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Application of WAG and SWAG injection Techniques in Norne E-Segment

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September 2012

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MSc PROJECT IN PETROLEUM ENGINEERING

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Abstract

Inside of the Norne E-segment remains a considerable amount of residual oil even after applying the primary and secondary oil recovery methods (water injection). Recently, several methods have been studied based on simulations to decrease the residual oil trapped by capillary forces and consequently improve the oil recoverability. Additionally, Norne E-segment is severely affected by stratigraphic barriers and faults of nature not sealing, semi sealing and completely sealing.

Water Alternating Gas (WAG) and Simultaneously Water Alternating Gas (SWAG) injection techniques are presented as potential candidates to increase oil productivity in the Norne E-Segment by decreasing the gas mobility and capillary forces guarantying effective microscopic displacement due to gas flooding and macroscopic sweep created by water injection.

In the first part of this study, based on simulations (Eclipse 100, Black oil simulator), sensitivity analyses of WAG cycles and WAG ratio were investigated combining with low injection rate and high injection rate. However, three WAG cycle were suggested (3 months, 6 months and 1years injection cycles) and different values of WAG ratio were studied based on low and high injection rates of water and gas. According to the results, WAG cycle doesn’t affect the fluids rates productions when low injection rate is used, but a slightly effect is noticed when high injection rate is applied, thus a slightly optimal WAG ratio was found to be 1:3 when high WAG ratio is used.

As a sequence, examination of three different injection patters scenarios were simulated to optimize the oil recoverability using both techniques WAG and SWAG, namely: injection studies using the injection wells already existed; injection studies using the injection wells already existed by doing a new completion within Ile and Tofte formations; injection studies placing a new injection well plus new completion of the injection well.

As a result, the last scenario using SWAG technique presented oil recovery around 73%, whose was approximately 5% higher than oil recoverability when WAG injection technique (68%), when high injection rate is applied.

Acknowledgements

First of all I would like to express my humidly thanks to God Almighty, for the immeasurable strength and spiritual guidance to overcome the difficulties and learn to persist and never give up face any difficulty.

Secondly, I pay homage to my supervisor, Jon Kleppe, who provided me the necessary means to accomplish my research work face all difficulties that my country's university is experiencing in terms of simulations tools. Thanks also for the advices and guidance provided during my master thesis lectures.

I would like to express my sincerely appreciation to my co-supervisor, Jan Ivar Jensen, for the advices and instructions about Eclipse simulator to make my project a reality.

My thanks go also to Richard Rwechungura, who provided all the Eclipse data's about Norne E-segment. Thank you for joint all the important information and make it available even being out side of Norway.

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Finally, I want to acknowledge and thank all the people that I did not mentioned here, but helped me to make this project a reality.

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CHAPTER I. Introduction

1.1. Background

With the technological advancement worldwide, petroleum has become the largest source of non-renewable energy generation to ensure the development of industrialized countries and in the developing world. Global demand for energy is growing exponentially which requires the creation of efficient methods for tertiary recovery of petroleum residual forms to ensure the maximum possible value of recovery of petroleum before it reaches the stage of abandonment of reservoir.

There are numerous techniques tertiary oil recovery (figure.1), since the implementation each reservoir depends on the characteristics of the candidate, the surface environment, the infrastructure in place, the environmental issue and how much oil we can recover.Chemical methods have been applied widely in North Sea fields, with great success. However, this process is costly. Appropriate techniques have been developed for improving oil recovery from North Sea reservoirs, where water injection method alone is not effective because of the lack of efficient gravity drainage. Considering this, several EOR process has been studied to evaluate its applicability to such type of reservoirs.

This project comes from some form present a new method for recovering residual oil, which can be successfully applied in oil field located in the North Sea known as the "Norne Field." This oil field is divided into five segments (Segment B, C, D, E and G). In a more specific, the study had taken place only in the segment E. Assuming this thread can be analyzed in a unique way as it is isolated from the rest of the segments by barriers made of clay failures.

The new techniques tertiary recovery techniques of oil, drawn in that master's thesis are known as water alternating gas (WAG) and water alternating gas Simultaneously (SWAG) injection techniques. The two tertiary recovery techniques of oil combines the advantages of the waterflooding and gas injection methods to control the gas mobility and optimize the residual oil production but SWAG technique presents higher values of efficiency when compared with the WAG technique. The main challenge shall apply both techniques of recovery to try to extract the residual oil in the E-segment Oilfield Norne field and make a comparison in terms of final yield.

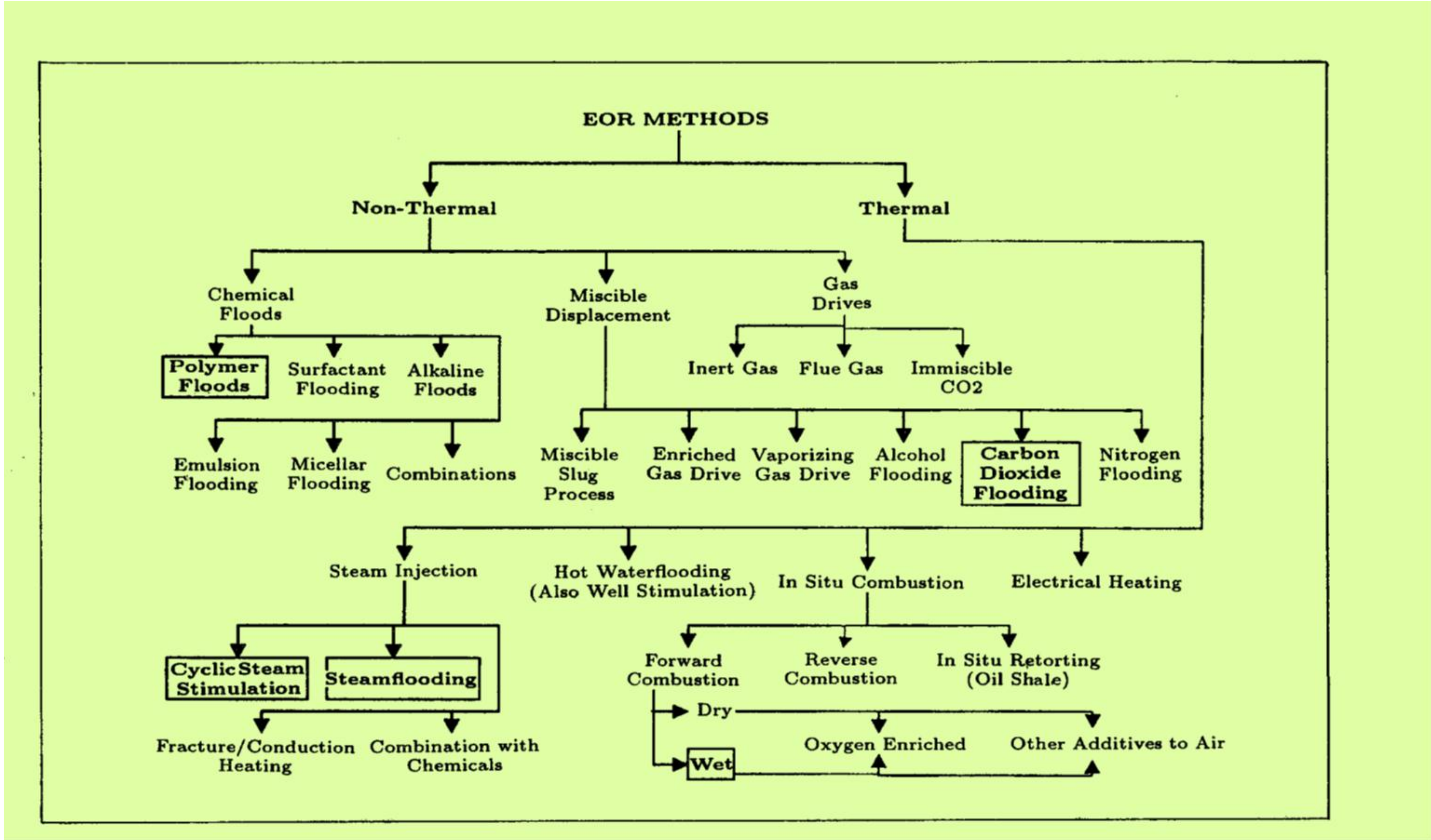

Figure 1. Classification of EOR methods

More precisely, the following chapters will provide an understanding study related with WAG injection method. After this study, a brief description of the Norne E-segment field and the simulation model will be done to better understand the reservoir behavior. Finally, WAG and SWAG process will be studied based on simulations using Eclipse simulator coupled with S3GRAF (reader of graphics).

1.2. Research Objectives

The main scope of the present work is to make a simulation study into the Norne E-segment about two enhanced oil recovery processes, the water alternating gas (WAG) injection technique and simultaneously water alternating gas (SWAG) injection technique for future oil recovery prediction. To achieve the main objective, the following tasks must be fulfilled:

1. Determining the optimum injection cycle time and WAG ratios;
2. Investigating the effect of high Injection rates and low injection rates on the ultimate oil recovery;
3. Studying the effect of WAG and SWAG injection methods on the sweep efficiency

1.3. Methodology

In order to accomplish the proposed objectives, Eclipse simulator is used to run the simulations coupled with S3 GRAF program to reading the results of simulations. Three different injection patterns were simulated, implementing water alternating gas and simultaneously water alternating gas injection techniques in separated, namely: original injection patterns, addition of a new well into the original model and new well and re-completion of the existing water injectors.

E-segment reservoir simulation model was used to optimize WAG cycle time, determine the optimum WAG ratio and evaluate different WAG injection patterns.

Chapter II. Literature Review

2.1. Water-Alternating-Gas (WAG) Process

The Water Alternating Gas (WAG) process is an enhanced oil recovery method defined as a cyclic method of injecting alternating cycles of gas followed by water and repeating this process several cycles desired by the operator (figure 2).

A comprehensive classification of the WAG process was suggested by many authors, which includes: MWAG (miscible), IWAG (immiscible), HWAG (hybrid), and SWAG (simultaneous) and SSWAG (selective). (Christensen, 1998; Al- Mamari, 2007; Skauge, 2007)

During miscible WAG process (MWAG), the injected gas is miscible with the reservoir oil in the first contact or with time as displacement continues under the prevailing conditions (Arne, 2007). Miscibility of gas provides an additional advantage of decreasing oil viscosity, thereby resulting in mobilization of trapped oil during later production stages. Miscible WAG occurs when the reservoir is above the minimum miscibility pressure (MMP). However, immiscible WAG process (IWAG), the injected gas is not miscible with the reservoir oil and it displaces the oil while maintaining its gaseous phase, with a front between the two phases (Zahoor, 2011; Fanchi, 2004). Immiscible WAG occurs when the reservoir is below the minimum miscibility pressure (MMP). According to Hustad (2002), Hybrid Wag consists in injecting previously a large slug of gas in to the reservoir followed by a number of small slugs of water and gas. In SWAG injection technique (Quijada, 2005), at the same time, water and gas are injected in the reservoir through a single injection well. However, when the water and gas are mixed at the surface and then injected in to the reservoir, the process is referred as SWAG injection, but when the gas and water are pumped separately using a dual completion injector without mix the two phases on the surface, the process is referred as selective simultaneously water alternating gas (SSWAG).

One vital element to the technical success of WAG process is the optimum utilization of gas injecting. WAG Optimization is widely recognized as a viable technique in controlling the Miscible Process. However, these process guaranties mobility control in the zones which gas tend to choose a preferential channel and consequently, extends the oil recovery.

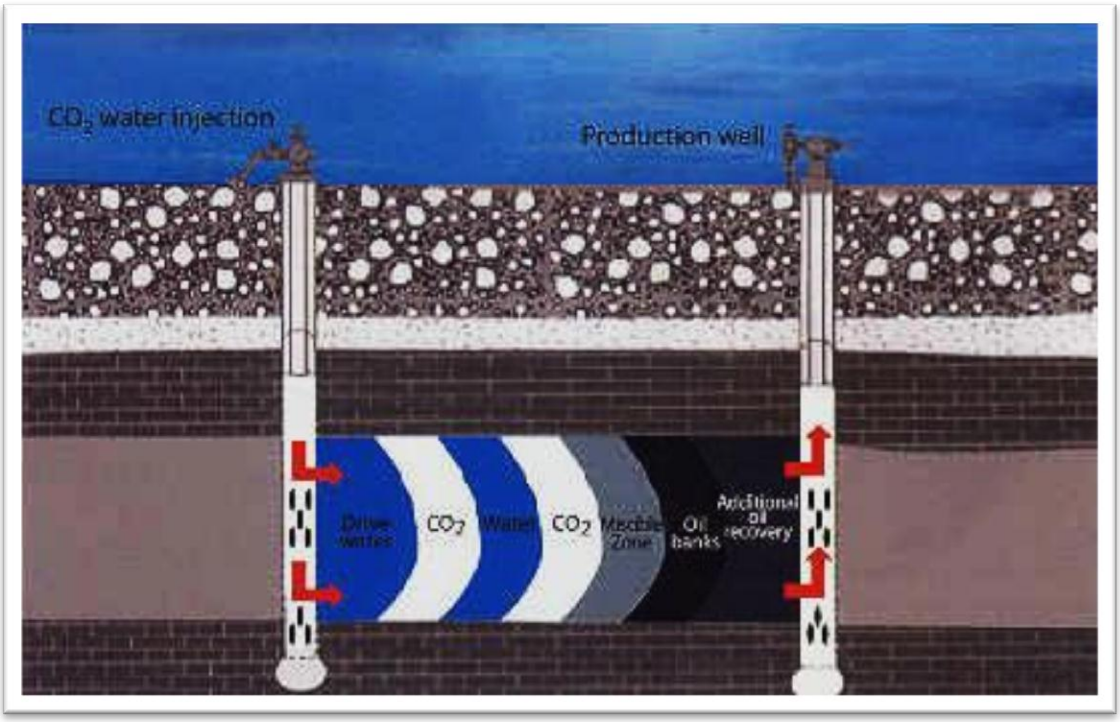

Figure 2. Schematic of the WAG process

Christensen et al. (2001) defined the SWAG method as simultaneous injection of both water and gas at the same time into a portion or the entire thickness of the formation. This process can be performed using two different techniques: Conventional SWAG technique, Modified SWAG technique (Algharib, 2007). In a Conventional SWAG technique, water and gas are mixed at the surface. However, in a modified SWAG technique (SSWAG), gas and water are injected together through a single well bore, no mixing takes place at the surface. The two phases are pumped separately using a dual completion injector and are selectively injected into the formation. Usually gas is injected at the bottom of the formation and water injected into the upper portion (Mazen, 2008).

In terms of oil recoverability, each reservoir is individuality, but normally the primary production will be around 15-25% of the original oil in place (OOIP), while secondary IOR using conventional techniques will lie between 20-40% of the OOIP and tertiary recovery. Tertiary recovery allows another 5% to 15% of the reservoir's oil to be recovered. Moreover, recent advances in reservoir technology as shown values of tertiary oil recovery estimated between 45-50% of OOIP. Values above 60% are very rare, but some mature fields in the Norwegian Sea, were predicting recovery of 64% OOIP with a possible 75% using a miscible WAG process.

2.2- Effect of capillary number and mobility ratio on residual oil recovery

The improvement on oil recovery during application of each EOR methods is due to effect of capillary number and mobility ratio. These properties dominate strongly the oil recovery.

We shall discuss the principle of these physical properties that cause and effect when by chance the modular value is increasing or decreasing.

Accordingly to S, Thomas (2008), *Capillary Number* represents the relative effect of viscous forces versus surface tension acting across an interface between two immiscible liquids. It is usually denoted Nc in the oil field. Mathematically, Capillary number is defined as:

$$N_c = \frac{v\mu}{\sigma}$$

The following formula is also valid:

$$N_c = \frac{k\,(\frac{\Delta p}{l})}{\sigma}$$

Where:

$\mu \rightarrow$ Displacing fluid viscosity

$v \rightarrow$ Darcy's velocity

$\sigma \rightarrow$ Interfacial tension (IFT) between the displaced and the displacing fluids.

$k \rightarrow$ Effective permeability to the displaced fluid

$\frac{\Delta p}{l} \rightarrow$ Pressure gradient

For a flowing liquid, if N_C >>1, then viscous forces dominate over interfacial forces; however if N_C <<1, then viscous forces are negligible compared with interfacial forces and the flow in porous media is dominated by capillary forces. However, Capillary numbers are usually large for high-speed flows and low for low-speed flows; thus, typically for flow through pores in the reservoir N_C ~10-6, and for flow in production tubular N_C ~1.

Capillary number in a miscible displacement becomes infinite, and under such conditions, residual oil saturation in the swept zone can be reduced to zero if the mobility ratio is "favourable".

Several authors studied the relation between capillary number and residual oil saturation that is presented in the figure 3. Thus, the significant increase in oil recovery was due lowering the interfacial tension (IFT) between the fluids and pressure gradient promoting a reduction in the capillary number.

To get a notion of the magnitude of the diminution of the IFT to amount of residual oil has to be recovered under laboratory condition, Reed (1954) found a IFT in the order 10^{-2}mN/m.

Taber (1969) studied the implication of the pressure gradient on oil recovery. This author concluded that the critical value of the critical pressure gradient has to be exceeded to effect a reduction in the residual oil saturation by lowering the IFT by a factor of about 1000. Notice that, this value can be easily achieved in laboratorial conditions, but extremely difficult under field conditions.

