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Simulation Study of the Polymer Flooding Applied to the Norne Field E-Segment

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Summary

The enhanced oil recovery (EOR) methods such as polymer flooding to increase oil production from water flooded fields are becoming more attractive. Water flooding can increase recovery up to 20-40%. Various EOR methods can yield significant increase in the oil recovery when compared to conventional water flood projects in certain reservoirs.

The main objective of this study is to analyze efficiency of polymer flooding for enhanced oil recovery for Norne field E-segment using the Eclipse 100 simulation model of the reservoir. The simulated model was manually history matched by modifying transmissibility factors, fault transmissibilities, the skin factor and Kh values of the production wells.

As a result of all adjustments the best possible history match was obtained. The polymer flooding was analyzed and tested on three dimensional, homogenous and flat synthetic model. The oil recovery increase about 8%.

The injection well F-3H was evaluated as the most appropriate well for the polymer flooding scenario. The polymer solution concentration sensitivity and injection rate sensitivity were performed to assess the efficiency of polymer flooding in the Norne E-Segment.

The oil recovery increased up to 1%, therefore it can be concluded that polymer flooding is not a good scenario for the Norne field E-Segment.

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Introduction

The oil is produced from the reservoir due to natural drive mechanisms at the initial stage of production. As the pressure goes down, most oil fields are produced by artificial pressure maintenance techniques, mainly by water injection or gas injection. Being the most widely used pressure maintenance technique, waterflooding, in many cases is not enough to obtain desirable recovery. During the waterflooding the oil-water mobility ratio and the reservoir heterogeneity factors must be favorable, otherwise it could yield to low volumetric sweep efficiency. This, in its turn, leads to use of Enhanced Oil Recovery methods, but only if it is commercially profitable. [1]

Main oil recovery mechanisms are shown in Figure 1.

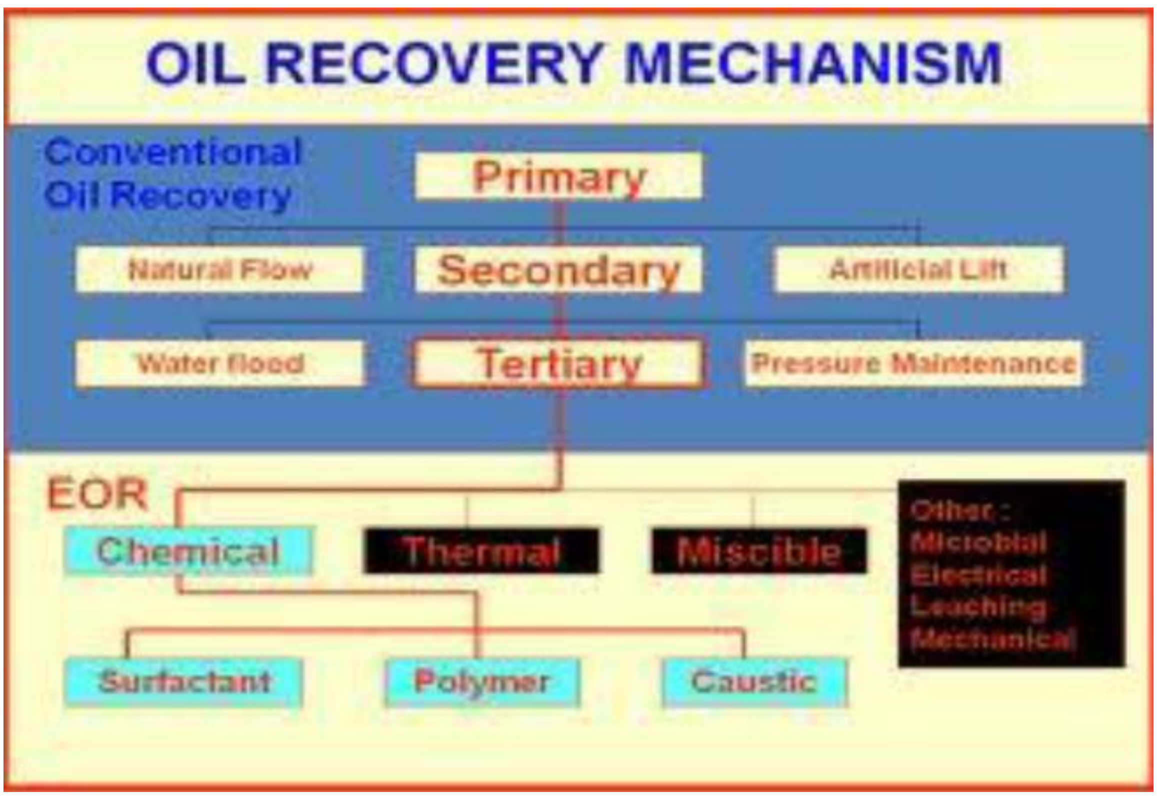

Figure 1. Classification of oil recovery mechanisms

Enhanced Oil Recovery (EOR) methods also known as tertiary methods have a potential to recover up to 60% of the oil initial in place what is comparatively much higher than secondary recovery methods. Generally, EOR methods are divided in four main groups:

- Chemical Methods (alkaline flooding, surfactant flooding, polymer flooding)
- Thermal Methods (in-situ combustion, steam flooding)
- Miscible Displacement (nitrogen flood, CO_2 injection)
- Microbial Enhanced Oil Recovery

Chemical methods involve mixing chemicals in water before injection. These methods require special conditions for water injection: low-to-moderate oil viscosities, and moderate-to-high permeabilities [1]. In order to produce capillary trapped residual oil in the reservoir, surfactants are injected. Polymers are injected to develop mobility ratio control and water to obtain the surfactant affected fluids to the producing well.

There are two main *thermal recovery methods*: in-situ combustion and steam flooding. During these processes air, steam water continuously injected to the reservoir reduces oil viscosity and moves the oil towards the production well. [1]

Miscible displacement is the process of miscible gases injection into the reservoir. Gas injection is definitely one of the oldest techniques used to improve recovery in the oil industry [2]. The gas maintains the reservoir pressure by means of lowered oil-water interfacial tension. CO_2 is the most widely used gas for injection, since it is cheap and reduces oil viscosity. However, other fluids, such as nitrogen, methane or propane under high pressure are also commonly utilized.

Microbial Enhanced Oil Recovery is a unique technique, where live microorganisms and bacteria are injected into reservoir. In cases microorganisms if microorganisms exist in the reservoir one have to inject only nutrients.[3] Bacteria produce metabolic products like biosurfactants and biopolymers that lead to enhanced oil recovery mobilization of residual oil, interfacial tension/oil viscosity reduction, and selective plugging of the most permeable zones.

Literature Study

1. Polymer Flooding

Polymer flooding is one of the first enhanced oil recovery methods with a low risk and wide range of application. It consists of dissolving polymer in the injected water. As a result, the water viscosity increases and the water effective permeability decreases what gives better mobility ratio and sweep efficiency in the reservoir. Better sweep efficiency significantly reduces the fingering effect. Figures 2 and 3 show the difference in fingering effects of water injection and the polymer injection. The important condition for the polymer flooding to be economically valuable is the high mobility ratio.[6] Daqing field in China is the first commercially successful polymer flooding project where the recovery factor was increased about 20% as a result of polymer flooding. [7]

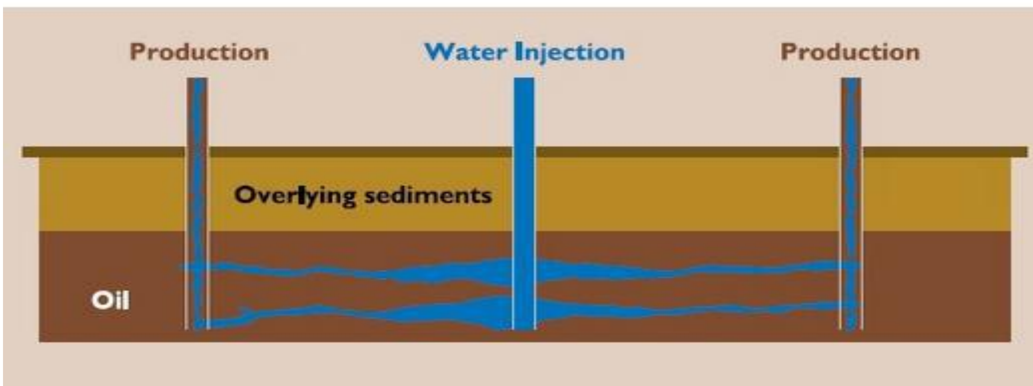

Figure 2. The fingering effect during the water injection [19]

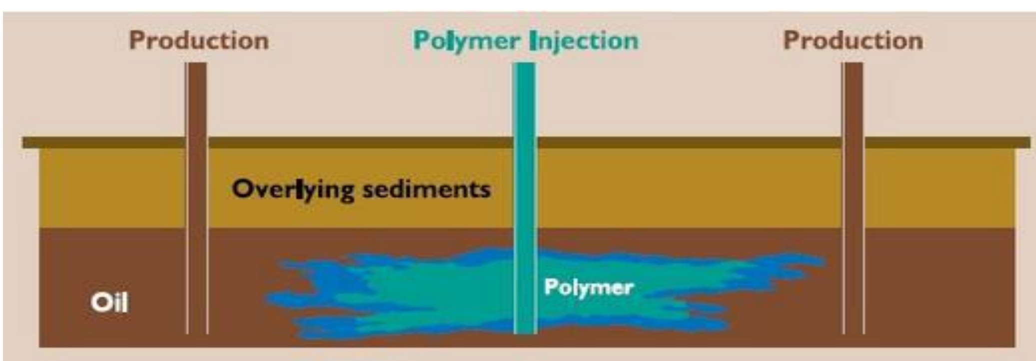

Figure 3. The fingering effect during the polymer injection [19]

1.1. Mechanics of Polymer Flooding

The following processes during the polymer flooding increase the volumetric sweep efficiency and yield better oil recovery:

- Increasing in water viscosity
- Decreasing of the oil-water mobility ratio
- Diverting water out of swept zones

Figure 4 demonstrates the comparison of polymer flooding to the water flooding.

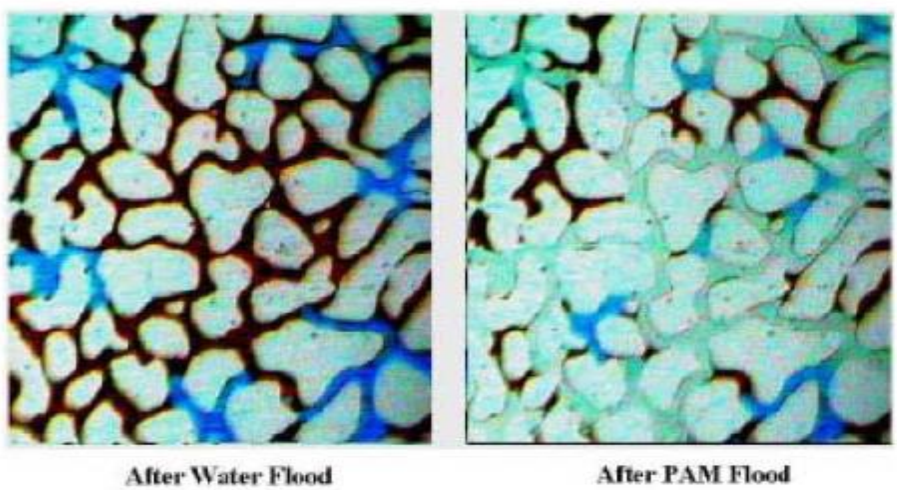

Figure 4. Visual comparison of water and polymer flooding behavior [20]

According to the experimental work of Dyes, Caudle and Ericson (1954) the mobility ratio is defined as

$$M = \frac{k_w/\mu_w}{k_o/\mu_o}$$

Better displacement occurs when the mobility ratio is equal or less than 1. That's why, to obtain good mobility factor, chemicals are added to the water. As a result the water viscosity increases and mobility ratio decreases.

1.2. Types of Polymers

Two different types of polymers are used in EOR applications: synthetic polymers and biopolymers. Synthetic hydrolyzed polyacrylamide (HPAM) and xanthan are two main polymer types utilized in the polymer flooding. Such substances as guar gum, sodium carboxymethyl cellulose and hydroxyl ethyl cellulose are less widely used polymers.

HPAM is the most largely used polymer in EOR projects. HPAM allowed to recover significantly more oil than xanthan during the Daqing project by demonstrating better viscoelasticity. Polyacrylamide is partially hydrolyzed since it adsorbs firmly on mineral surfaces. So the adsorption is reduced by reacting with a base, such as sodium or potassium hydroxide or sodium carbonate. [4] Hydrolysis converts some of the amide groups (CONH2) to carboxyl groups (COO-), as shown in Figure 5.

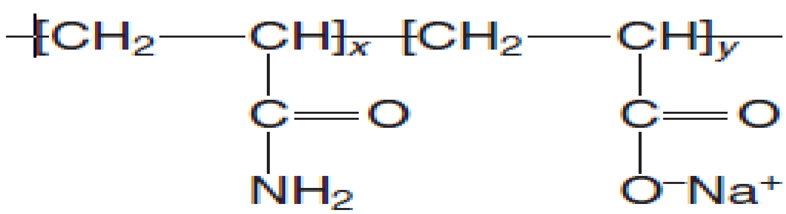

Figure 5. Partially hydrolyzed HPAM [4]

The degree of hydrolysis of amide groups ranges from 15 to 35%.Hydrolysis of polyacrylamide creates negatively charged molecules on the backbones that have a great effect on the rheological properties of the polymer solution. Polyacrylamide is mainly anionic, but could be nonionic or cationic (Green and Willhite, 1998). HPAM used in EOR projects usually has molecular weights up to higher than 20 million Daltons. [4]

Another widely used polymer is *xanthan gum* .(biopolymer). It was derived from a fermentation process. Xanthan biopolymers are supplied as a dry powder or as a concentrated broth. The structure of a xanthan biopolymer is shown in Figure 6. Due to its molecular structure xanthan is a great viscosifier in saline water. Molecular weight of xanthan used in EOR projects varies between 1-15 million. The viscosity of copolymers is lower than that of biopolymers in the saline water (10,000 ppm TDS). Some permanent shear loss of viscosity could occur for polyacrylamide, but not for polysaccharide at the wellbore. However, the residual permeability reduction factor of polysaccharide polymers is low. [4], [5].

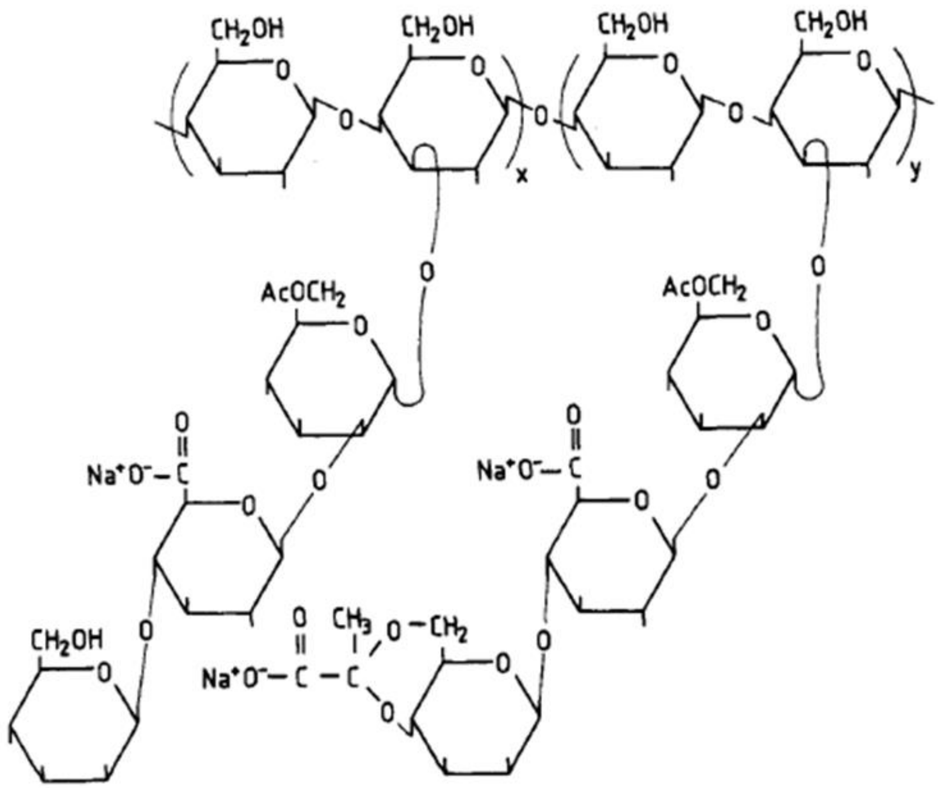

Figure 6. Molecular structure of Xanthan [5]

Generally, HPAM is more widely used than any other polymer type. Other biopolymers that potentially can be utilized in EOR processes are scleroglucan, alginate simusan and so on [4].

1.3. Behavior of Polymer Solutions in Porous Media

Polymer Rheology

The viscosity is defined as the measure of the fluid resistance to gradual deformation by shear stress or tensile stress. The viscosity is the relationship between the shear stress and shear rate [8]

$$\mu = \frac{\tau}{\dot{\gamma}}$$

Where, τ- shear stress

γ – shear rate

μ – viscosity

The polymer solution viscosity is the main parameter in order to obtain better oil-water mobility ratio. The polymer viscosity depends on polymer molecular weight, polymer concentration and inversely depends on the temperature. An increase in salinity may reduce the polymer solution viscosity as well.

