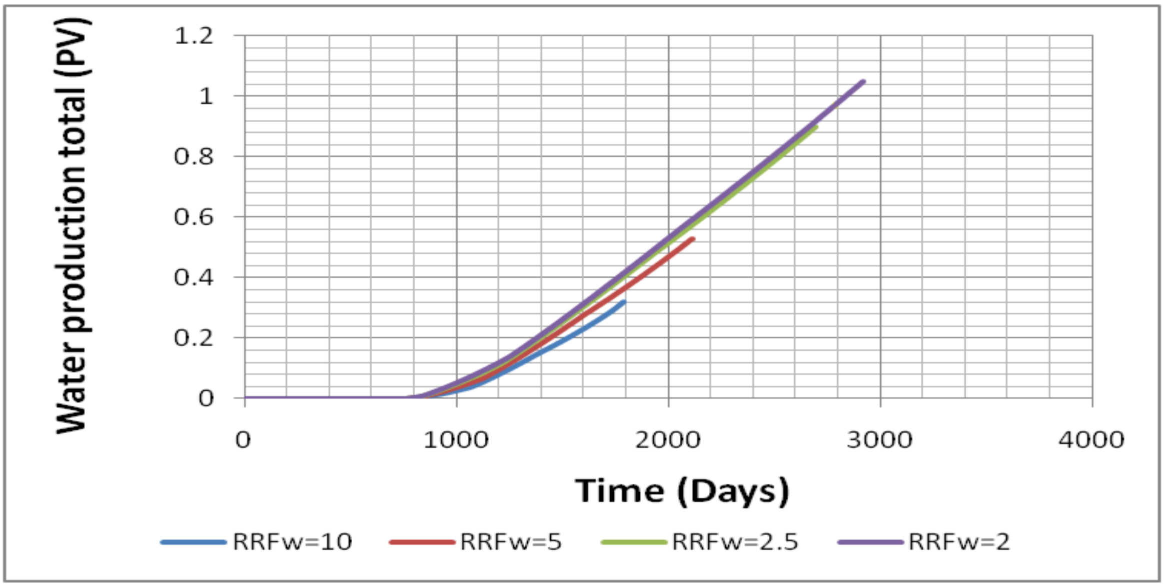

Figure 21 Case 3 Total water production versus time

As the total operation time is shorter and for most period of production time water cut is lower for the scenarios with higher RRFw values, the total water production is fairly lower for these scenarios. Two fold decrease from RRFw equal to 10 to RRFw equal to 5 increases the operation time by approximately 16%, while two fold decrease from RRFw equal to 5 to RRFw equal to 2.5, the increase in operation time is about 27%. So for the lower values of RRFw, total operation time is very sensitive to change in RRFw value. And as this addition of operation time does not increase the oil recovery significantly, it reflects in total water production.

Observation:

- Post-treatment water relative permeability reduction factor impacts significantly the sweep efficiency, total production time, total water production and reservoir pressure behaviour. Therefore any reservoir simulation regarding DPR treatment should take into account the uncertainties involved in RRF_w values.
- Even in the worst scenario of DPR treatment that is when RRF_w is equal to 2, the operation time and total water production is fairly lower and oil recovery is slightly higher than the base scenario. Normally the value of RRF_w is much larger than our worst scenario. Therefore DPR treatment for this reservoir is strongly recommended.

3.5.2.3 Case 4 – Impact of absolute permeability reduction by gelant injection:-

DPR treatment is essentially an introduction of gel in the reservoir. Therefore this process tends to introduce skin around the wellbore up to the depth of invasion and damage reservoir to certain extend. In this subsection, aim is to understand and approximately quantify the effect of absolute permeability reduction on pilot performance and to check if the damage done to reservoir outdoes the benefits of DPR treatment.

For this case four scenarios are considered. Each scenario differs from other by RRF value i.e. damage introduced by DPR treatment. The first scenario assumes that absolute permeability is not affected by DPR treatment. In the other three scenarios the absolute permeability was affected by the gelant injection but to different extents.

- Scenario 1 - DPR treatment with RRF value 1
- Scenario 2 – DPR treatment with RRF value 10
- Scenario 3 – DPR treatment with RRF value 3.33
- Scenario 4 – DPR treatment with RRF values 2
- Base scenario – No treatment was carried out

		Scenarios				
		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Base Scenario
Polymer volume injected during treatment (Sm^3)		300				-
Time of treatment after start of production (days)		740				-
Depth of invasion (m)	1st layer	11.65				-
	2nd layer	11.65				-
	3rd layer	6.87				-
	4th layer	4.084				-
Oil recovery (%)		63.0039	59.47	61.65	62.35	64.38
Total water production (PV)		0.3211	0.1233	0.2069	0.254	1.3774
Corresponding time of production (Days)		1792	1532	1642	1702	3420

Table 6 case 3 Design details and pilot performance comparison

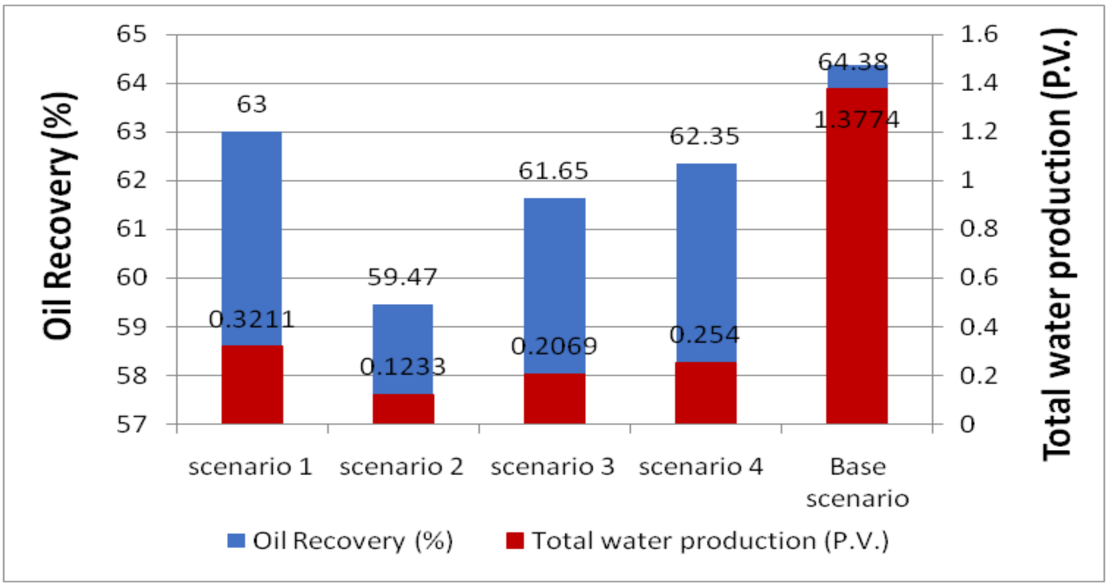

Figure 22 Case 4 Oil recovery and total water production

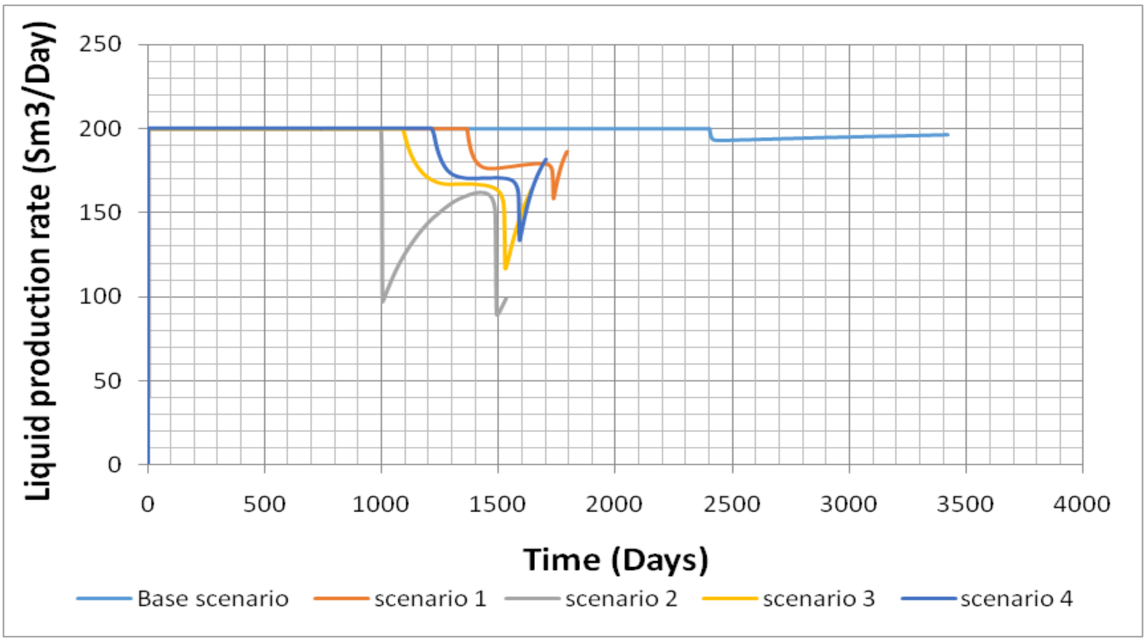

Figure 23 Case 4 Liquid production rate versus Time

The liquid production rate can only be sustained for shorter production time for scenarios with higher RRF values. Also in these scenarios drop in liquid rate is very drastic.

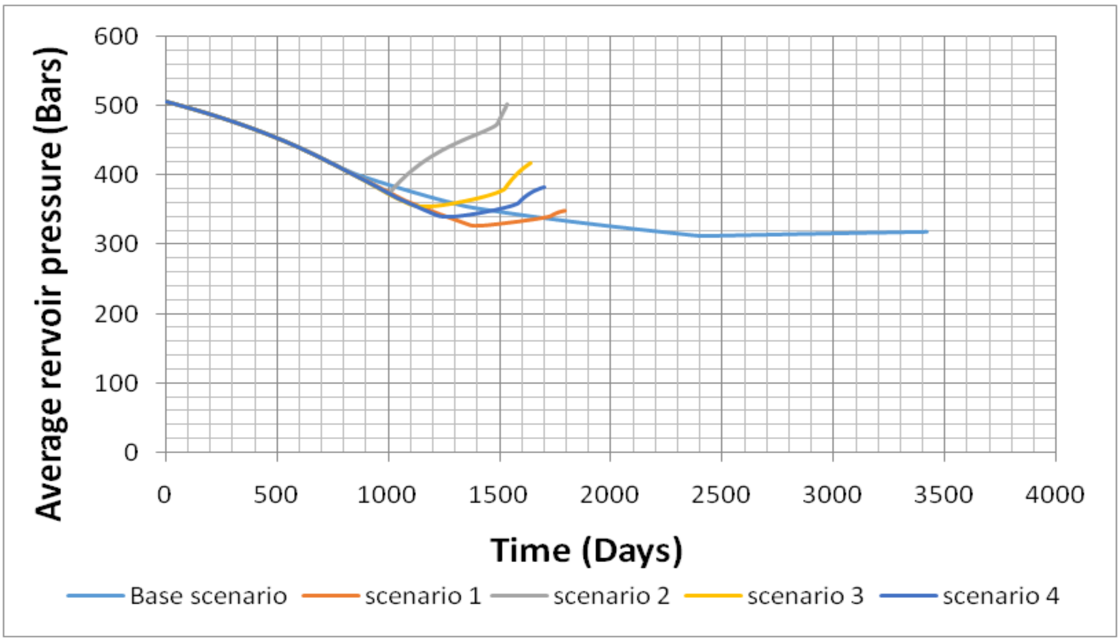

Figure 24 Case 4 Average reservoir pressure versus Time

After the liquid rate drops, pressure in reservoir increases due to imbalance between liquid production rate and water injection rate. But in scenario of higher RRF values, this pressure increase is more drastic. This happens because as we have seen in previous graph, there is not only the difference in when liquid rate drops but also in the way it drops. Liquid production rate drops very drastically in scenario of higher RRF value which is reflected by a drastic increase in average reservoir pressure.

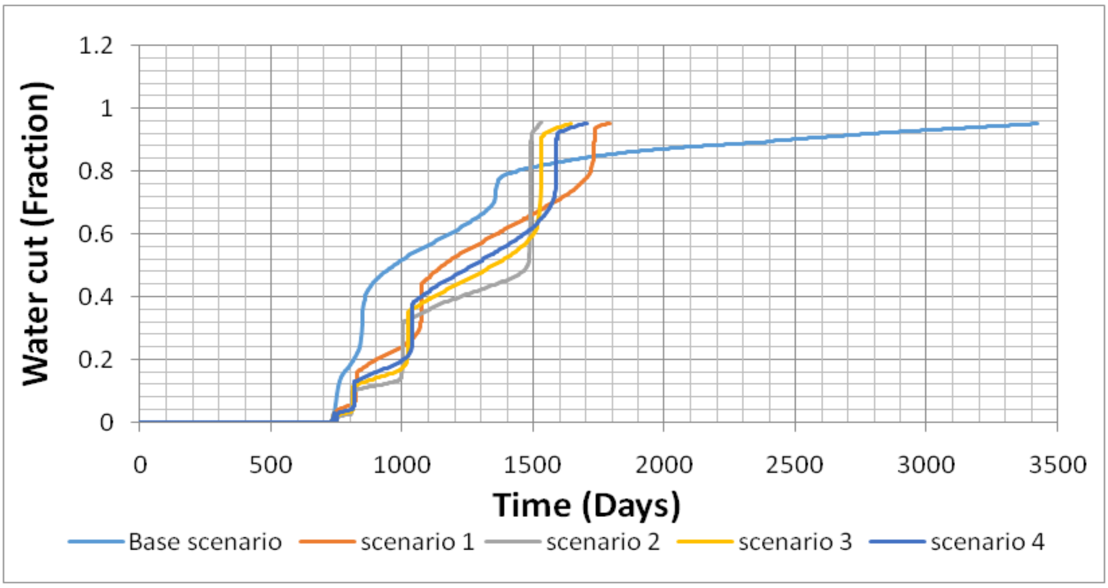

Figure 25 Case 4 Water cut versus time

Water cut behaviour shows that higher skin causes water breakthrough much earlier in each layer. We have also seen that the liquid rate is reduced much earlier in the scenarios of higher RRF values. This indicates that the reduction in absolute permeability also causes the water to bypass the oil to certain extent due to imbalance caused by the higher water injection rate and lower liquid production rate. But at the same time we can see from the graph that the water cut even in the worst scenario, i.e. when RRF is equal to 10, for most of its production life is less than base scenario i.e. the scenario with no DPR treatment. Also we observe that as the RRF value increases, the increase in the water cut is much shaper. This happens because as the permeability is reduced, the water fronts in the water flooding are sharper.

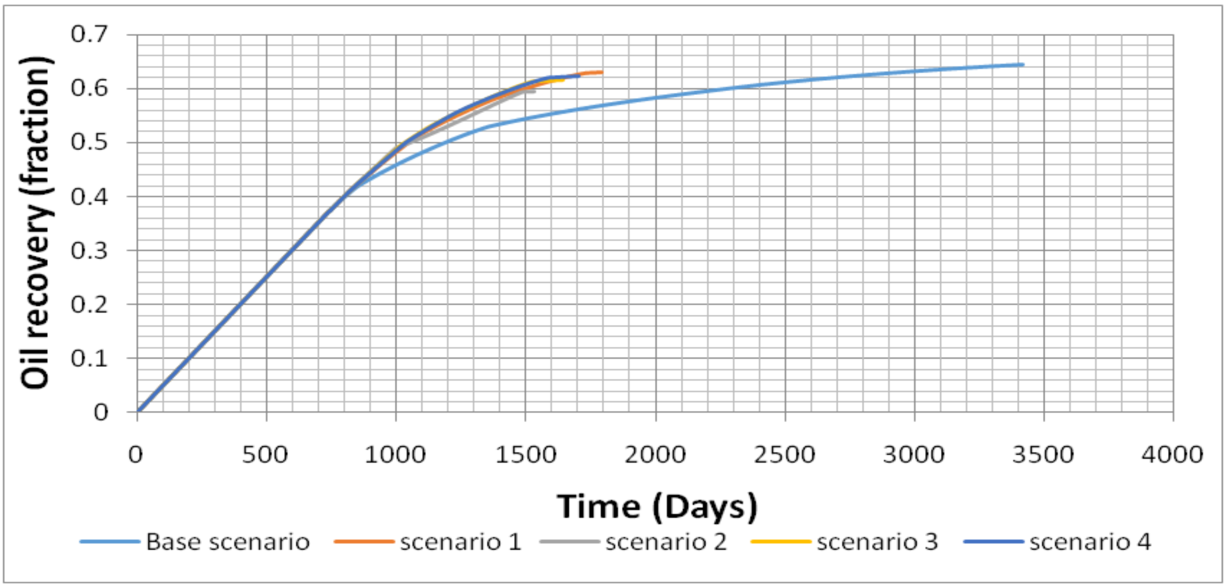

Figure 26 Case 4 Oil recovery versus time

The oil recovery behaviour bears the mark of absolute permeability reduction. If we compare best scenario DPR treatment scenario and worst scenario DPR treatment scenario, that is when RRF is equal to 1 and RRF is equal to 10 respectively, the oil recovery reduction is about 4%.