The other factor that affects the residual oil recovery is the ***Mobility ratio***, defined by S. Thomas as mobility of the displacing phase divided by the mobility of the displaced phase. It is usually denoted M in the oil field. Mathematically, mobility ratio is defined as:

$$M = \lambda_{ing} / \lambda_{ed},$$

Where:

λ_{ing} →Mobility of the displacing fluid, ($\frac{k_{ing}}{\mu_{ing}}$)

λ_{ed} →Mobility of the displaced fluid, ($\frac{k_{ed}}{\mu_{ed}}$)

Since mobility ratio is less than one (M<1), the displacement is stable, a fairly sharp "shock front" separates the mobile oil and water phases, and the permeability to water stabilizes fairly quickly. In other case, where the mobility ratio is slightly greater than one ($M > 1$) is considered unfavourable, because it indicates that the displacing fluid flows more readily than the displaced fluid (oil), and it can cause channelling of the displacing fluid, and as a result, bypassing of some of the residual oil. Under such conditions, and in the absence of viscous instabilities, more displacing fluid is needed to obtain a given residual oil saturation. However, if the value is close enough or equal to unity that the displacement is nearly piston-like, and is denoted a favourable mobility ratio. Mobility ratio influences the microscopic (pore level) and macroscopic (areal and vertical sweep) displacement efficiencies.

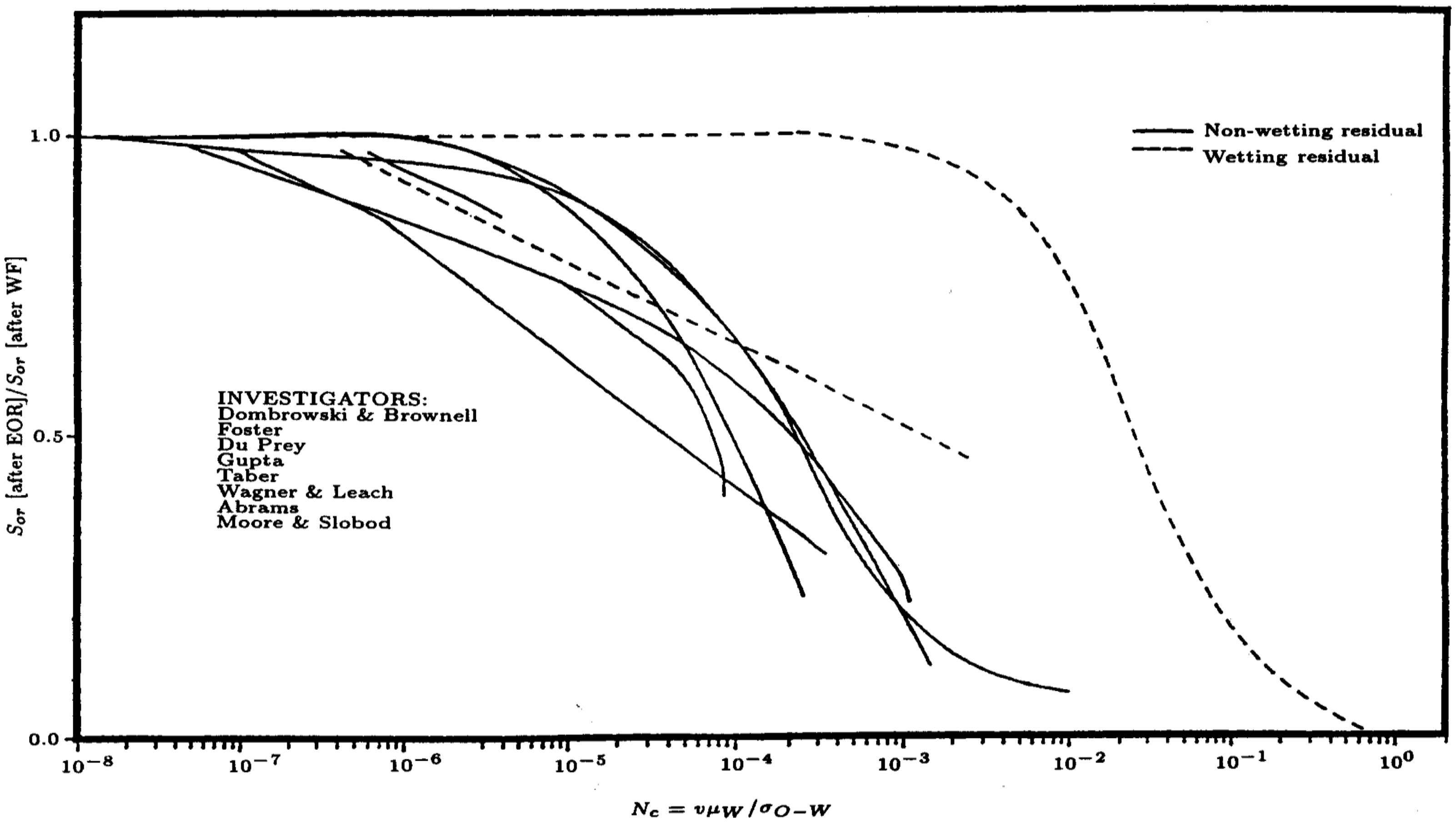

Figure 3- Residual oil saturation as a function of capillary number (S.M. Farouq Ali and S. Thomas,)

The following graph (figure 4), represents a simple case of a waterflood were displaceable oil is variating as a funcion of mobility ratio, for fixed volumes of the injected fluid. Displacement efficiency increase as the mobility ratio decrease.

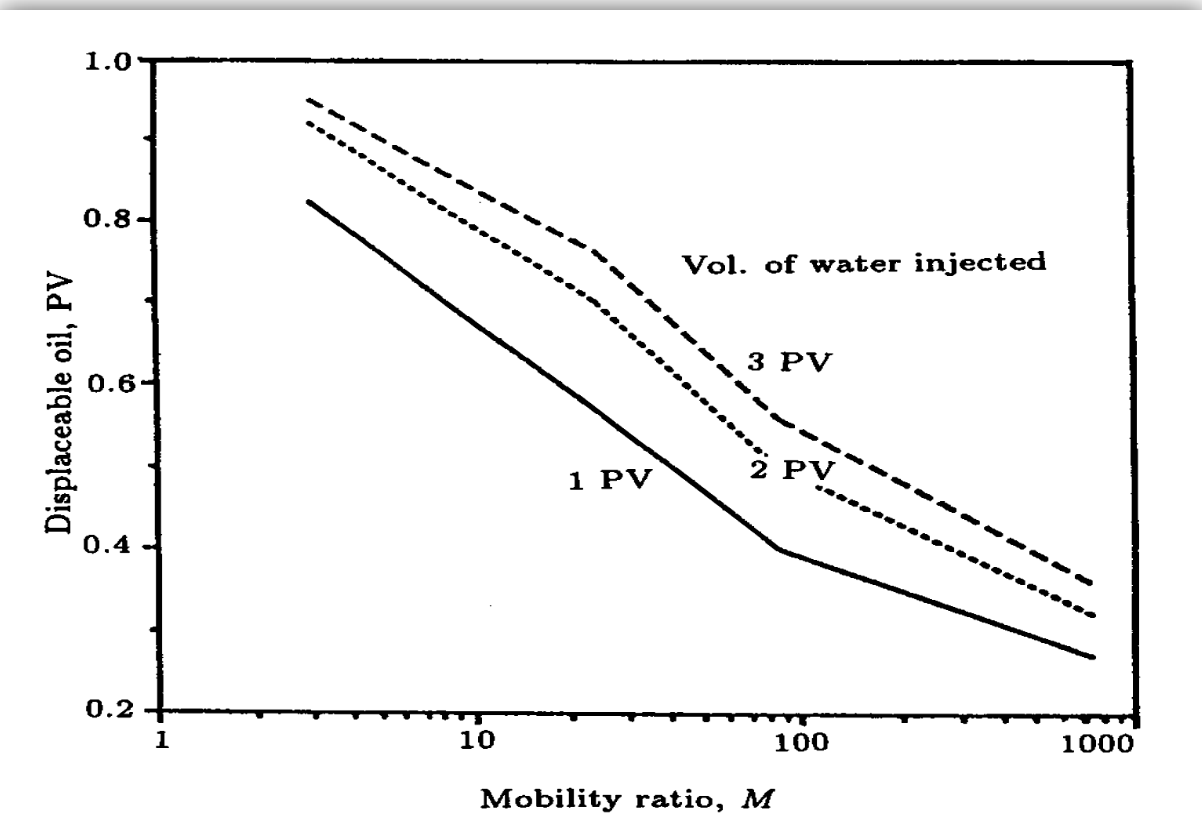

Figure 4- Effect of mobility ratio on water flood oil recovery (S.M. Farouq Ali and S. Thomas, 1994)

The mathematical relationship between microscopic and macroscopic recoveries efficiencies are represented using the oil recovery factor (R_f), and it can be given by the following formula:

$$R_f = E_v \times E_\mathrm{h} \times E_m$$

Where:

$$E_m = E_I(S_{oI} - S_{or})$$

The macroscopic sweep efficiency is defined by the horizontal and the vertical sweep efficiencies (E_v *and* E_h). The horizontal sweep efficiency is related to the mobility ratio and the vertical sweep efficiency depends on viscous to gravity forces ratio.

2.3. Factors influencing WAG process design

The main design issues for WAG injection techniques are fluid properties, rock-fluid interaction, availability and composition of injection gas, WAG ratio, heterogeneous permeability, injection pattern, cycling time, WAG ratio, injection/production pressure and rate, three-phase relative permeability effects and flow dispersion and finally time to initiate the WAG (Christensen et al., 2001; Heeremans et al., 2006; Zahoor, 2011;).

2.3.1. Fluid properties and rock fluid interaction

The property of a fluid is directly related to the viscosity of crude oil within the reservoir. These properties are determined by standardized laboratory procedures. Unfortunately the test results do not represent a general characteristic of the reservoir, because the samples are taken from different sites within the reservoir. The prediction of the reservoir fluid properties becomes even more complex when the prevailing conditions within the reservoir change as a result of undergoing processes, leading to unexpected reaction during injection and production operations (Zahoor, 2011).

Variations in rock-fluid interaction with changing conditions in a reservoir result in wettability variations, which in turn affect flow parameters such as capillary pressure and relative permeability (Josephina et al., 2006; Zahoor, 2011).

In terms of reservoir simulation, the rock fluid properties like adhesion, spreading and wettability are normally analysed as one parameter, "relative permeability". Thus, this parameter is very important when predictions are realised in the reservoir simulation (Rogers, 2000).

2.3.2. Reservoir Heterogeneity and Stratification

The degree of interconnection between the pores of an oil reservoir, are usually not evenly distributed due to non-uniformity of pore size, which gives rise to disordered and complex reservoir fluid flow behaviour. Geologically speaking, this is known as phenomenon of heterogeneous permeability that can manifest different individual layers, forming different homogeneous layers within the oil reservoir with different permeability’s.

The effects of stratification and heterogeneity can be distinct in different reservoirs, affecting various parameters such as capillary pressure, relative permeability, and mobility ratios (Ahmadet al., 2009; Farshid et al., 2010). The presence of different permeability's and heterogeneity in a reservoir, affects the displacement of the native fluids by the injected fluid. Channelling of the solvent through high permeability regions reduces the storage and displacement efficiency of the displacing solvent (X. WU, 2004). However, it strongly affects the efficiency in the WAG process design, since this phenomenon controls the injection and sweep patterns in the floodThis phenomenon can cause large variations in the vertical and horizontal permeability of the reservoir.Vertical permeability is influenced by cross flow, Viscous, capillary, gravity and dispersive forces (Madhav, 2003). However, high recoveries result from low vertical to horizontal permeability ratio because the gravity segregation do not dominate the fluid flow behaviour (Zahoor, 2011; John and Reid, 2000).

2.3.3. Availability and composition of injection gas

The availability of gas in WAG process design affects greatly the economic viable choice. Usually, the gas produced with oil from a reservoir is separated and re-injected during the WAG process, promoting less expense.

Accordingly to Jensen (Jensen, 2000), hydrocarbon gas, was suggested to be more suitable for Ekofisk field, even though CO2 WAG yielded higher incremental production under laboratory conditions(14).

Mustafa (2001) made a numerical study to evaluate the application of an EOR method for oil production improvement at B.Kozluca Field in Turkey. Initially, the oil gravity of the field was around 12.6 0API with a very high viscosity of 500 cp at reservoir conditions. In order to increase the oil recovery, a CO2 gas injection method was chosen among others no thermal methods, because of the fact that in about 10 km from the B.Kozluca field, there is a CO2 reservoir available at Camurlu Field. Therefore, the availability of the gas injection is very important to choose the right WAG ratio.

Gas composition, in particular, is crucial in the design WAG process, a decision parameter that determines whether the process will be miscible or immiscible under the prevailing conditions of pressure and temperature within the oil reservoir (Zahoor, 2011). anotherGas composition, in particular, is crucial in the design WAG process, a decision parameter that determines whether the process will be miscible or immiscible under the prevailing conditions of pressure and temperature within the oil reservoir (Zahoor, 2011).

2.3.4. WAG ratio

In WAG process, gas and water slugs are alternately injected in a fixed ratio called the WAG ratio. According to WU (2004), WAG ratio can be also defined as the ratio of the volume of water injected within the reservoir compared to the volume of injected gas.

WAG ratio represents, one important parameter to optimize during WAG process. According to Chen (2010), WAG ratio plays an important role in obtaining the optimum value of the recovery factor corresponding to an optimal value of the WAG ratio. This optimal WAG ratio is reservoir dependent because the performance of any WAG scheme depends strongly on the distribution of permeability as well as factors that determine the impact of gravity segregation (fluid densities, viscosities, and reservoir flow rates) (X. WU, 2004) . Studies made by John and Reid (2000), showed that the WAG ratio strongly depends on reservoir’s wettability and availability of the gas to be injected.

When the WAG ratio is high, may cause oil trapping by water blocking or at best may not allow sufficient solvent-oil contact, causing the production performance behave like a water flood. On the other hand, if the WAG ratio is very small, the gas may channel and the production performance would tend to behave as a gas flood, the pressure declines rapidly, which would lead to early gas breakthrough and high declination on production rate (X. WU, 2004). To find the optimal WAG ratio is necessary to perform sensitivity analysis, proposing different relations of WAG ratio to study the effect on oil recovery.

Kudal (2010) performed a simulation sensitivity analyses study of a western Indian onshore field to evaluate the effect of different critical parameters on the recovery factor using immiscible WAG process. As results, better performance was achieved with 1:2 WAG ratio in six months injection period. Normally is preferable to inject higher gas volumes as compared to water in oil-wet reservoirs. The amount of volumes to be injected at the desired pressures strongly affects the cost of surface facilities, like compressors and pumps, which in turn strongly influences the WAG ratios due to economic constraints (Zahoor, 2011).

2.3.5. Injection pattern

The choice of the Wells spacing, in WAG process design, is very important because of the fact that the sweep efficiency of the oil is strongly affected by distance between the injector and the producer well (Christensen et al., 1998, 2001; Mohammad et al., 2010).

In many cases, a Five-spot injection pattern is very popular, as it can provide better control on frontal displacement (Zahoor, 2011). However, the results of a recent study made by Mohammad et al. (2010) in an Iranian fractured reservoir shows that a 4-spot pattern (4 producers with 2 injectors) gives higher recovery than a 5-spot pattern (6 producers with 2 injectors). It means that the best injection patters have to be chosen after simulation studies analysis, because it varies from reservoir to reservoir.

Chase and Tood (1984) reported about well's orientation and theirs opinion is that the combination of vertical producers with horizontal injectors can give better recovery.

The advances in computer technology and software development have made this possible, that the optimum location of wells and their orientation, together with parameters like WAG ratio, can be selected through simulation studies by preparing a different numbers of scenarios (different field development models of reservoir) and analysing the front propagation and recovery enhancement (Farzaneh et al. 2009).

2.3.6. Injection / production pressure and rates

Producer bottom hole pressure is one of the most important factors that affect the production performance. To study the effect of the producer bottom hole pressure on oil recovery, earlier simulation studies made by WU (2004) on heterogeneous reservoir showed that the producer bottom hole pressure should be a little less than the bubble point pressure, and at this pressure, the oil recovery is maximum. For instance, if the producer bottom hole pressure is much lower than the bubble point pressure, the gas breakthrough occurs very early, which leads to oil production to decline.

Displacement pressure for solvent floods should be maintained above MMP to develop miscibility and displaces oil more efficiently. This determines the lower limit for the injection and production pressures. However, the upper limit of displacement pressure is set by the formation fracture pressure. The ideal design goal is to inject and produce at the maximum possible rates within these pressure limits.

The injectivities of water and gas in low and high permeability layers can be controlled by the water-gas ratio and injection rates (Surguchev, 1992).

2.3.7. WAG cycle time

Other variable that can be considered in optimizing WAG scheme include the timing of switch from gas to water. Furthermore, the sequencing of gas, water and WAG injection across a large field can offer significant opportunities for increases gas storage (X. WU, 2004).

Previous WAG cycle design procedures used steady state methodology and accepted industry rules of thumb. The use of a simulator permits a more rigorous analysis to optimize WAG cycle parameters such as cycle time (Pritchard, 1992).

(X. WU, 2004) recommends to examine different cycle lengths by simulating WAG process, in this way we will get to know which cycle lengths is recommendable for our specific case and also get to know the effect of slug sizes of water and gas on oil recovery.

2.3.8. Time to Initiate WAG process

One important factor to consider in designing the WAG process is when to initiate the WAG process. According with WU (2004) studies made by using two approaches include starting WAG process at the very beginning of the reservoir development (Initial WAG), or after obvious miscible inject ant breakthrough (Post Breakthrough WAG). WU (2004) concluded that, the two cases have almost the same breakthrough time, with very low production rate period. After the solvent breaks through, the total productions from both cases increase significantly, but the “Initial WAG” case shows a slightly higher cumulative oil recovery than “Post Breakthrough’ case when the injection pore volume reach approximately 1.2. Therefore, based on simulation results, WU recommends initiating the WAG injection as early as possible in the reservoir development cycle, to maintain the average reservoir pressure and achieve high oil recovery.

2.4. Advantages and Disadvantages of the WAG techniques

This new injection technique has been used in several fields north. Various fields in Canada, also has enjoyed the benefits of these methods. The efficiencies typically result in considerable amounts depending on the characteristics of the reservoir and how the technique is designed. The efficiency is due to the advantages offered by this technique, including:

- Controls mobility (reduces Gas processing)
- Improves operation (less gas cycling)
- Improve residual oil recovery

However, as every process, WAG technique has also disadvantages. The first disadvantage considered in the present project is the difficult to Control gas breakthrough as flood matures. The second disadvantage is related with slug size; sometimes optimum slug size may be 50% HCPV inj. The last disadvantage referred here is loss of injectivity (water), it can be as high as 70%.