Another important parameter that strongly influence to the effectiveness of the polymer flooding is the polymer molecular weight. Polymer with higher molecular weight will give the higher viscosity and higher oil recovery. [9]

Polymer Retention

Different mechanisms such as, mechanical entrapment, hydrodynamic retention are parts of polymer retention and adsorption Mechanical entrapment and hydrodynamic retention are related and occur only in flow-through porous media. Retention by mechanical entrapment is viewed as occurring when larger polymer molecules become lodged in narrow flow channels. Excessive retention will increase the amount of polymer that must be added to achieve the desired mobility control. The level of polymer retained in a reservoir depends on several rock and polymer properties: permeability of the rock, nature of the reservoir rock (sandstone, carbonate, minerals, or clays), nature of the solvent for the polymer (salinity and hardness), molecular weight of the polymer, ionic charge on the polymer, rock surface and brine salinity [4], [5].

Polymer Adsorption

Adsorption is the adherence of ions to different surfaces. Polymer adsorption depends on the type of the polymer, rock surface, salinity, molecular weight and polymer concentration. For example, synthetic polymer adsorption is lower than biopolymer adsorption. Adsorption goes up with the increase in salinity. Besides, polymer adsorption is considerably higher in packed sands than in cores. Usually, polymer adsorption is assumed as irreversible, thus, it remains stable with decreasing polymer concentration. [4], [6]

Inaccessible Pore Volume

Another notable phenomenon regarding polymers was observed during polymer flooding experiments. It was noticed and reported for the first time by Dawson and Lantz. The polymer was injected together with a tracer and it became clear that polymer breakthrough happens faster than the tracer breakthrough.[5] **(Figure 7.)**. This could be explained with the fact that some pore volumes are way too much small for larger polymer molecules. Hence, the volume of these pores is called inaccessible pore volume (IPV). [4]

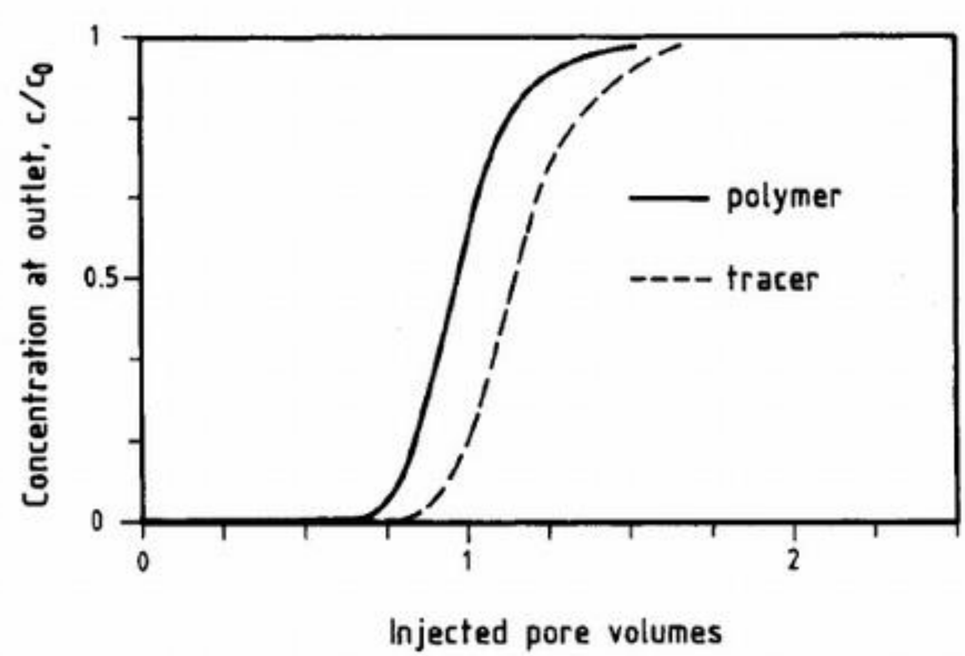

Figure 7. Inaccessible pore volume [5]

Inaccessible pore volume usually is in a range between 1 to 30% of pore volume.

Permeability Reduction

Polymer adsorption or polymer retention lead to permeability reduction of porous media. That's why rock permeability is reduced when a polymer solution is flowing through it, compared with the permeability when water is flowing. And the permeability reduction is defined by the permeability reduction factor (Fkr), which is the ratio between rock permeabilities of water and polymer solutions. [4]

$$F_{kr} = \frac{\text{Rock perm. when water flows}}{\text{Rock perm. when aqueous polymer solution flows}} = \frac{k_w}{k_p}$$

Where

k_w – water permeability

k_p- polymer permeability

Relative Permeabilities in Polymer Flooding

According to traditional belief polymer flooding has no effect on residual oil saturation in a micro scale. The displacing fluid viscosity and volumetric sweep efficiency are the parameters that increase due to polymer flooding. Besides, relative permeability curves do not depend on fluid viscosities. Thus, it was concluded that the relative permeabilities in polymer flooding and in waterflooding after polymer flooding are the same as those measured in waterflooding before polymer flooding. The conventional belief has been verified by several experiments, including Schneider and Owens (1982) and Chen and Chen (2002) [4].

1.4. Criteria for the Polymer Flooding

Figure 8 illustrates the main properties that are necessary criteria for polymer flooding.

Properties	Standard
Oil Viscosity	From 10 to 3000 cp
Temperature	up to 120°C
Permeability	10 md to 10 Darcy
Reservoirs	sandstone (preferred)
Oil gravity	>15° APl
Salinity	< 250,000 TDS
Oil saturation	>50%
Water injectvity	Good

Figure 8. Criteria for Polymer Flooding [11]

During polymer flooding process, viscosity of water is greatly enlarged, water mobility is obviously lowered; as a result, at the front of polymer slug an oil bank is accumulated. With time going, polymer slug flows towards producing wells, before which, the oil bank flows to producing wells earlier, and the oil production rate gradually increases to peak value. Shortly after that the polymer concentration peak value is also reached, then the oil production rate decreases more quickly to the lowest value, and the whole polymer flooding process tends to finish. [9]

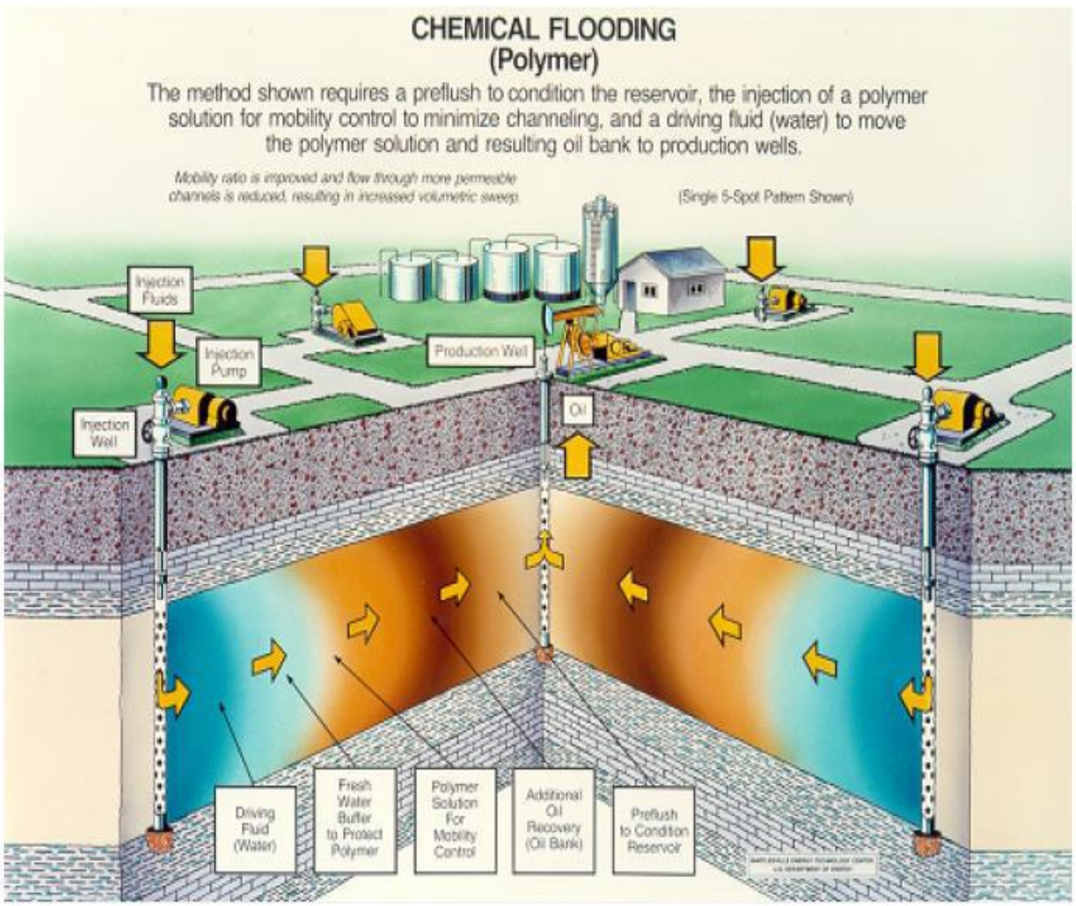

Figure 9. Polymer flooding process [10]

2. Norne Field

2.1. General Information

The Norne oil field is located in the Norwegian Sea 200 km from the coastline and about 80 km north of Heidrun field. The water depth at the field's area is 380 meters It was discovered in 1991. The field is situated in the blocks 6608/10 and 6508/1 in the Southern part of the Nordland II area. The field's location, relative to the neighbouring fields is shown in Figure 10. [12], [13]

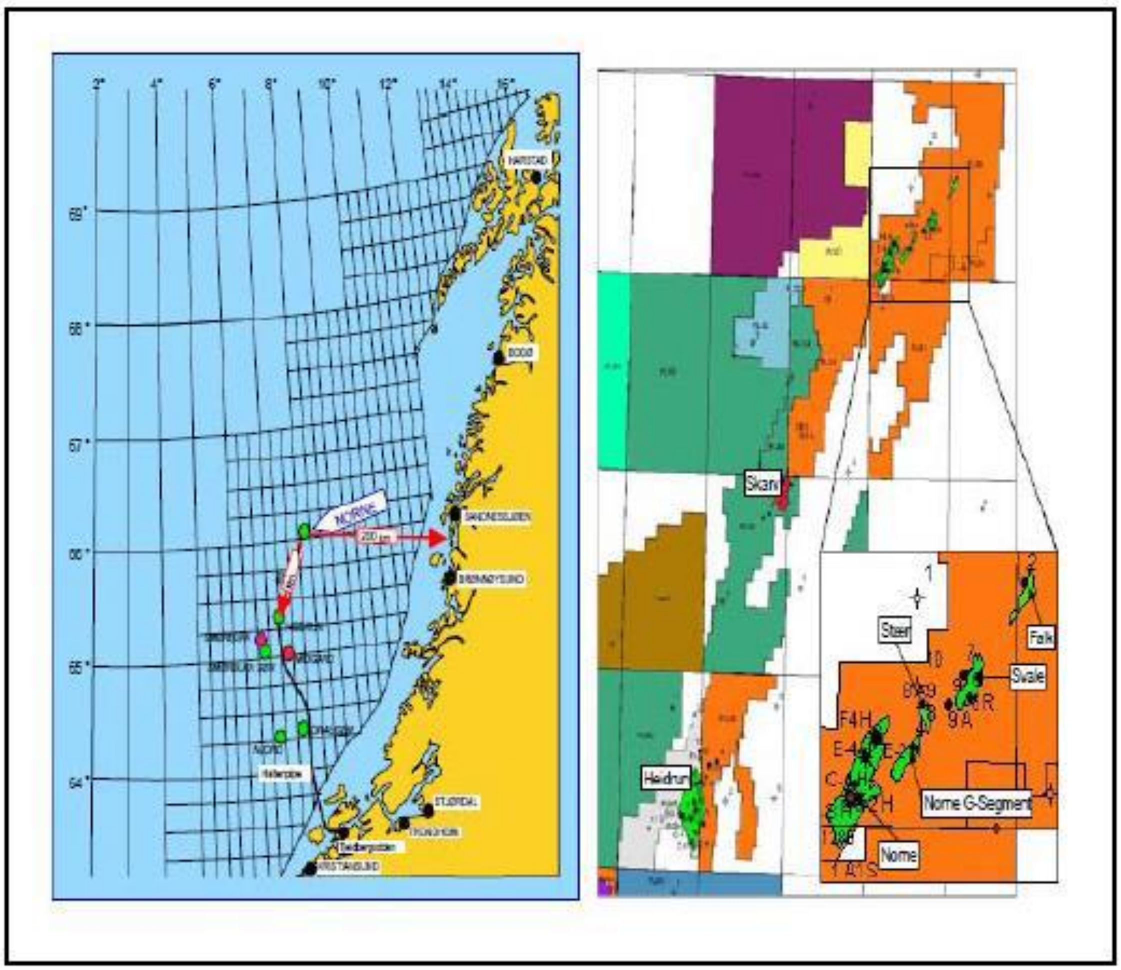

Figure 10. The location of the Norne Field. [12]

The field consists of two individual oil compartments which are

- Norne Main Structure (Norne C, D and E-segment). This part of the field contains 97% of the OIP
- North-East Segment (G-segment) (Figure 8)

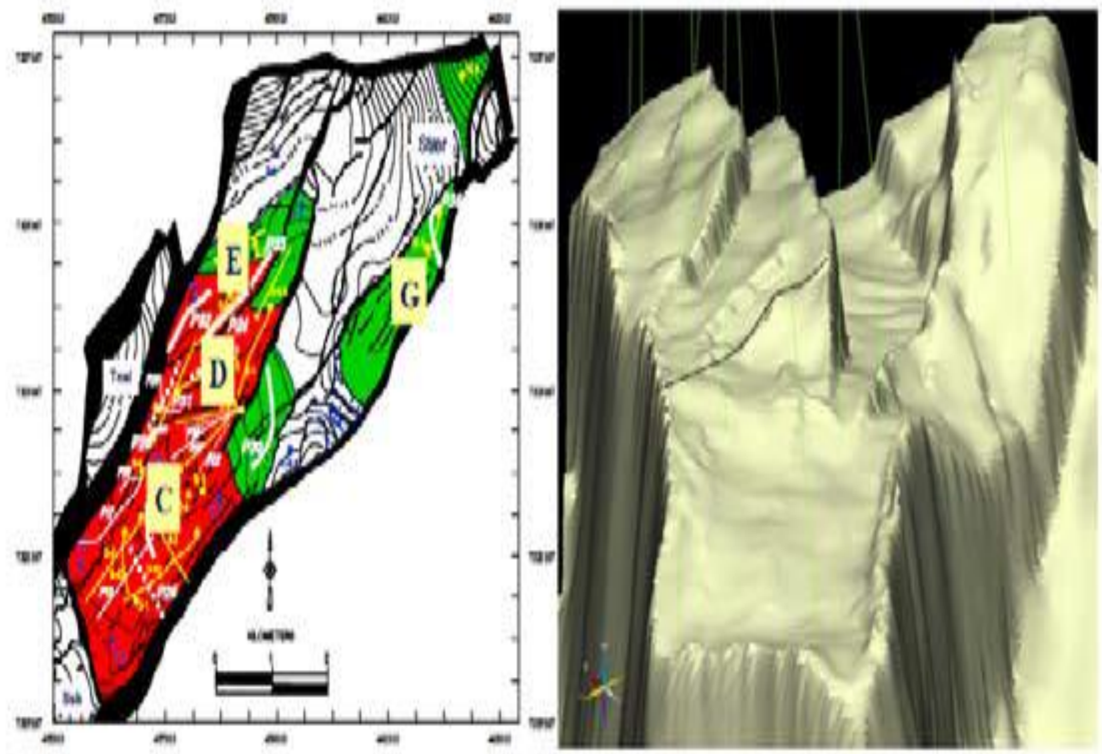

Figure 11: The Norne Field segments and wells [12]

The Norne Main Structure has a total hydrocarbon column of 135 m containing 110 m of oil and 25 m of gas. About 80% of oil is at Ile and Tofte formation and gas is in the Garn formation. The age of hydrocarbon-bearing rocks is Lower and Middle Jurassic. [Statoil, 2001]

The main structure is almost flat with a gas filling the Garn formation and the GOC is near to the Not formation. According to the data acquired from the development wells it's concluded that the Not formation behaves as a seal and reservoir communication is absent across the Not formation. [12], [14]

2.2. Development

The development drilling began in August 1996. In November 1997 the oil production started. The oil is produced only by water injection as the drive mechanism. Gas injection was used at the beginning of the production but it was ceased in 2005 and all gas is exported now.

The field is developed with a vessel “Norne FPSO” connected to seven subsea wellhead templates. The oil is loaded to the tankers for export while the gas is transported through Åsgard pipeline to Kårstø terminal. [12], [13]

The following figures are provided by NPD showing the recoverable and remaining reserves as well as total oil production as for 31 December 2013. [15].