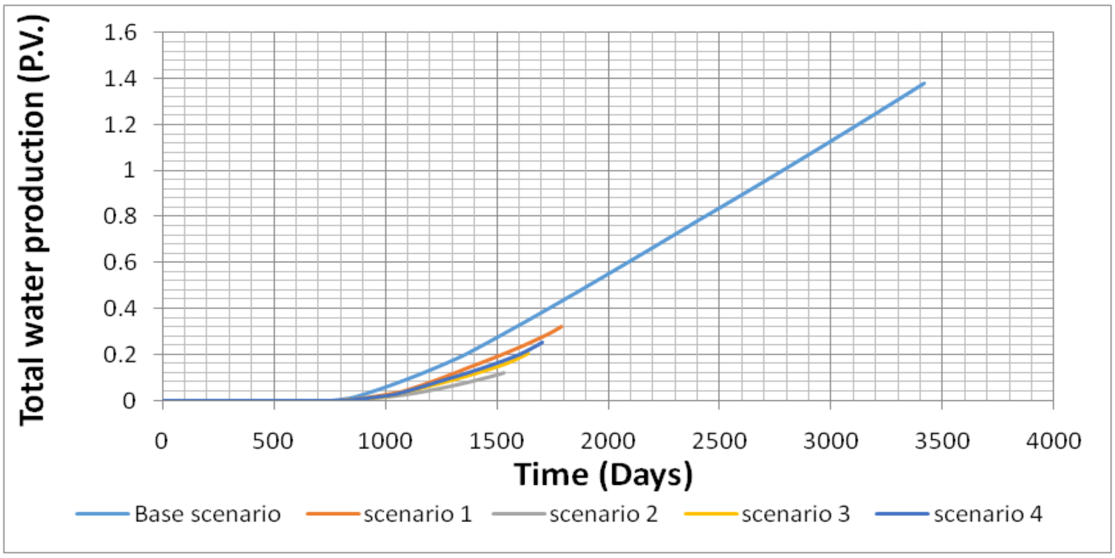

Figure 27 Case 4 Total water production versus Time

Due to lower liquid rate and lower operation time the total water production is lesser in scenario of damaged reservoir.

Observations

- The reduction in absolute permeability reduces the recoverable oil at current conditions.
- Operation time and total water production in the reservoir even with high permeability reduction are small and performs far better than base scenario.

3.5.2.4 Case 5 – Time of treatment:-

DPR treatment is used to prevent the water production. Normally a producer well initially produces hydrocarbons and water is produced during the later period of production life. If we use DPR during the initial production period it will hurt the hydrocarbon productivity. So using DPR too early can damage the reservoir.

Water will breakthrough first in the layer with highest permeability and as fluid in this layer has high productivity if we do not block the water production in this layer it will have a large impact on reservoir pressure, hydrocarbon production and total water production. Water shutoff at the time of water saturation rise in high permeability layer is very important. And delaying DPR may cause an irreparable damage as the water in this layer has already been produced and reservoir pressure has already dropped.

This subsection considers the impact of time of treatment on reservoir performance. The aim is to evaluate the change in the pilot performance with the change in the time of DPR treatment and potentially find the best time for DPR treatment. Following five scenarios are considered based on the water cut from the highest permeability layer which in this scenario is first sandstone layer.

- Scenario 1:- DPR treatment after water cut in the first layer reached 0.25 that is after production time of 740 days
- Scenario 2:- DPR treatment after water cut in the first layer reached 0.5 that is after production time of 760 days
- Scenario 3:- DPR treatment after water cut in the first layer reached 0.75 that is after production time of 840 days
- Scenario 4:- DPR treatment after water cut in the first layer reached 0.83 that is after production time of 1000 days
- Scenario 5:- DPR treatment after water cut in the first layer reached 0.94 that is after production time of 1400 days

Following table gives the simulation results for each scenario.

		Scenario					
Polymer Volume Injected		scenario 1	scenario 2	scenario 3	scenario 4	scenario 5	Base scenario
Polymer volume injected during treatment (Sm^3)		300					-
Time of treatment after start of production (days)		740	760	840	1000	1400	-
Depth of invasion (m)	1st layer	11.65					-
	2nd layer	11.65					-
	3rd layer	6.87					-
	4th layer	4.08					-
Oil Recovery (%)		63.0039	63.01	63	63.04	63.19	64.38
Total water production (PV)		0.3211	0.321248	0.3211	0.361	0.473	1.377
Corresponding time of production (Days)		1792	1792	1802	1852	2032	3420

Table 7 Case 6 treatment design details and pilot performance comparison

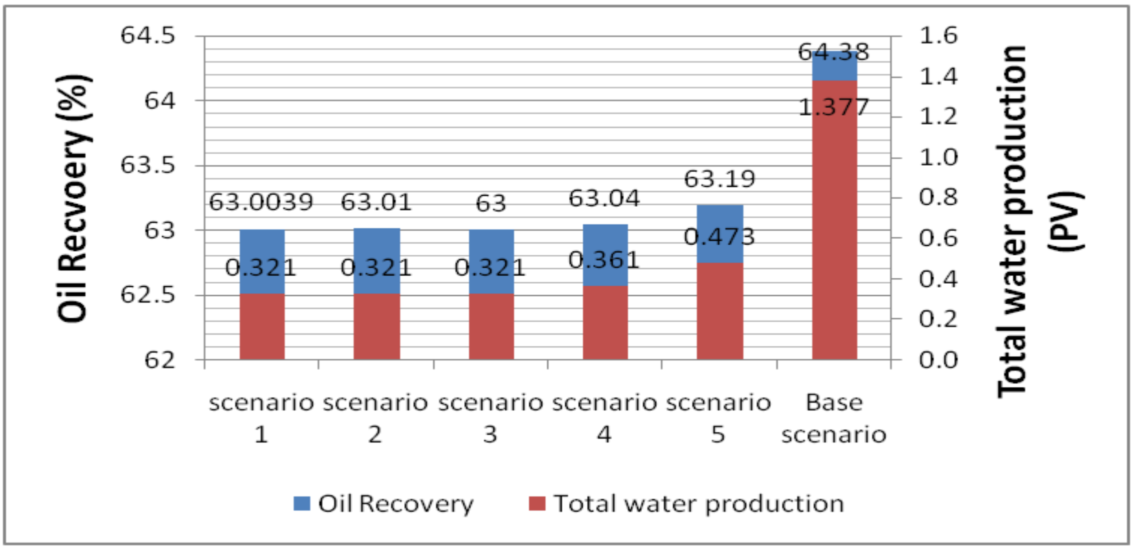

Figure 28 Case 5 Oil recovery and total water production

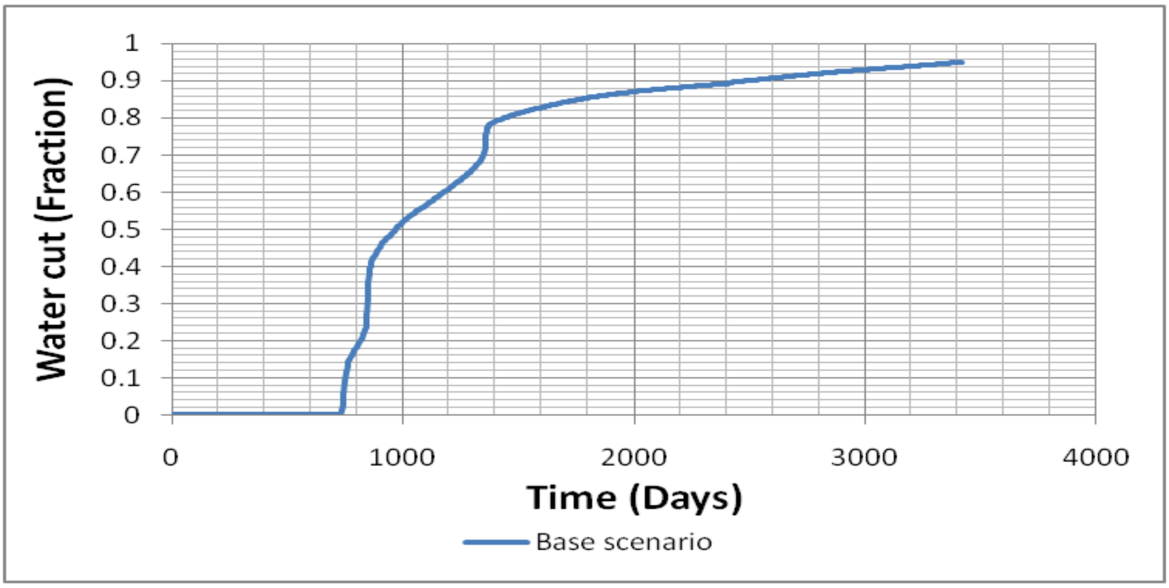

Figure 29 Case 5 Water cut versus Time (no DPR treatment)

Each jump in the water cut plot indicates time of water breakthrough from a layer if no DPR treatment is carried out. High permeability layers are first one to breakthrough. Therefore chronological order for water breakthrough in each layer is first sandstone layer, second sandstone layer, third sandstone layer and then forth sandstone layer. Comparison of this graph and time of treatment for each scenario shows that in scenario 1 and 2 the treatment was carried out before water breakthrough from 2nd layer. In scenario 3, gelant was injected at the time of water breakthrough from second layer. In scenario 4, the DPR treatment was carried out after first two layers experienced water breakthrough and in scenario 5 the DPR treatment was carried out after water broke through in three out four layers. From the simulation results we see that the pilot performance is insensitive to time of treatment for scenario 1, 2 and 3.While in scenario 4 and scenario 5, the operation time and total water production has considerably increased. So recommendation for this reservoir is that the DPR treatment should be carried out in between the 740 days to around 840 days of production period i.e. before water breakthrough from second layer. But we should note that the pilot performance is better in scenario 4 and 5 compared to base scenario that is when No DPR is carried out.

3.5.2.5 Case 6 – Effect of depth of invasion when skin effect is introduced

In the 1st case we concluded that the reservoir performance is not affected significantly by depth of gelant invasion. But we did not take into account the skin introduced due to gelant invasion in the reservoir. As we have seen in the case 3, the skin has very significant impact on pilot performance. Also if the gelant causes the damage in the invaded zone, then depth of treatment can be a determining parameter for extent of this damage.

In this subsection, the aim is to quantify the maximum effect that depth of invasion can have on the reservoir. In order to find out maximum effect of depth of invasion, scenario considered is with maximum RRF considered in case 3, i.e. RRF equal to 10. This will reduce the absolute permeability of invaded zone by factor of 10. Following tables shows the simulation results

		Scenario				
Gelant Volume Injected		Scenario 1	Scenario 2	Scenario 3	Scenario 4	Base scenario
Gelant volume injected during treatment (Sm^3)		50	300	500	900	-
Time of treatment after start of production (days)		740				-
Depth of invasion (m)	1st layer	4.05	11.65	15.18	19.77	-
	2nd layer	4.05	11.65	15.18	15.18	-
	3rd layer	2.39	6.87	6.87	11.65	-
	4th layer	1.41	4.08	5.27	5.27	-
Oil Recovery (%)		60.06	59.47	59.34	59.31	64.38
Total water production (PV)		0.1382	0.1233	0.1183	0.1126	1.3774
Corresponding time of production (Days)		1552	1532	1522	1512	3420

Table 8 Case 6 Treatment design details and pilot performance comparison

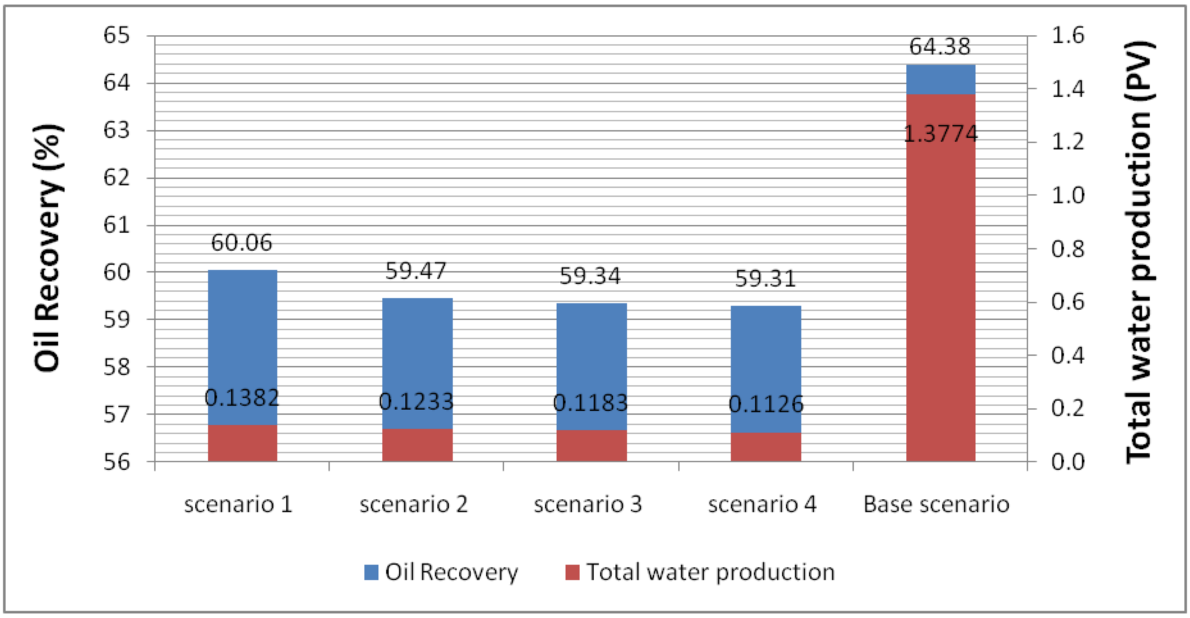

Figure 30 Case 6 Oil recovery and total water production

Greater effect of depth of invasion on reservoir performance was expected as the damage of invaded zone was taken into consideration. But as the tables and the bar chart above shows pilot performance is not very sensitive to depth of treatment under the conditions mentioned above.

3.5.2.6 Case 7 – Comparison of Bullheading and selective gelant injection:-

DPR treatment is used for water shutoff in high permeability layers so that the water production in these layers will not compete with hydrocarbon production from low permeability zones. During bullheading injection process, the gelant solution invades all the layers. But the for the gelant solution, the high permeability layers will have high injectivity as in turn higher depth of investigation for following reasons

1. High permeability: Naturally higher permeability of rocks eases the fluid flow and so the fluid entry
2. High water saturation: We tend to do DPR treatment after water has broken through high permeability layers and before low permeability layers experience water breakthrough. Therefore at the time of treatment higher permeability layers have higher water saturation and the DPR gelant are hydrophilic. Therefore they have higher injectivity for high permeability layers.

So when volume of gelant injected is not very large, the damage caused to low permeability layers is comparatively small and normally insignificant. But when high volume of gelant solution is injected the invasion in the low permeability zones can be considerably high and can damage low permeability layers in the reservoir permanently. If that is the scenario then selective injection should be preferred to bullheading.