When WAG process is well optimized, the following desired results can be achieved in a field wide scale: improve overall recovery (sweep efficiency and oil recovery) and improve financial performance (net cash flow).

CHAPTER III. Norne field overview

3.1. General information

Norne is an oil field discovered in December 1991, started the oil production in November 1997 and gas production in 2001. The norne field is located around 80km north of the Heidrun oil field in the Norwegian Sea, embraces blocks 6608/10 and 6608/11 as we can see in the figure 5. The reservoir is found at a depth of 2,500 metres below sea level. Total Hydrocarbon column (based on well 6608/10-2) is 135 m which contains 110 m oil and 25 m gas.

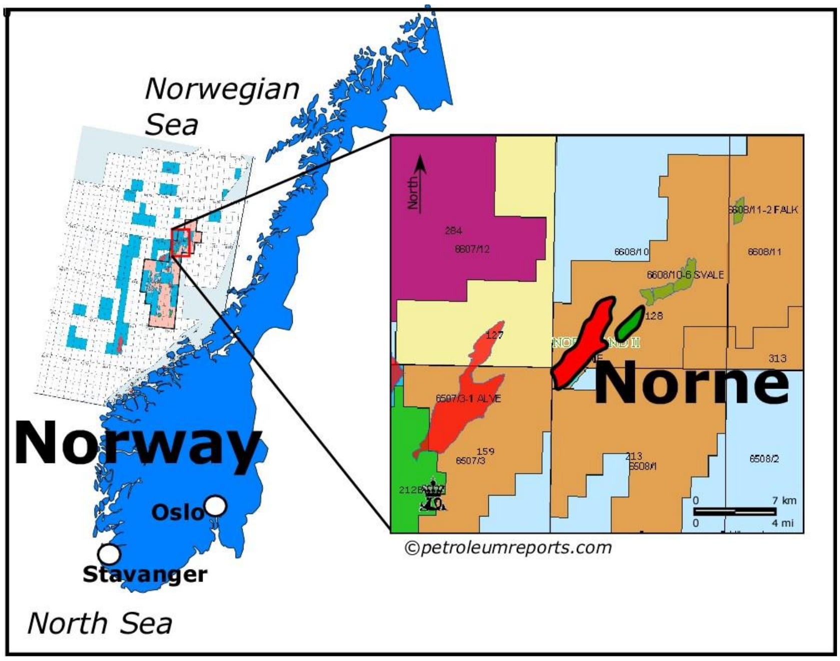

Figure 5- Norne Field Geographic Location

Totally 50 wells have been drilled in the field which contains 33 producers (16 active wells, 2010), 10 water injectors (8 active wells, 2010) and 7 observation wells. Table 1 illustrates the active development wells in this field. In our days, Norne field has 56 wells: 4 exploration, 52 production and injection wells.

The norne field consists of two separate oil compartments; Norne Main Structure (Norne C-, D and E-segment), which contains 97% of the oil in place, and the North-East Segment (Norne G- segment). Oil is mainly found in the Ile and Tofte formations (about 80%), and gas in the Garn formation (see figure 6).

Wellbore name	Entry date	Completion date	Purpose	Status	Content
6608/10-B-1 H	26.01.1999	05.04.1999	PRODUCTION	PLUGGED	OIL
6608/10-B-1 AH	06.11.2005	03.12.2005	OBSERVATION	PLUGGED	NOT APPLICABLE
6608/10-B-1 BH	04.12.2005	09.01.2006	PRODUCTION	PRODUCING	OIL
6608/10-B-2 H	13.12.1996	09.12.1997	PRODUCTION	PRODUCING	OIL
6608/10-B-3 H	21.05.1999	05.07.1999	PRODUCTION	PRODUCING	OIL
6608/10-B-4 H	12.01.1998	06.02.1998	PRODUCTION	PLUGGED	NOT AVAILABLE
6608/10-B-4 AH	13.06.2001	12.07.2001	OBSERVATION	PLUGGED	NOT APPLICABLE
6608/10-B-4 BH	13.07.2001	07.08.2001	PRODUCTION	PLUGGED	OIL
6608/10-B-4 CH	03.06.2004	19.06.2004	OBSERVATION	PLUGGED	NOT APPLICABLE
6608/10-B-4 DH	20.06.2004	10.07.2004	PRODUCTION	PRODUCING	OIL
6608/10-C-1 H	12.02.1998	20.07.1998	INJECTION	INJECTING	WATER
6608/10-C-2 H	01.10.1998	27.11.1998	INJECTION	INJECTING	WATER
6608/10-C-3 H	06.04.1999	20.05.1999	INJECTION	INJECTING	WATER
6608/10-C-4 H	18.11.1996	18.08.1997	INJECTION	PLUGGED	GAS
6608/10-C-4 AH	15.11.2003	13.01.2004	INJECTION	INJECTING	WATER
6608/10-D-1 H	28.09.1996	18.11.1996	PRODUCTION	PLUGGED	NOT AVAILABLE
6608/10-D-1 AH	28.05.2002	25.06.2002	OBSERVATION	PLUGGED	NOT APPLICABLE
6608/10-D-1 BH	26.06.2002	05.09.2002	PRODUCTION	PLUGGED	NOT AVAILABLE
6608/10-D-1 CH	30.09.2003	07.11.2003	PRODUCTION	PRODUCING	OIL
6608/10-D-2 H	09.01.1997	05.01.1998	PRODUCTION	PRODUCING	OIL
6608/10-D-3 H	05.07.2000	04.08.2000	PRODUCTION	PLUGGED	NOT AVAILABLE
6608/10-D-3 AH	05.08.2000	30.08.2000	PRODUCTION	PLUGGED	OIL
6608/10-D-3 BY2H	12.08.2005	25.09.2005	PRODUCTION	PRODUCING	OIL
6608/10-D-3 BY1H	06.07.2005	7. 10.2005	PRODUCTION	PRODUCING	OIL
6608/10-D-4 H	07.01.1998	18.06.1998	PRODUCTION	PLUGGED	NOT AVAILABLE
6608/10-D-4 AH	11.01.2003	09.06.2003	PRODUCTION	PRODUCING	OIL
6608/10-E-1 H	28.05.1999	19.06.1999	PRODUCTION	SUSP.AT TD	OIL
6608/10-E-1 Y2H	26.10.2009	3.12.2009	PRODUCTION	SUSP.AT TD	OIL
6608/10-E-2 H	16.10.1999	21.11.1999	PRODUCTION	PLUGGED	OIL
6608/10-E-2 AH	28.07.2005	15.08.2005	PRODUCTION	PLUGGED	OIL
6608/10-E-2 BH	23.11.2007	14.02.2008	OBSERVATIO	N PLUGGE	D
6608/10-E-2 CH	15.02.2008	09.03.2008	PRODUCTION	PRODUCING	NG OIL
6608/10-E-3 H	29.07.1998	23.09.1998	PRODUCTION	PLUGGED	OIL
6608/10-E-3 AH	02.10.2000	12.12.2000	PRODUCTION	PLUGGED	OIL
6608/10-E-3 BH	09.03.2005	03.04.2005	OBSERVATION	PLUGGED	NOT APPLICABLE
6608/10-E-3 BH	09.03.2005	03.04.2005	OBSERVATION	PLUGGED	NOT APPLICABLE

Table 2- Wells of the Norne E-segment field

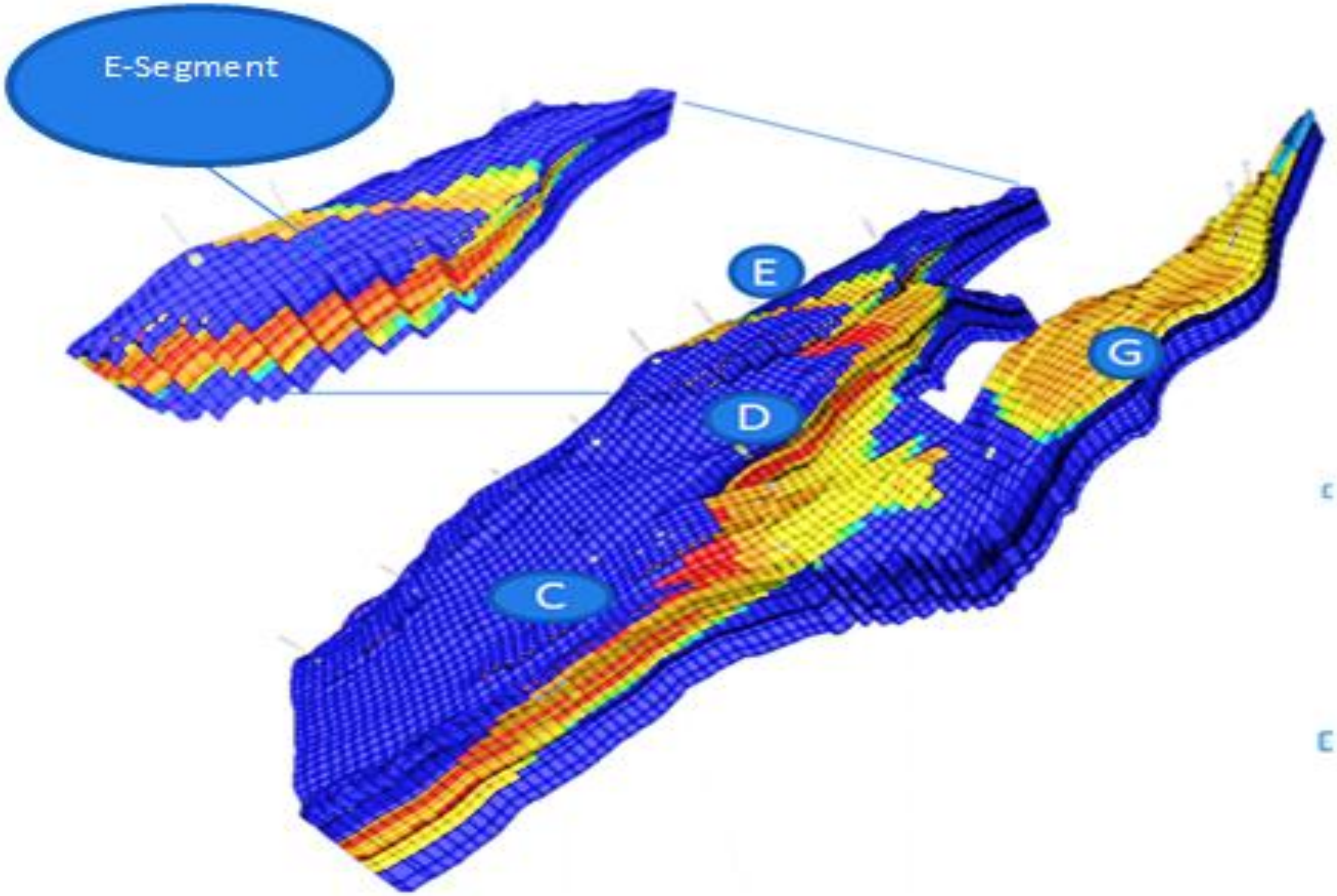

Figure 6- Norne Field model

The oil is produced with water injection as drive mechanism. Gas injection ceased in 2005 and all gas was planned to be exported. In order to avoid rapid pressure depletion in the gas cap, gas will be injected for an extended period of time.

Norne produced 13.9 million barrels of crude oil and 6.4 billion cubic feet of gas during 2009. The cumulative production till 2009 is 520 million barrels of oil and 214 billion cubic feet of gas. Peak production from the field was 71 million barrels of oil in 2010. It was initially estimated to produce 220,000 barrels of oil per day (see figure 7.).

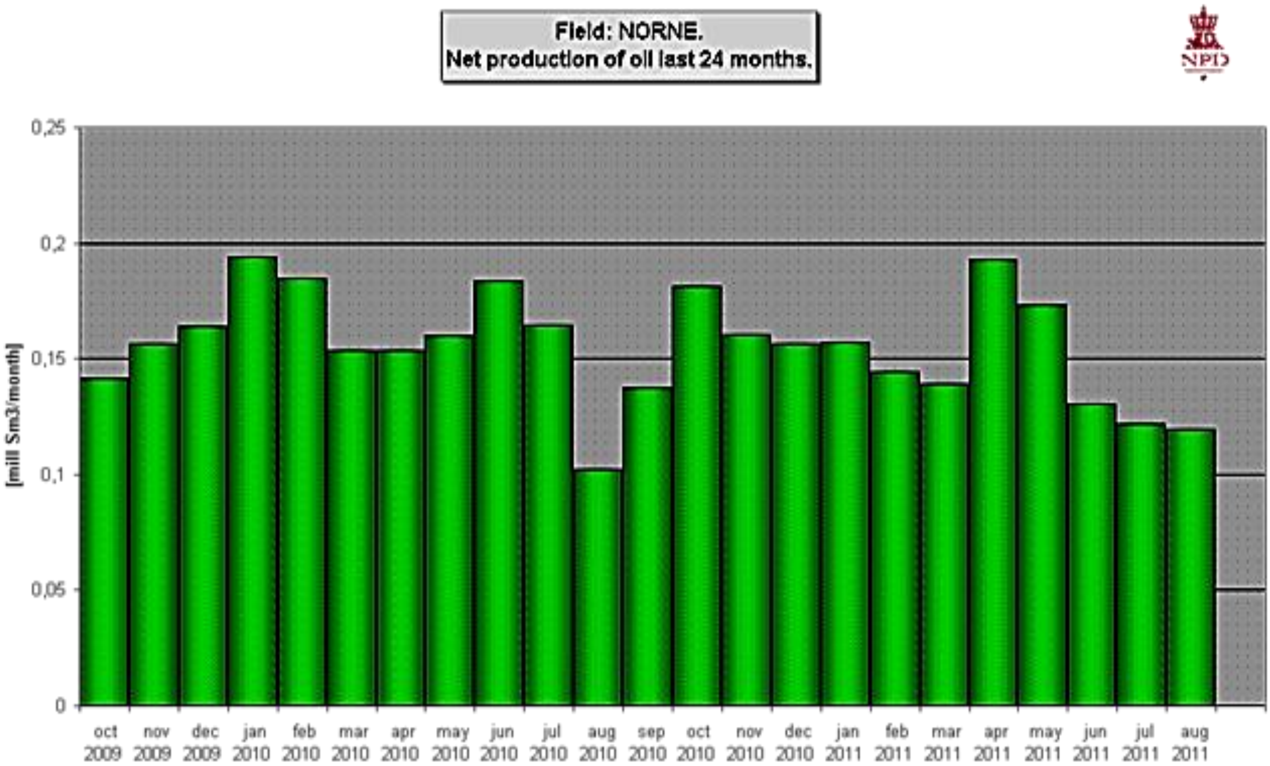

Figure 7- Cumulative production of the Norne field

The field life of Norne is expected to be around 20 to 24 years with complete abandonment during 2020. The field is expected to generate $4.4 billion in revenues (undiscounted) during its remaining life (starting from 01/01/2010) and is expected to yield an IRR of around 14.19%.

3.2. Geological Description

Norne field is a sandstone reservoir with different grains size changing from fine-grained and well to very well stored sub-arkosic arenites. The hydrocarbons in this reservoir are located in the Lower to Middle Jurassic sandstones. The reservoir stratigraphy is composed for the following formations: Garn, Ile, Tofte and Tilje. Additionally, there is a cap rock which acts as a reservoir seal called Melke Formation. The Not Formation behaves as a sealing layer, preventing communication between the Garn and Ile Formations (figure 9). As we can see in the figure 8, porosity vary in the range of 15% to 29% and the permeability changes from 20 mD to 2500 mD.

As referred before, ***Melke Formation*** acts as a reservoir seal. This formation is mainly composed by claystone with thin siltstone in the middle. Depending on the location of the exploration well, the thickness of the melke formation varies from 212 m to 160 m.

The next formation, from the top to the base of the Norne field, is ***Garn Formation***. This formation is subdivided in three reservoir zones (Garn 1, Garn 2, Garn 3) with different properties. Garn 1 is thin coarse grained sandstone that acts as a stratigraphic barrier to vertical fluid flow into the reservoir. Garn 2 is fine grained sandstone with different type of layers, some layers are bioturbated and others are laminated, but the top of the Garn 2 is composed by calcareous cemented sandstone which can be a local barrier to vertical flow. Consecutively, Garn 3 is composed by fine grained sandstone with sandstone and mudstone sediments with floating clasts, at the top. The upper part of this zone is made up of low angled cross bedded and fine grained sandstone.

The ***Not Formation*** is constituted by dark grey to black claystone with siltstone lamina. This formation is believed to act as stratigraphic barriers to vertical fluid flow within the reservoir. The thickness of the Not Formation across the field is between 7 and 10 m.

After not formation, the ***Ile formation*** is found. It is formed by three different reservoir zones: Ile 1, Ile 2 and Ile 3. Ile 1 and Ile 2 both consist of fine to very fine grained sand but they are separated by a cemented calcareous layer that are believed to be the result of minor flooding events in a generally regressive period. Ile 3 is made up by fining sandstone of fine to very fine grains containing also glauconites, phosphorite nodules and clay clasts.