Table 1 The NPD estimate for reserves and oil in place volumes [15]

Reserves	Oil MSm3	Gas MSm3	NGL MSm3	Condensate MSm3
Recoverable	91,00	11,30	1,5	0,00
Produced	88,02	6,75	1,55	0,00
Remaining	3,20	4,6	0,7	0,00

2.3. Geology

Lithostratigraphically the Norne reservoir is divided in two groups: FANGST (Garn, Not, Ile) and BÅT (ROR, Tofte, Tilje, Åre). (**Figure 12)** Hydrocarbons are detected in the Lower to Middle Jurassic sandstones, which are mostly fine-grained and well to very well sorted sub-arkosic arenites. The sandstones are deposited at the depth of 2500-2700 meters and are influenced by diagenetic processes. Most of the sandstones have good reservoir properties despite the mechanical compaction which reduces the reservoir quality. The porosity is 25-30% and permeability changes in the range of 25-2500 mD. Almost 80% of the oil reserves is located in Tofte and Ile formations. [13], [16]

Tofte Formation

The Tofte formation was deposited during the Late Toarcian period above the unconformity. It consists of 50 meters thick sandstone layer. Main formation is subdivided in three zones from top to base: Tofte 3,2 and 1. (**Figure 12)** Tofte 3 contains very fine to fine grained sandstone with vague depositional structures. This is a result of extensive bioactivity. The same phenomena can be observed in Tofte 2, which is highly bioturbated, fine-grained zone. However, in Tofte 1 only lower part is relatively bioturbated while the upper parts are laminated with to coarse grain package. [16]

Ile Formation.

The Ile formation was deposited during the Aalenian stage of the Middle Jurassic. It's located between NOT and ROR formations **(Figure 12)** The approximate thickness is 32-40 meters. This formation has three zones Ile 3,2,1, which are largely bioturbated fine to very fine grained sandstone zones. A thin cemented calcareous layer separates Ile 2 and Ile 1, as well as Ile 1 and ROR formations **(Figure 12**) These layers apparently formed as a result of minor flooding events in a generally regressive period. Both layers are extensive throughout the Norne Field. [16]

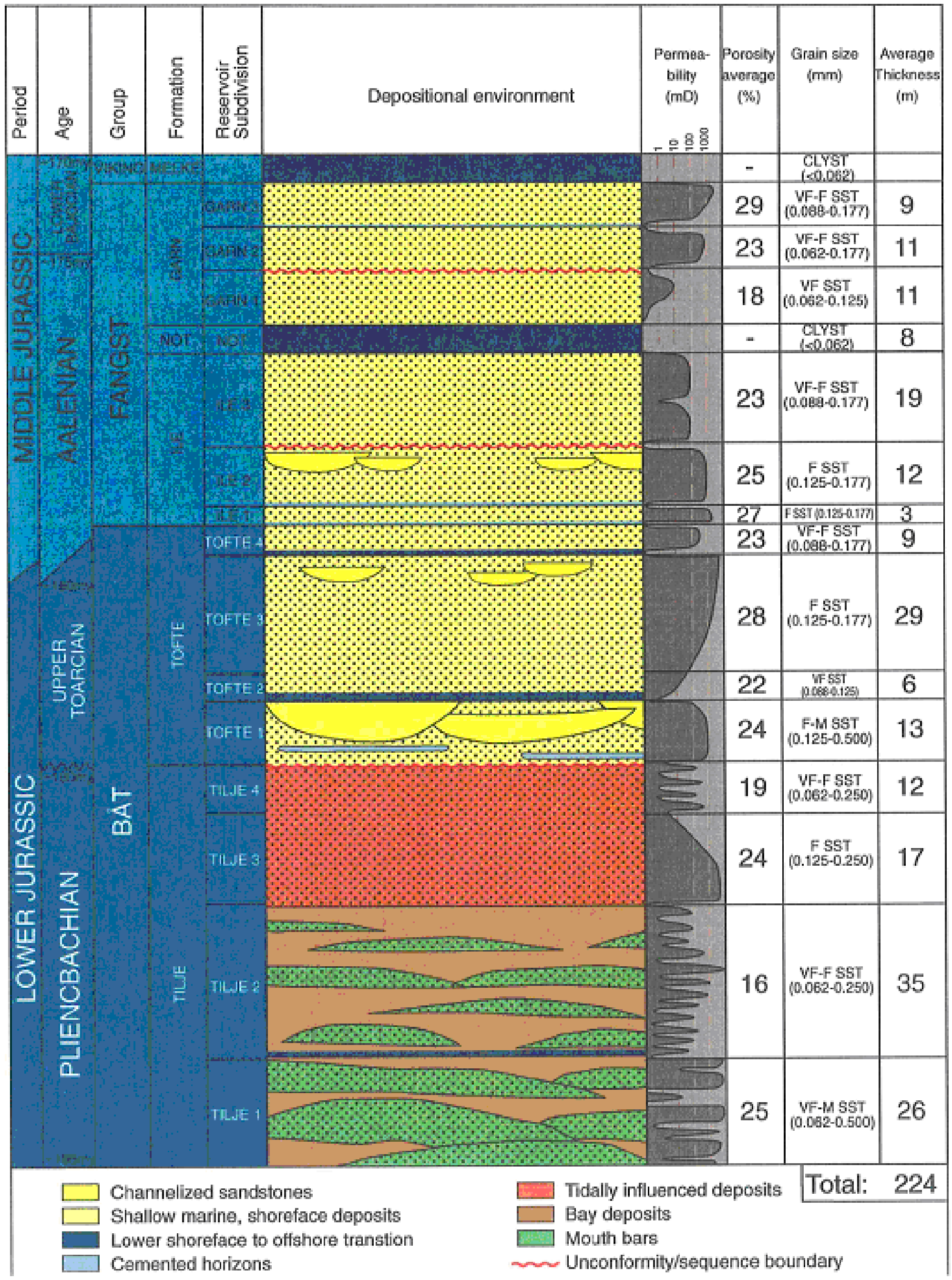

Figure 12. Stratigraphical division of the Norne Reservoir [16]

2.4. Drainage Strategy

In 1997 the main drainage strategy was to maintain the reservoir pressure by re-injection of produced gas into the gas cap and water injection into the water zone. During the first year of production it was observed that the Not Formation is sealing over the Norne Main Structure, and the drainage strategy was reviewed, so the gas injection has been injected into the water zone and the lower part of the oil zone. The gas injection was ultimately stopped in 2005 and now all gas is going to export. [17] **(Figure 13 , Figure 14**)

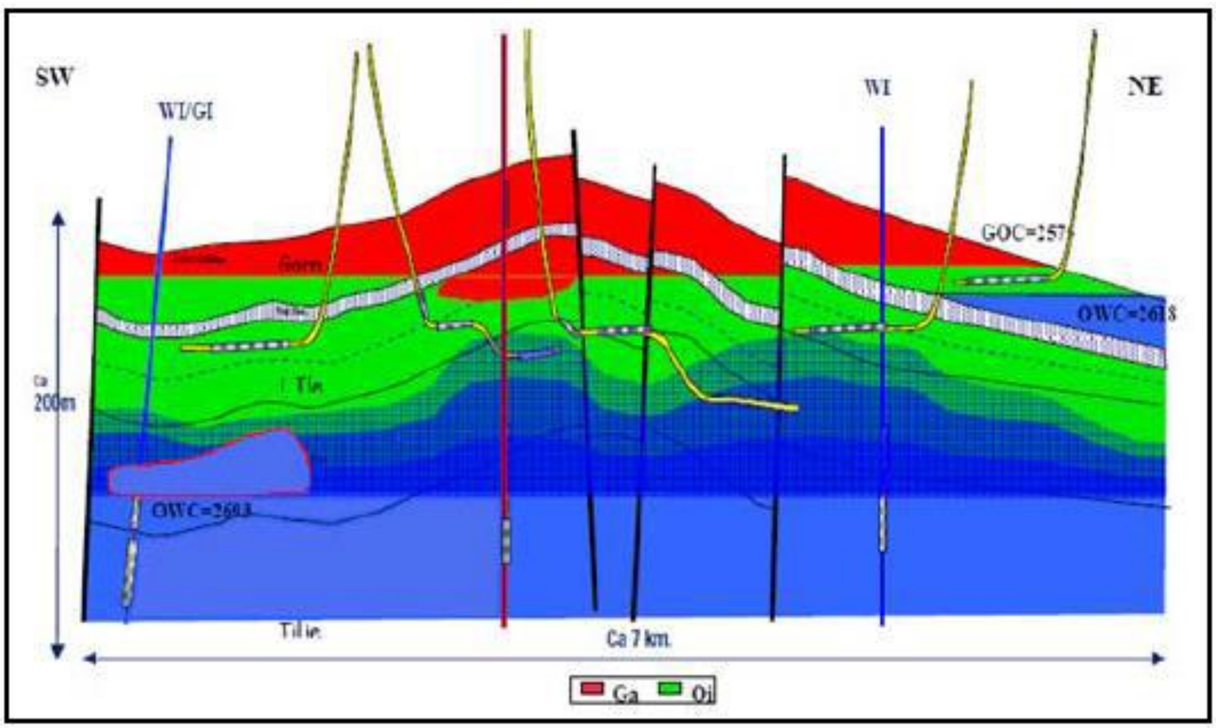

Figure 13. The cross-section of fluid contacts of the Norne Field [17]

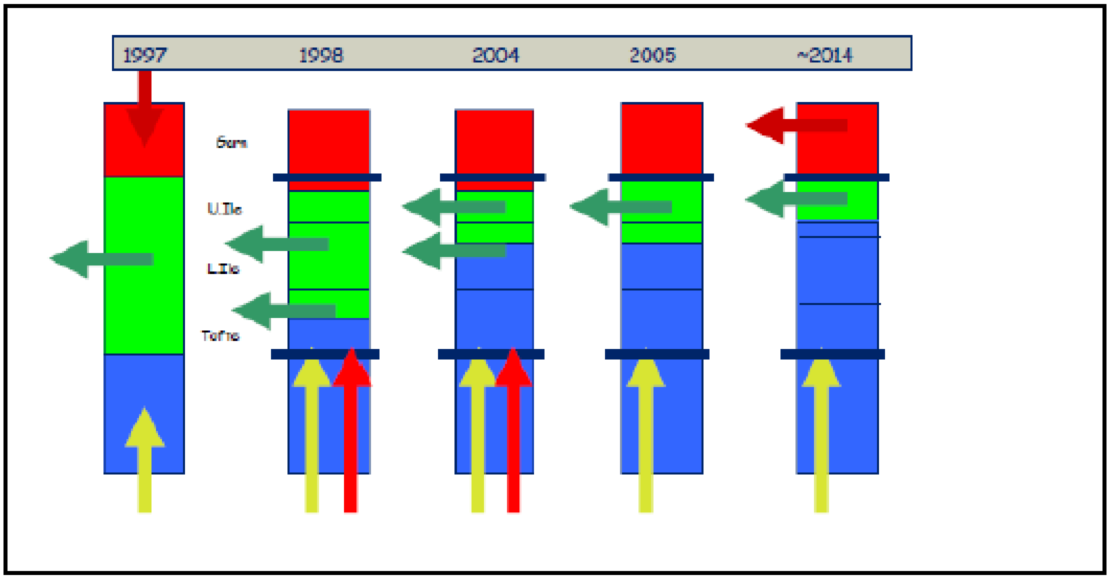

Figure 14. The drainage strategy for the Norne Field from pre-start and until 2014. [17]

2.5. Norne Field E-Segment

The Norne Main Structure consists of three segments (C,D and E) and contains about 97% of the oil initial in place. The Ile and the Tofte formations are two major formations in the Norne E-Segment, since almost 80% of oil is kept in these two major formations. According to Eclipse simulation model of the Norne Field there were five active wells in the E-Segment before 2005: two injectors (F-1H and F-3H) and three producers (E-2H, E-3H, E-3AH) (**Table 2)**

Table 2. Well Status in the Norne E-Segment

Well Name	**Well Type**	**Well Status**
E-2H	Oil Producer	Active
E-3H	Oil Producer	Shut
E-3AH	Oil Producer	Active
F-1H	Water Injector	Active
F-3H	Water Injector	Active

2.6. Norne E-Segment Eclipse Simulation Model

The Norne E-Segment is three dimensional fully implicit three phase black oil model in Eclipse 100. The E-Segment is separated from the rest of the Norne Field and contains 46 grids in the X-direction , 112 grids in the Y-direction and 22 layers. As it was mentioned before Ile and Tofte are the main formations in the E-Segment. The Ile covers layers 5 to 11 where the Tofte contains layers 12 through 18. The simulation started on 14 November and lasted until 1 December 2004. [13]. The reservoir properties of the hydrocarbons as well as water in the Norne E-Segment are presented in the table below.

Table 3. Reservoir fluid properties of the Norne Field. [18]

Fluid Properties	Units	Norne Main Structure (C,D & E Segment)	Norne G-Segment
Initial pressure	bar	273.2	273.2
Bubble point pressure	bar	251	216
Gas oil ratio	Sm^3/Sm^3	111	96
Oil formation volume factor at bubble point	Rm^3/Rm^3	1.347	1.30
Oil viscosity at bubble point	cp	0.58	0.695
Oil density at bubble point	g/cm^3	0.712	0.729
Gas formation volume factor	Rm^3/Rm^3	4.74 E-3	
Initial temperature	^0C	98.3	98.3

Figure 15 shows the coarsened Norne Field model with the E-Segment.

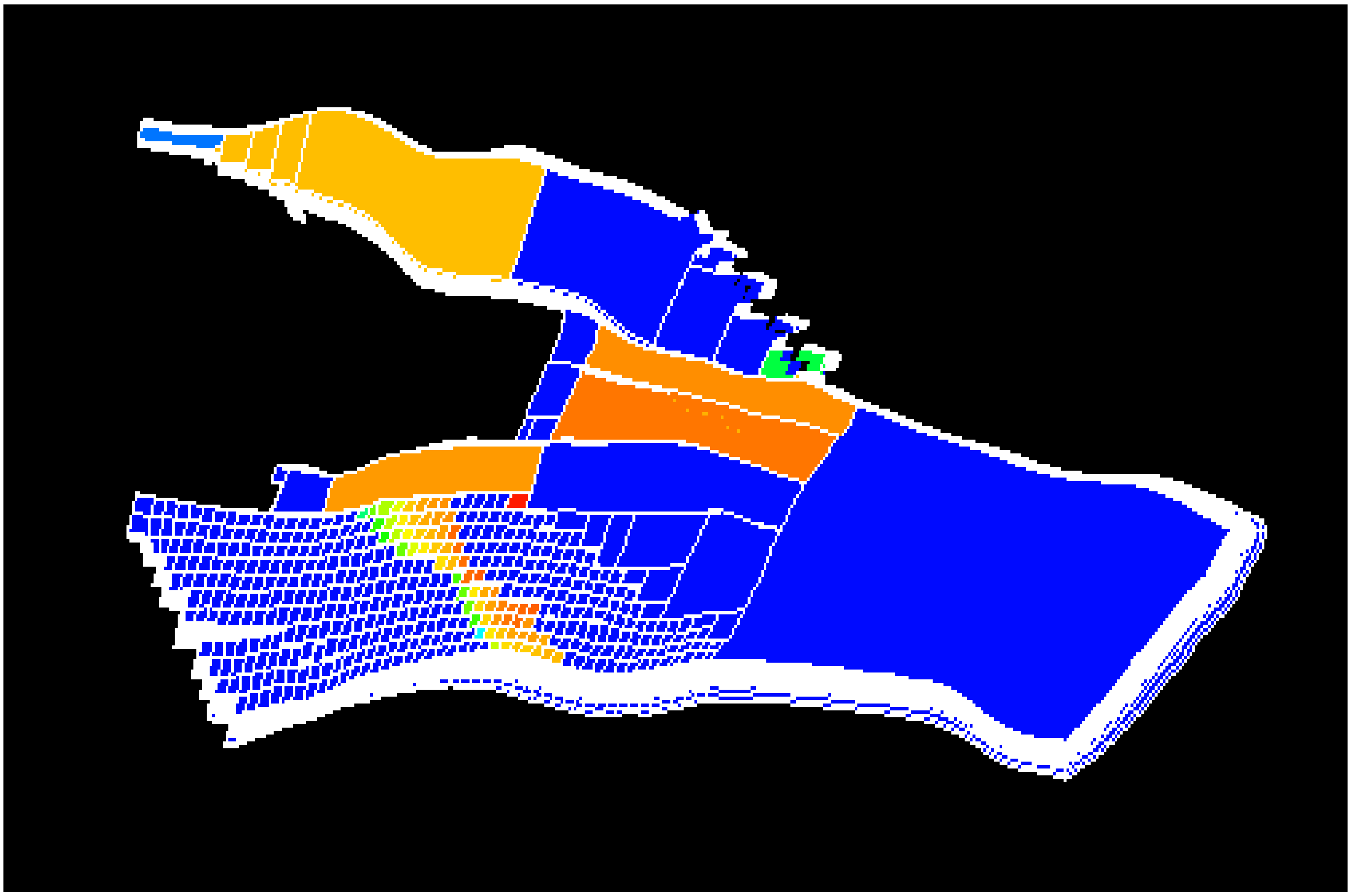

Figure 15. The simulation model of the Norne Field with E-Segment

Simulation Results and Discussion

1. History Matching of the Simulation Model

The main objective of this part of my thesis work was to history match the simulated data with observed field data. The resulted history matched model will be used for the future prediction of the well/ reservoir performance

After construction of the simulation model, it has to be analyzed, checked and compared with observed reservoir history data. In case of substantial difference, the model data is adjusted to diminish this gap. The following procedure is called history matching. After obtaining the history matched model we can make forecasts and prediction of the reservoir performance in the future.

With the developing technology over the last few decades many new methods of history matching have been created and some methods have been improved. Nowadays, engineers and researchers around the world utilize various automatic history matching methods.

However, for this particular work, traditional (manual) history matching method can be applied with a particular degree of accuracy. Manual history matching method is the conventional trial-and-error procedure. The simulation data was changed manually in order to reduce the difference between observed data and simulation data.

Figure 16 and Figure 17 shows the field oil and water production data respectively. It can be clearly observed that the difference between the simulation model and history data is significant. Our goal is to reduce this difference by changing several key parameters.