This subsection investigates if the gelant injection when injected in large volume does damage the low permeability layers. For this reason we are using one bullheading scenario where the gelant invades as deep as 12 m in third layer and 5 m in 4^{th} layer. For the selective injection two scenarios are used one that injects gelant only in 1^{st} layer while 2^{nd} that injects gelant in first two layers. Gelant volume for the selective injection is selected in such a way that depth of invasion for high permeability layers is similar to bullheading scenario

We have considered the following scenarios:-

- Scenario 1: - Gelant was injected in the first layer.
- Scenario 2: - Gelant was injected in first two layers.
- Scenario 3: - Gelant was injected in all four layers.
- Base scenario: - No DPR treatment was carried out.

Volume of gelant injected is different in each scenario above as the number of pay zone treated is different in each scenario.

The aim is to find out if the damage done to lower permeability layers during bullheading gelant injection for the scenario 3 is significant and also as we are doing selective injection, we will find out which are the main layers that contribute to the water production problems

Following table gives the details and simulation results for each scenario.

		Scenarios			
		Scenario 1	Scenario 2	Scenario 3	Base scenario
Gelant volume injected during treatment (Sm^3)		350	650	900	-
Time of treatment after start of production (days)		740	740	740	-
Depth of invasion (m)	1st layer	19.77	19.77	19.77	-
	2nd layer	-	15.18	15.18	-
	3rd layer	-	-	11.65	-
	4th layer	-	-	5.27	-
Oil Recovery (%)		64.16	63.62	63.2	64.38
Total water production (PV)		0.6735	0.3727	0.3618	1.3774
Corresponding time of production (Days)		2342	1882	1852	3420

Table 9 Simulation results for case 7

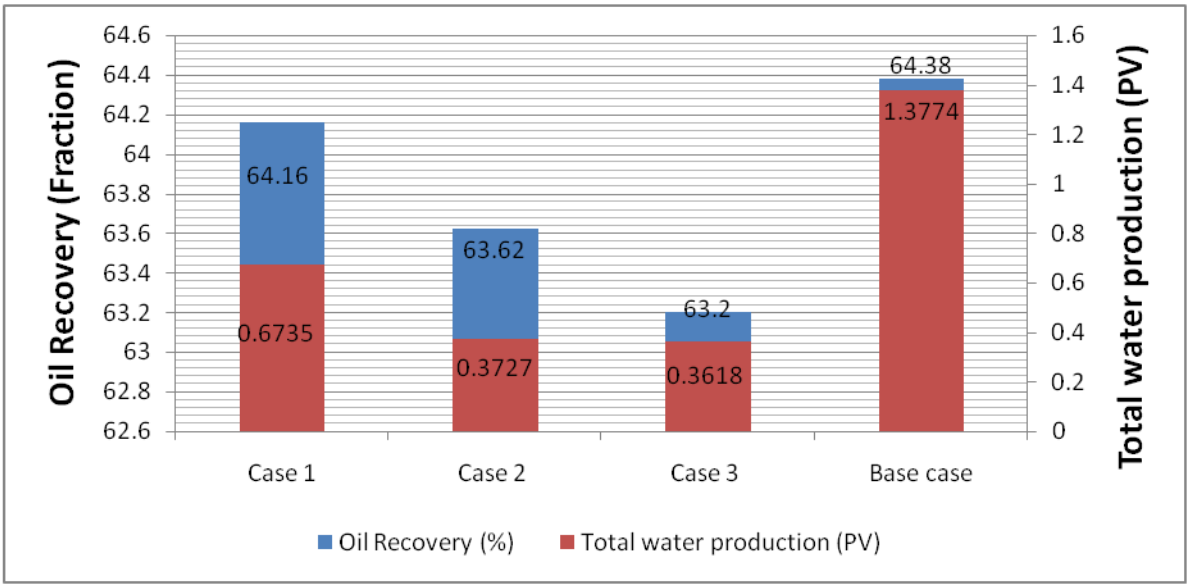

Figure 31 Case 7 Oil recovery and total water production

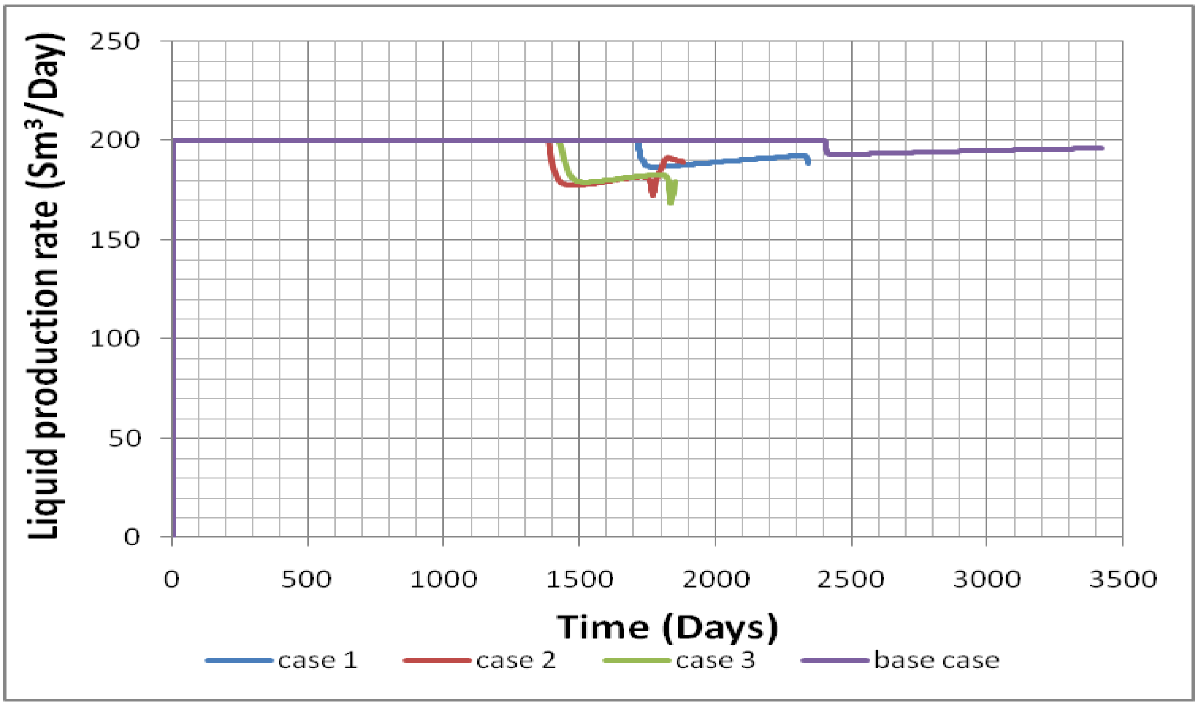

Figure 32 Case 7 Liquid production rate versus Time

For scenario 1 the production time is fairly longer than in scenario 3. But when first two layers are treated with gelant the liquid rate behaviour is quite similar to scenario 3.

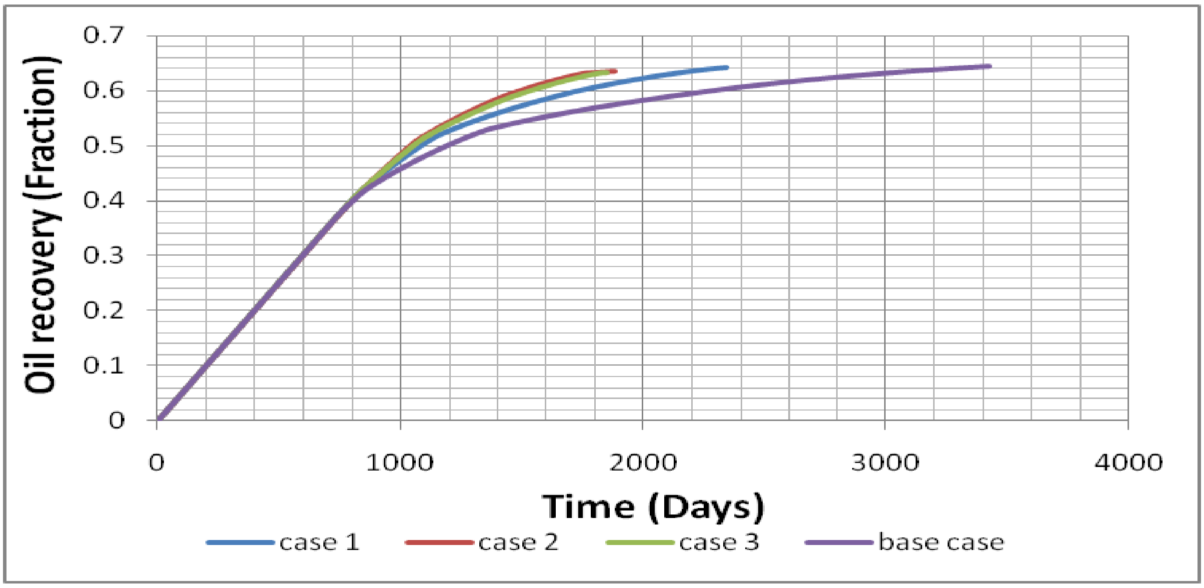

Figure 33 Case 7 Oil recovery versus Time

The oil recovery for scenario 1 and scenario 2 are slightly higher than oil recovery for scenario 3. This is because there is no damage to low permeability layers i.e. layer 3 and layer 4 in scenario 1 and scenario 2. But small difference shows that this damage is not significant.

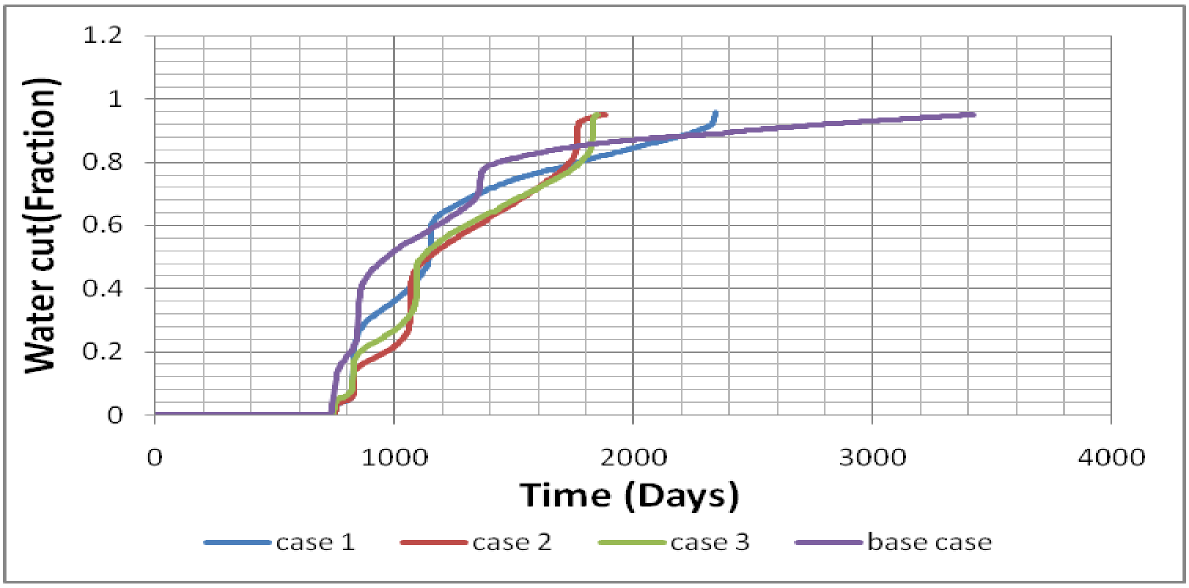

Figure 34 Case 7 Water cut Vs Time

This graph like previous graphs shows that the water cut behaviour is similar for scenario 2 and scenario 3. But for scenario 1, water cut behaviour is similar to scenario 2 and scenario 3 until the second layer experience water breakthrough which can be seen in the graph by a sudden increase in water cut at around 800 days after production started. After this, the water cut behaves quite differently in scenario 1. The reason behind this change is, in scenario 1 after water breaks through second layer, production from low permeability layers gets affected by of high water production from 2nd layer. While in scenario 2 and 3, the water production from layer 2 faces the resistance due to DPR treatment. Therefore, even after 2nd layer breakthrough sweep efficiency in scenario 2 and 3 is much better than scenario 1 causing earlier water breakthrough in layer 3 and 4. But in scenario 2, the behaviour is quite similar to scenario 3 even after 3rd layer breaks through. This shows that the water production problems in the reservoir are mainly caused by layer 1 and 2 while layer 3 and 4 which are low permeability layers do not cause much of the problem regarding water production.

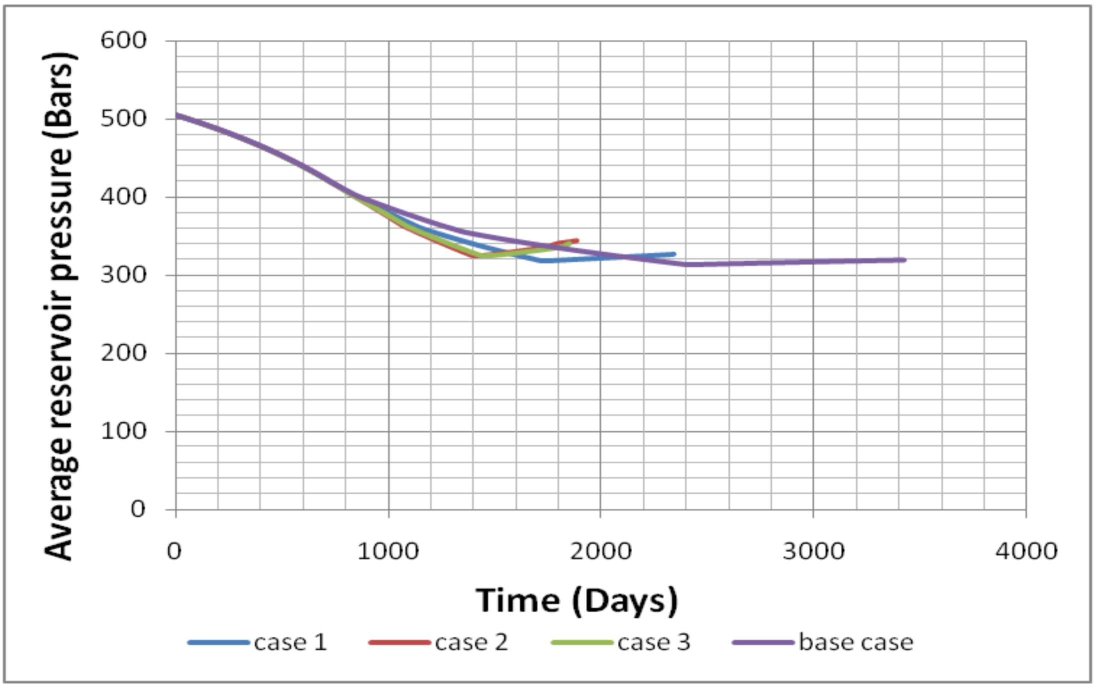

Figure 35 Case 7 Average reservoir pressure versus time

Pressure drops more drastically in scenario 2 and scenario 3 than in scenario 1. This is because the water cut in scenario 1 is higher due to water production from layer 2. If liquid produced contains more water, the pressure drop required to produce the liquid would be comparatively smaller.

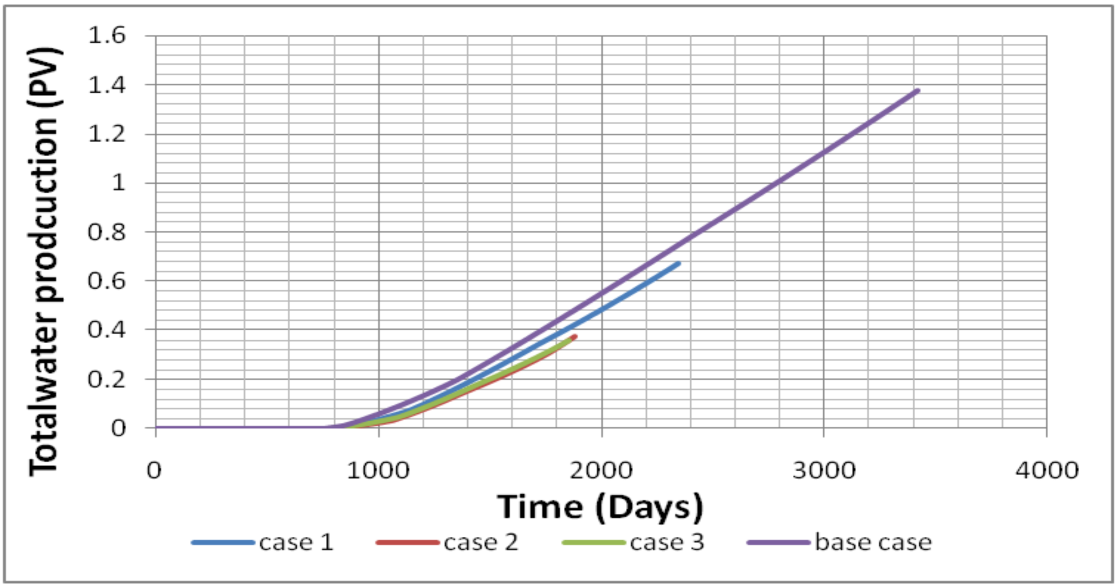

Figure 36 Case 7 Total water production vs Time

Naturally as the production time and water cut behaviour are similar for scenario 2 and scenario 3, the total water production for these layers is almost same. But for scenario 1, in which water production in layer 2 is not obstructed causing higher water cut and also longer production time, total water production is much higher compared to other two scenarios.