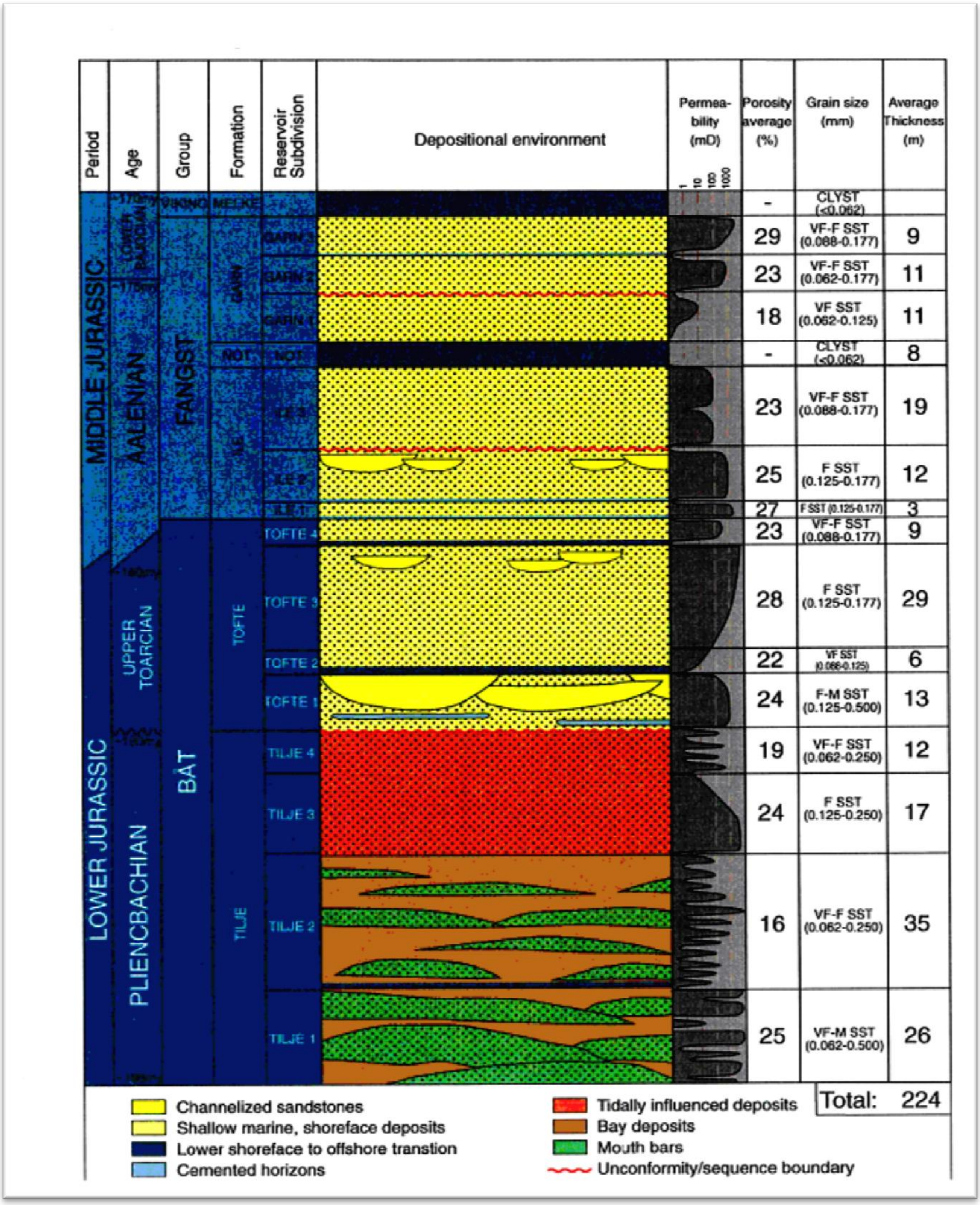

Figure 8- Stratigraphical sub-division of the Norne reservoir (Statoil, 2001).

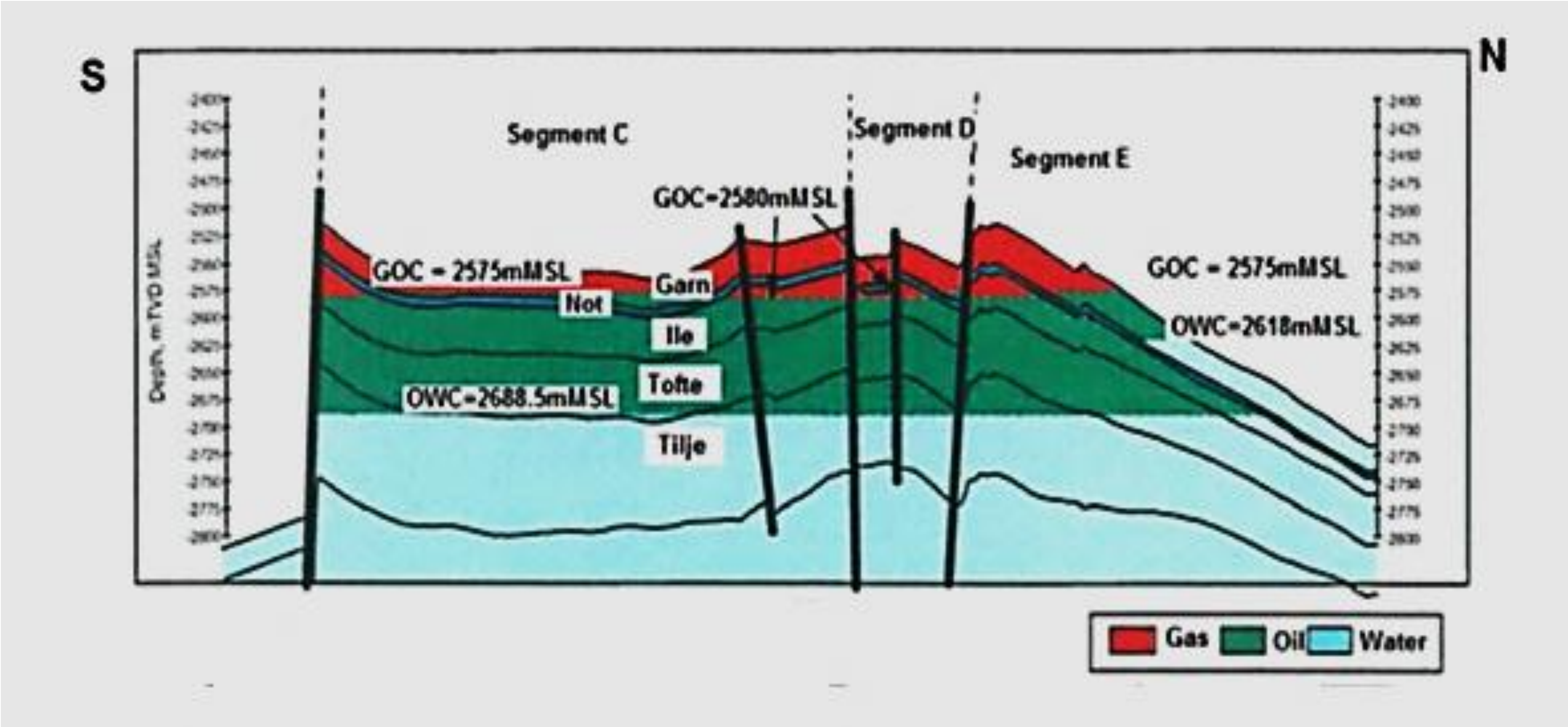

Figure 9- Structural cross sections through the Norne Field with fluid contacts (Statoil, 2001).

The ***Tofte Formation*** is divided into three reservoir zones. Tofte 1 consists of medium to coarse grained sandstones with steep dipping lamina. The lower parts are more bioturbated and have finer grains. The dip of the layers suggests that the source area for sediments was to the north or northeast of the field. Another important issue related to Tofte 1 is the limited distribution in the east-west or northeast-southwest direction. Tofte 2 is an extensively bioturbated, muddy and fine grained sandstone unit. Floating clasts can be found in the lowermost part of the section, which is coarsening upward. Tofte 3 consists of very fine to fine grained sandstone where almost none of the depositional structures are visible because of bioturbation.

The ***Tilje Formation*** Sediments deposited are mostly sand with some clay and conglomerates. The Tilje Formation is divided into four reservoir zones based on biostratigraphic events and similarities in log pattern. Tilje 1 is not cored in either of the wells 6608/10-2 nor 6608/10-3, but it is believed to consist of two sequences of sand that are coarsening upward and more massive sand at the top. Tilje 2 has a heteroclitic composition consisting of; sandstone layers of variable thicknesses, heavily bioturbatedshales, laminated shales and conglomeratic beds. A varying depositional environment is characteristic for Tilje 2 deposits. Tilje 3 consists of fine grained sand which has a low degree of bioturbation. It is therefore possible to see muddrapes, crossbedding and wave ripples in the depositions. Implications of the presence of fresh water are also found. Tilje 4 is a fine grained, bioturbated and muddy sandstone in the lower parts, while upper parts have conglomeratic beds interbedded with thin sandstone and shale layers.

3.3. Reservoir communications

When talking about communication in reservoirs of oil, we will rely on the communication of fluid between layers and segments. Normally, may be affected by faults or semi-sealing sealants, formation of nature sealing between layers with good permeability (stratigraphic barriers). During fluid flow drainage strategy these factors constitute important parameters to be analysed, it affects the performance of the drainage of petroleum.

In the specific case of the Norne field, lateral and vertical flows are severely affected by faults and stratigraphic barriers. The figure.10 (Eric master, 2010) shows the major faults existing in the Norne field.

Beside gravitational, viscous and capillary forces effects, stratigraphic barriers act in the Norne field complicating the normal flow of fluids in the vertical direction. These barriers are mainly constituted of layers of sizes of some variables being cemented and other Carbonate formation of Claystone. The vertical barriers which restrict the vertical fluid flow within the Norne Field are listed below:

- ✓ Garn 3/Garn 2 - Carbonate cemented layer at top Garn 2
- ✓ Not Formation - Claystone formation
- ✓ Ile 3/Ile 2 - Carbonate cementations and increased clay content at base Ile 3
- ✓ Ile 2/Ile 1 - Carbonate cemented layers at base Ile 2
- ✓ Ile 1/Tofte 4 - Carbonate cemented layers at top Tofte 4
- ✓ Tofte 2/Tofte 1 - Significant grain size contrast
- ✓ Tilje 3/Tilje 2 - Claystone formation

The main barriers so severe that affect the vertical flow of fluids between those presented above are including the Not Formation, the carbonate cemented layers which separate Ile 1 and Tofte 4 Formations, and the claystone which separate Tilje 3 and Tilje 2 Formations. (Statoil, 2001).

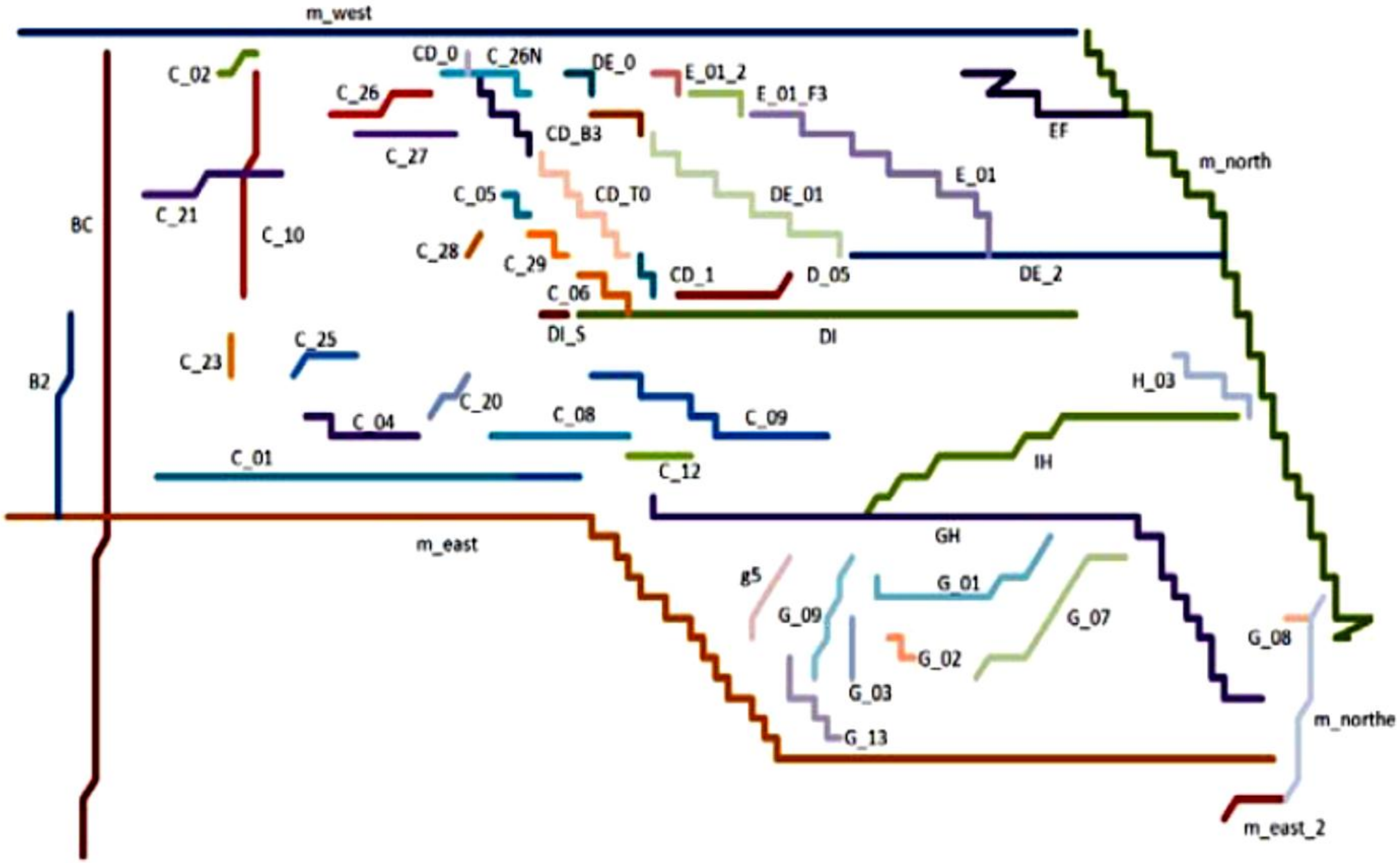

Figure 10- Faults into the Norne fiel (Eric master, 2010)

3.4. 9Wellbores

After the phases of exploration, identification and evaluation of a potential reservoir of petroleum, an exploration well has to be drilled to confirm the presence or absence of hidrocarbons. During this phase, is recommended to drill several exploration wells in different locations to confirm the formation stratigraphy and formation properties and characteristics. As sequence, development wells are drilled to produce the hydrocarbons and inject fluids to keep the pressure constant.

In real case of the Norne field, according to Statoil (2001), 50 wells have been drilled in the field until 2010. Entre eles, 43 well are development wells and 7 exploration wells. Within the 43 development wells, 33 are in production (16 active wells), 10 injectors. An updated file of the Norne field, shows more the 50 wells in total, which we can confirm in the table 1.

Remember that the main objective of this master's thesis, and make a study of the efficiency of water injection and gas form the simultaneous and alternating within the E-segment of the Norne Field. Therefore, it is necessary to have a vast overview of the wells that are into the E-segment. Among the wells presented above, the following part of And-segment:Well 6608/10-B-3 H, Well 6608/10-E-1 H, Well 6608/10-E-2 H, Well 6608/10-E-3 H, Well 6608/10-E-3 AH, Well 6608/10-F-1 H, Well 6608/10-F-2 H and Well 6608/10-F-3 H (figure. 11).

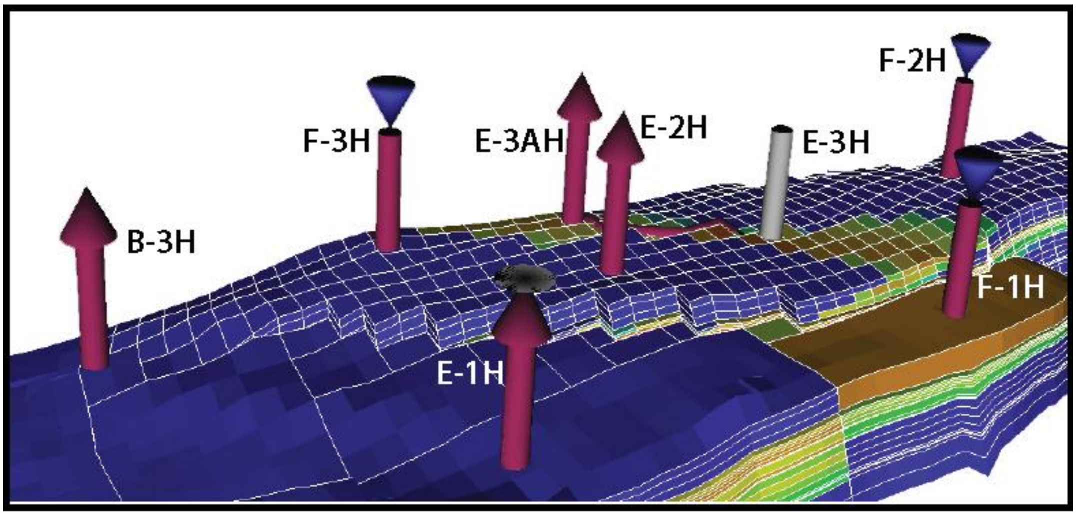

Figure 11- well location into the Norne E-segment

Well 6608/10-B-3 had been drilled as horizontal well with two horizontal sections, one in Ile and other in the Tofte formations. The well was initially completed in the Ile and Tofte

Formations. In 1st of July 1999, started oil production covering from the western part of the D-segment and the southern part of the E-segment.

Well 6608/10-E-1 H is a horizontal production well, completed in the Ile 2 and Ile 3 Formations. This well was intentionally originated to drain oil in the southern part of the E-segment.

Well 6608/10-E-2 H was drilled as a horizontal well, designed to produce oil from the southern part of E-segment. The completion was planned to be implemented in the Ile 3 and Ile 2 Formations, but during drilling operation, it was drilled deeper than planned   starting producing oil in November 1999 and in July 2005 stopped producing oil due to earlier water breakthrough, therefore a new completion was made in the   Ile 2.1 Formation and it restarted to produce oil in August 2005..