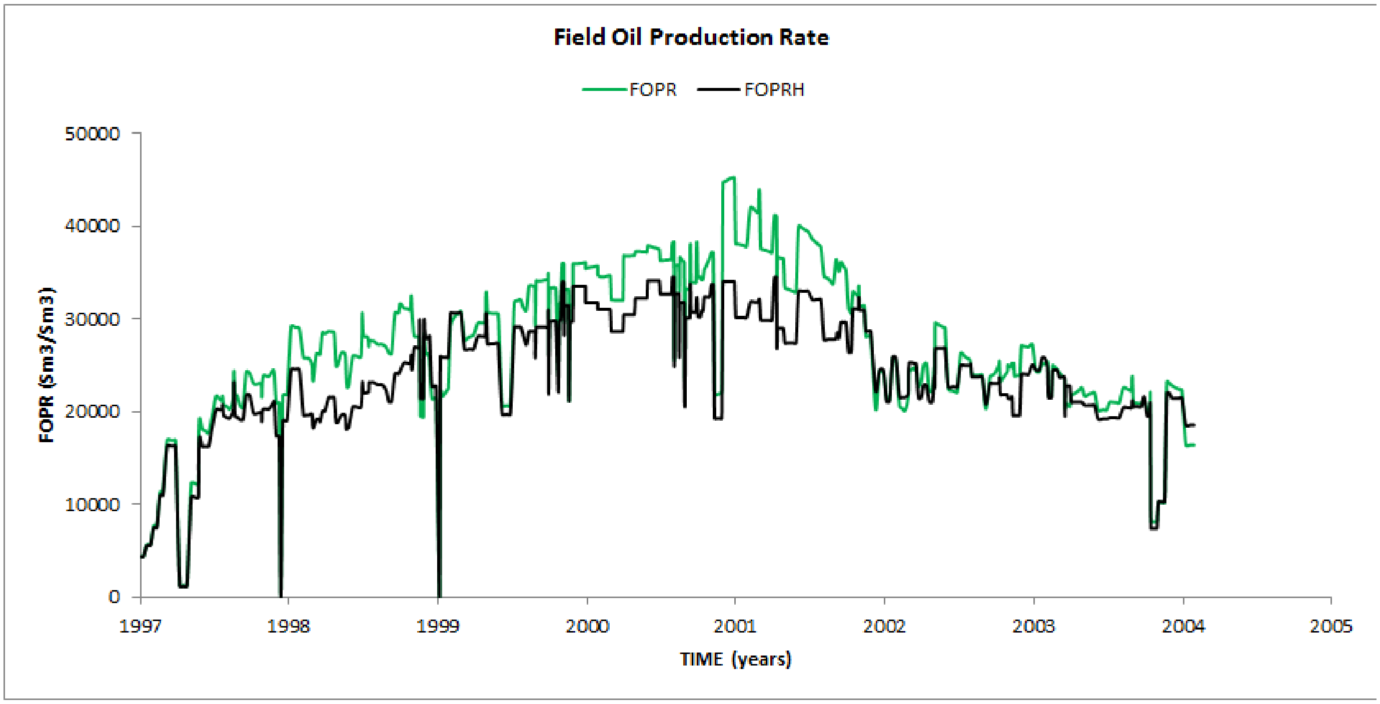

Figure 16. Field Oil Production Rate

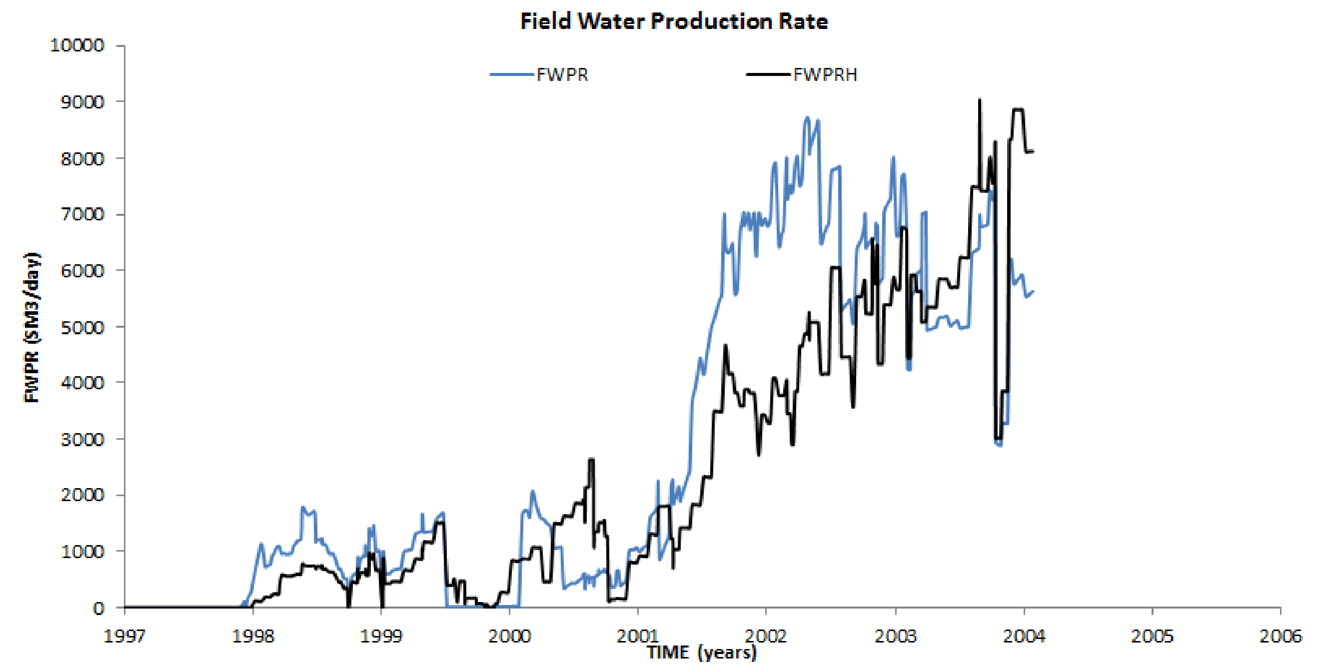

Figure 17. Field Water Production Rate.

Generally, in order to make a history matching we have to adjust the parameters with the biggest level of uncertainty. For Norne E-Segment, transmissibility factors, fault transmissibilities across the faults, skin factors and KH values around the production wells were selected as main parameters to be modified.

In order to modify transmissibilities, the EDIT section has been added to the data file. The transmissibilities were overwritten by using TRANX and TRANY keyword that have been specified with MULTIPLY keyword.

Firstly, vertical transmissibilities were modified on a field scale, but main changes have been made by changing transmissibilities around the production wells E-2H and E-3AH. Both wells were carefully examined individually in order to obtain more accurate history matching.

The next parameter that had been modified for history matching was the transmissibility across the faults. The transmissibility multipliers were adjusted for faults 'E_01' and 'E_01_F3'. It was made in order to reduce the water cut of the production wells. However the outcome was considered unsatisfactory.

The following graphs demonstrate a difference between simulation data and real data.

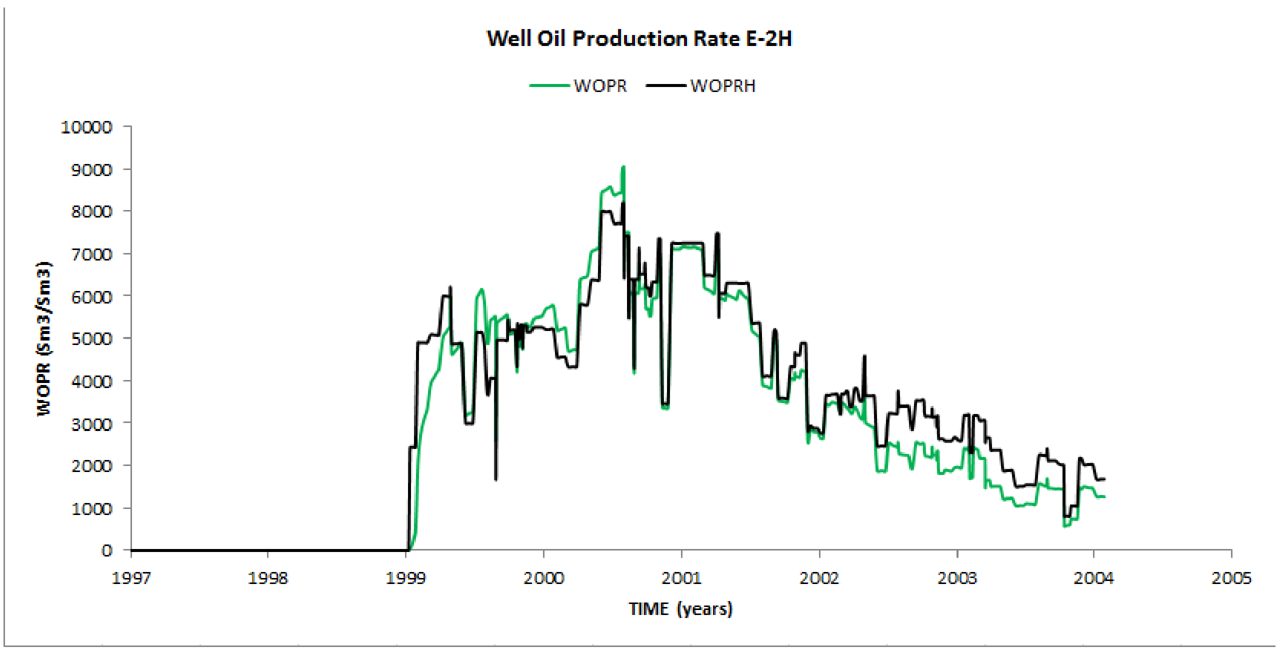

Figure 18. E-2H Oil Production Rate

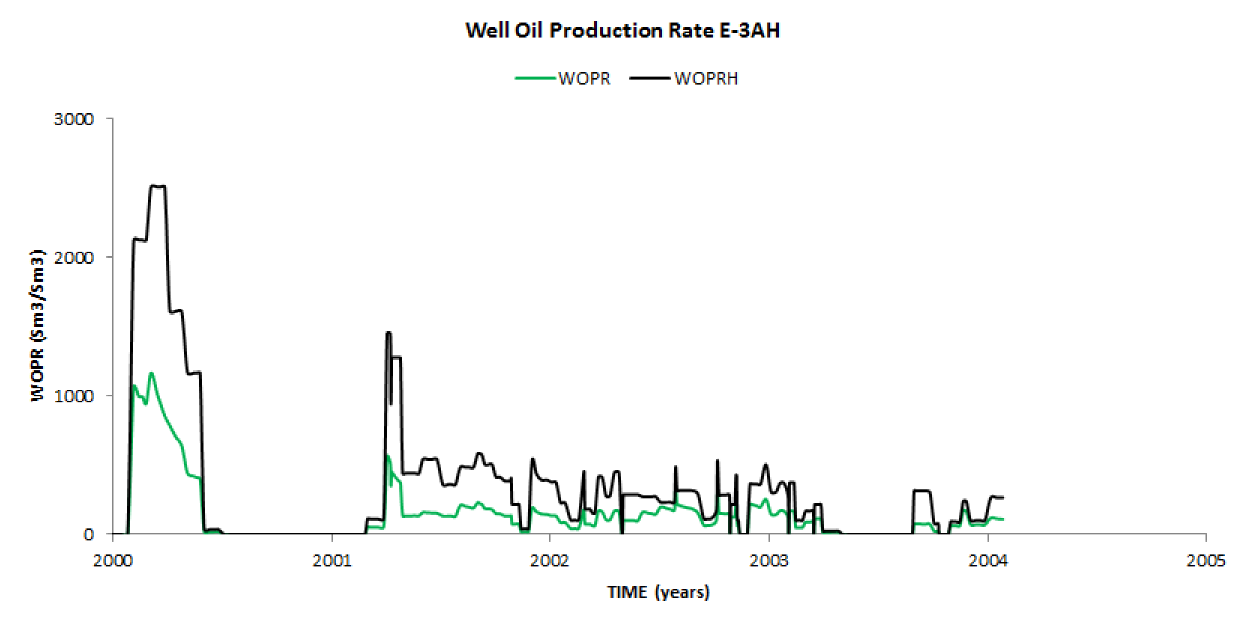

Figure 19. E-3AH Oil Production Rate

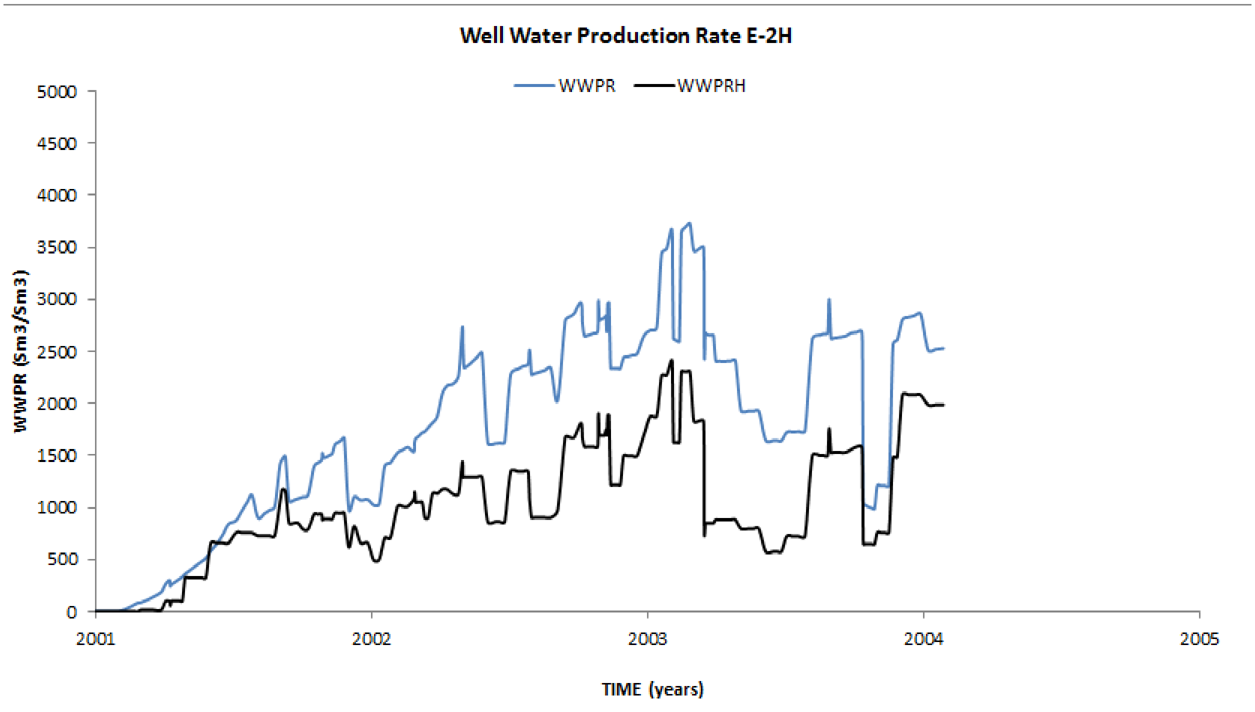

Figure 20. E-2H Water Production Rate

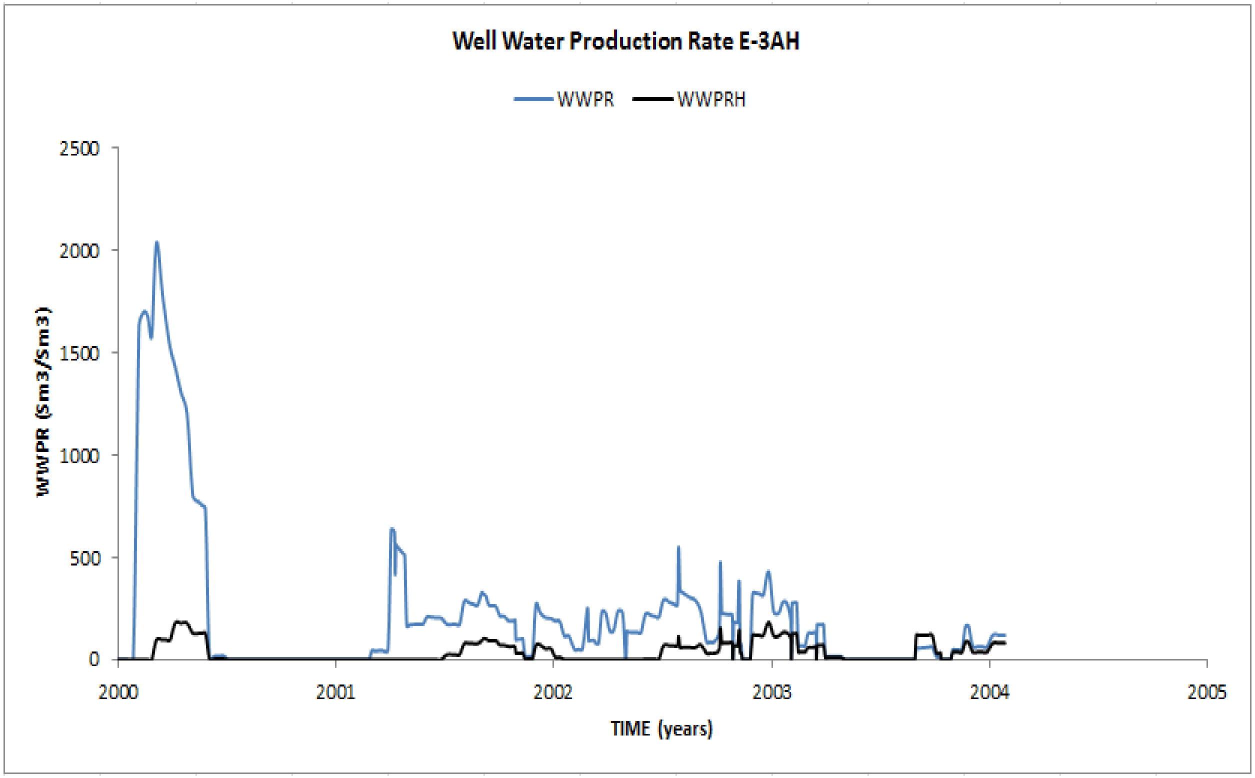

Figure 21. E-3AH Water Production Rate

As it was mentioned above, the water cut was the most difficult data to history match. It required adjusting two more key parameters in order to get better final match. In the COMPDAT section skin factor has been changed to -2 where in the base case it was equal to 0. Besides the effective Kh value of the connection was modified to comply with negative skin factor.