3.5.3 Section 3

3.5.3.1 Case 8 – Effect of depth of invasion (With vertical lift performance calculations)

This subsection considers the impact of depth of treatment on pilot performance when both reservoir flow calculation and vertical lift performance calculations are taken into account. Range of gelant volume for injection considered for case is from 50 Sm3 to 900 Sm3. The following table summarises the simulation results for this case.

<table>
<tr><th colspan="2"></th><th colspan="6">Scenarios</th></tr>
<tr><th colspan="2">Gelant Volume Injected</th><th>scenario1</th><th>scenario2</th><th>scenario3</th><th>scenario4</th><th>scenario5</th><th>No DPR</th></tr>
<tr><td colspan="2">Gelant volume injected during treatment (Sm3)</td><td>50</td><td>150</td><td>300</td><td>500</td><td>900</td><td>-</td></tr>
<tr><td colspan="2">Time of treatment after start of production (days)</td><td colspan="5">740</td><td>-a</td></tr>
<tr><td rowspan="4">Depth of invasion (m)</td><td>1st layer</td><td>4.05</td><td>8.95</td><td>11.65</td><td>15.18</td><td>19.77</td><td>-</td></tr>
<tr><td>2nd layer</td><td>4.05</td><td>6.87</td><td>11.65</td><td>15.18</td><td>15.18</td><td>-</td></tr>
<tr><td>3rd layer</td><td>2.39</td><td>5.27</td><td>6.87</td><td>6.87</td><td>11.65</td><td>-</td></tr>
<tr><td>4th layer</td><td>1.41</td><td>3.1075</td><td>4.08</td><td>5.27</td><td>5.27</td><td>-</td></tr>
<tr><td colspan="2">Oil Recovery (%)</td><td>62.69</td><td>62.49</td><td>62.71</td><td>62.36</td><td>62.25</td><td>61.02</td></tr>
<tr><td colspan="2">Total water production (PV)</td><td>0.3359</td><td>0.2995</td><td>0.3016</td><td>0.275</td><td>0.2635</td><td>0.8262</td></tr>
<tr><td colspan="2">Corresponding time of production (Days)</td><td>1772</td><td>1712</td><td>1712</td><td>1672</td><td>1642</td><td>2480</td></tr>
</table>

Table 10 case 7 Treatment design details and pilot performance comparison

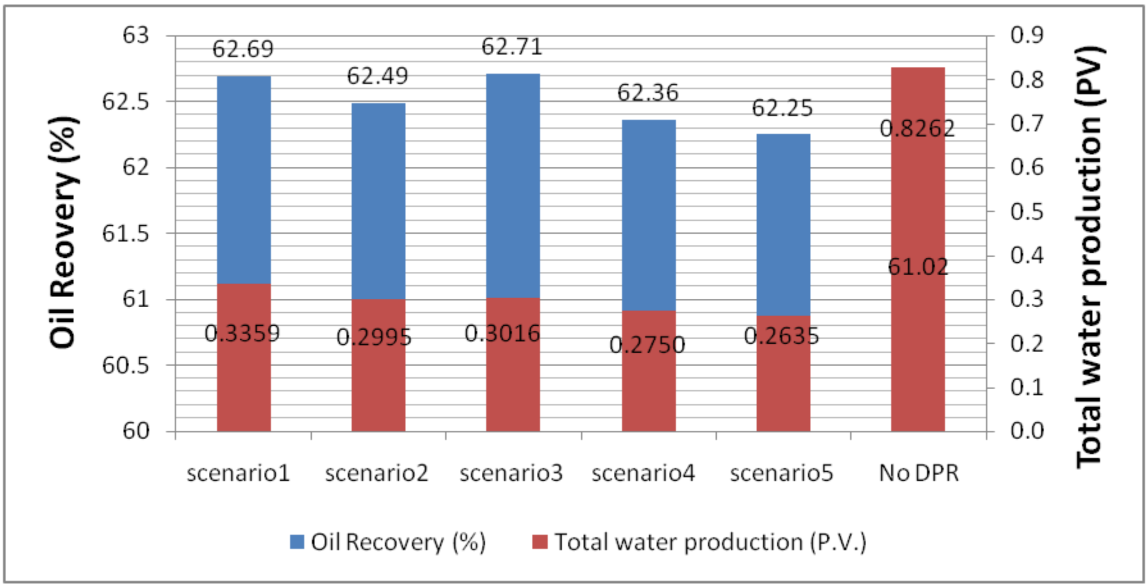

Figure 37 Case 8 Oil recovery and total water production

The table and bar chart in this case show, that the change in treatment volume which in turn changes the depth of invasion does not have a considerable impact. The oil recovery in all the scenarios for the DPR treatment is in the range of 62.25 % to 62.71 % while injection volume ranges from 50 Sm^3 to 900 Sm^3. This insensitivity of in the oil recovery and the fact that the oil recovery for scenarios 1 to scenario 5 is higher than base scenario, indicates for range of the injection volume mentioned low permeability layers have not been considerably damaged. Therefore the results of case 7 are consistent with the findings in case 2.

3.5.3.2 Case 9 - Water relative permeability reduction (including VLP calculations)

Previously in case 3, we found that the pilot performance is very sensitive to RRF_w values, especially the water cut and water production behaviour. The produced liquid dictates the pressure drop in tubing. Therefore it is very important to consider the vertical lift performance calculations in order to understand the overall effect of water relative permeability reduction on pilot performance after DPR treatment.

In this subsection, the aim is to find out what effect does the change in relative permeability have on pilot performance when fluid flow calculations in reservoir as well as tubing are taken in consideration. Also we will further compare these results with case 3 in order to find out how vertical lift performance responds to change in fluid flow performance in reservoir caused by change in relative permeability curves for reservoir fluid.

Following table gives the simulation results for this analysis

		Scenarios					
		scenario 1	scenario 2	scenario 3	scenario 4	scenario 5	Base scenario
Polymer volume injected during treatment (Sm^3)		300					-
Time of treatment after start of production (days)		740					-
Depth of invasion (m)	1st layer	11.65					-
	2nd layer	11.65					-
	3rd layer	6.87					-
	4th layer	4.084					-
Oil recovery (%)		62.01	62.71	62.93	62.51	61.76	61.02
Total water production (%)		0.1791	0.3015	0.4638	0.6709	0.6937	0.8262
Corresponding time of production (Days)		1522	1712	1972	2282	2302	2480

Table 11 case 8 Treatment design details and pilot performance comparison

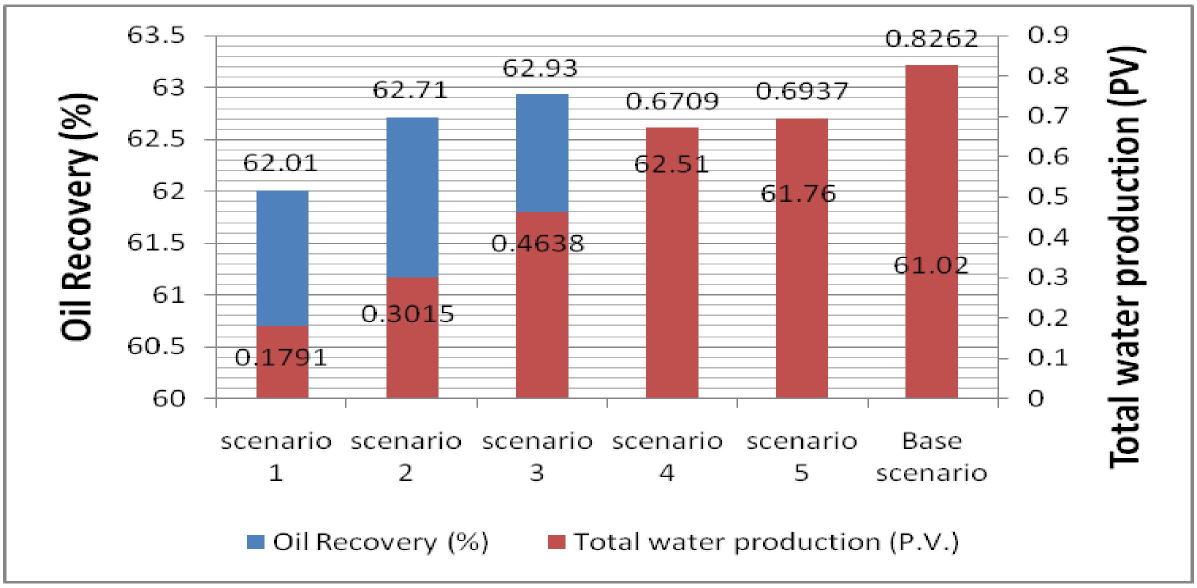

Figure 38 Case 9 Oil recovery and total water prodcution

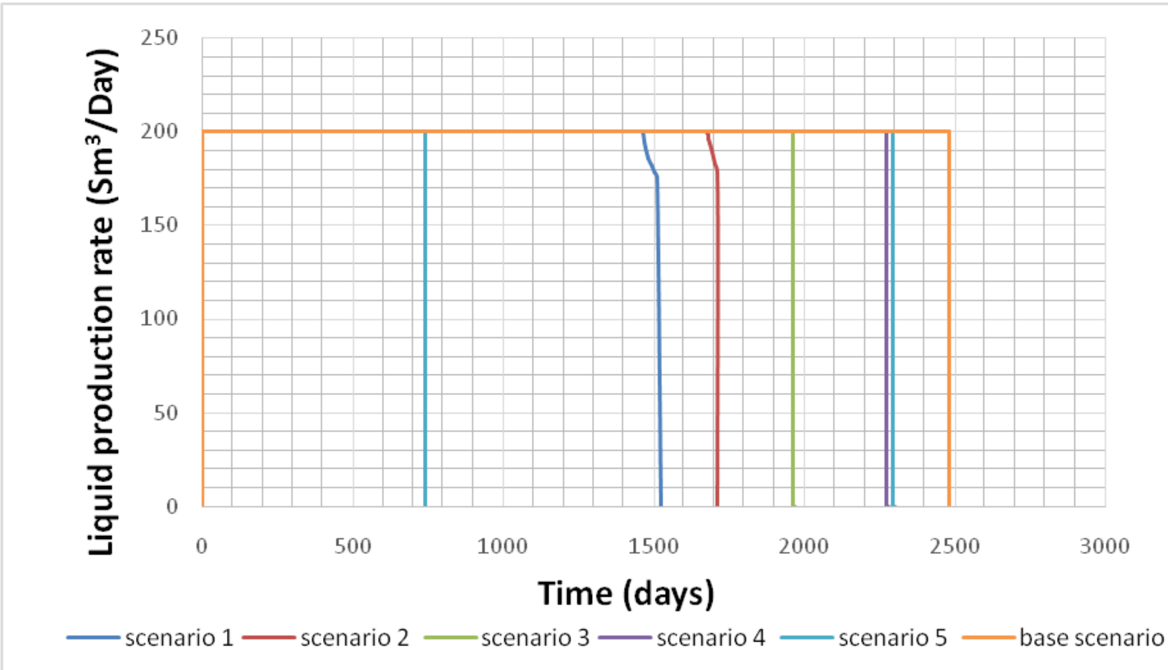

Figure 39 case 9 Liquid production rate versus Time

Liquid production rate is sustained for shorter period of time for higher RRF_w values. As a result, production time decreases as RRF_w value increases.

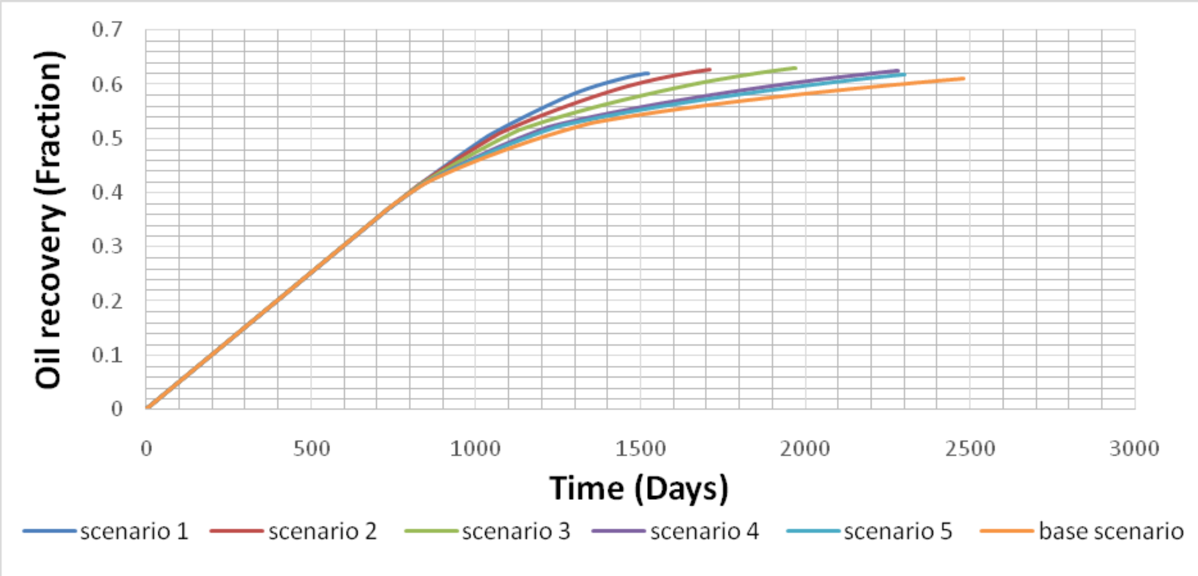

Figure 40 Case 9, Oil recovery versus time

RRF_w value does impact the oil recovery slightly. The oil recovery goes on increasing slightly with RRF_w value until RRF_w value equals 2.5. Further increase in RRF_w value decreases the oil recovery.

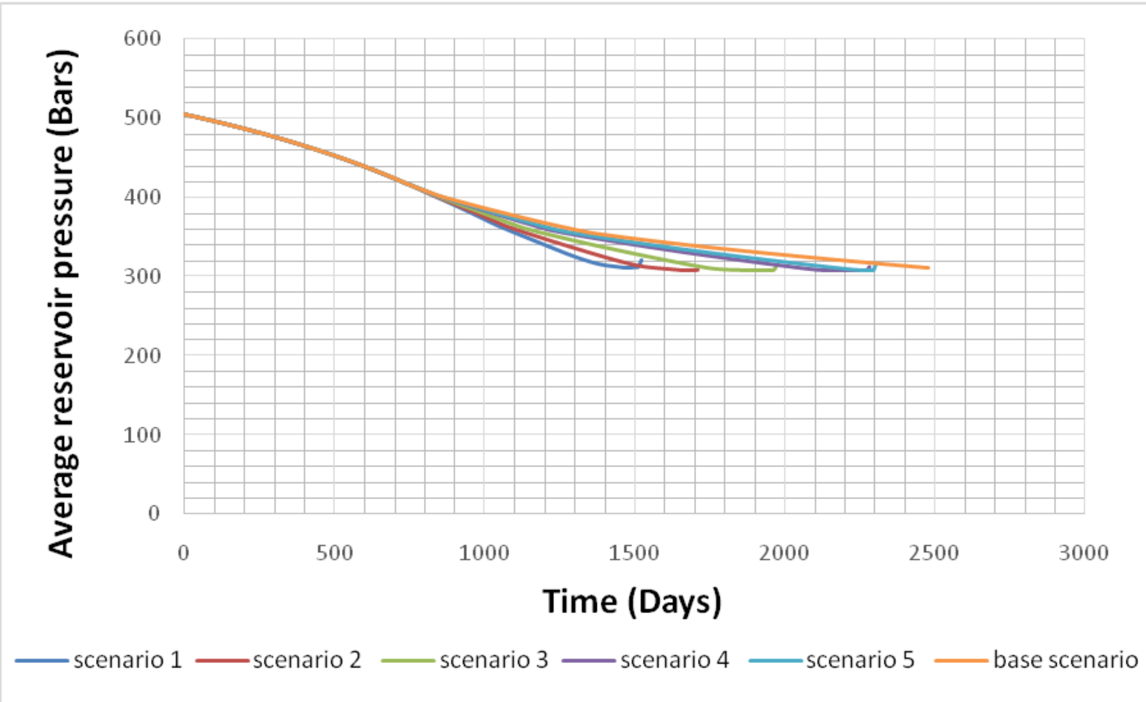

Figure 41 Case 9 Average reservoir pressure versus time

The reservoir pressure drops more drastically for higher RRF_w values which means that the pressure required to produce same amount of liquid causes high pressure drop if RRF_w values are higher for DPR treatment. Also the pressure at which the production with maximum liquid rate becomes unsustainable is higher for high RRF_w.