Well 6608/10-E-3 H was initially designed to drain oil from the northern Part of E-segment. It is an horizontal well with an slight inclination in a way that the well perforates throughout Garn, Not, Ile and Tofte formations. The well completion was realised in the Ile and upper Tofte Formations. Well 6608/10-E-3 H started production December 2000 and was plugged May 2000.

Well 6608/10-E-3 AH started the oil production in December 2000 and stopped producing in January 2005. However, it is a horizontal well, originally designed to drain oil from the Garn Formation in the northern part of E-Segment. The well was located in sands containing oil the whole section except for an interval in the water zone.

Well 6608/10-F-1 H is a vertical well that was drilled through Garn, Ile, Tofte and Tilje Formations. The well was perforated approximately 23 m TVD below the oil-water contact in the Ile and Tofte Formations. In addition, this well is located into the north of the Norne E-Segment. Originally designed to inject water in the aquifer in northern part of the field. Injection from this well started September 1999.

Well 6608/10-F-3 H was originally designed to drain oil in the south-western part of the E-segment. The well was drilled with an angle of up to 50 in the top whole section and less than 20 in the reservoir. Completion was performed in the Tofte and Tilje Formations. However, Injection started in September 2000.

3.5. Wellbores facilities

A good strategy for production ensures high amounts of petroleum recovered. Therefore, they take it into account during the development phase of the reservoir. The wells of the Norne field were designed based on the following principles:

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

The water injection strategy was made in a way that the areal distributions of the water Injectors maintain a steady rise of the water level and hence good areal sweep. Moreover, the vertical communication in the Norne reservoir is restricted by cemented layers, it was necessary to convert the drainage strategy from vertical to flank sweep. This objective was obtained by locating the water injectors toward the flanks. Additionally, the water injector's wells are completed in the Tilje 3 up to Ile 3 formation.

Additionally, the locations are optimized according to gas and water breakthrough times by use of reservoir simulation studies.

3.6. Drainage Strategy within the E-segment

One of the most important factors in designing drainage strategy is the injection storage volume that needs to be provided to achieve flood control and minimise the water and gas breakthrough in the production wells.

In this section, an examination of the drainage strategy within Norne field will be realised. The initial strategy to maintain reservoir pressure was to reinject produced gas into the gas cap and water into the water zone. But since the gas cap had high pressure and was sealed off by the Not formation, the gas injection was changed to the water zone and the lower part of the oil zone. This change in strategy was successful; however, the prediction of gas flow in the reservoir became more complicated and uncertain. A higher GOR than expected caused the production to be restricted by gas handling capacity. Gas export was started in order to obtain a balanced gas- and water injection strategy, and prevent further increase in GOR.

CHAPTER .IV. Norne E-segment simulation model

4.1. Case Study

In this project, the E-segment model is considered as a single entity model to precisely characterize and predict fluid behaviour in this segment. Therefore, from the original Norne field complete model, was separated the E- segment. The E-segment reservoir simulation model was programed using ECLIPSE100, black oil model, with three phases (oil, gas and water). The segment reservoir model is discretized by *46×112×22* grid blocks with 8733 active cells. In total, the E-segment has 8 wells. These comprise of one observation well, 2 injector and 5 producers. Below is showed the E-segment eclipse model:

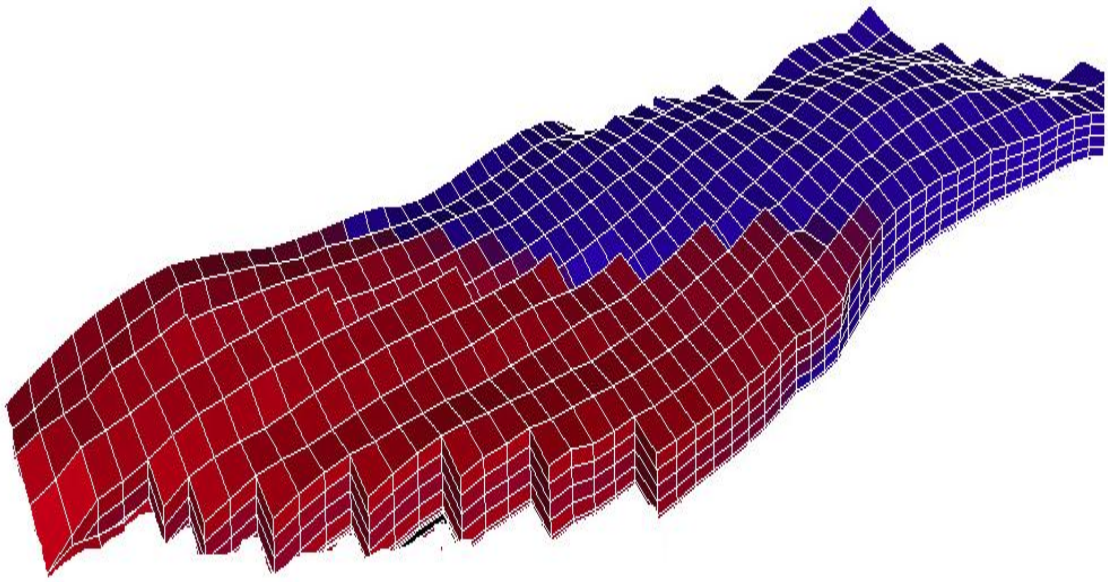

Figure 12- Norne E-segment simulation model

4.2. Characteristics and properties of the E-segment simulation model

4.2.1. Initial reservoir conditions

The reservoir model was initiated at a uniform pressure of 273.2 bar and constant temperature of 98.3 ^{0}C. Water compressibility used in the eclipse model was 4.67 X 10-5 1/bar at 277 bars while the water formation volume factor used was 1.0328 Rm3/Sm3. The rock compressibility of 4.84 X 10-5 1/bar was used in the entire reservoir while the water viscosity is 0.318cp. Oil formation volume factor of 1.32 Rm^3/Sm^3, gas formation volume factor 0.0047, oil density of 859.5 kg/m^3 and API equal 32.7^0, gas density of 0.8545 kg/m^3.
Connate water saturation related to E-Segment varies from 0.05 to 0.38 among different relative permeability curves, reservoir wettability is believed to be mixed wet. The geologic model provided an estimate of OOIP 17.4 million barrels at initialization.

4.2.2. Reservoir properties

To describe a petroleum reservoir, the key properties are *porosity*, *pore saturation*, and *permeability*. In general, *Porosity* refers to the maximum capacity of the reservoir to hold fluids. In the E- segment generation of total porosity is executed by use of the equation

$$\varphi = a + b.\rho_b$$

Where ρ_b is the bulk density, while a and b are constants.

Cross plots of overburden corrected core porosity vs. density log are used to find these constants. The constants are found for the different zones, which are grouped together for improving correlations. Some uncertainties are related to the determination of the constants a and b from cross plots (Statoil, 1994). Typical porosities in different Norne E-segment layers are represented in the figure. 15.

Permeability (see figures 13 and 14) is a factor that quantifies how hard or how easy it is for the fluid to flow through the reservoir to the oil producing well; the greater the permeability, the easier the fluid flows. In the norne field log estimated permeability was established by use of the relationship between overburden corrected core porosity and overburden corrected core permeability. Log permeabilities in the horizontal and vertical directions were found to be unrelated. Hence, vertical permeability was defined in the same way as the horizontal permeability. It is found that both horizontal and vertical permeability were overestimated in Tilje 3, Tilje 4 and Tofte 3 zones. Core permeability was less than 2000 mD in these zones, so the log derived permeability was cut on a maximum value of 2000 mD here. In the other zones, the maximum value was 10000 mD (Statoil, 1995).

Table 2. Average values of porosity and permeability in modelling (Statoil, 1994)

Formation	Net/Gross (Fraction)	Dept M TVD/MSL	Porosity Fraction	Permeability mD
Garn 3	0.94	2553	0.29	813.9
Garn 2	0.86	2562	0.23	518.6
Garn 1	0.78	2570	0.18	44.5
Not		2581	0.12	0
Ile 3.2	0.89	2591	0.23	137.6
Ile 3.1	0.92	2601	0.23	87.6
Ile 2.2.2	0.99	2614	0.26	723.9
Ile 2.1	0.8	2622	0.22	508.1
Ile 1	0.97	2630	0.27	793.5
Tofte 4	0.93	2628	0.23	108.8
Tofte 3. 4.2	1	2637	0.31	1348.2
Tofte 3. 4.1	1	2641	0.30	1063.7
Tofte 3. 3.2	1	2645	0.28	590.7
Tofte 3. 3.1	1	2649	0.27	375.3
Tofte 3.2	1	2653	0.26	255.9
Tofte 3.1	1	2663	0.26	166.7
Tofte 2	0.97	2666	0.22	58.5
Tofte 1.2	0.9	2679	0.24	971.6
Tofte 1.1	0.89	2686	0.23	819.6
Tilje 4	0.83	2694	0.19	308.7
Tilje 3	0.87	2709	0.24	555.4
Tilje 2	0.72	2731	0.16	212.4
Tilje 1	0.90	2771	0.25	1614