After all modifications and adjustments made for the wells E-2H and E-3AH the simulated data and actual data have shown visibly better match. The results for history matching after all modifications are given in the graphs below. (Figures 22 through 27)

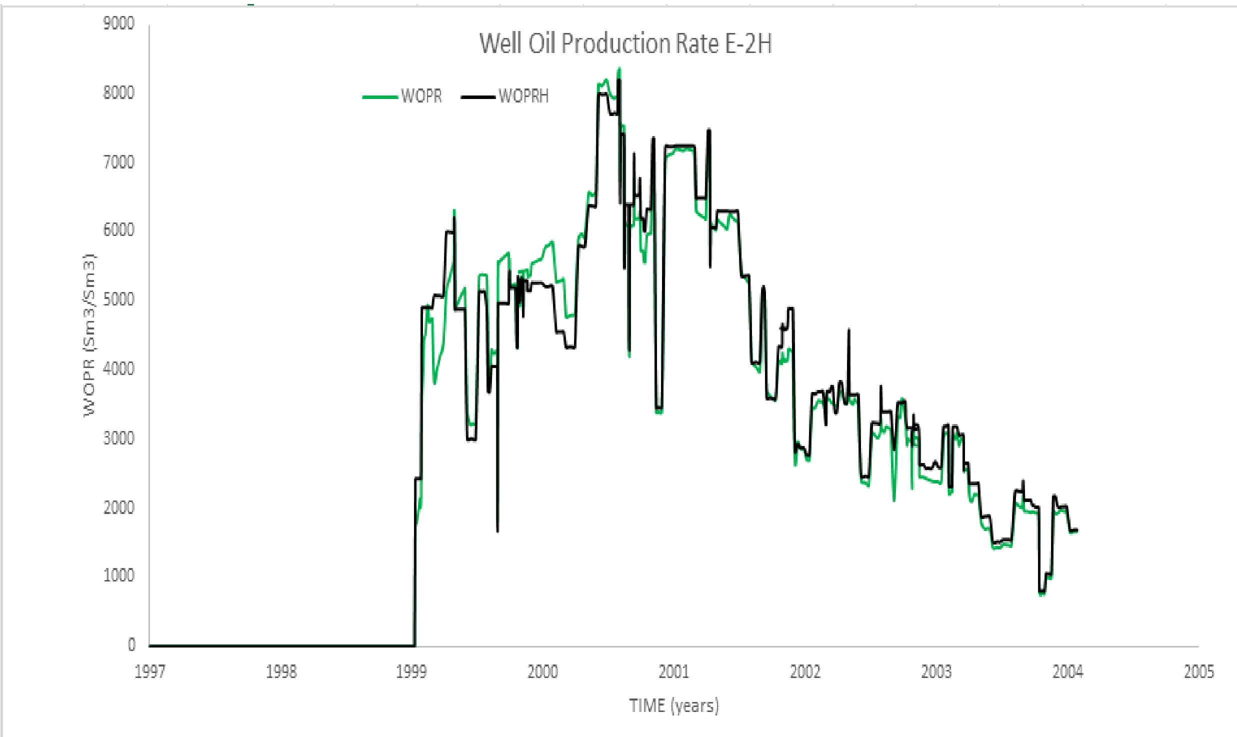

Figure 22. E-2H Oil Production Rate (final match)

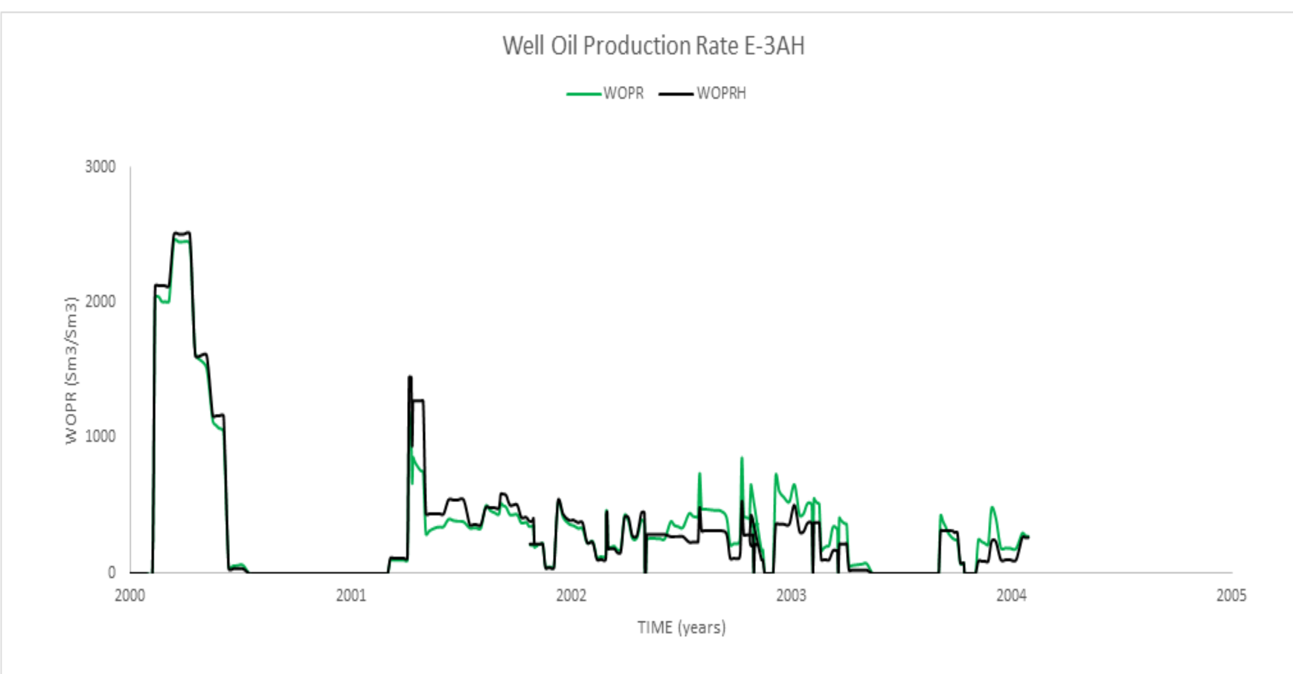

Figure 23. E-3AH Oil Production Rate (final match)

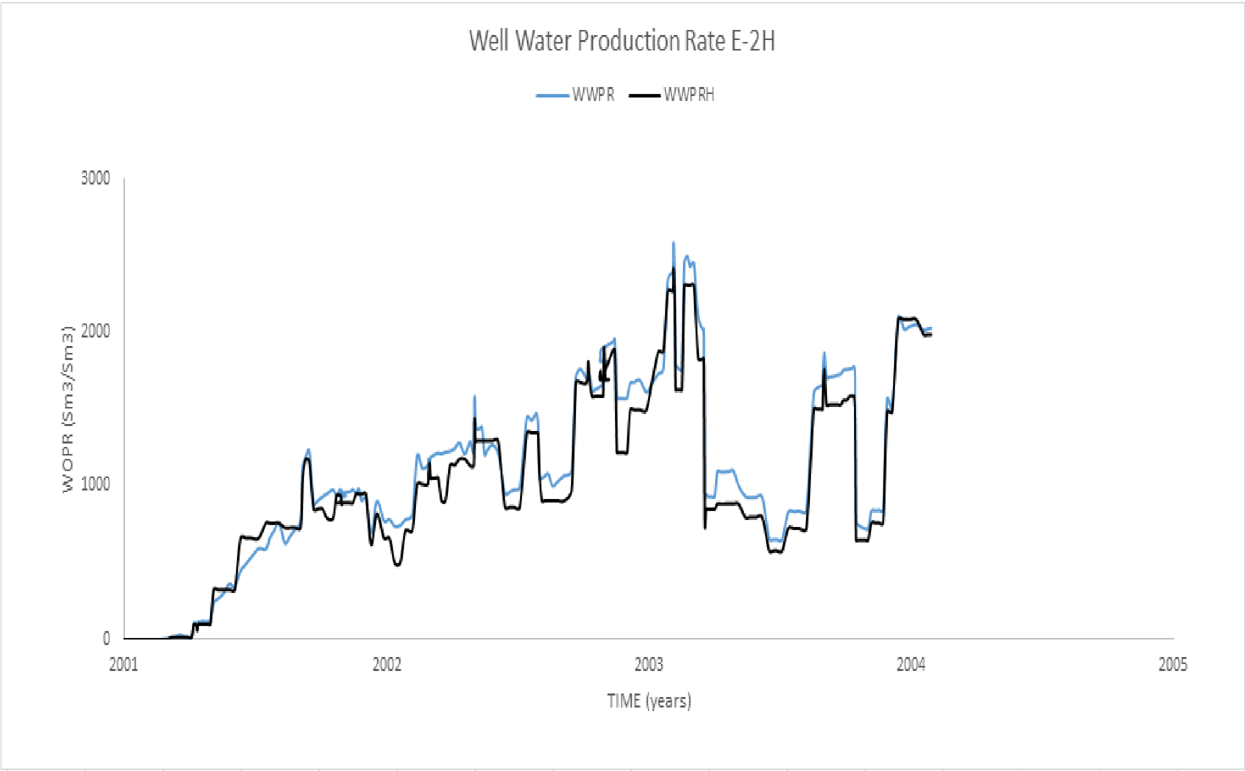

Figure 24. E-2H Water Production Rate (final match)

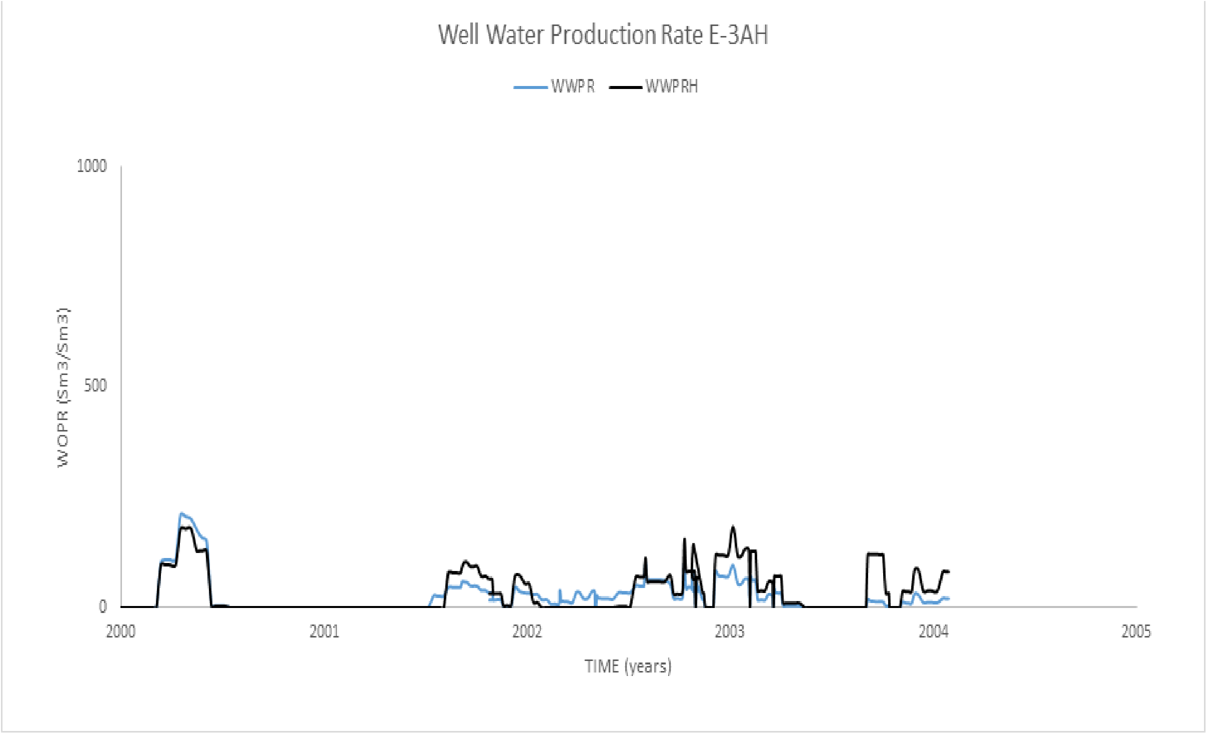

Figure 25. E-3AH Water Production Rate (final match)

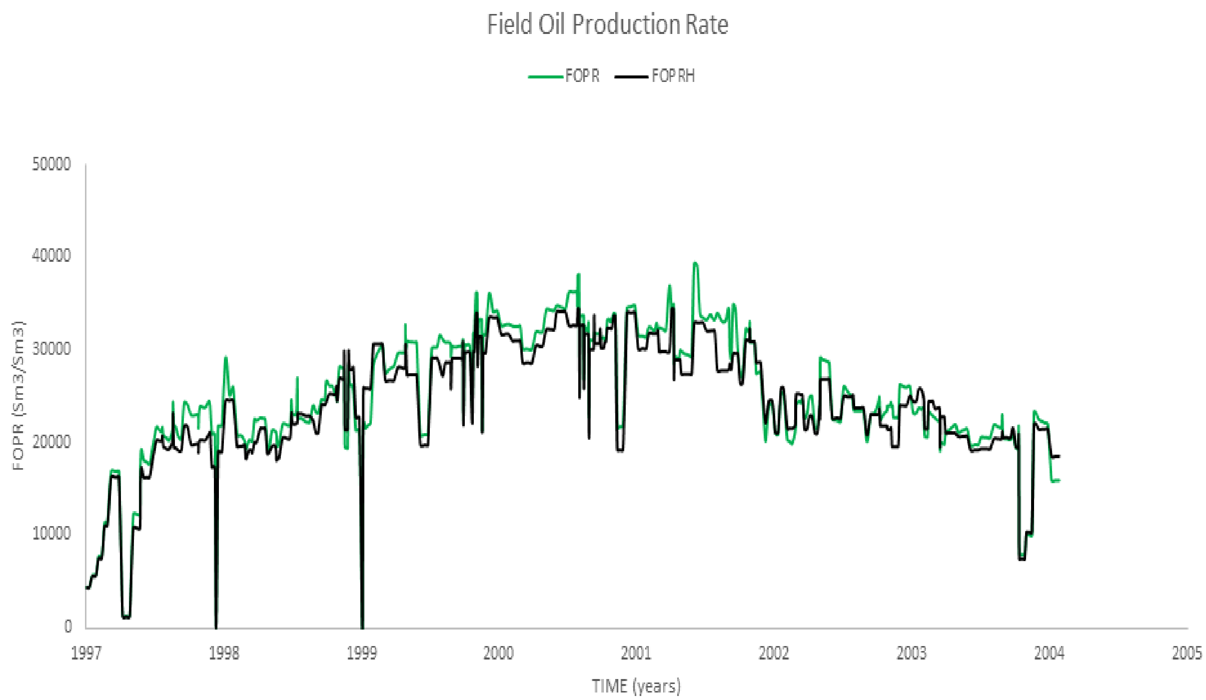

Figure 26. Field Oil Production Rate (final match)

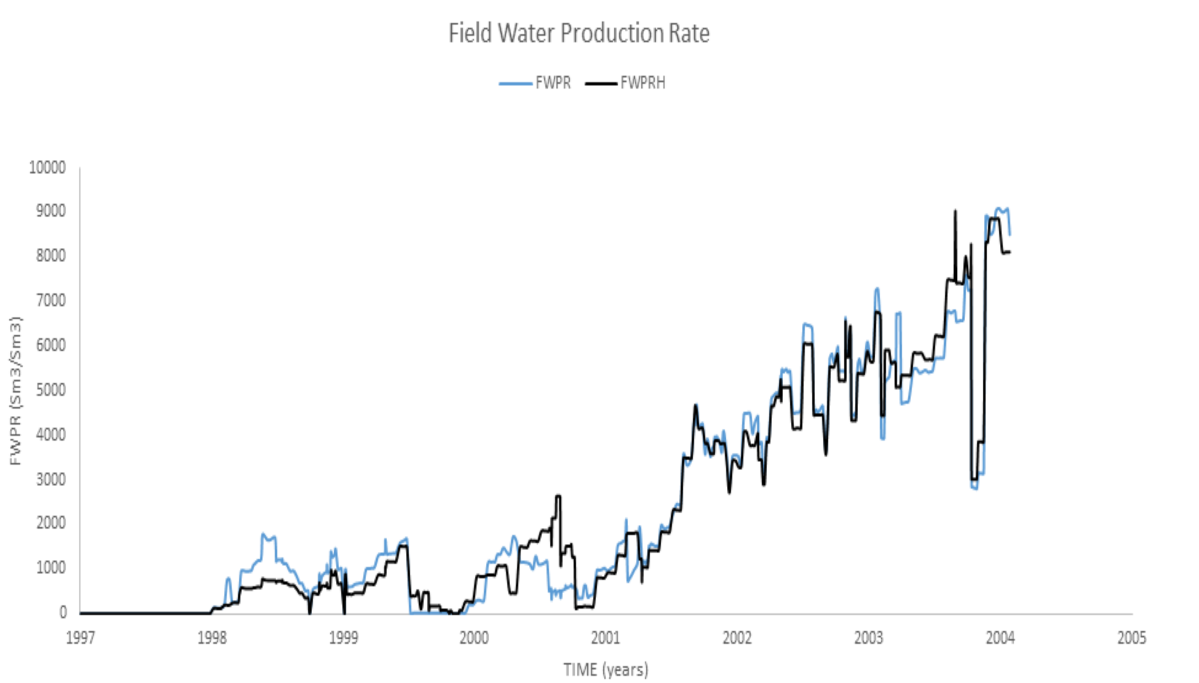

Figure 27. Field Water Production Rate (final match)

2. Synthetic Model Simulation for Testing Polymer Flooding Model

The Synthetic model was built to simulate the flooding process in this study The new Cartesian model contains 12x12x3 grid blocks with the porosity of 0.27. The base case model has two phases: oil and water. Two wells have been included in the model, one production and one injection well where the production well penetrates I=12, J=12 grid block while the injection well is located in I=1, J=1 grid block. Simulation lasted 600 days. Different cases have been simulated. As a result, the best recovery achieved during the polymer injection first 540 days with the following water injection. The best polymer concentration is 0.5 kg/m3.