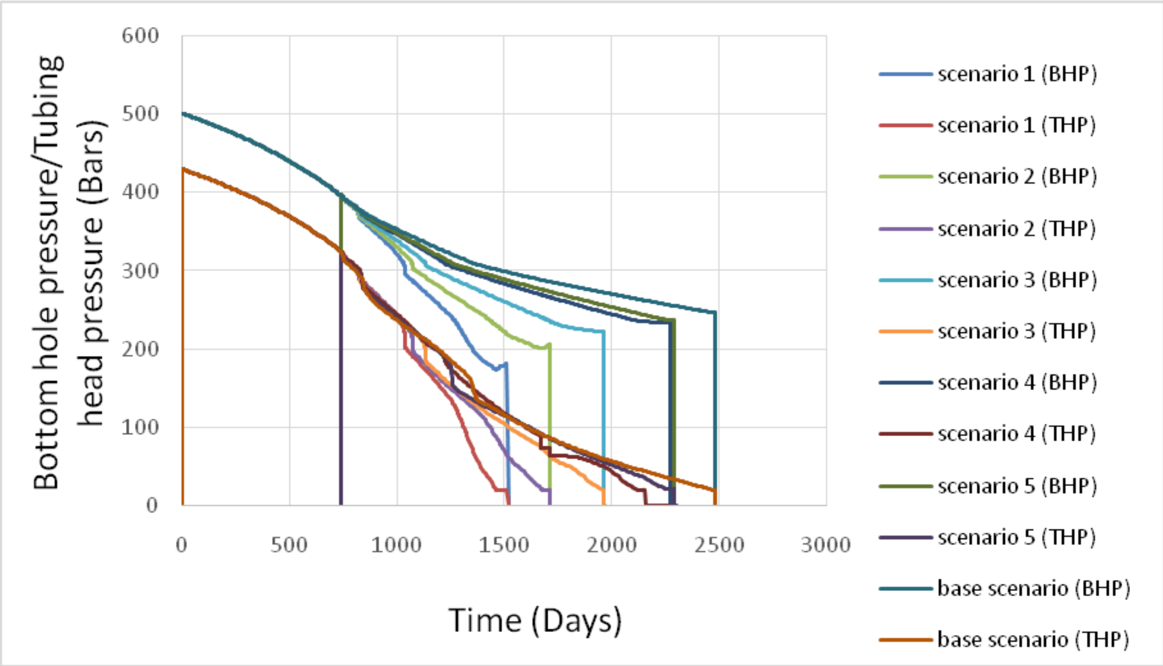

Figure 42 Case 9 Bottom hole pressure/ Tubing head pressure versus time

The difference between the bottom hole pressure and tubing head pressure is the pressure drop required for lifting the fluid in the tubing. This pressure drops increases with time in each scenario. But this difference is smaller for higher RRF_w values. Also we have seen that the average reservoir pressure is slightly higher at the time it becomes unsustainable to produce with maximum liquid rate for higher RRF_w values. But at the same time bottom hole pressure for those scenarios is lower. This indicates that for scenarios for higher RRF_w values, the pressure drop in reservoir increases to produce same amount of liquid while the pressure drop required to lift that same amount of fluid decreases.

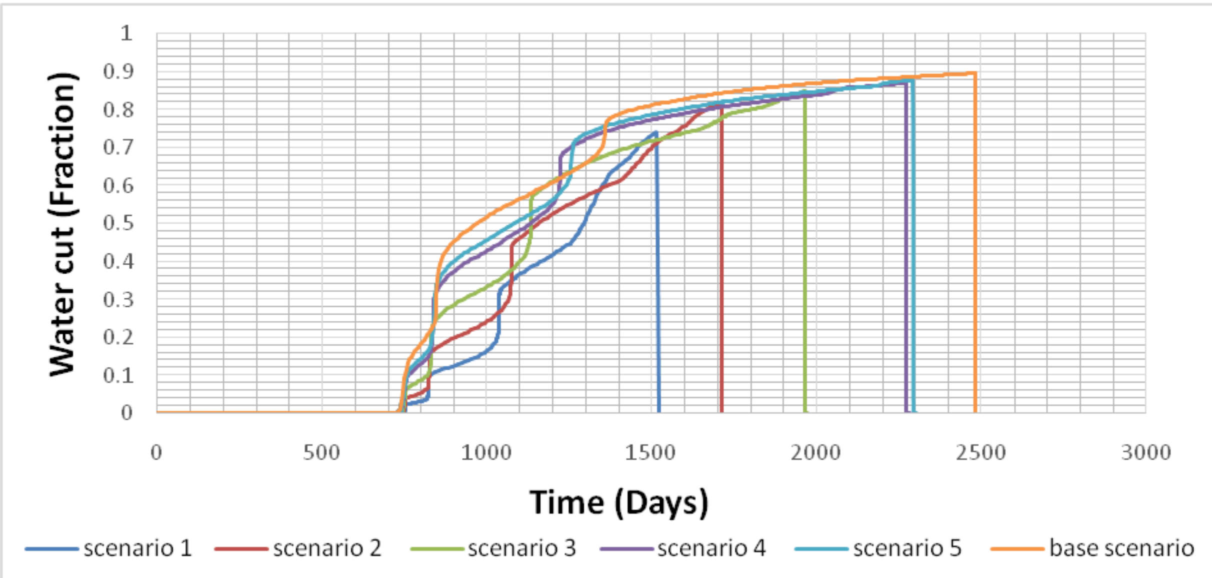

Figure 43 Case 9 water cut versus time

The water cut behaviour for this case is similar to the case 2. But the time when any further production becomes unsustainable, the water cut for higher RRF_w values is lower than that for lower RRF_w values. The water being denser but less viscous fluid than oil requires low pressure drop in flow through reservoir and high pressure drop to be lifted. This explains why the pressure drop in the tubing is lower but reservoir pressure drops more drastically while producing at same liquid rate for higher RRF_w values.

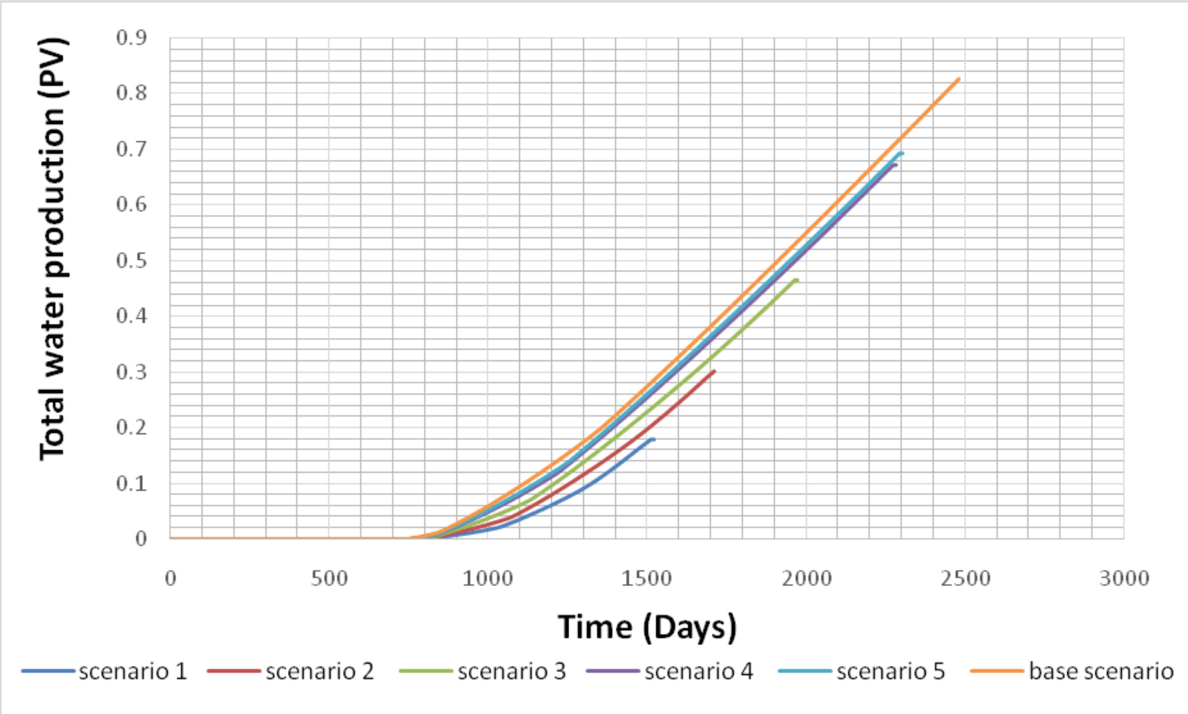

Figure 44 Case 9 Total water production versus time

Naturally as the production time is shorter and water cut is lower for most of the production life for higher RRF_w values, the total water production is also smaller.

3.5.3.3 Case 10: Impact of absolute permeability reduction (Including VLP calculations)

This subsection studies the impact of absolute permeability reduction in reservoir caused due to DPR treatment. Four scenarios with DPR treatment are considered. In the first scenario RRF value is 5, in 2nd scenario RRF value is 3.33, in the third scenario RRF value is 2, and the forth scenario is when RRF value is 1 i.e. no damage done to reservoir in terms of absolute permeability.

The aim of this subsection is to understand the response to the fluid flow in the reservoir as well as tubing and in turn pilot performance to the absolute permeability reduction.

		Cases				
		scenario1	scenario2	scenario3	scenario4	Base scenario
Polymer volume injected during treatment (Sm3)		300				-
Time of treatment after start of production (days)		740				-
Depth of invasion (m)	1st layer	11.65				-
	2nd layer	11.65				-
	3rd layer	6.87				-
	4th layer	4.084				-
Oil Recovery (%)		62.16	62.67	62.98	62.71	61.02
Total water Production (PV)		0.2175	0.2401	0.2761	0.3016	0.8262
Corresponding time of production (Days)		1630	1660	1710	1712	2480

Table 12 Treatment design details and pilot performance comparison

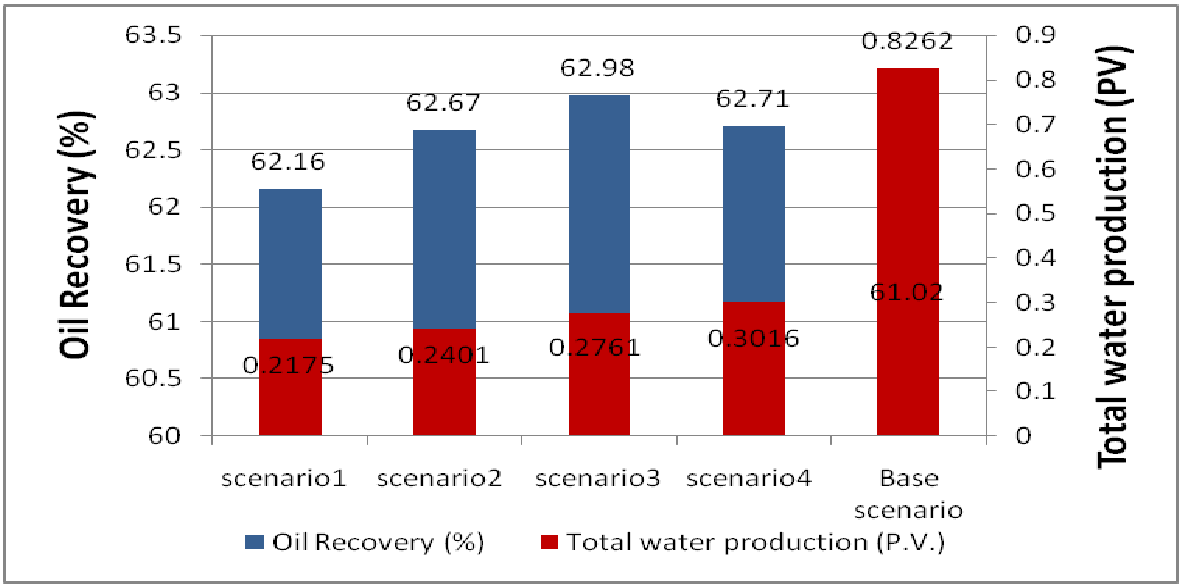

Figure 45 Case 10 Oil recovery and total water production

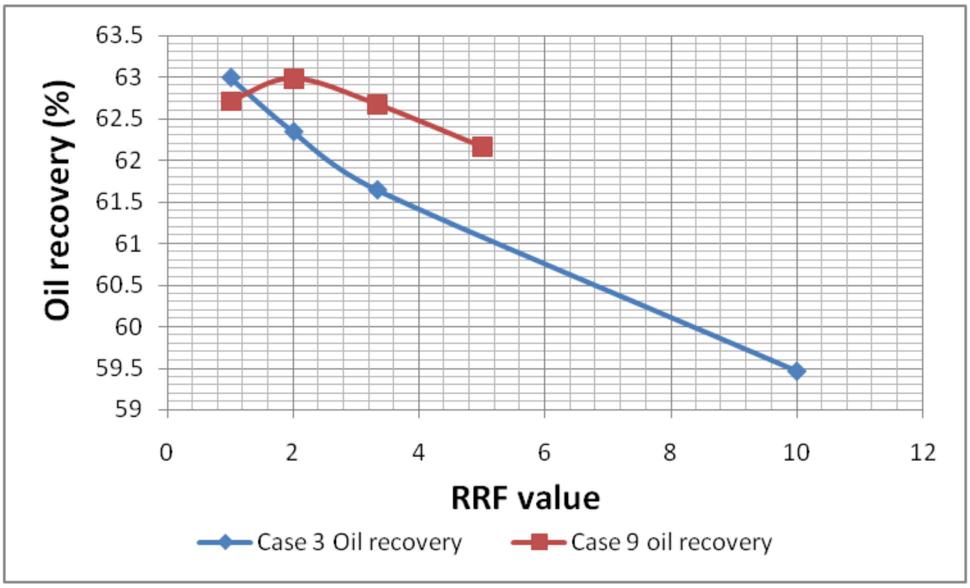

Figure 46 Case 4 and case 10 oil recovery comparison

Graph above shows the behaviour of the oil recovery with RRF value, i.e. damage done to reservoir. The difference between case 4 and case 10 is that in case 10 the vertical lift performance calculations were taken into account. The DPR treatment design and time of treatment are same in both of the cases. Due to numerical problems faced in case 9, we could not simulate scenario with RRF value equal to 10. Therefore instead the scenario with RRF value equal to 5 was used. The graph shows that for case 4 the achievable oil recovery decreases as the RRF value increases. On the other hand the optimum scenario in case 9 in terms of achievable oil recovery is when RRF value is equal to two and not when least damage was done to reservoir i.e. when RRF value was equal to one.