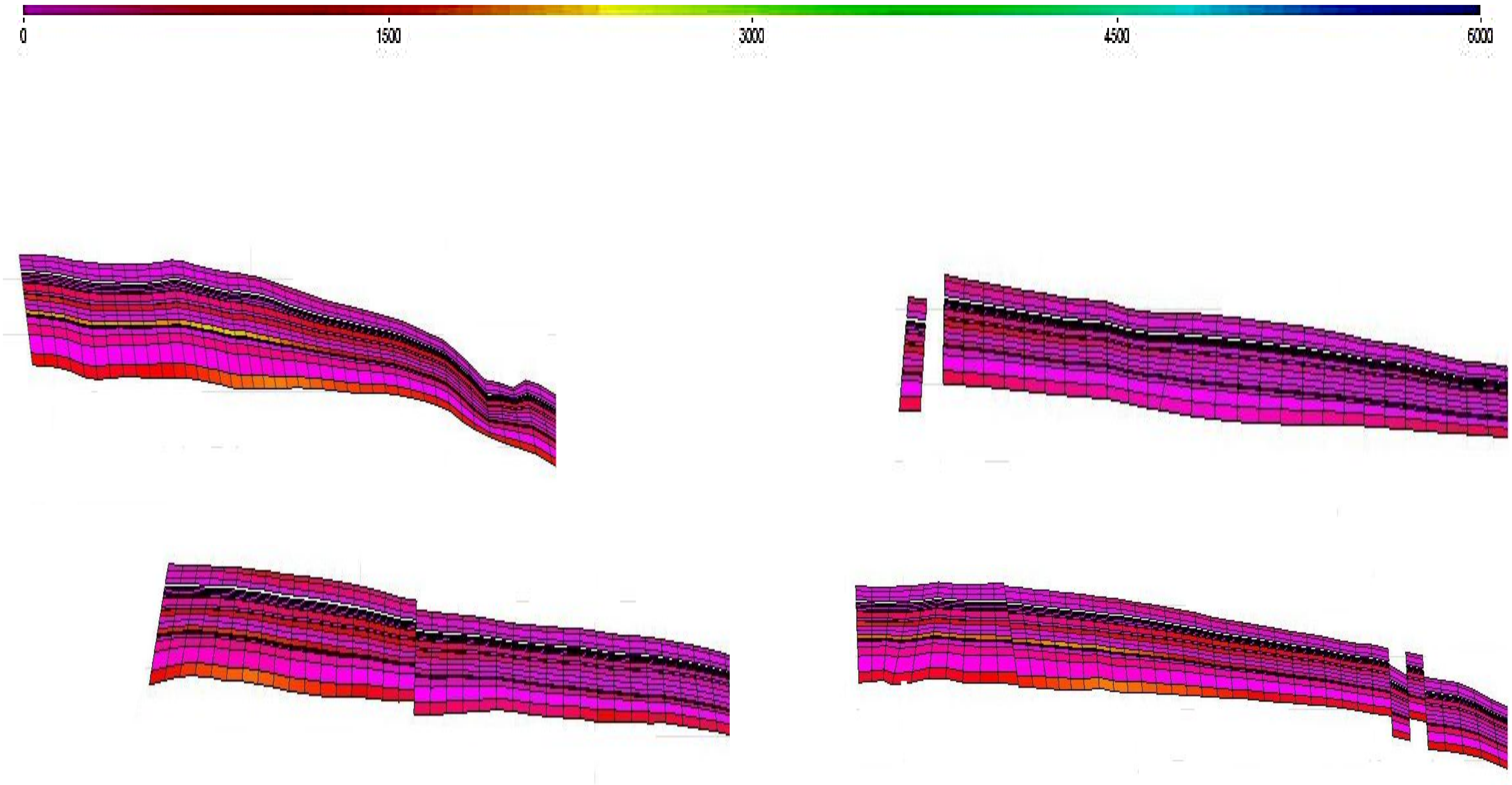

Figure 13- Horizontal permeability of the Norne E-segment reservoir model

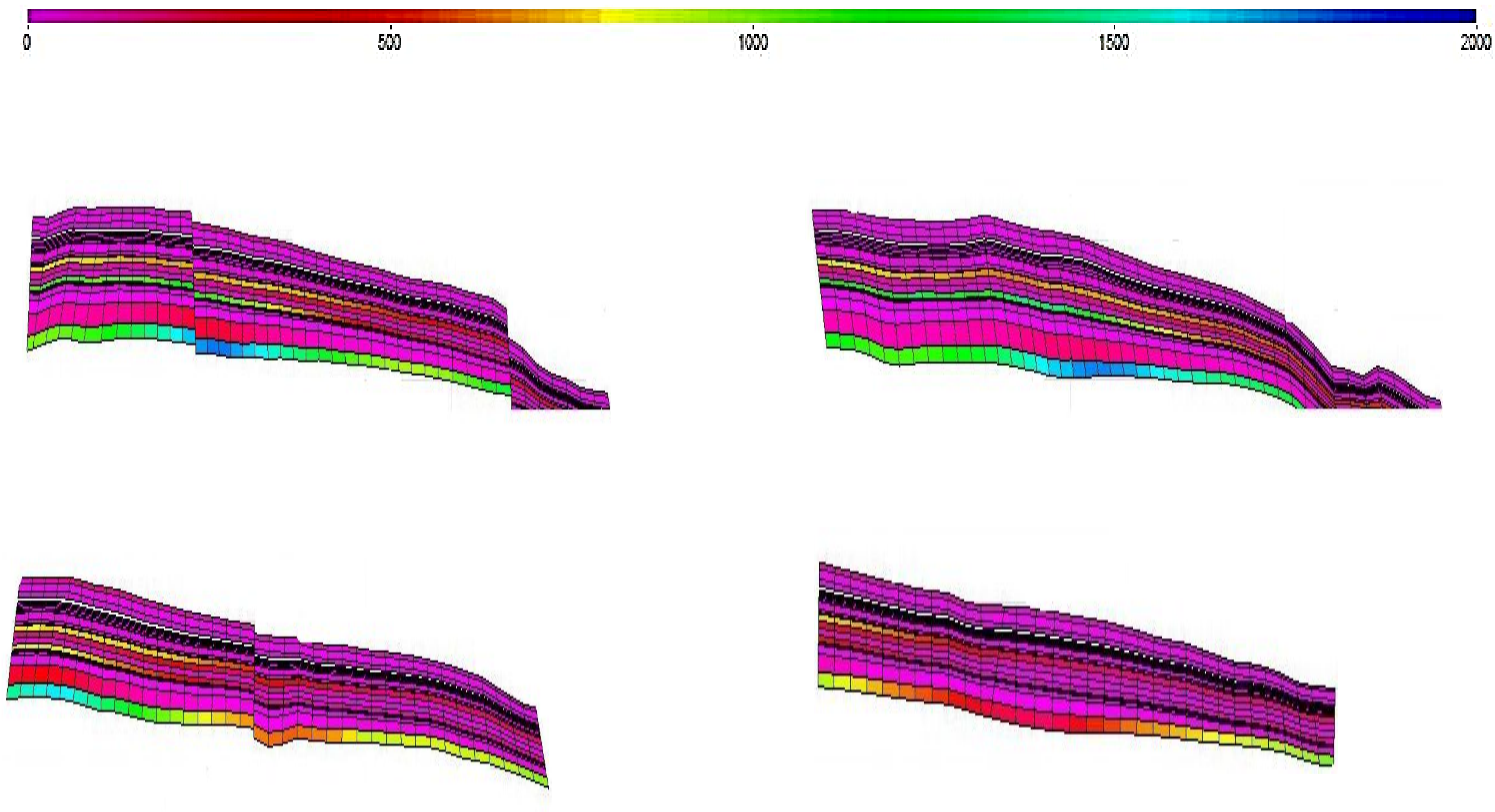

Figure 14- Vertical permeability of the Norne E-segment reservoir model

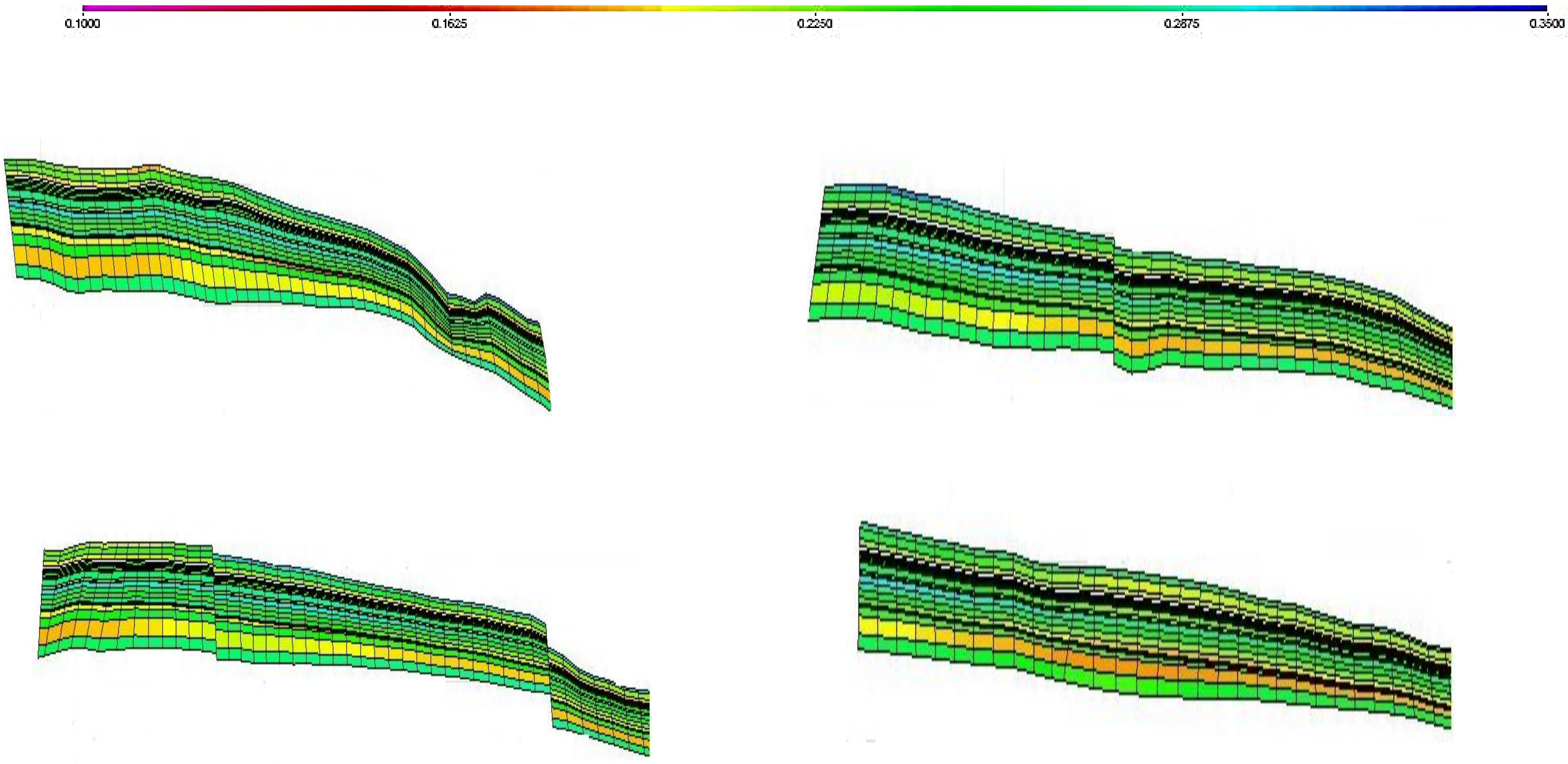

Figure 15- porosity variation of the Norne E-segment reservoir model

4.2.3. Fluid contacts

Horizontal contacts of fluids are usually assumed, although tilted contacts occur in some reservoirs. The contact between fluids is usually gradual rather than sharp, forming a transition zone of mixed fluid. A mixed-fluid reservoir will stratify according to fluid density, with gas at the top, oil in the middle, and water below. The fluid contact is not static, during production of fluids often perturbs the fluid contacts in a reservoir.

Fluid contacts there is a common oil-water contact at 2688.5 m TVD/MSL for wells 6608/10-2 and 6608/10-3, while well 6608/10-4 had a oil-water contact at 2574.5 m and did not contain any gas. There were two different gas-oil contacts for wells 6608/10-2 and 6608/10-3; 2580 m and 2575 m respectively. The gas systems seem to be common over the entire **fi**eld. That is also the case for the oil systems, except the oil above the Not Formation in well 6608/10-3.

Table 3. Fluid contacts in the E-segment simulation model (Clara, 2010)

		WOC	GOC	Comment	
Datum	**Pressure**	**Depth**	**Depth**	**Segment**	**Formation**
m	bar	m	m	-	-
2582.0	268.56	2692.0	2582.0	C+D	Garn
2500.0	263.41	2585.5	2500.0	G	Garn
2582.0	269.46	2618.0	2582.0	E	Garn
2200.0	236.92	2400.0	2200.0	G	Ile-Tilje
2585.0	268.77	2693.3	2585.0	C+D+E	Ile-Tilje

4.2.4. Faults

The incorporation of faults into reservoir models has often been a fragmented process with different faults being treated in different ways. Despite the fact that faults can significantly impact fluid flow within the reservoir with the correct fault fluid flow characterization often critical to getting a good history match and despite faults playing an important part in the ultimate recovery and sweep efficiency within the reservoir, a single and integrated fault modelling workflow continues to remain illusive.

Norne field faults, especially major faults, can be discovered by studying the seismic data. Each subarea of the fault planes has been assigned transmissibility multipliers. To describe the faults in the reservoir simulation model, the fault planes are divided into sections which follow the reservoir zonation. These are functions of fault rock permeability, fault zone width, the matrix permeability and the dimensions of grid blocks in the simulation model.

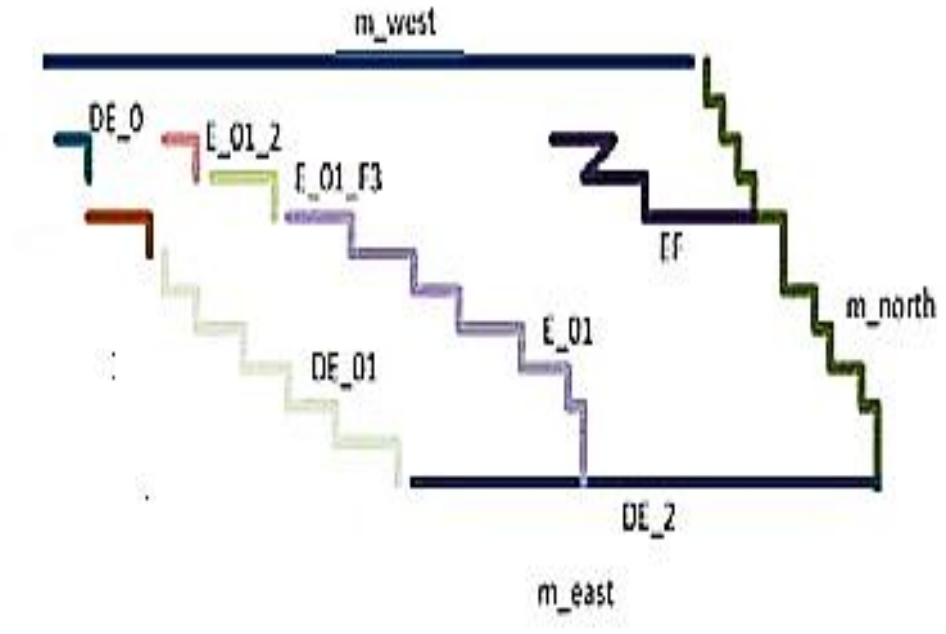

Figure 16- Faults within the E-segment (Eirik, 2010)

4.3. History Matching

History matching is one of the first steps before prediction, during the simulation of hydrocarbon reservoir performance and optimization stages using eclipse simulator. However, Reservoir engineers take advantage of this stage to evaluate the quality of the reservoir model to simulate future reservoir behaviour with a higher degree of confidence.

The eclipse data set initially specifies real data's measured during production period (production and injection rates), and some uncertain parameters such as permeability, layering structure, aquifer strength and individual well performance are specified as normal in the remainder of the data file. The main task is try to match the simulated results with measured production rates which has been producing for a specific period of time because the well rates calculated by ECLIPSE , will not correspond to the measured rates specified by the user. Therefore, identify reservoir properties subject to the greatest uncertainty and adjusting them to bring the simulated and measured rates to an acceptable degree of correspondence, becomes a frustrating exercise for reservoir engineers (ECLIPSE 300 Reference Manual, 2004).

The term History Matching can be defined as the adjustment of reservoir parameters in the model until the simulated performance matches the measured information as closely as possible. It is the most time-consuming phase of a simulation study to obtain a match of dynamic data and sometimes it can be frustrating and complex because there is no precise approach for conducting history matching that is universally used, initially the reservoir engineers has to do an analytical sensibility study and then try to match the reservoir parameter through several iterations. Normally, the special techniques most commonly used consist in modifying the parameters of the initial model, proceeding by trial and error. To adjust the reservoir parameters in the model with the simulated performance becomes necessary to perform several iterations changing one or more parameters that show sensitivity to overlay data simulation.

The effectiveness of the history match should be evaluated by the quality of the match in history reservoir parameters applied at the field level, at some areal subdivision ofhe field, and at individual wells. In a way that, average field properties may differ from average model properties by only a few pounds per square inch.

Automatic history matching has been apply, but the major part of reservoir engineers use manual rather than automatic methods of history matching because of the limitations and expense of currently available automatic methods.

4.3.1. Workflow

According to Eirik (2010) , advises to perform history matching in two phases commonly called "gross phase" and a "detailed phase."

In the gross phase, uncertain parameters are changed to match field data. In fact, in this stage average reservoir properties like average pressures and production rates of a reservoir are matched. In the second stage, changes are made to match individual well rates such as water cuts, GOR"s and breakthrough times. These changes may affect the quality of the match obtained during the first stage or the quality of the match in other areas of the field.

4.3.2. History Matching at Norne E-segment

There are several uncertain reservoir properties that can be modified during history matching, among them we have: aquifer transmissibility, aquifer storage, reservoir transmissibility, relative permeability and Capillary pressures functions.
For Norne E-segment field, Eirik (2010) suggested the following actions that has to be applied to the 2004 simulation model (BC0407) in order to create the base case:

- ✓ Previous history matching updates are removed.
- ✓ Faults are set to partially sealing (MULTFLT = 0.1).
- ✓ The fault E_01_F3H is enabled.
- ✓ Field-wide stratigraphic barriers in the layers 1, 4, 8, 11, 12, 15, 20 are implemented using the parameter MULTZ. The parameter values are assigned according to the Norne Reservoir management plan from 2001 (see Table 4).

In general, the data that are matched are pressure, water/oil ratio's (WOR"s), gas/oil ratios (GOR"s), water/gas ratios (WGR"s).

Table 4. Recommended MULTZ values for the stratigraphic barriers in the Norne Field

Layer	Barrier	MULTZ	Description
1	Garn 3/Garn 2	0.01	Carbonate cemented layer at top Garn2
4	Not formation	0.00	Claystone formation
8	Ile 2.1.1/Ile 1.3	0.05	Carbonate cementations and increased clay content at base Ile 3
11	Ile 1.2/Ile 1.1	0.01	Carbonate cemented layers at base Ile 2
12	Ile 1.1/ Tofte 2.2	0.01	Carbonate cemented layers at top Tofte 4
15	Tofte 2.1.1/Tofte 1.2.2	0.05	Significant grain size contrast
20	Tilje 3/Tilje 2	0.00001	Claystone formation

In figures 17-21, we can see the results for the updated case compared with the initial model. The updated model is responding positively to the reduction in vertical communication. The carbonate barrier in layer 11 and 12 is highly sensitive to controlling the water rise. Although the total water production in Figure 21 picks up on historical behaviour, a closer inspection of the individual wells suggest otherwise. Some wells are producing too little while some wells are producing way too much water.

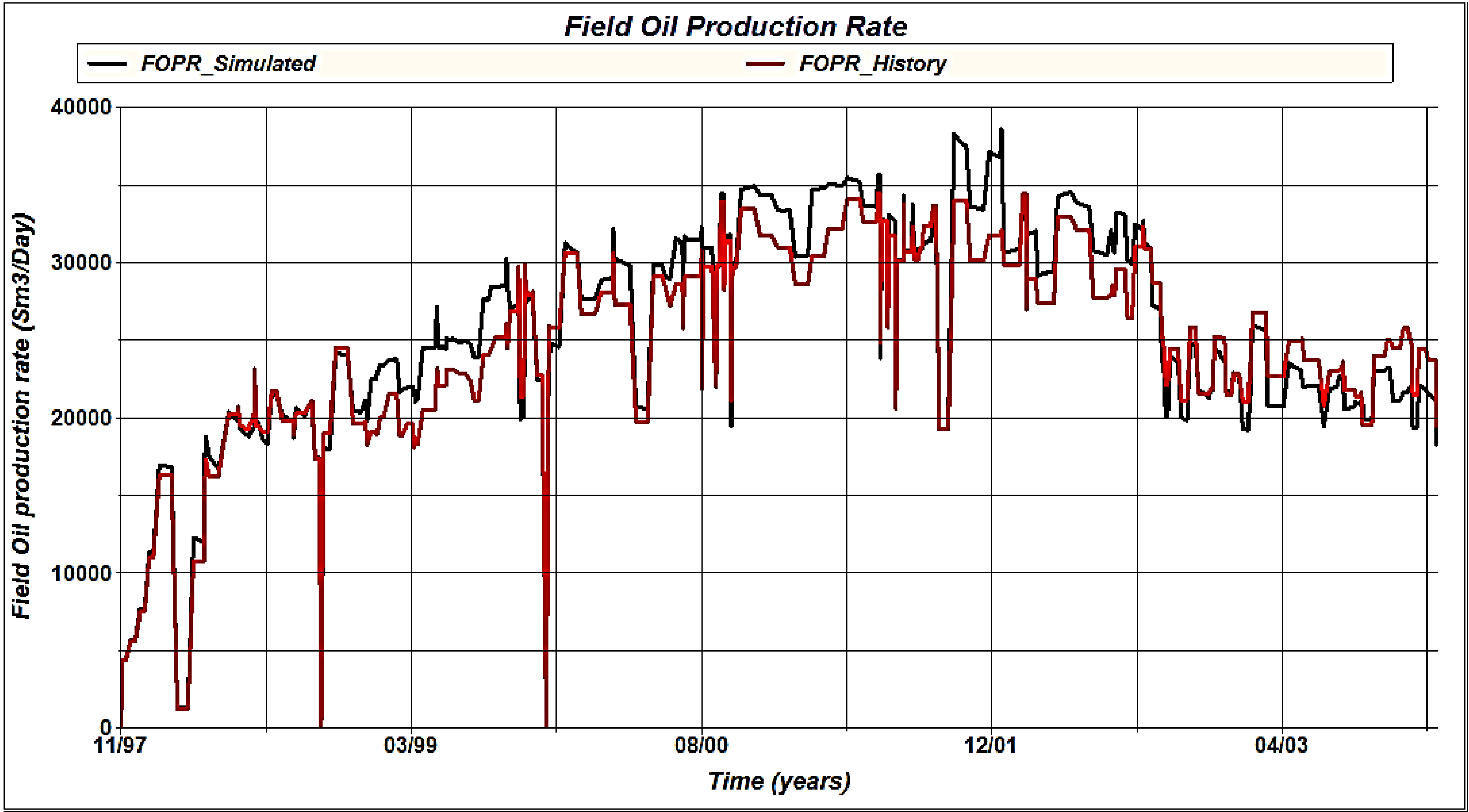

Figure 17- Field Gas-Oil ratio history matching

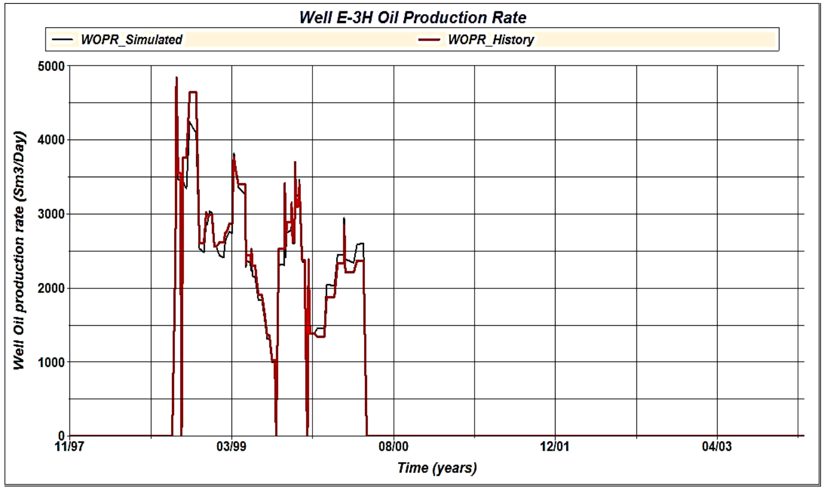

Figure 18- E-3H well: Oil production rate history match.

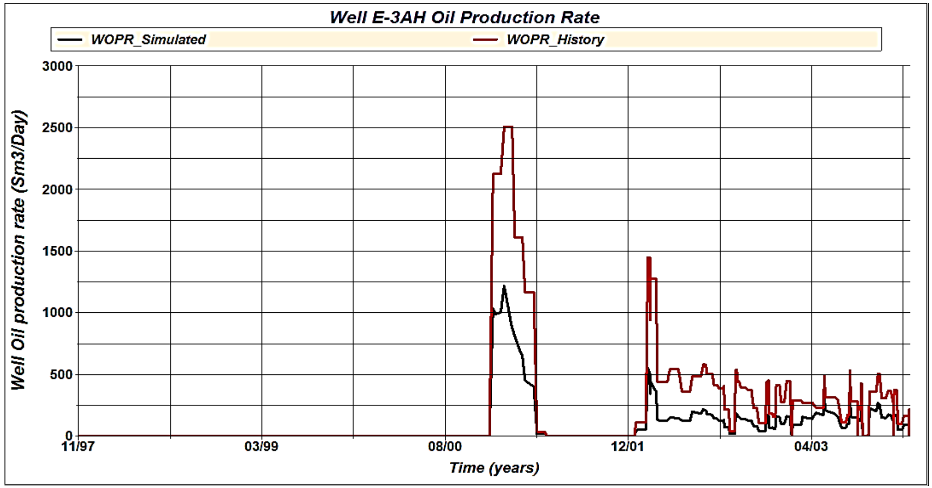

Figure 19- E-3AH well: Oil production rate history match.