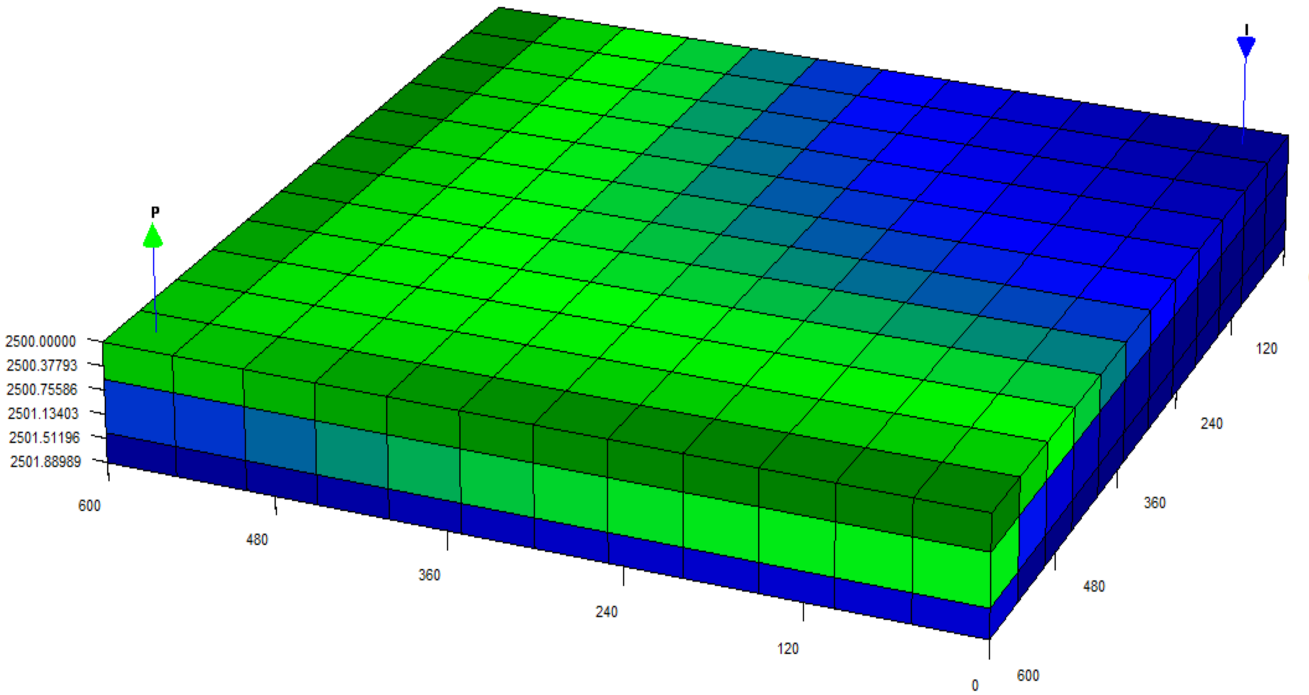

Figure 28. Synthetic model

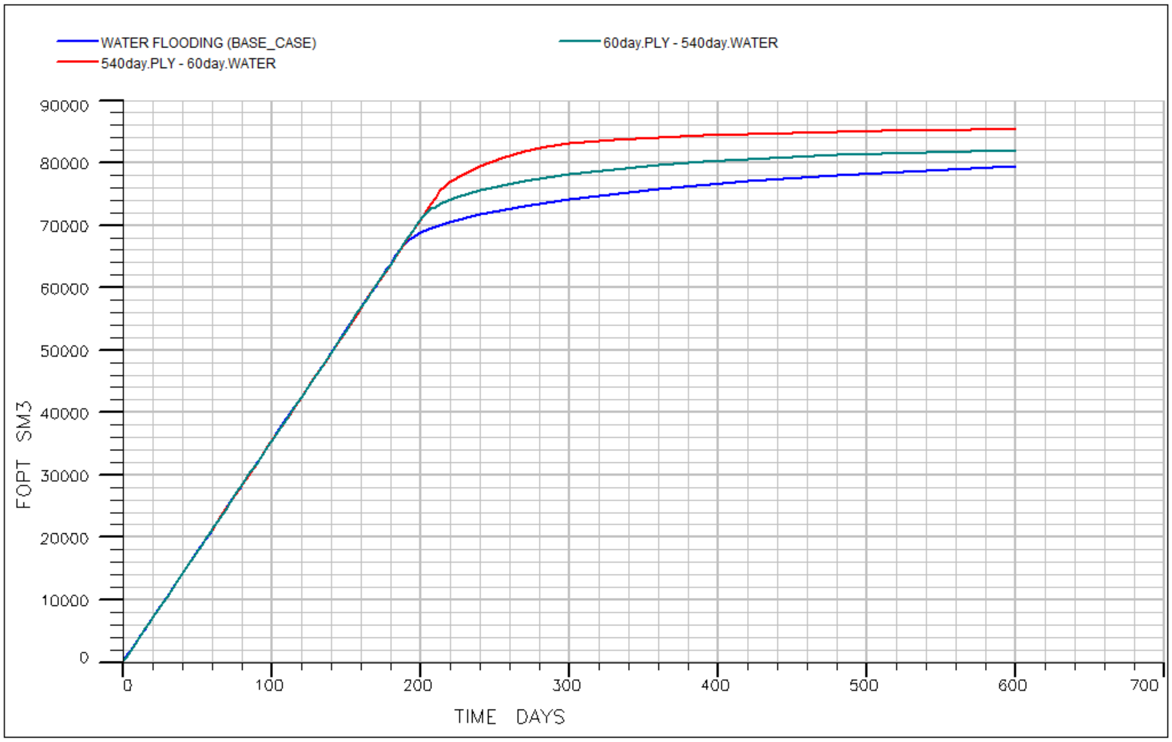

Figure 29. Field Oil Recovery for different injection time

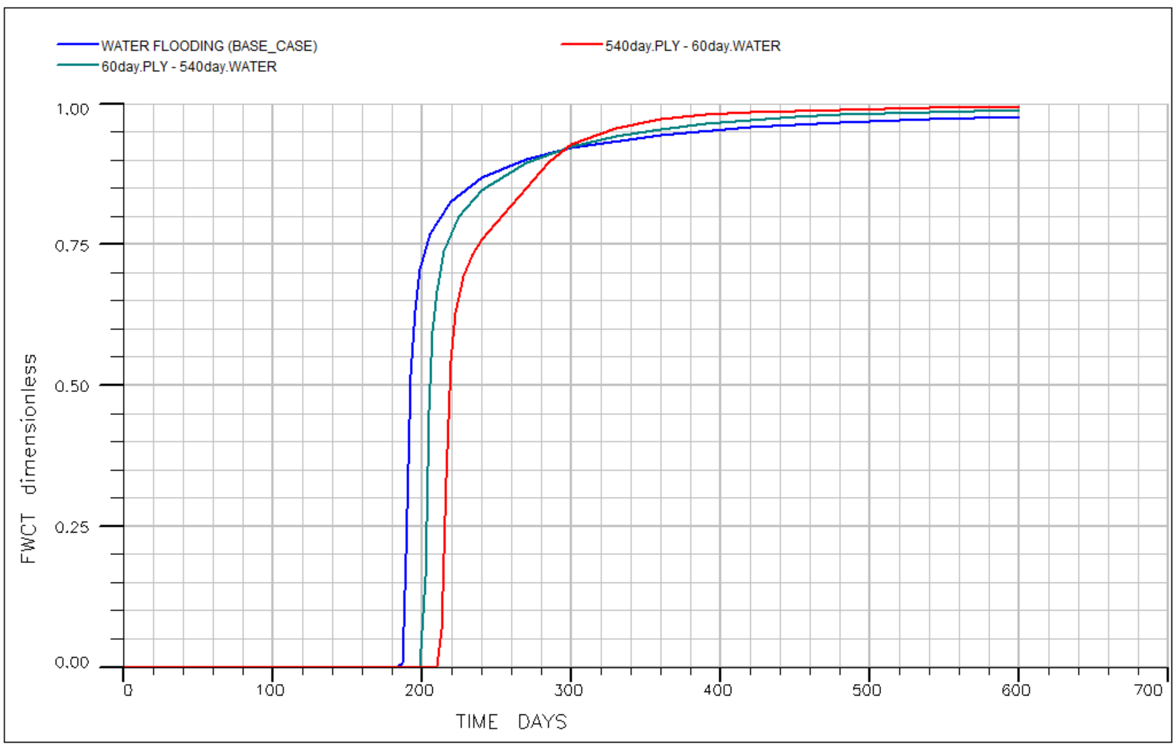

Figure 30. Total Water Production for Different Injection Time

The polymer flooding provides an increase in the oil recovery around 8%. The positive results of the synthetic model polymer flooding gives us the confidence to apply the polymer study for the real Norne E-Segment simulation model. Though, it may not give desirable results in the real model, since the synthetic model was assumed homogenous and did not take into account any heterogeneity.

3. Polymer Flooding Study in the Norne E-Segment

There are 5 wells in the Norne E-Segment. 2 active producers (E-2H, E-3AH) and two injectors F-1H amd F-3H

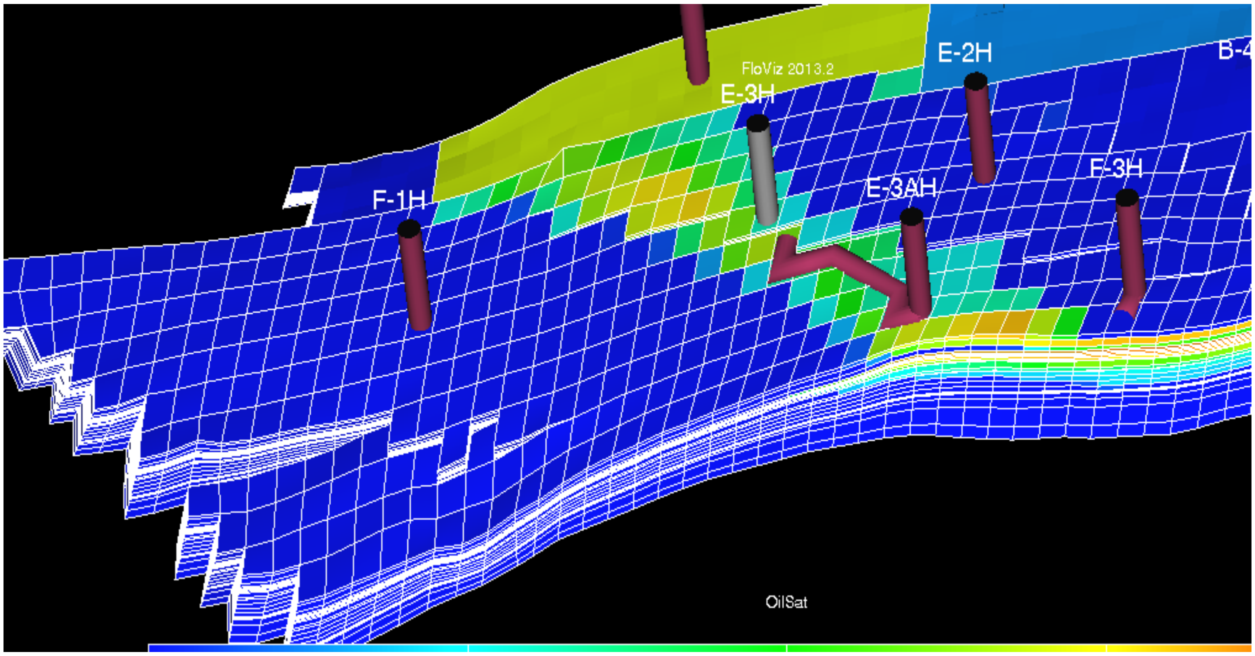

Figure 31. Norne E-Segment.

As it can be seen from the Figure 31. Well F-1H is located in the water region and polymer injection will not have an effect. That's why, well F-3H is selected as the main injector for the polymer flooding.

The Norne E-Segment base case model is simulated until December 2004. Thus, the prediction was made from 2005 until 2021 and the polymer injection was applied from July 2014 until January 2018 followed by water injection until 2021.

Two main sensitivity analyses were implemented for the polymer study:

- Polymer concentration sensitivity
- Water injection rate sensitivity

3.1. Polymer Concentration Sensitivity

In order to analyze the effect of the polymer concentration the simulation model has been run for different concentrations. Since the viscosity depends on the polymer concentration and the oil recovery is influenced by the viscosity it is important to carefully examine the polymer concentration effect. The polymer has been injected from July 2014 to January 2018 followed by water injection without polymer. The graphs below illustrate the simulation results with the concentrations at 0,2 kg/m3, 0,35 kg/m3, 0,6 kg/m3 and 0,85 kg/m3.

It can be seen from the figure 32 that higher polymer concentration of 0.85 kg/m3 gives greater oil production and the concentration at 0.2 kg/m3 represents the lower production. An obvious reason for that is that the polymer concentration diminishes the mobility ratio by increasing the water viscosity. Thus, the efficiency of the polymer flooding increases with increasing viscosity.

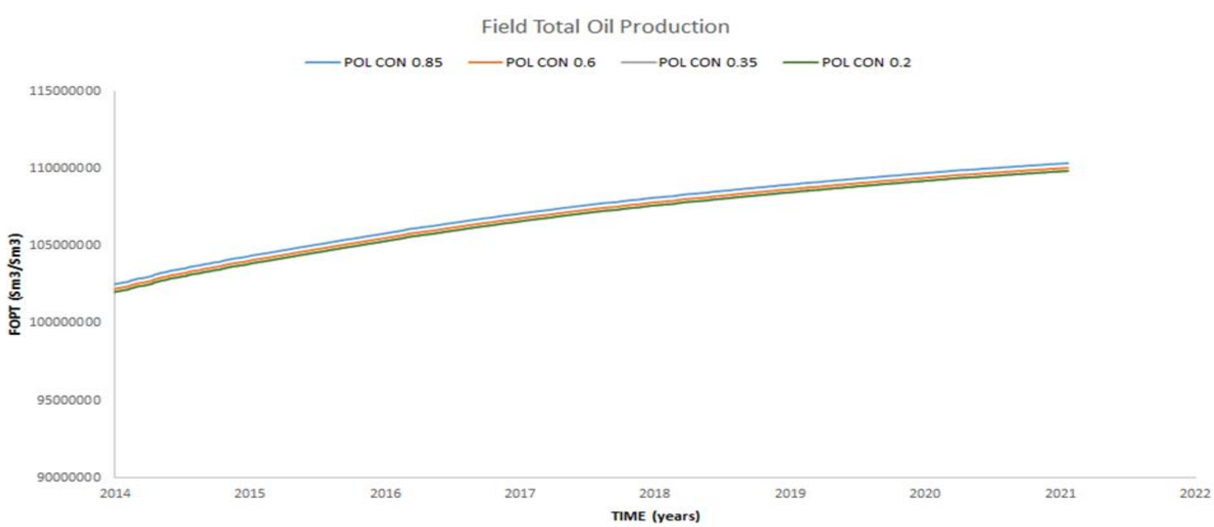

Figure 32. Field Total Oil Production for Different Polymer Concentrations

Figure 33 represents the polymer production plot. It can be observed that higher polymer concentrations correspond to the lower polymer production. It can be explained by the fact that higher concentrations increase the viscosity which yields better mobility ratio. This could develop the bigger sweep area and the polymer adsorption level increases.