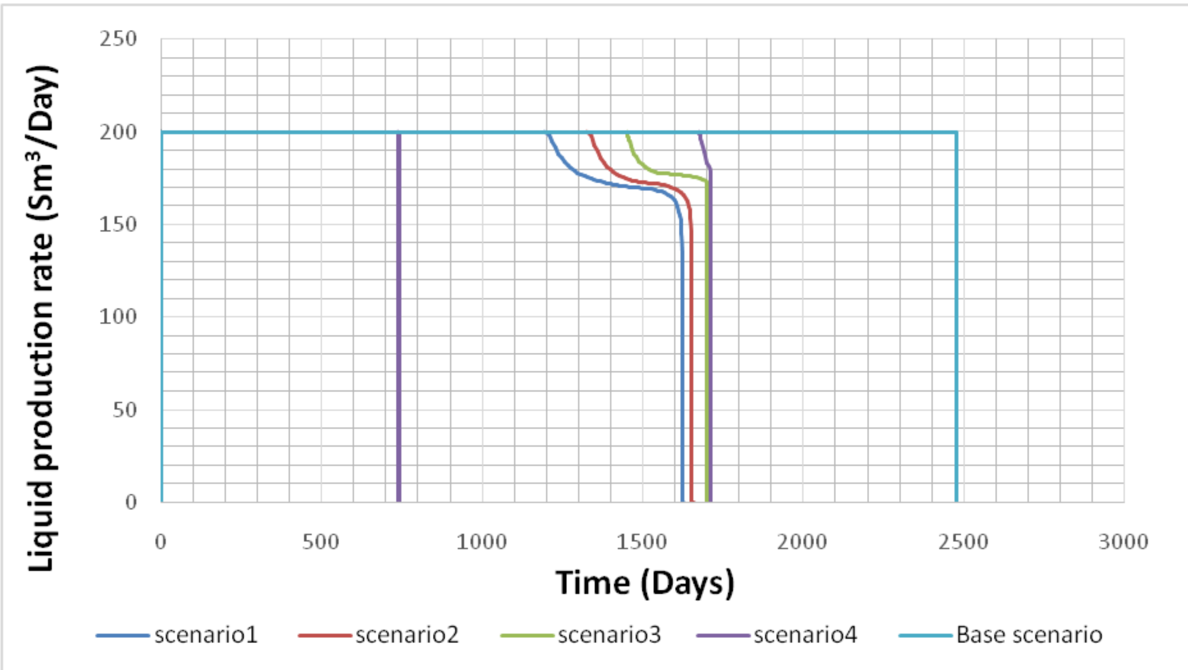

Figure 47 Case 10, Liquid production rate versus time

Maximum liquid rate can be sustained for shorter period of time for when RRF values are high.

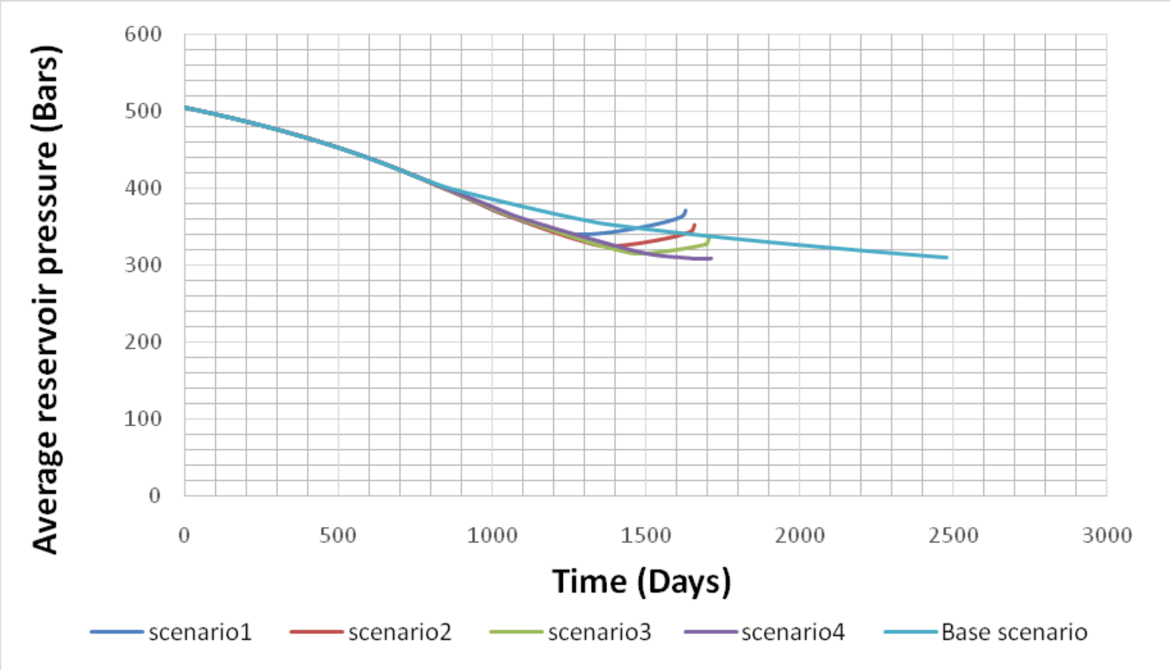

Figure 48 Case 10, Average reservoir pressure versus time

After the treatment, initially the reservoir pressure drop is similar for all the scenarios. But as we have seen for high RRF values the liquid rate drops earlier for the maximum liquid rate permitted, it creates an imbalance between the liquid produced and water injected causing reservoir pressure to rise.

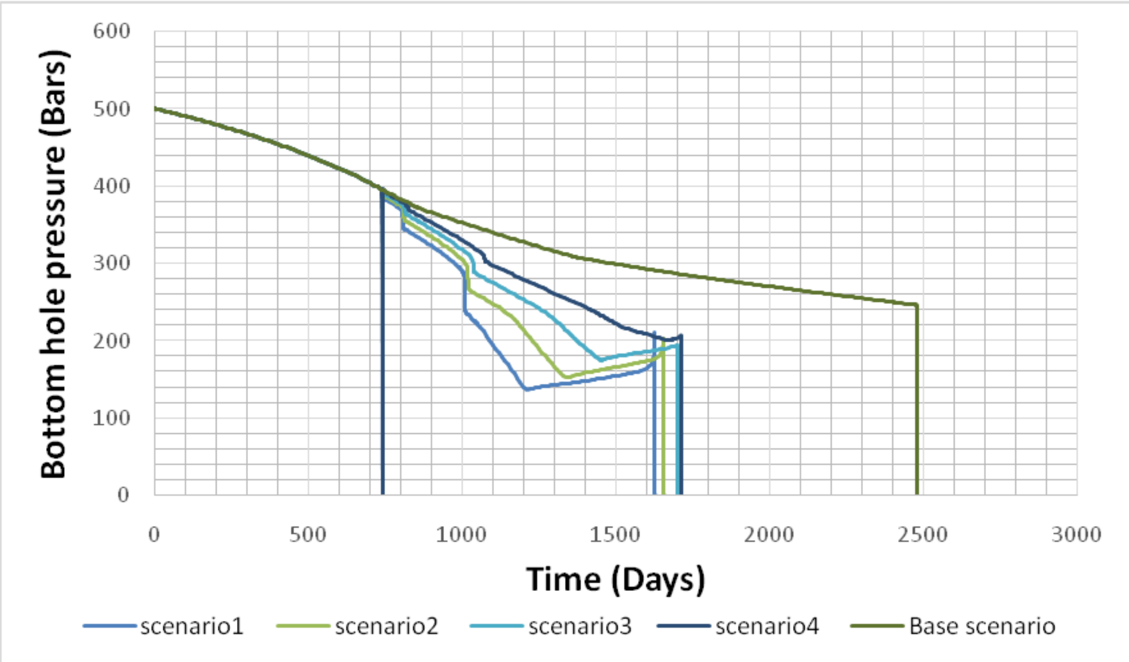

Figure 49 Case 10 Bottom hole pressure versus time

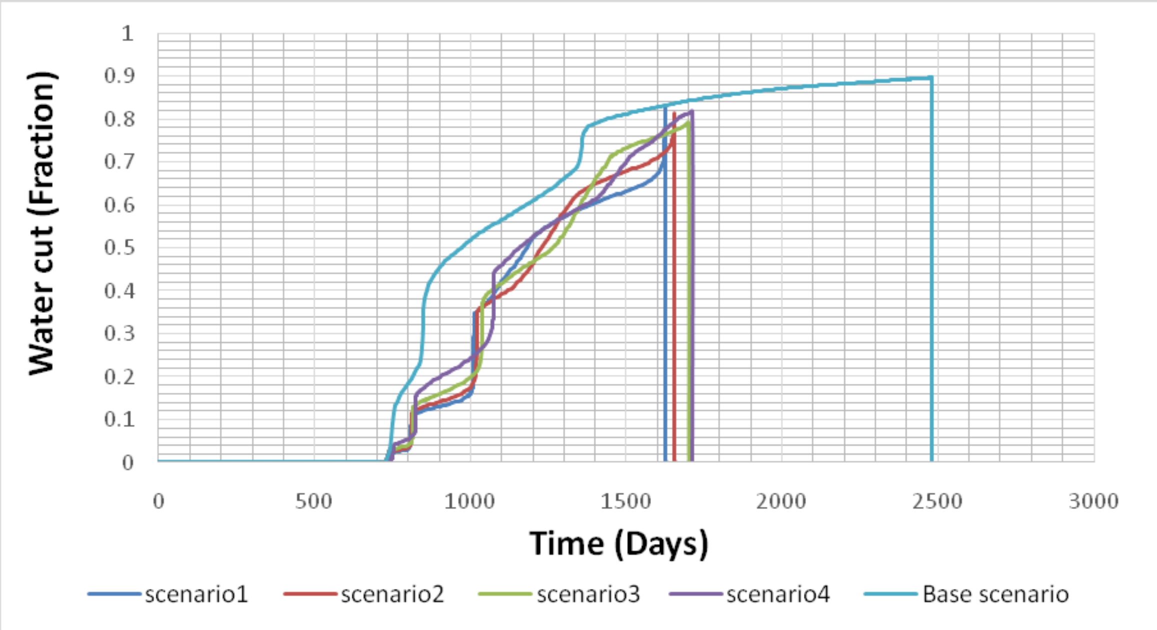

Figure 50 Case 10 water cut versus time

In the case 4, observation showed that the water cut increase at the time of 3rd and 4th layer breakthrough were very sharp for scenarios with low RRF value while in this case corresponding increase in water cut is very gradual. This can be explained by the difference in reservoir conditions in both cases at the time of water breakthrough. In case 4 one of the pressure constraint for the producer was 250 bars of minimum bottom hole pressure while in this case there is no constraint based on bottom hole pressure. It is replaced by minimum tubing head pressure of 20 bars. Now the bubble point pressure for the black oil used in the model is 250 bars. Therefore, in case 4 no gas was formed in the reservoir. But in this case at the time of water breakthrough i.e. after around 1000 thousand days of production, the bottom hole pressure was well below the 250 bars, i.e. well below the bubble point pressure of oil, in all four scenarios. Therefore the gas was present in the reservoir at the time of breakthrough. This can be the reason why water cut increments and in turn the water front of the water flood appears to be smoother at the time of breakthrough in this case. And this presence of gas might have caused the flow conditions that optimised the oil recovery for the scenario when RRF value was 2.

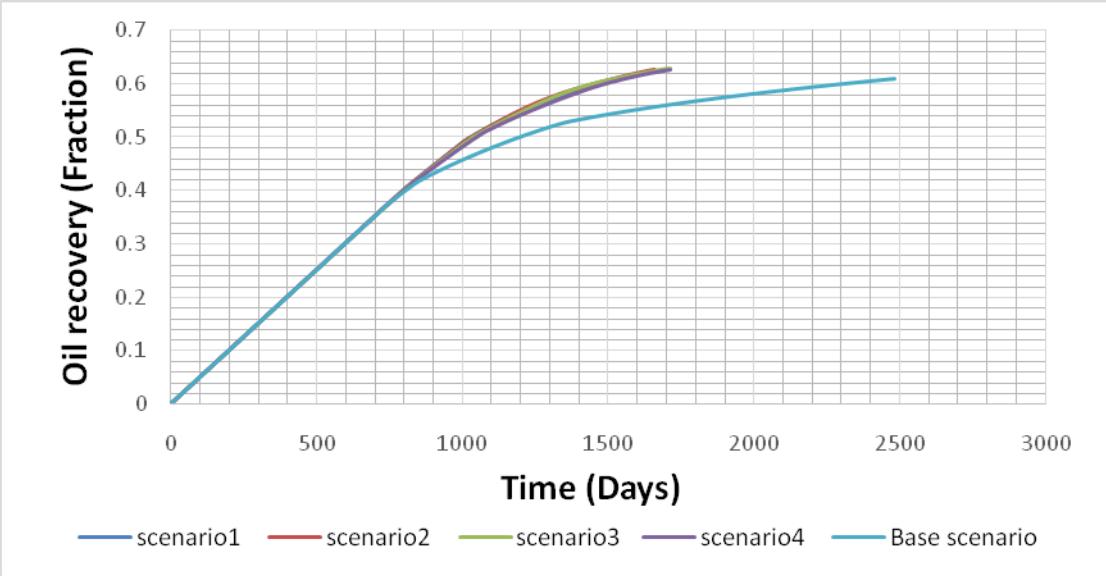

Figure 51 Case 10 Oil recovery versus time

Oil recovery behaviour is almost similar in all the scenarios. But in scenario 3, the oil recovery is slightly better than rest of the scenarios. One explanation can be that slight reduction in absolute permeability helps improving the sweep efficiency of water flooding. We know that as the depth of invasion is higher for the high permeability layers. Therefore when RRF value is 2, the first two layers bears the mark of the damage while for layer 3 and 4, this damage is not significant, causing a better sweep efficiency and resulting in best outcome in terms of oil recovery. But further increase in RRF values cause damage in all the layers causing a reduction in oil recovery in scenario 1 and scenario 2.

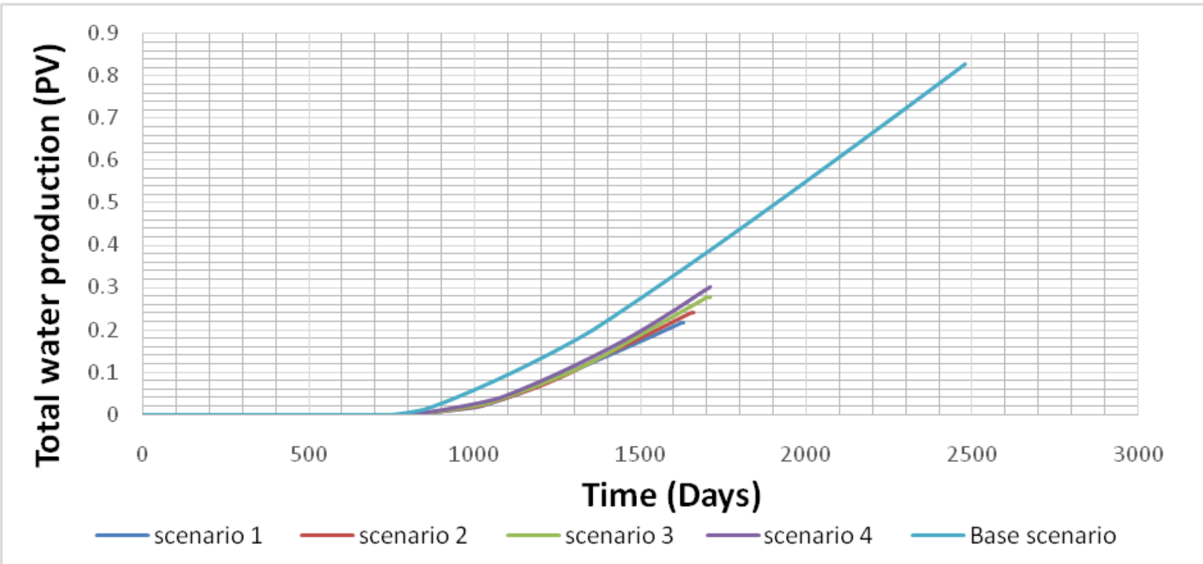

Figure 52 Case 10 Total water production versus time

The water cut behaviour was found to be very similar in all the scenarios. But the liquid rate dropped earlier and production period was shorter for higher RRF values. Therefore total water production value decreases as the RRF value increases.

Observation:

- Reservoir performance is better for scenarios with slight damage to reservoir permeability than for scenarios with no damage to reservoir permeability

3.5.3.4 Case 11 – Effect of time of treatment (With VLP calculations)

This subsection is concerned with the effect of time of treatment on the pilot performance when the calculations of fluid flow in reservoir and tubing are considered.