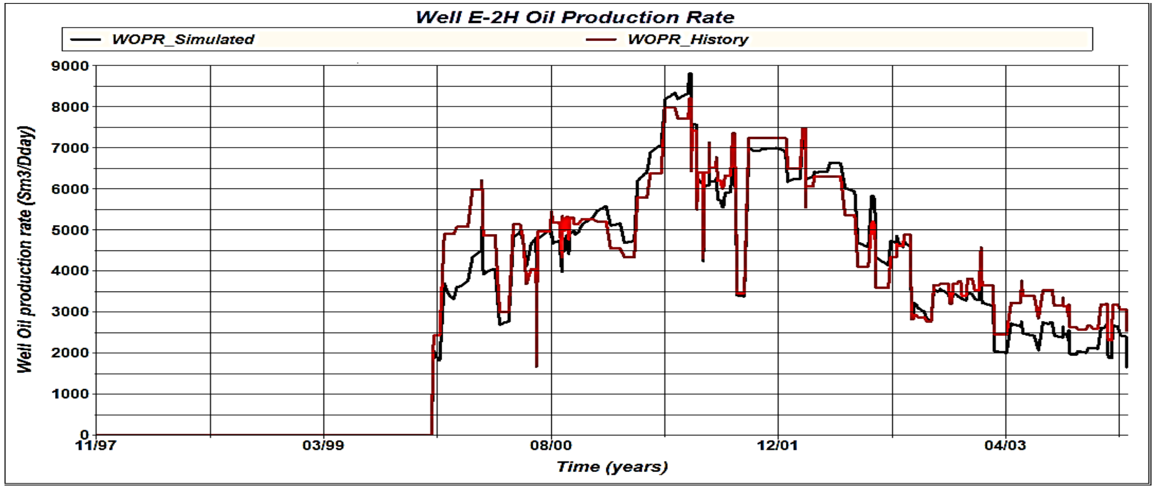

Figure 20- E-2H well: Oil production rate history match.

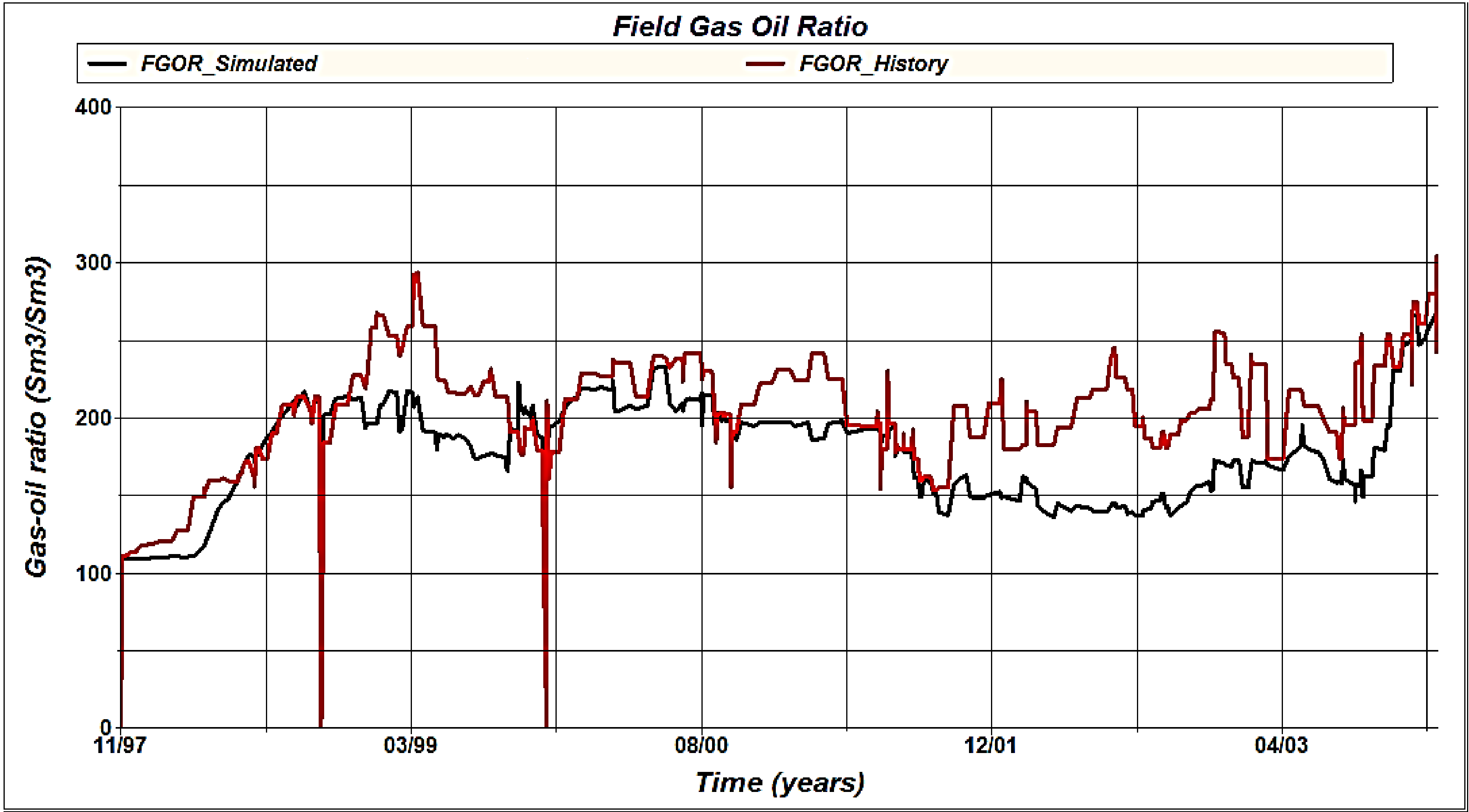

Figure 21- Field Gas-Oil ratio history matching

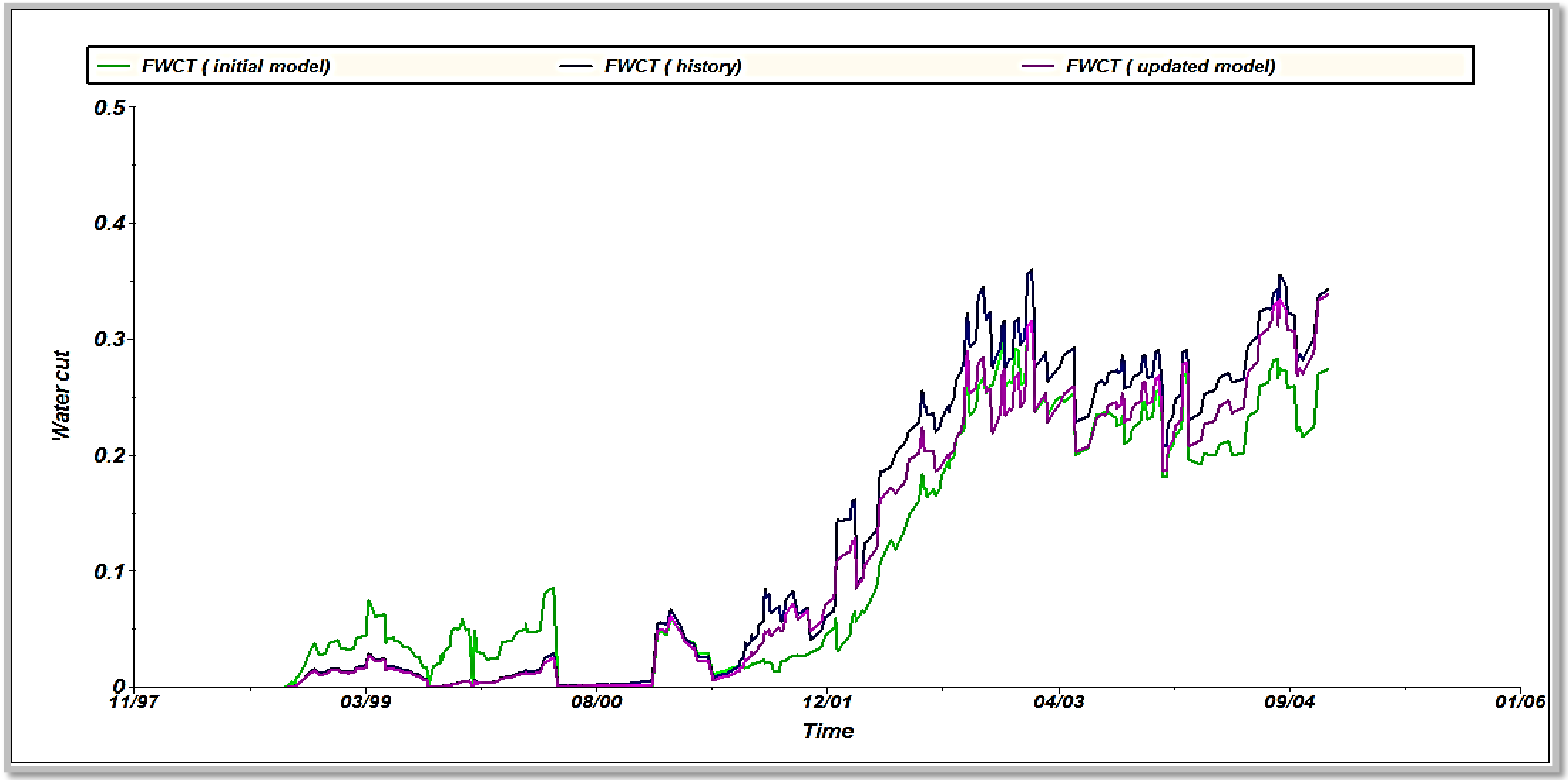

Figure 22- Field Water Cut history matching

CHAPTER.V. Oil recovery prediction on Norne E-Segment

5.1. Sensitivity Injection Analyses within E-Segment

Before analyse WAG or SWAG injection techniques in a fixed injection rate, it is mainly necessary to study the effect of different parameters on oil production rate. Thus, the reservoir engineer in this stage, analyse the best conditions to simulate the different scenarios created to predict oil recovery. More specifically, the main parameter affecting WAG and SWAG injection techniques are cycle time and slug injection.

5.1.1. WAG cycle time

WAG cycle time can be understood as the timing of switch from gas to water during water alternating gas injection in a large field simulation. Normally, this property has to be determined after several simulations, changing the alternating time of switch from gas to water injection. To determine the best WAG cycle time in the Norne E-segment, three cases were considered: Three months WAG cycle, Six months WAG cycle and One year WAG cycle. These three cases were studied using the original Eclipse model of the E-Segment, predicting 14 years of production injection response, using a constant low injection rates of 2000 sm^3/ day for water and 4500 sm^3/ day for gas; 430414.393 sm^3/ day of water and 1291243.185 sm^3/ day of gas. The intent was to ascertain which case would guarantee a better residual oil recovery. Figure 23 and 24 shows clearly the variation with time of the oil production total for three different WAG cycle cases presented above using low and high injection rates. Thus, oil production total variation is regardless of time during low injection rate. Para todos os efeitos, o ciclo de injeccao neste caso nao altera nem influencia o valor final de recuperacao residual de petroleo. However, for high WAG injection rate, the final value of recovered oil, for all WAG cycle injection cases, are the same, but a slightly difference between the plots is noticed between 2007 and 2014. When oil production is dependent of time, for high WAG injection rate, it seems that three months cycle injection case will present the best results of oil recoverability. When low WAG injection is considered, the field pressure decrease abruptly with time below the bubble point pressure, instead, for high WAG injection rate pressure profile increase significantly above the bubble point pressure (see figure 24 and 25), keeping the E-segment in the undersaturated conditions (bubble point is about 251 BARA) which is desirable during fluids miscibility phase.

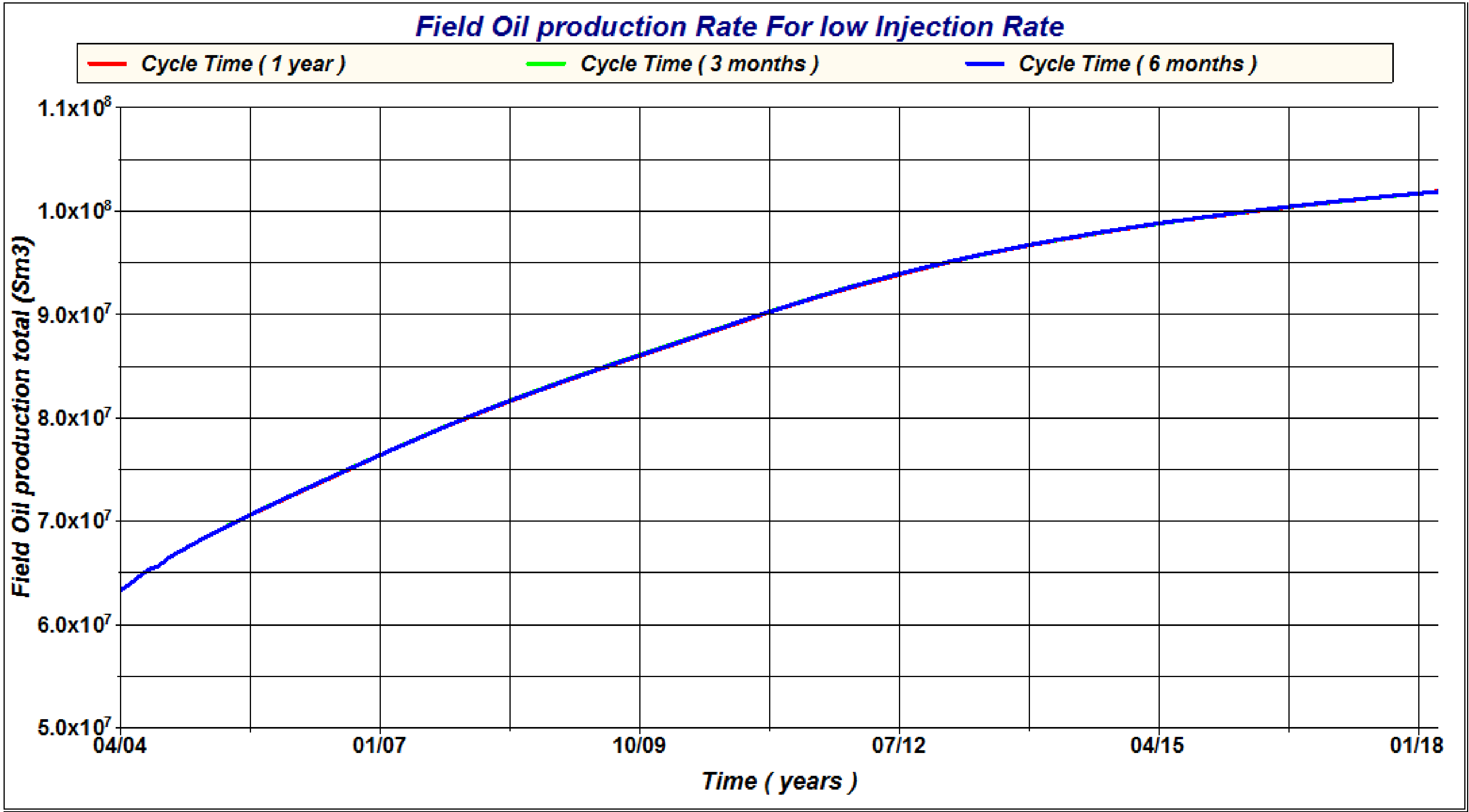

Figure 23- Field Oil Production total behaviour using different cycle time and low injection rate

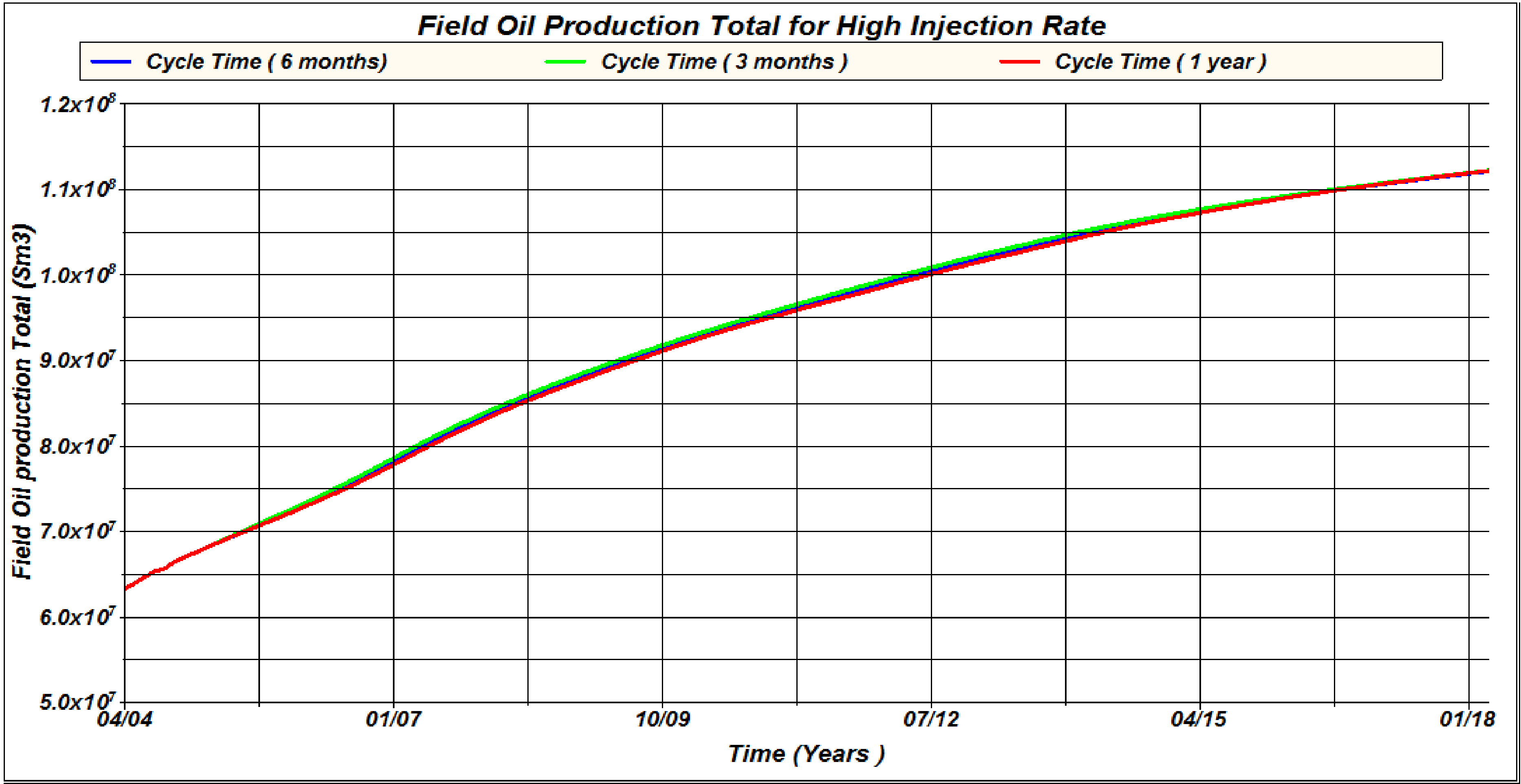

Figure 24. Field Oil Production total behaviour using different cycle time and high injection rate