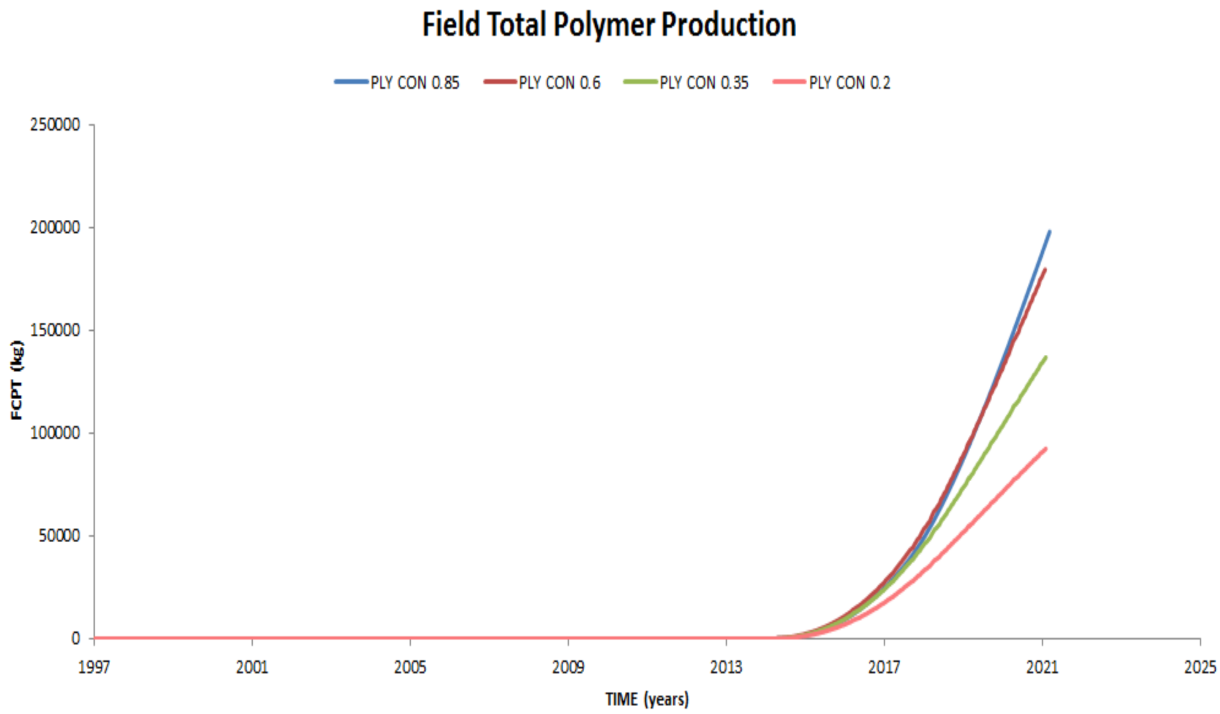

Figure 33. Field Total Polymer Production

Figure 34 shows the bottom-hole pressure of the production well F-3H.In accordance with simulation results, higher polymer concentration corresponds to higher reservoir pressure. Polymer flooding at concentration of 0.85 kg/m3 shows big increase in oil recovery compare to other cases but at that concentration the incremental bottom-hole pressure of injection increases more than 50 bara which makes this case impracticable. However, the case of 0.6 kg/m3 could be considered as fine suggestion.

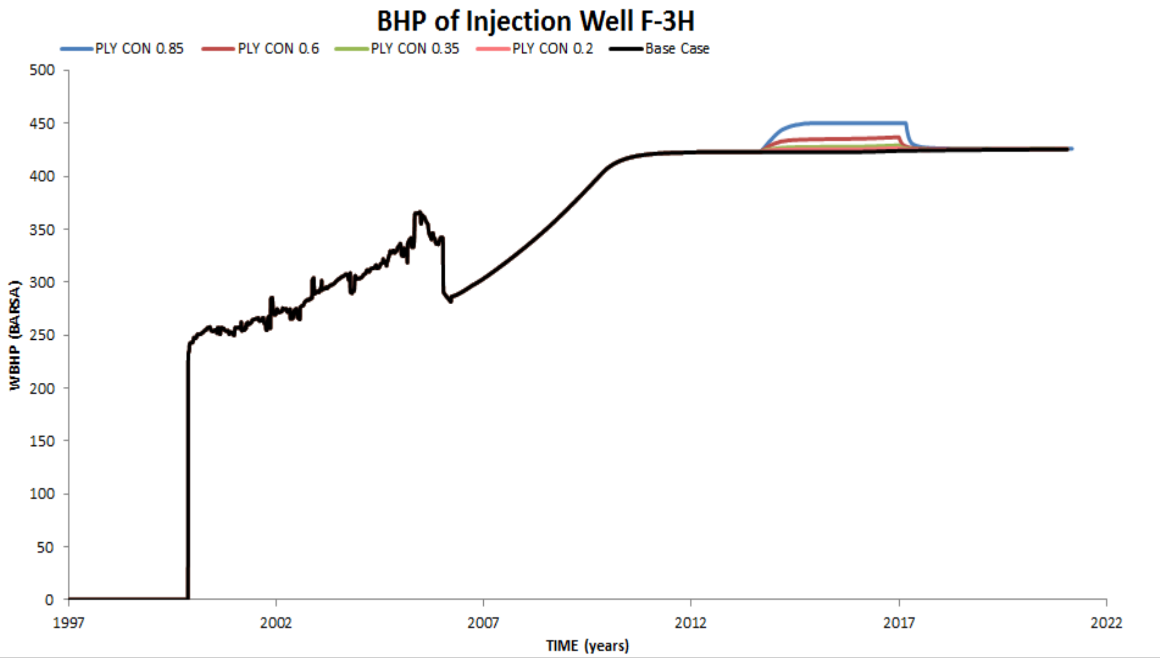

Figure 34: Bottom-hole Pressure of the Injection Well F-3H for different concentration

3.2. Water Injection Rate Sensitivity

The next sensitivity analysis was implemented for the changing injection rates. The model has been run for four different injection rates of 1500 Sm3/day, 4000 Sm3/day, 7000 Sm3/day and 10000 Sm3/day. The rate of 4000 Sm3/day was assumed as the base case injection rate for well F-3H and the concentration were kept at 0,35 kg/m3 for all cases.

It is observed from the Figure 35 that the oil production decreases with increasing injection rates. The oil production at 1500 Sm3/day is slightly greater than the base case oil production. It can be explained by early water breakthrough.

The reservoir pressure and the bottom-hole pressure show the similar behavior at the base case injection rate (4000 Sm3/day) and 1500 Sm3/day. At lower injection rates the pressure drop is also low. At the same time higher rates give high WBHP and low oil production. According to the simulation results the injection rate at 4000 Sm3/day or lower might be applicable for the Norne E-Segment.

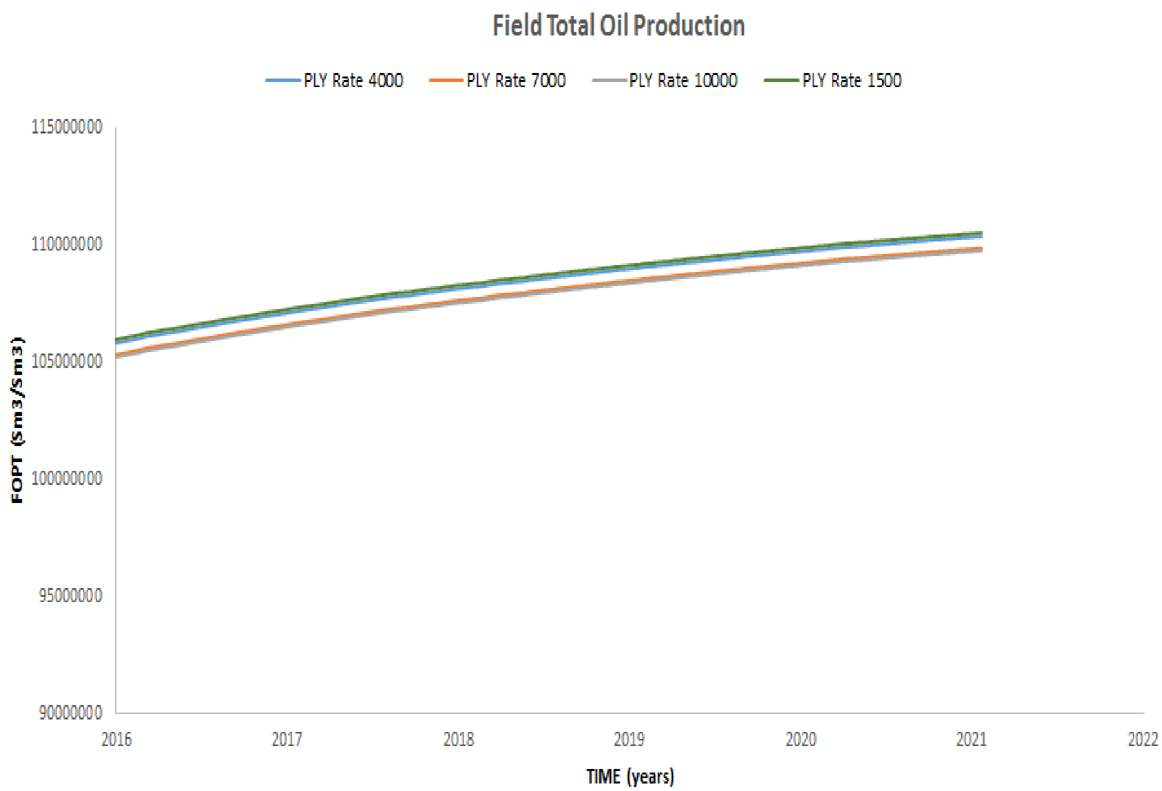

Figure 35. Field Total Oil Production for Different Injection Rates

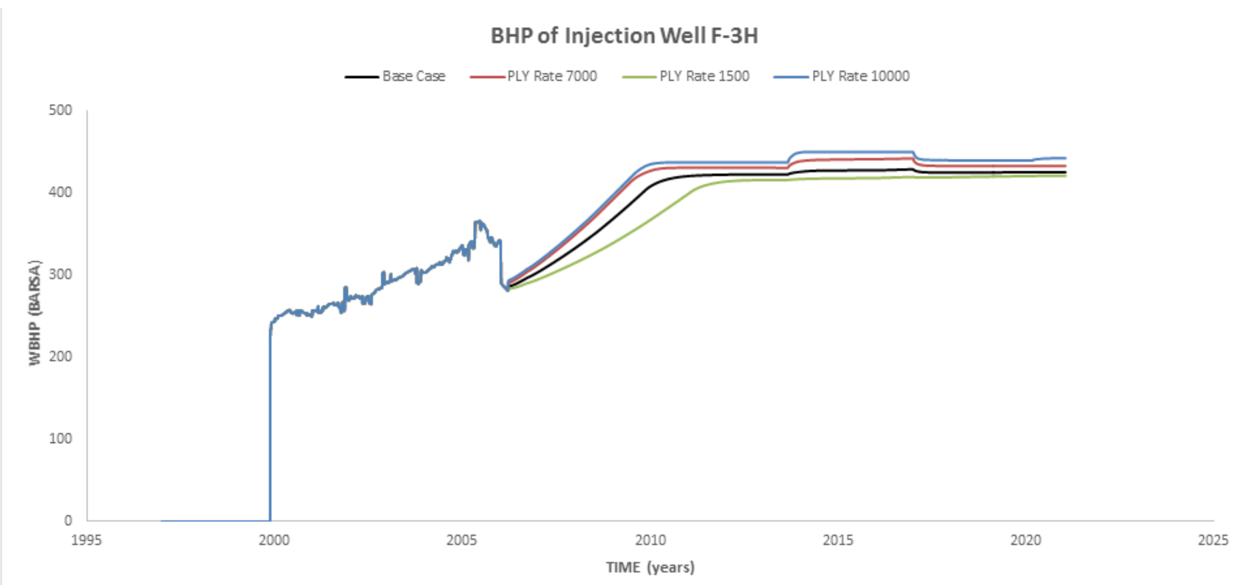

Figure 36: Bottom-hole Pressure of the Injection Well F-3H for different injection rate

Conclusions

- Transmissibility adjustments in a field scale and especially around the production wells gives better match between simulation model and real data.
- The water cut was the most difficult parameter to adjust. In order to reduce the water cut the skin factor and Kh values of the production wells have been modified.
- As a result of all modifications and adjustments the difference between actual and model data have been decreased and better match was obtained for Norne E-Segment

- F-3H was selected as an injector for polymer flooding
- Oil production is higher for higher polymer concentrations
- Higher polymer concentrations correspond to the lower polymer production.
- Polymer flooding at 0.85 kg/m3 concentration is not applicable due to high incremental BHP of injection. The case of 0.6 kg/m3 might be proposed instead as it gives good oil production.
- The rate of injection of 4000 Sm3/day or lower might be favorable for polymer flooding.
- Polymer did not show a good performance for the field model, however for the synthetic model an increase in the oil recovery around 8% was observed.

Recommendation

The time and the duration of the polymer injection is very important considering that the polymer flooding is less efficient during lower oil saturations.

Different types of polymers can be studied and analyzed to select the appropriate polymer for the field application. The right polymer type with suitable properties can be elaborated in the laboratory.

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Appendix

1. Polymer Properties

--PLYSHEAR

--Polymer shear thinning data

-- Wat. Velocity		Visc reduction
-- m/day	CP	
--0.0		1.0
--2.0		1.0 /

-- Polymer solution Viscosity Function

PLYVISC

-- Ply conc.	Wat. Visc. mult.	
-- kg/m3		
0.0		1.0
0.1		1.55
0.3		2.55
0.5		5.125
0.7		8.125
1.0		21.2 /

/

-- Polymer Adsorption Function

PLYADS

-- Ply conc.	Ply conc.	
--	Adsorbed by rock	
-- kg/m3	kg/kg	
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-- Todd-Longstaff Mixing Parameters
PLMIXPAR
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-- Polymer-Salt concentration for mixing
-- maximum polymer and salt concentration
PLYMAX
-- Ply conc.      Salt conc.
-- kg/m3          kg/m3
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1.0                 0.0 /

--Polymer-Rock Properties
PLYROCK
--dead      residual        mass       Ads.      max.
--pore      resistance      density    Index     Polymer
--space     factor                     adsorption

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0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /
0.16	1.0	2650.0 2	0.000017 /

0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /
0.16	1.0	2650.0	2	0.000017 /

```
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
0.16        1.0        2650.0 2    0.000017 /
RPTPROPS
'PLYVISC' /
```