In this analysis, we will investigate a potential time range during which DPR treatment should be carried out.

Following table gives the simulation results for case 11.

		scenario					
Polymer Volume Injected		scenario 1	scenario 2	scenario 3	scenario 4	scenario 5	Base scenario
Polymer volume injected during treatment (Sm3)		300					-
Time of treatment after start of production (days)		740	760	840	1000	1400	-
Depth of invasion (m)	1st layer	11.65					-
	2nd layer	11.65					-
	3rd layer	6.87					-
	4th layer	4.08					-
Oil recovery (%)		62.71	62.43	62.39	62.44	62.35	61.01
Total water production (PV)		0.3016	0.2871	0.2925	0.3325	0.4517	0.8262
Corresponding time of production (Days)		1712	1680	1687	1760	1932	2480

Table 13 Case 11 treatment design details and pilot performance comparison

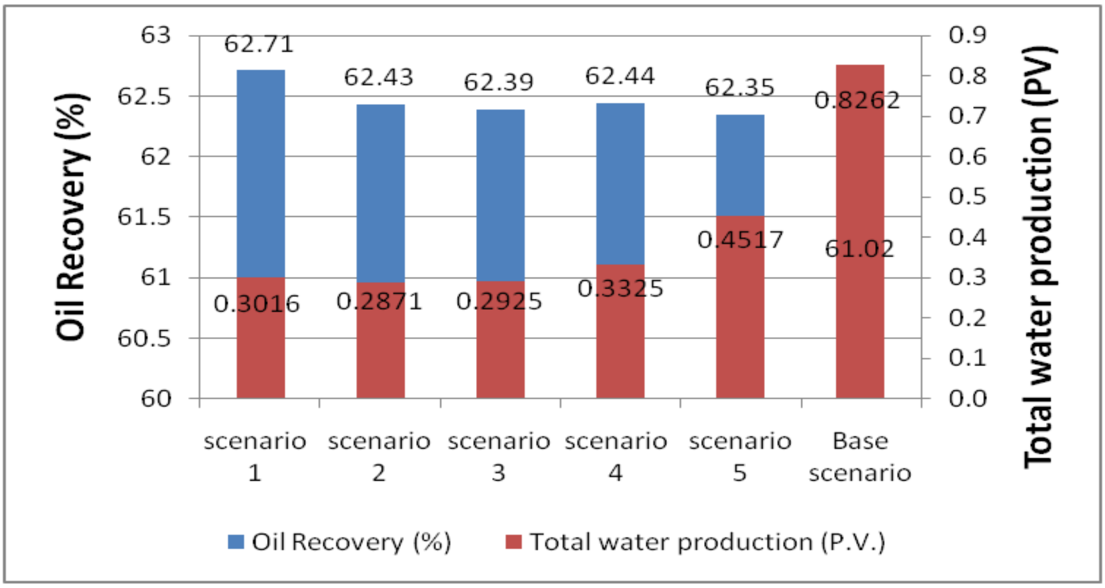

Figure 53 Case 11 Oil recovery and total water production

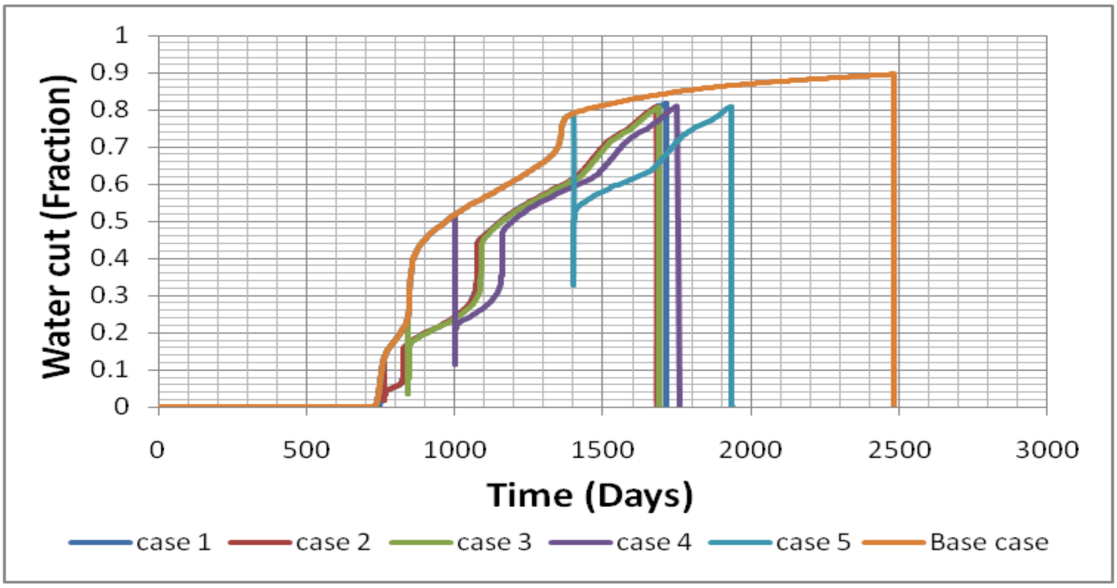

Figure 54 Case 11 Water cut versus time

From the tables we see that the reservoir performance is quite similar for scenario1, 2 and 3. But the effect of delay in the treatment can be seen from scenario 4. In scenario 4, the operation time is longer and the water production has also increased by small percentage. But for scenario 5 this difference is considerable higher. The reason behind this behaviour is as we have seen in case 7, mainly layer 1 and layer 2 contribute in excessive water production problem. In scenario 4 we wait until water breaks through the second layer and produce water for a period of time and then carry out DPR treatment. During that time layer 1 is also producing water without any resistance. This causes an irreparable damage to the reservoir performance in terms of inflow performance and outflow performance index. In scenario 5 we still wait until water breaks through 3^{rd} layer and then carry out DPR treatment. We can see from the results that this delay cause even more damage in terms of operation time and total water production. If we compare the increase in the water production due to delay, the water production has increased by approximately 13.5 % in scenario 4 compared to scenario 3. While in scenario 5 it has increased by approximately 36% compared to scenario 4. There is time difference of 160 days between time of treatment in scenario 3 and scenario 4 while in between scenario 4 and scenario 5 this time difference is 400 days. Therefore in both scenarios, scenario 4 and scenario 5 total water production at the end of production time increases by approximately 0.085% for every one day delay in DPR treatment. But for the cases carried out before water breakthrough in second layer, the impact on the water production is not significant. This means that reservoir performance is not very sensitive to time of treatment as long as DPR treatment is done before 2^{nd} layer experience water breakthrough. And therefore it is recommended that the DPR treatment should be carried out before second layer breakthrough. But at the same time we should note that the pilot performance, even in the worst scenario, i.e. when DPR treatment was carried out after 1400 days of production period, is better than that of in base case.

3.5.3.5 Case 12: Impact of treatment volume/depth after absolute permeability reduction (Including vertical lift performance calculation)

Previously in case 8 we saw that the change in depth of invasion showed a greater impact on the pilot performance, when vertical lift performance calculations were taken in to consideration. In this subsection, we are going a step further by including the damage done to the invaded volume of reservoir due to gelant injection during DPR treatment. This damage of reservoir manifests itself by absolute permeability reduction of invaded volume of reservoir.

This case study is aimed at finding the optimum depth of investigation after maximising negative impact of DPR treatment and to compute if there are any scenarios in which negative impact of DPR treatment outdo the benefits of the DPR treatment.

In this subsection three scenarios are considered each with different treatment volume. To account for absolute permeability reduction, the RRF value used in each scenario is equal to 5.

		Scenario			
Gelant Volume Injected		scenario1	Scenario2	scenario 3	Base scenario
Gelant volume injected during treatment (Sm^3)		50	300	500	-
Time of treatment after start of production (days)		740			-
Depth of invasion (m)	1st layer	4.05	11.65	15.18	-
	2nd layer	4.05	11.65	15.18	-
	3rd layer	2.39	6.87	6.87	-
	4th layer	1.41	4.08	5.27	-
Oil Recovery (%)		62.53	62.16	62.07	61.02
Total water production (PV)		0.2309	0.2175	0.2146	0.8262
Corresponding time of production (Days)		1652	1630	1630	2480

Table 14 Case 12 treatment design details and pilot performance comparison

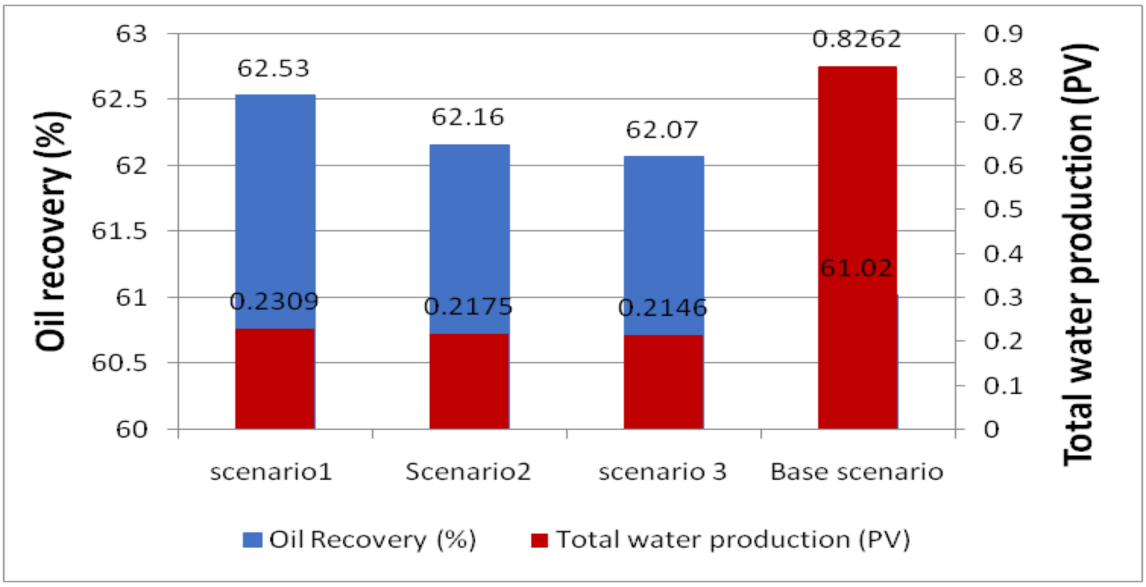

Figure 55 Case 12 Oil recovery and total water production

Data above shows that in this case pilot performance is not much affected by the depth of invasion. Therefore these results corroborates the conclusion of case 2, case 6 and case 8, i.e. impact of depth invasion in DPR treatment is very small on the reservoir performance.

3.5.3.6 Case 13 Comparison of Bullheading injection and selective injection (including vertical lift performance):

This subsection aims at quantifying if there is any significant damage caused by bullheading injection of gelant as a part of the DPR treatment to the low permeability layers. And if it is then is the selective injection better choice and which layers should be treated during the selective injection.

Similar analysis was done in case 7. But in case 7, vertical lift performance calculations were not included. In case 7 we found that pilot performance was quite similar for gelant injection with bullheading technique and for selective injection for first two layers. But we have seen before that pilot performance and its responses to change in conditions were different when vertical lift performance calculations were included. In this case, we will see if such changes and in turn magnification of effect on the reservoir performance due to depth of invasion takes place.

Here we considered three scenarios. In first two scenarios DPR treatment was carried out using the selective injection, while in 3rd scenario the bullheading was used to inject the gelant.

We have considered the following scenarios:-

- Scenario 1: - Gelant was injected in the first layer.
- Scenario 2: - Gelant was injected in first two layers.
- Scenario 3: - Gelant was injected in all four layers.

➢ Base scenario: - No DPR treatment was carried out.

		Cases			
		scenario 1	scenario 2	scenario 3	Base scenario
Polymer volume injected during treatment (Sm^3)		350	650	900	-
Time of treatment after start of production (days)		740	740	740	-
Depth of invasion (m)	1st layer	19.77	19.77	19.77	-
	2nd layer	-	15.18	15.18	-
	3rd layer	-	-	11.65	-
	4th layer	-	-	5.27	-
Oil Recovery (%)		63.09	63.04	62.25	61.02
Total water production (P.V.)		0.5463	0.2995	0.2635	0.8262
Corresponding time of production (Days)		2102	1722	1742	2479

Table 15 Case 13 Treatment design details and pilot performance comparison

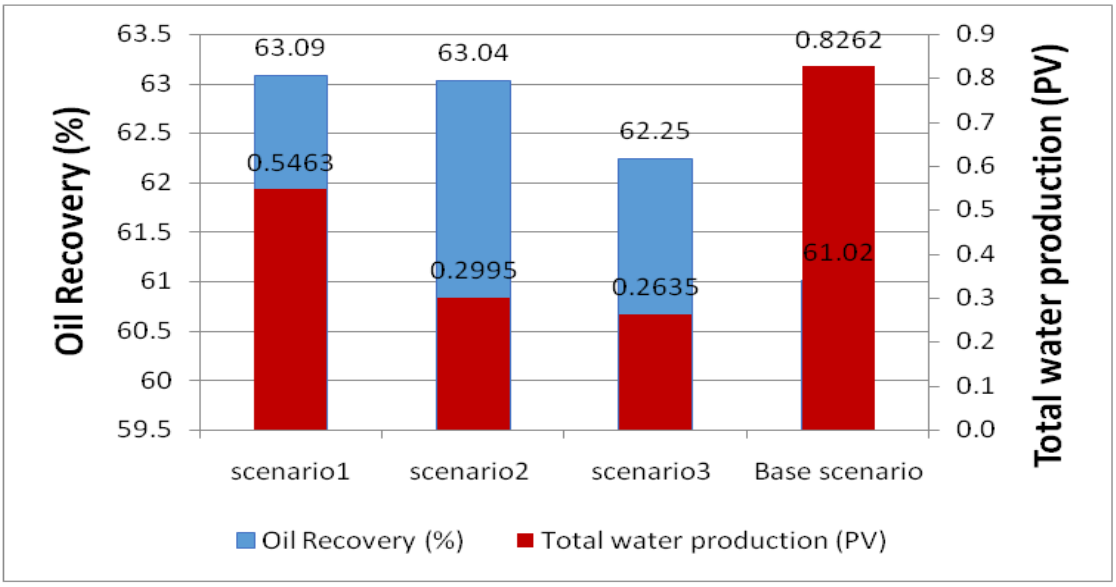

Figure 56 Case 13 Oil recovery and total water production

Results above show that the oil recovery is significantly higher for scenario 1 and 2 than in scenario 3.

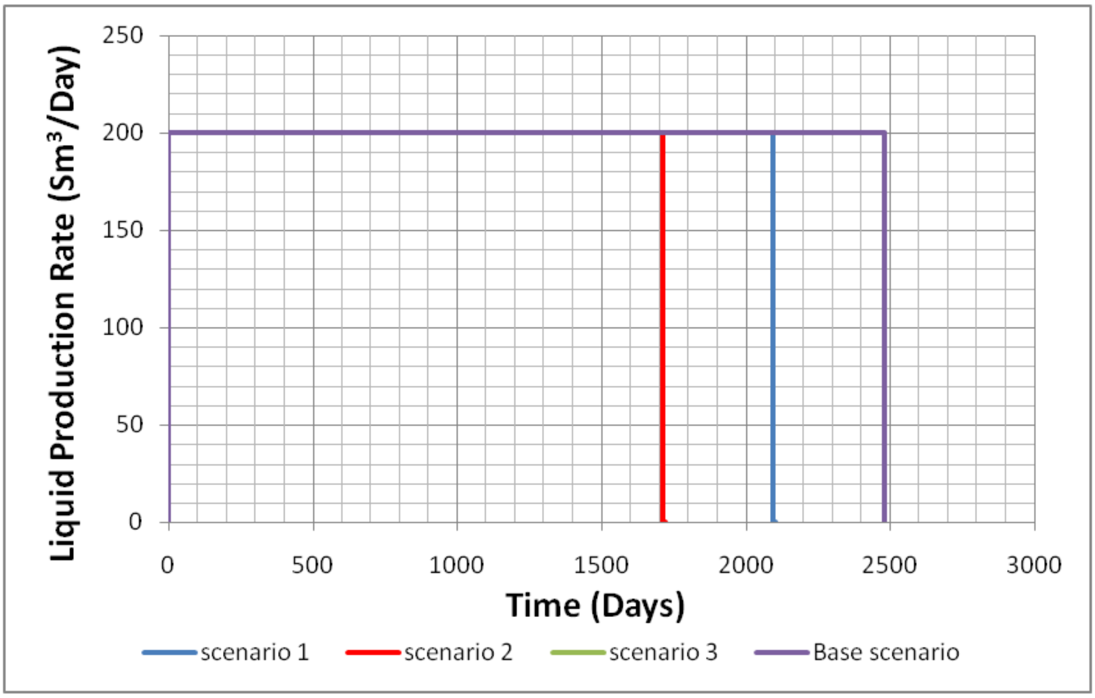

Figure 57 Case 13, Liquid production rate versus time

The liquid production graph shows that the maximum liquid production is sustained for longer time in scenario 1 than in scenario 2 and 3. But the increment in oil recovery in scenario 1, as we have seen before, is very small compared to scenario 2.

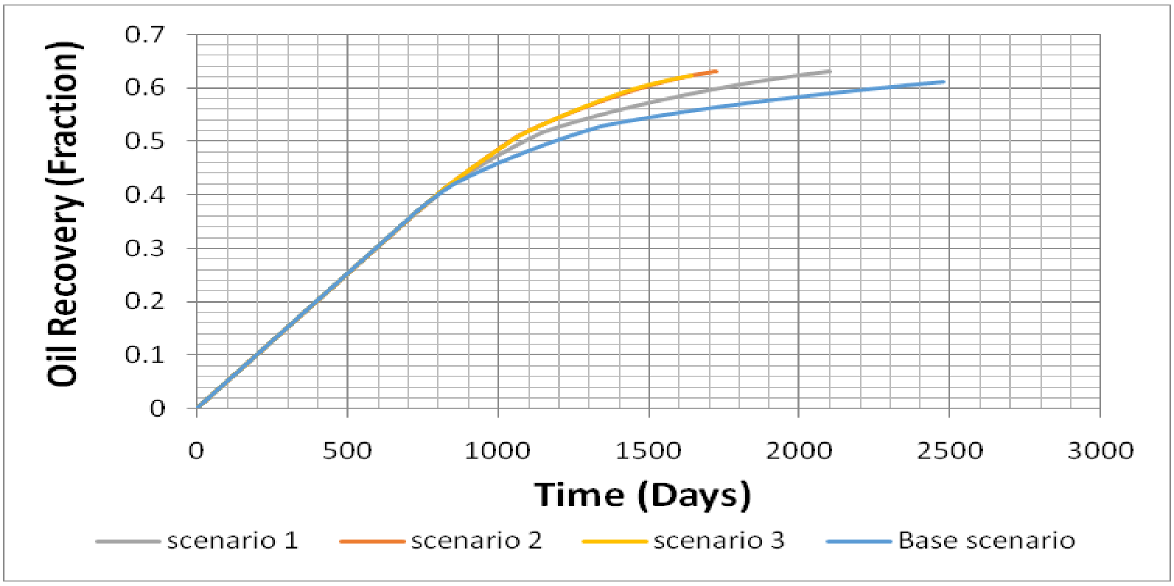

Figure 58 Case 13, Oil recovery versus time

The oil recovery behaviour for scenario 2 and 3 is quite similar. But as the production time for scenario 2 is longer than that of scenario 3, the final oil recovery for scenario 2 is significantly higher than that of scenario 3.

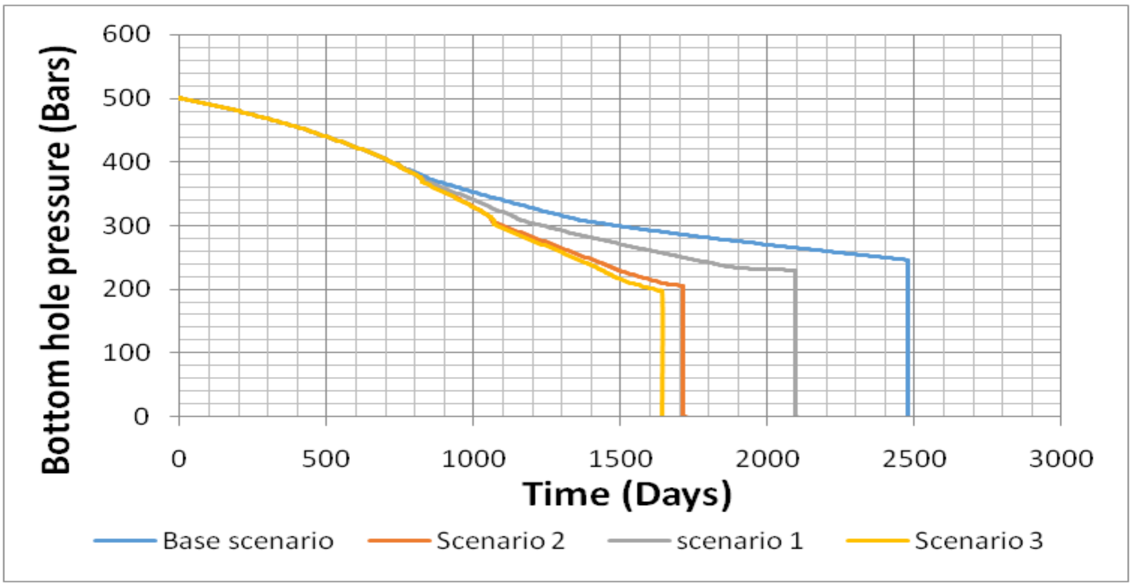

Figure 59 Case 13 Bottom hole pressure versus time

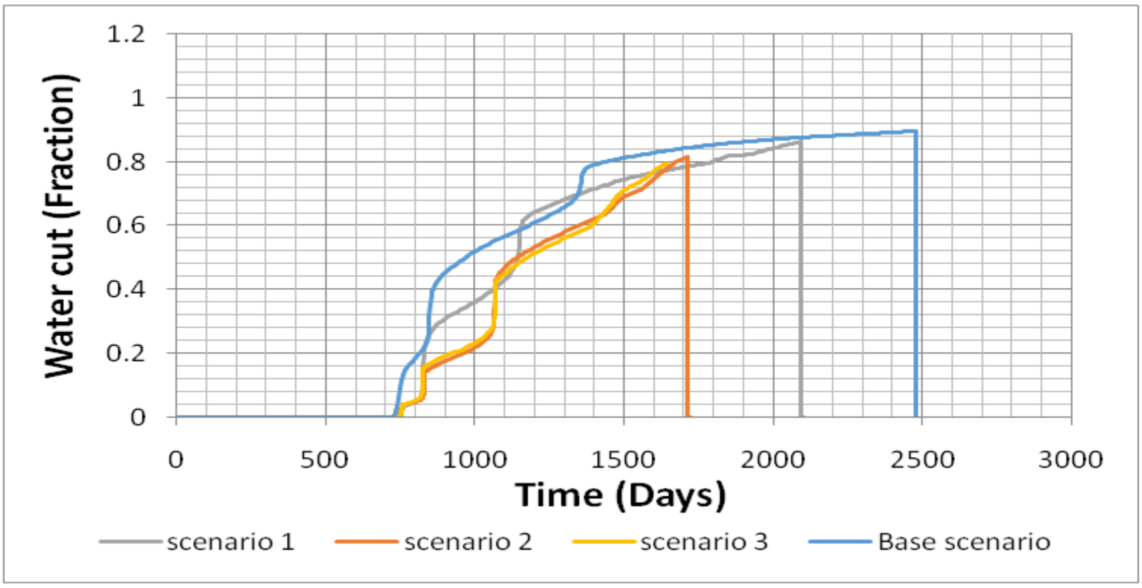

Figure 60 Case 13, Water cut versus time

The water cut for scenario 1 is significantly higher than scenario 2 and 3 after second layer breakthrough. This means that the layer 2 contribute significantly in excessive water production problems and therefore needs to be treated. Also for all scenarios, the increase in water cut when third layer breakthrough occurs is sharper while further increment in water cut is very gradual when forth layer breakthrough occurs. While in case 7, these increments during 3rd and 4th layer water breakthrough were much sharper. This difference can be due to the formation of the gas in the reservoir at the time of 4th layer breakthrough in case 13 which we did not allow in case 7. In this case the bottom hole pressure at the time of 4th layer breakthrough is well below bubble point pressure of black oil used in this model which caused the presence of gas in reservoir. This formation of gas might have magnified effects of damage in the third and forth layers causing the oil recovery in scenario 1 and 2 much higher than in scenario 3. Also even though the water cut behaviour is same, the bottom hole pressure drops more in scenario 3. Therefore the pressure drop in the reservoir is higher for the scenario 3 than in scenario 2 even though the produced liquid composition is same for both scenarios. This has to be due to the extra pressure drop caused by the damage of 3rd and 4th layer in scenario 3.

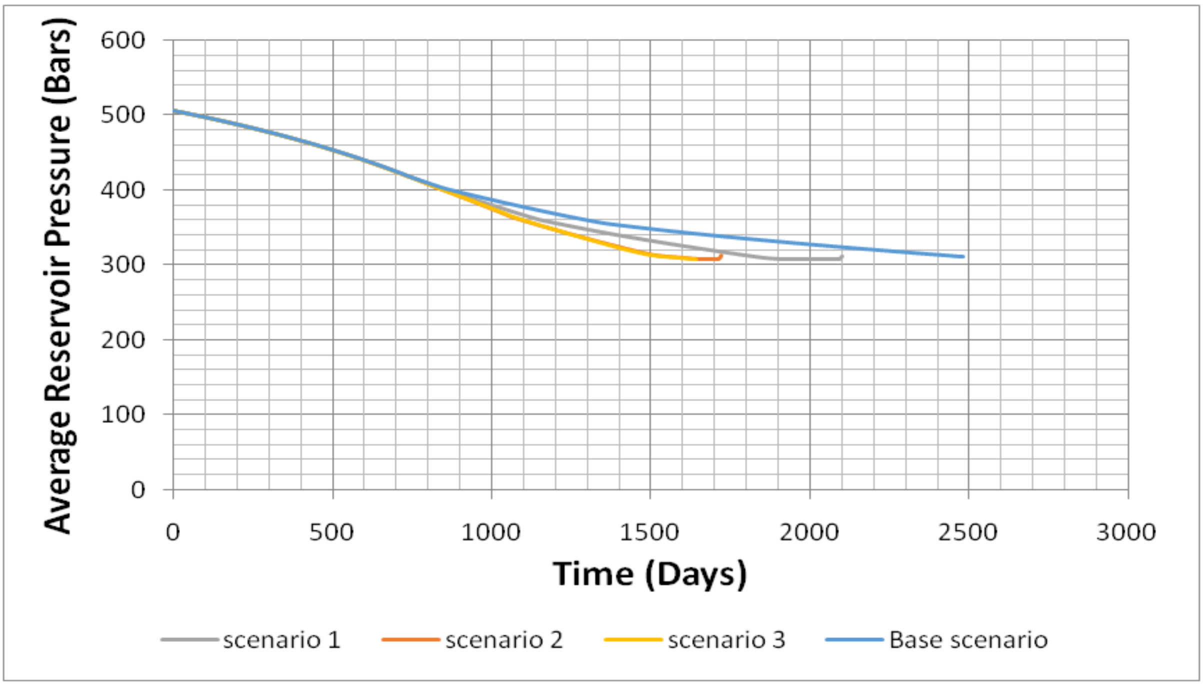

Figure 61, Case 13 Average reservoir Pressure versus time

The average reservoir pressure behavior for scenario 2 and 3 is similar but for scenario 1, pressure drop is comparatively gradual. Gas formation in the reservoir is caused due to solution gas coming out of the oil. The amount of gas that will be formed by this process is dictated by the surrounding pressure in the reservoir. Same reservoir pressure at any time in scenario 2 and 3 and similar water cut in the produced liquid suggest that the fluid composition in the reservoir at any time was similar in both of the scenarios. This behavior again points towards same conclusion that the extra presure drop in the reservoir must have caused due to the damage of 3rd and 4th layer.

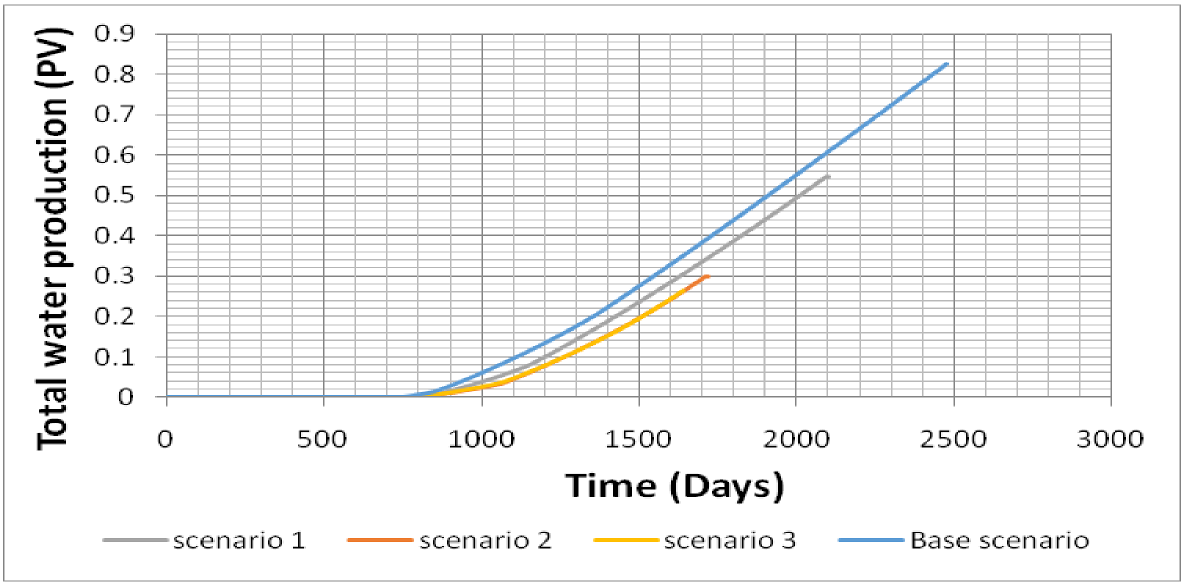

Figure 62 Case 13 Total water production versus time

Due to higher water cut for most of production period and higher production time the total oil production for scenario 1 is significantly higher than that for the scenario 2 and scenario 3. This behaviour corroborates the conclusion in case 7, which was that layer 1 and layer 2, both have serious contribution in excessive water production problem. Therefore both of the layers should be subjected to water shut off treatment.

Observations

- The effect of the damage caused by DPR treatment is magnified when VLP calculations are considered.

4. Conclusion and recommendations

Conclusions:-

This project was aimed at investigating if DPR treatment should be employed on the proposed reservoir model as well as at understanding reservoir performance's sensitivity with different designing parameters of the DPR treatment

Conclusions are as follows:

1. DPR treatment improved the pilot performance in terms of reduction in water production and production time and improvement in oil production.
2. DPR treatment did not increase final oil recovery significantly and in some cases deteriorated the final oil recovery
3. DPR treatment has a significant impact not only on the fluid flow performance in the reservoir but also in the tubing
4. The effect of the delay in the DPR treatment increased drastically as the number of high permeability layers started producing the water
5. Reservoir performance is insensitive to the treatment volume
6. Damage done to low permeability layers due to gelant invasion during DPR treatment using bullheading injection was significant.

Recommendations:-

1. Inclusion of the vertical lift performance calculations is necessary in designing and simulation of DPR treatment.
2. Water cut should be monitored for production from each high permeability layer that can potentially cause excessive water production rather than water cut of the combined production from all the layers in order to decide the time of DPR treatment.
3. Inclusion of the uncertainties related to relative permeability reduction factor and reservoir permeability reduction factor are inevitable for a good prediction of the post-treatment reservoir performance.
4. If low permeability layers have high pay zone thickness then the selective injection of gelant solution is preferable.

Limitations:-

1. The model considered is an ideal candidate for the DPR treatment.
2. Uncertainties in the residual resistance factor of oil were not addressed.
3. Analysis is limited for black oil reservoirs.
4. Capillary pressure changes caused due to DPR treatment were not addressed

5. Bibliography

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