2. Eclipse Base Case Data File for the Norne E-Segment

```
-- water injection rate of F-1, F-2, and F-3 by 50

----------------------------------------------------------------------------

-- Ny model July 2004 build by marsp/oddhu
-- New grid with sloping faults based on geomodel xxx
-------------------------------------

RUNSPEC

--LICENSES
--'NETWORKS' /
--/

DIMENS
 46 112 22   /

--NOSIM


--
-- Allow for multregt, etc. Maximum number of regions 20.
--
GRIDOPTS
 'YES' 0 /

OIL

WATER
```

```
GAS

DISGAS

VAPOIL

METRIC

-- use either hysteresis or not hysteresis
--NOHYST
HYST

START
 06  'NOV' 1997 /

EQLDIMS
 5  100  20 /

EQLOPTS
 'THPRES'  /   no fine equilibration if swatinit is being used

REGDIMS
-- ntfip  nmfipr  nrfreg  ntfreg
    22      4      1*      20    /

TRACERS
--  oil  water  gas  env
    1*    10    1*    1*   /

WELLDIMS
```

```
--ML  40  36  15  15 /
 130  36  15  84 /

--WSEGDIMS
-- 3  30  3 /

LGR
-- maxlgr maxcls mcoars mamalg mxlalg lstack interp
      4   2000   693      1      4      20  'INTERP' /

TABDIMS
--ntsfun ntpvt nssfun nppvt ntfip nrpvt ntendp
    110     2     33     60   16    60 /

-- WI_VFP_TABLES_080905.INC = 10-20

VFPIDIMS
 30    20   20 /

-- Table no.
-- DevNew.VFP        = 1
-- E1h.VFP           = 2
-- AlmostVertNew.VFP = 3
-- GasProd.VFP       = 4
-- NEW_D2_GAS_0.00003.VFP = 5
-- GAS_PD2.VFP = 6
-- pd2.VFP           = 8 (flowline south)
-- pe2.VFP           = 9 (flowline north)
-- PB1.PIPE.Ecl  = 31
-- PB2.PIPE.Ecl  = 32
-- PD1.PIPE.Ecl  = 33
```

```
-- PD2.PIPE.Ecl  = 34
-- PE1.PIPE.Ecl  = 35
-- PE2.PIPE.Ecl  = 36
-- B1BH.Ecl = 37
-- B2H.Ecl  = 38
-- B3H.Ecl  = 39
-- B4DH. Ecl= 40
-- D1CH.Ecl = 41
-- D2H.Ecl  = 42
-- D3BH.Ecl = 43

-- E1H.Ecl  = 45
-- E3CH.Ecl = 47
-- K3H.Ecl  = 48


VFPPDIMS
 19  10  10  10  0  50 /

FAULTDIM
10000 /

PIMTDIMS
1  51 /

NSTACK
 30 /

UNIFIN
UNIFOUT
```

```
--RPTRUNSPEC

OPTIONS
77* 1 /

-------------------------------------------------------
--
--   Input of grid geometry
--
-------------------------------------------------------
GRID

NEWTRAN

GRIDFILE
  2  /

-- optional for postprocessing of GRID
MAPAXES
 0.  100.  0.  0.  100.  0.  /

GRIDUNIT
METRES  /

-- do not output GRID geometry file
--NOGGF
-- requests output of INIT file
INIT

MESSAGES
 8*10000  20000 10000 1000 1* /
```

```
PINCH
 0.001 GAP  1* TOPBOT TOP/

NOECHO

---------------------------------------------------------
--
--   Grid and faults
--
---------------------------------------------------------


--
-- Simulation grid, with slooping faults:
--
-- file in UTM coordinate system, for importing to DecisionSpace
INCLUDE
 './INCLUDE/GRID/IRAP_1005.GRDECL' /
--  '/project/norne6/res/INCLUDE/GRID/IRAP_0704.GRDECL' /

--
INCLUDE
 './INCLUDE/GRID/ACTNUM_0704.prop' /

--
-- Faults
--
--
INCLUDE
 './INCLUDE/FAULT/FAULT_JUN_05.INC' /
```

```
-- Additional faults

--Nord for C-3 (forlengelse av C_10)
EQUALS
  MULTY  0.01   6  6 22 22  1 22  /
/
-- B-3 water
EQUALS
  'MULTX'  0.001  9 11 39 39  1 22 /
  'MULTY'  0.001  9 11 39 39  1 22 /
  'MULTX'  0.001  9  9 37 39  1 22 /
  'MULTY'  0.001  9  9 37 39  1 22 /
/
-- C-1H
EQUALS
  'MULTY'  0.001     26 29 39 39  1 22 /
/

-------------------------------------------------------
--
--   Input of grid parametres
--
-------------------------------------------------------

--
INCLUDE
 './INCLUDE/PETRO/PORO_0704.prop' /

--
INCLUDE
 './INCLUDE/PETRO/NTG_0704.prop' /
```

```
--
INCLUDE
 './INCLUDE/PETRO/PERM_0704.prop' /

-- G segment north
EQUALS
  PERMX  220  32  32  94  94   2   2 /
  PERMX  220  33  33  95  99   2   2 /
  PERMX  220  34  34  95  97   2   2 /
  PERMX  220  35  35  95  98   2   2 /
  PERMX  220  36  36  95  99   2   2 /
  PERMX  220  37  37  95  99   2   2 /
  PERMX  220  38  38  95 100   2   2 /
  PERMX  220  39  39  95 102   2   2 /
  PERMX  220  40  40  95 102   2   2 /
  PERMX  220  41  41  95 102   2   2 /
/

-- C-1H
MULTIPLY
  PERMX    4  21  29  39  49  16  18 /
  PERMX  100  21  29  39  49  19  20 /
/

COPY
   PERMX PERMY /
   PERMX PERMZ /
/

-- Permz reduction is based on input from PSK
```

```
-- based on same kv/kh factor
-- ******************************************
-- CHECK! (esp. Ile & Tofte)
-- ******************************************
MULTIPLY
  'PERMZ' 0.2    1 46 1 112  1  1 /    Garn 3
  'PERMZ' 0.04   1 46 1 112  2  2 /    Garn 2
  'PERMZ' 0.25   1 46 1 112  3  3 /    Garn 1
  'PERMZ' 0.0    1 46 1 112  4  4 /    Not (inactive anyway)
  'PERMZ' 0.13   1 46 1 112  5  5 /    Ile 2.2
  'PERMZ' 0.13   1 46 1 112  6  6 /    Ile 2.1.3
  'PERMZ' 0.13   1 46 1 112  7  7 /    Ile 2.1.2
  'PERMZ' 0.13   1 46 1 112  8  8 /    Ile 2.1.1
  'PERMZ' 0.09   1 46 1 112  9  9 /    Ile 1.3
  'PERMZ' 0.07   1 46 1 112 10 10 /    Ile 1.2
  'PERMZ' 0.19   1 46 1 112 11 11 /    Ile 1.1
  'PERMZ' 0.13   1 46 1 112 12 12 /    Tofte 2.2
  'PERMZ' 0.64   1 46 1 112 13 13 /       Tofte 2.1.3
  'PERMZ' 0.64   1 46 1 112 14 14 /       Tofte 2.1.2
  'PERMZ' 0.64   1 46 1 112 15 15 /       Tofte 2.1.1
  'PERMZ' 0.64   1 46 1 112 16 16 /       Tofte 1.2.2
  'PERMZ' 0.64   1 46 1 112 17 17 /       Tofte 1.2.1
  'PERMZ' 0.016  1 46 1 112 18 18 /       Tofte 1.1
  'PERMZ' 0.004  1 46 1 112 19 19 /       Tilje 4
  'PERMZ' 0.004  1 46 1 112 20 20 /       Tilje 3
  'PERMZ' 1.0    1 46 1 112 21 21 /       Tilje 2
  'PERMZ' 1.0    1 46 1 112 22 22 /       Tilje 1
/
```

```
--
--      Barriers
--
-------------------------------------------------------
-- 20 flux regions generated by the script Xfluxnum
--
INCLUDE
 './INCLUDE/PETRO/FLUXNUM_0704.prop' /



-- modify transmissibilites between fluxnum using MULTREGT
--
INCLUDE
 './INCLUDE/PETRO/MULTREGT_D_27.prop' /

NOECHO

MINPV
  500 /

EQUALS
'MULTZ'   0.00125  26  29  30  37  10  10  /  better WCT match for B-2H
'MULTZ'   0.015    19  29  11  30  8  8    /  better WCT match for D-1CH

'MULTZ'   1        6   12  16  22  8  11  / for better WCT match for K-3H
'MULTZ'   .1       6   12  16  22  15 15  / for better WCT match for K-3H
/

COARSEN
-- I1 I2 J1 J2 K1 K2 NX NY NZ
 6 29 11 44  1  3 1 1  3/
```

6 29 11 44 5 22 1 1 18 /

16 19 45 67 1 3 1 1 3 /

16 19 45 67 5 22 1 1 18 /

20 25 45 67 1 3 1 1 3 /

20 25 45 67 5 22 1 1 18 /

26 29 45 67 1 3 1 1 3 /

26 29 45 67 5 22 1 1 18 /

30 41 63 75 1 3 1 1 1 /

30 41 63 75 5 20 1 1 16 /

30 41 63 75 22 22 1 1 1 /

30 41 76 93 1 3 1 1 1 /

30 41 76 93 5 9 1 1 5 /

30 41 76 93 12 20 1 1 9 /

30 41 76 93 22 22 1 1 1 /

30 37 58 62 1 3 1 1 1 /

30 37 58 62 5 22 1 1 18 /

30 34 54 57 1 3 1 1 1 /

30 34 54 57 5 18 1 1 14 /

30 34 54 57 20 22 1 1 3 /

30 32 51 53 1 3 1 1 1 /

30 32 51 53 5 22 1 1 18 /

30 30 48 48 1 3 1 1 1 /

30 30 50 50 1 3 1 1 1 /

30 30 48 48 5 22 1 1 18 /

30 30 50 50 5 22 1 1 18 /

33 33 52 53 1 3 1 1 1 /

33 33 52 53 5 22 1 1 18 /

35 36 57 57 1 3 1 1 1 /

35 36 57 57 5 22 1 1 18 /

38 38 59 60 1 3 1 1 1 /

38 38 59 60 5 22 1 1 18 /

38 39 61 62 1 3 1 1 1 /

38 39 61 62 5 22 1 1 18 /

17 19 68 85 1 3 1 1 1 /

17 19 68 85 5 22 1 1 18 /

17 19 86 89 1 3 1 1 1 /

17 19 86 89 5 22 1 1 18 /

22 25 68 70 1 3 1 1 1 /

26 29 68 70 1 3 1 1 1 /

20 21 68 70 5 22 1 1 18 /

20 21 68 69 1 3 1 1 1 /

22 25 68 69 5 22 1 1 18 /

26 29 68 69 5 22 1 1 18 /

10 15 45 51 1 3 1 1 3 /

10 15 45 51 5 22 1 1 18 /

13 15 52 57 1 3 1 1 3 /

13 15 52 57 5 22 1 1 18 /

11 12 52 54 1 3 1 1 3 /

11 12 52 54 5 22 1 1 18 /

12 12 55 56 1 3 1 1 3 /

12 12 55 56 5 22 1 1 18 /

10 10 52 53 1 3 1 1 3 /

10 10 52 53 5 22 1 1 18 /

13 15 58 59 1 3 1 1 3 /

13 15 58 59 5 22 1 1 18 /

14 15 60 61 1 3 1 1 3 /

14 15 60 61 5 22 1 1 18 /

15 15 62 64 1 3 1 1 3 /

15 15 62 64 5 22 1 1 18 /

16 16 68 69 1 3 1 1 3 /

16 16 68 69 5 22 1 1 18 /

8 9 45 46 1 3 1 1 3 /

```
 8  9 45 46  5 22 1 1 18 /
 9  9 47 48  1  3 1 1  3 /
 9  9 47 48  5 22 1 1 18 /
31 41 94 95  1  3 1 1  1 /
31 41 94 95  5 22 1 1 18 /
34 41 96 97  1  3 1 1  1 /
34 41 96 97  5 22 1 1 18 /
36 41 98 99  1  3 1 1  1 /
36 41 98 99  5 22 1 1 18 /
39 41 100 102  1  3 1 1  1 /
39 41 100 102  5 22 1 1 18 /
/

--------------------------------------------------

PROPS
--------------------------------------------------------------------------------
--
--    Input of fluid properties and relative permeability
--
---------------------------------------------------------

NOECHO



-- Input of PVT data for the model
-- Total 2 PVT regions (region 1 C,D,E segment, region 2 Gsegment)
--
INCLUDE
 './INCLUDE/PVT/PVT-WET-GAS.DATA' /
```

```
TRACER
  'SEA'  'WAT'  /
  'HTO'  'WAT'  /
  'S36'  'WAT'  /
  '2FB'  'WAT'  /
  '4FB'  'WAT'  /
  'DFB'  'WAT'  /
  'TFB'  'WAT'  /
/

-------------------------------------------------------
--
-- initialization and relperm curves: see report blabla
--
-------------------------------------------------------

-- rel. perm and cap. pressure tables --

--
INCLUDE
 './INCLUDE/RELPERM/HYST/swof_mod4Gseg_aug-2006.inc' /


--Sgc=10 0.000000or g-segment
--
INCLUDE
 './INCLUDE/RELPERM/HYST/sgof_sgc10_mod4Gseg_aug-2006.inc' /

--
--INCLUDE
-- './INCLUDE/RELPERM/HYST/waghystr_mod4Gseg_aug-2006.inc' /
```

```
  './INCLUDE/RELPERM/HYST/waghystr.inc' /

--RPTPROPS
-- 1 1 1 5*0 0 /


--------------------------------------------------------------------------------


REGIONS

--
INCLUDE
 './INCLUDE/PETRO/FIPNUM_0704.prop' /

--
INCLUDE
 './INCLUDE/PETRO/SATNUM_0704.prop' /

EQUALS
'SATNUM'  102  30 41  76 112  1 1 /
'SATNUM'  103  30 41  76 112  2 2 /
'SATNUM'  104  30 41  76 112  3 3 /
/

--
INCLUDE
 './INCLUDE/PETRO/IMBNUM_0704.prop' /

EQUALS
'IMBNUM'  102  30 41  76 112  1 1 /
```

```
'IMBNUM'  103  30 41  76 112  2 2 /
'IMBNUM'  104  30 41  76 112  3 3 /
/

--
INCLUDE
 './INCLUDE/PETRO/PVTNUM_0704.prop' /

EQUALS
'PVTNUM'  1  1 46   1 112    1 22  /
/

--
INCLUDE
 './INCLUDE/PETRO/EQLNUM_0704.prop' /

-- extra regions for geological formations and numerical layers
INCLUDE
 './INCLUDE/PETRO/EXTRA_REG.inc' /

--------------------------------------------------------------------------------

SOLUTION

RPTRST
  BASIC=2 /

RPTSOL
FIP=3 /
--------------------------------------------------------------------------------
-- equilibrium data: do not include this file in case of RESTART
```

```
--
--
INCLUDE
 './INCLUDE/PETRO/E3.prop' /

-- restart date: only used in case of a RESTART, remember to use SKIPREST
--RESTART
-- 'BASE_30-NOV-2005' 360    /   AT TIME     3282.0   DAYS    ( 1-NOV-2006)

THPRES
  1 2 0.588031 /
  1 3 0.787619 /
  1 4 7.00083  /
/

-- initialise injected tracers to zero
TVDPFSEA
1000   0.0
5000   0.0 /
TVDPFHTO
1000   0.0
5000   0.0 /
TVDPFS36
1000   0.0
5000   0.0 /
TVDPF2FB
1000   0.0
5000   0.0 /
TVDPF4FB
1000   0.0
5000   0.0 /
```

```
TVDPFDFB
1000   0.0
5000   0.0 /
TVDPFTFB
1000   0.0
5000   0.0 /

--------------------------------------------------------------------------------

SUMMARY
RUNSUM
SEPARATE
EXCEL

--
INCLUDE
 './INCLUDE/SUMMARY/summary.data' /

---------------------------------------------------------------------------------



SCHEDULE
NOWARN

-- use SKIPREST in case of RESTART
--SKIPREST

-- No increase in the solution gas-oil ratio?!

DRSDT
 0  /
```

```
-- Use of WRFT in order to report well perssure data after first
-- opening of the well. The wells are perforated in the entire reservoir
-- produce with a small rate and are squeesed after 1 day. This pressure
-- data can sen be copmared with the MDT pressure points collected in the
-- well.


NOECHO

------------------------------------------
--=======Production Wells========--
------------------------------------------

--
INCLUDE
 './INCLUDE/VFP/DevNew.VFP' /
--
INCLUDE
 './INCLUDE/VFP/E1h.VFP' /
--
INCLUDE
 './INCLUDE/VFP/NEW_D2_GAS_0.00003.VFP' /
--
INCLUDE
 './INCLUDE/VFP/GAS_PD2.VFP' /
--
INCLUDE
 './INCLUDE/VFP/AlmostVertNew.VFP' /
--
INCLUDE
```

```
 './INCLUDE/VFP/GasProd.VFP' /
```

-- 01.01.07 new VFP curves for producing wells, matched with the latest well tests in Prosper. lmarr

```
--
INCLUDE
 './INCLUDE/VFP/B1BH.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/B2H.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/B3H.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/B4DH.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/D1CH.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/D2H.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/D3BH.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/E1H.Ecl' /
--
```

```
INCLUDE
 './INCLUDE/VFP/E3CH.Ecl' /
--
INCLUDE
 './INCLUDE/VFP/K3H.Ecl' /



------------------------------------------
--=======Production Flowlines========--
------------------------------------------
--
-- 16.5.02 new VFP curves for southgoing PD1,PD2,PB1,PB2 flowlines -> pd2.VFP
--
INCLUDE
 './INCLUDE/VFP/pd2.VFP' /
--
-- 16.5.02 new VFP curves for northgoing PE1,PE2 flowlines -> pe2.VFP
--
INCLUDE
 './INCLUDE/VFP/pe2.VFP' /


-- 24.11.06 new matched VLP curves for PB1 valid from 01.07.06
--
INCLUDE
 './INCLUDE/VFP/PB1.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PB2 valid from 01.07.06
--
INCLUDE
```

```
 './INCLUDE/VFP/PB2.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PD1 valid from 01.07.06
--
INCLUDE
 './INCLUDE/VFP/PD1.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PD2 valid from 01.07.06
--
INCLUDE
 './INCLUDE/VFP/PD2.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PE1 valid from 01.07.06
--
INCLUDE
 './INCLUDE/VFP/PE1.PIPE.Ecl' /

--24.11.06 new matched VLP curves for PE2 valid from 01.07.06
--
INCLUDE
 './INCLUDE/VFP/PE2.PIPE.Ecl' /



------------------------------------------
--=======INJECTION FLOWLINES 08.09.2005     ========--
------------------------------------------
-- VFPINJ nr. 10 Water injection flowline WIC
--
INCLUDE
 './INCLUDE/VFP/WIC.PIPE.Ecl' /
```

```
-- VFPINJ nr. 11 Water injection flowline WIF
--
INCLUDE
 './INCLUDE/VFP/WIF.PIPE.Ecl' /

---------------------------------------------
--=======   INJECTION Wells 08.09.2005       ========--
---------------------------------------------
-- VFPINJ nr. 12 Water injection wellbore Norne C-1H
--
INCLUDE
 './INCLUDE/VFP/C1H.Ecl' /

-- VFPINJ nr. 13 Water injection wellbore Norne C-2H
--
INCLUDE
 './INCLUDE/VFP/C2H.Ecl' /

-- VFPINJ nr. 14 Water injection wellbore Norne C-3H
--
INCLUDE
 './INCLUDE/VFP/C3H.Ecl' /

-- VFPINJ nr. 15 Water injection wellbore Norne C-4H
--
INCLUDE
 './INCLUDE/VFP/C4H.Ecl' /

-- VFPINJ nr. 16 Water injection wellbore Norne C-4AH
--
```

```
INCLUDE
 './INCLUDE/VFP/C4AH.Ecl' /

-- VFPINJ nr. 17 Water injection wellbore Norne F-1H
--
INCLUDE
 './INCLUDE/VFP/F1H.Ecl' /

-- VFPINJ nr. 18 Water injection wellbore Norne F-2H
--
INCLUDE
 './INCLUDE/VFP/F2H.Ecl' /

-- VFPINJ nr. 19 Water injection wellbore Norne F-3 H
--
INCLUDE
 './INCLUDE/VFP/F3H.Ecl' /

-- VFPINJ nr. 20 Water injection wellbore Norne F-4H
--
INCLUDE
 './INCLUDE/VFP/F4H.Ecl' /



TUNING
1 10  0.1  0.15  3  0.3  0.3  1.20  /
5*   0.1   0.0001   0.02  0.02  /
--2* 40 1* 15 /
/
```

```
-- only possible for ECL 2006.2+ version
ZIPPY2
'SIM=4.2' 'MINSTEP=1E-6' /
/


--WSEGITER
--/

-- PI reduction in case of water cut
--
INCLUDE
 './INCLUDE/PI/pimultab_low-high_aug-2006.inc' /

-- History and prediction --
--
INCLUDE
 './INCLUDE/BC0407_2004.SCH' /

END
```