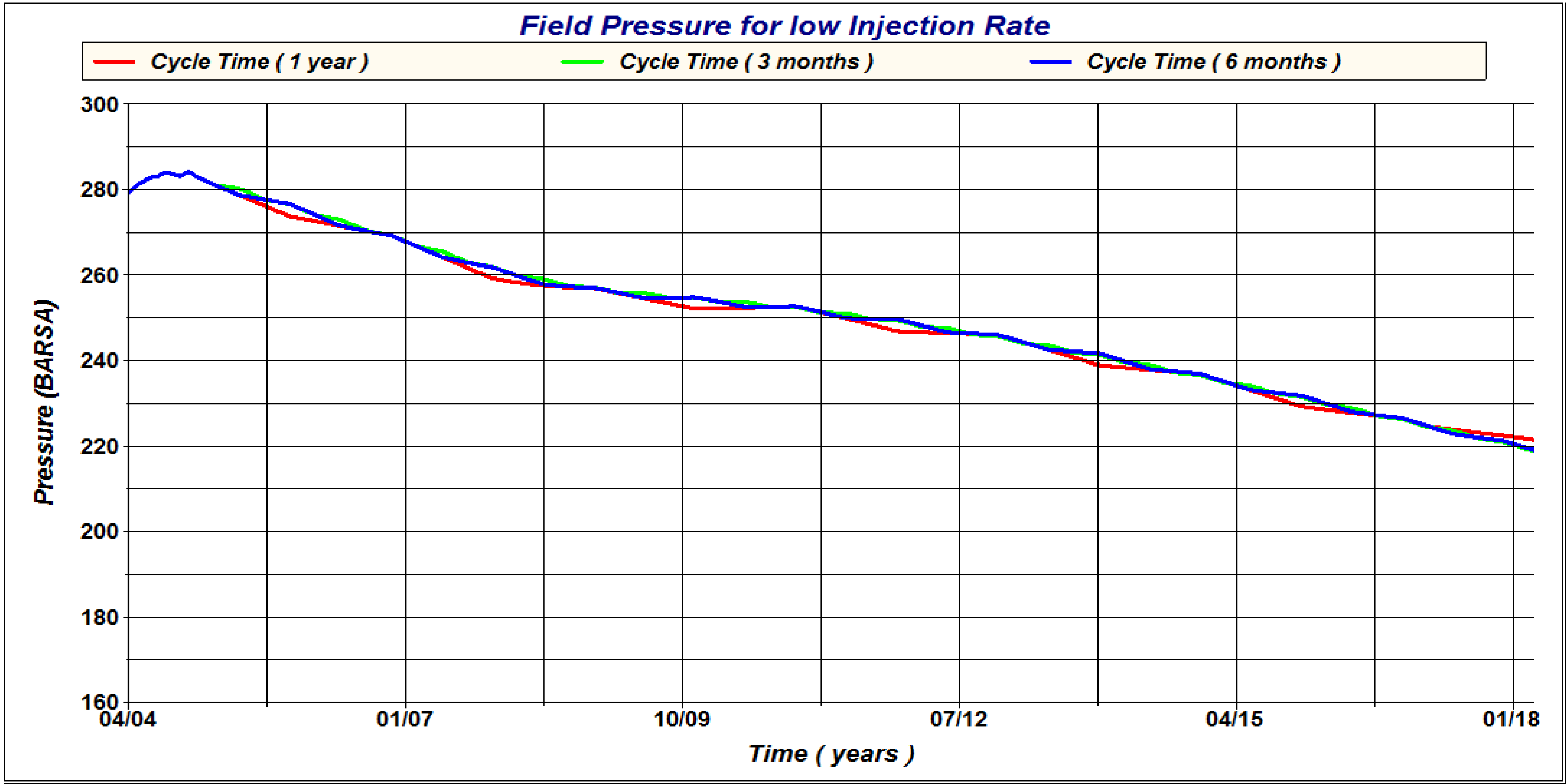

Figure 25- Field Pressure behaviour using different cycle time and low injection rate

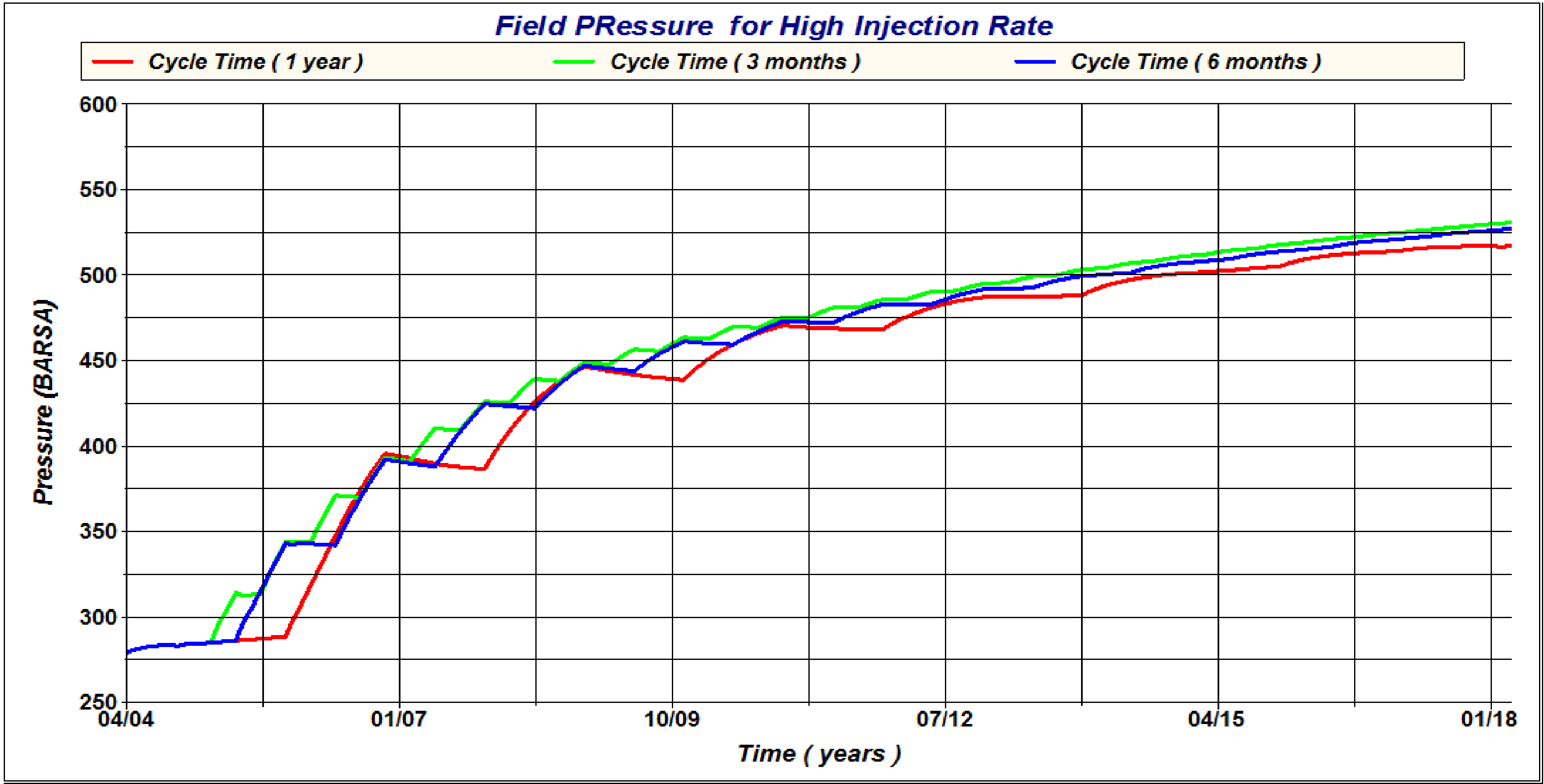

Figure 26- Field Pressure behaviour using different cycle time and high injection rate

a condition (bubble point is about 251 BARA) which is desirable during fluids miscibility phase keeping the reservoir pressure above or fluctuating minimum miscible pressure (MMP). From this analysis, the following conclusion is taken: when low injection rate is considered, it can be seen that is rather wasteful to inject water and gas for 1 year cycle or 6 years, because the incremental of residual oil is independent of time.

5.1.2. WAG Injection rate

WAG injection rate can be understood as the gas and the water slugs that are alternately injected in a fixed ratio into the reservoir. It is an important parameter to determine, as it is crucial to find the best conditions that guaranties high degree of recovery. The literature defend that at low WAG ratios, gas may channel and breakthrough very early, however, at high WAG ratios may cause oil trapping by water blocking or at best may not allow sufficient solvent-oil contact, therefore choosing an optimal value of WAG ratio is very important. Normally, the optimal value of WAG ratio is finding by doing much iteration with different values of WAG ratio and observes the effects on residual oil recovery. In order to find the optimal value of WAG ratio in the Norne E-segment field, the following values were suggested initially:

Table 5. WAG rate sensitivity analyses using low injection Rates

Cases	Water rate (Sm^3/day)		Gas rate (Sm^3/day)	
	Well F-1H	Well F-3H	Well F-1H	Well F-3H
Case A	1000	1000	2500	2500
Case A1	1000	500	2500	1500
Case B	500	500	1500	1500
Case B1	500	250	1500	750
Case C	2000	2000	4500	4500
Case C1	2000	1000	4500	3000

In the eclipse simulator, these iterations will be performed injecting at 6 months cycle time interval. Some results are presented in the figures 27-30.

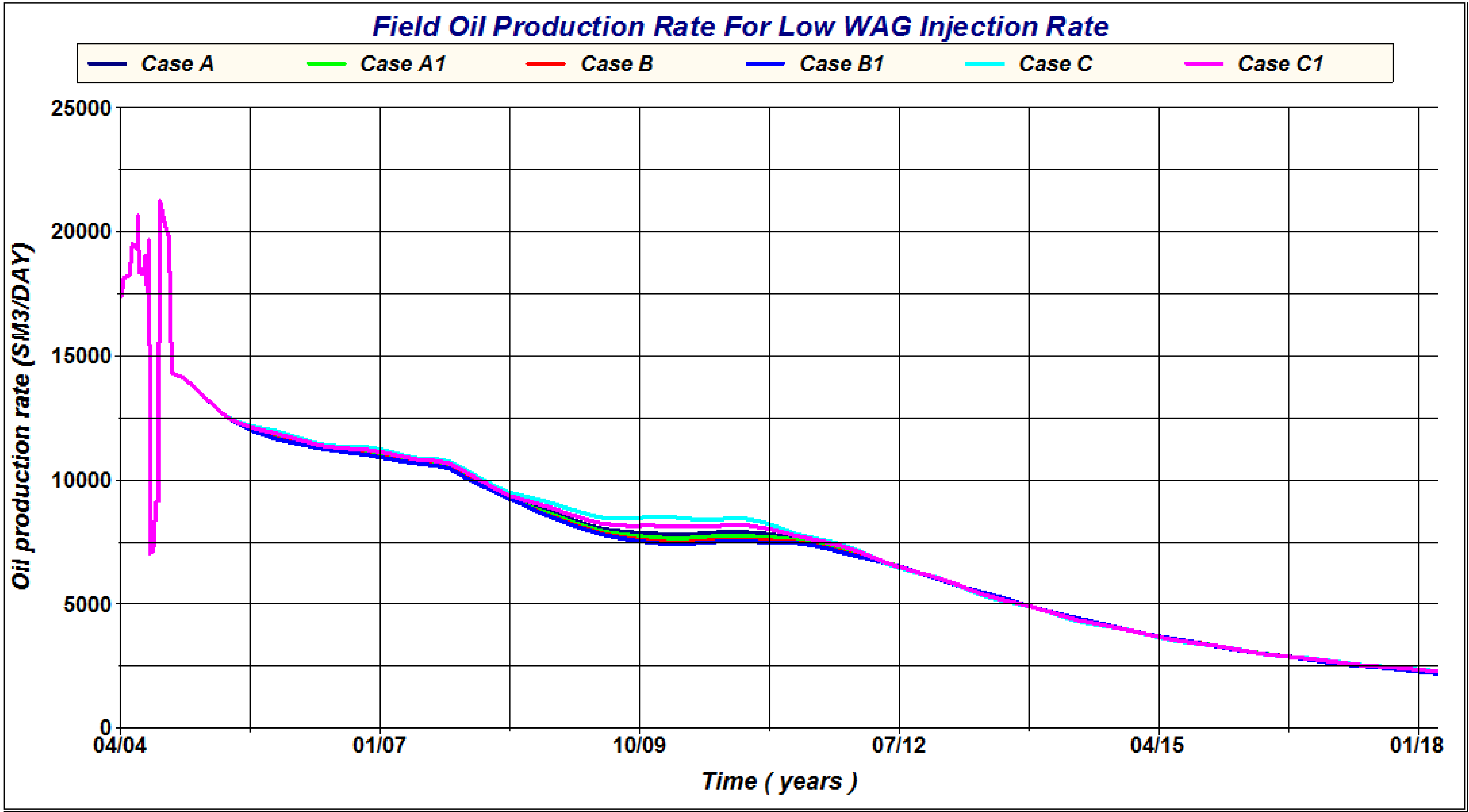

Figure 27- Field Oil Production rate for WAG low injection rate

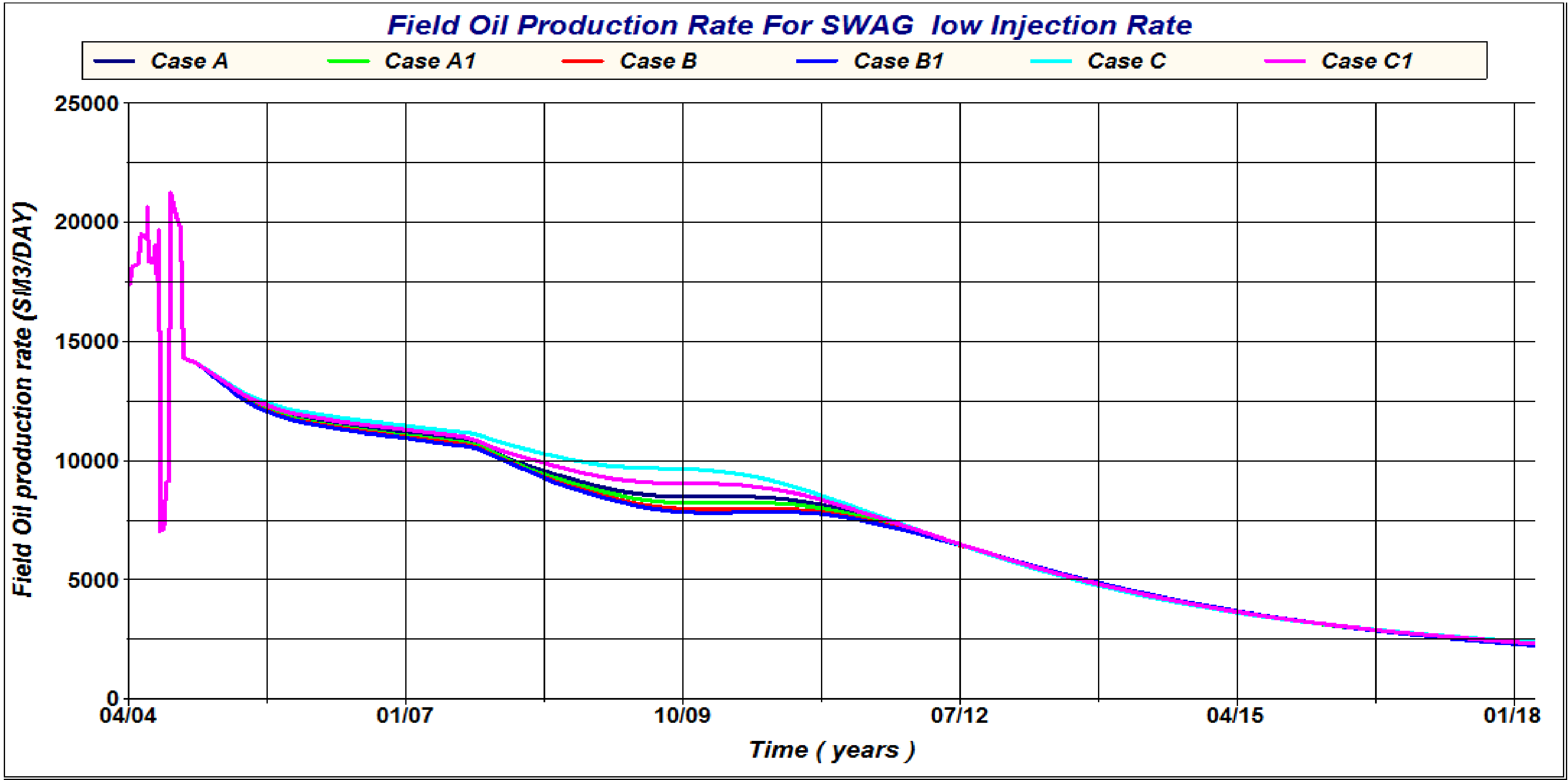

Figure 28- Field Oil Production rate for SWAG low injection rate

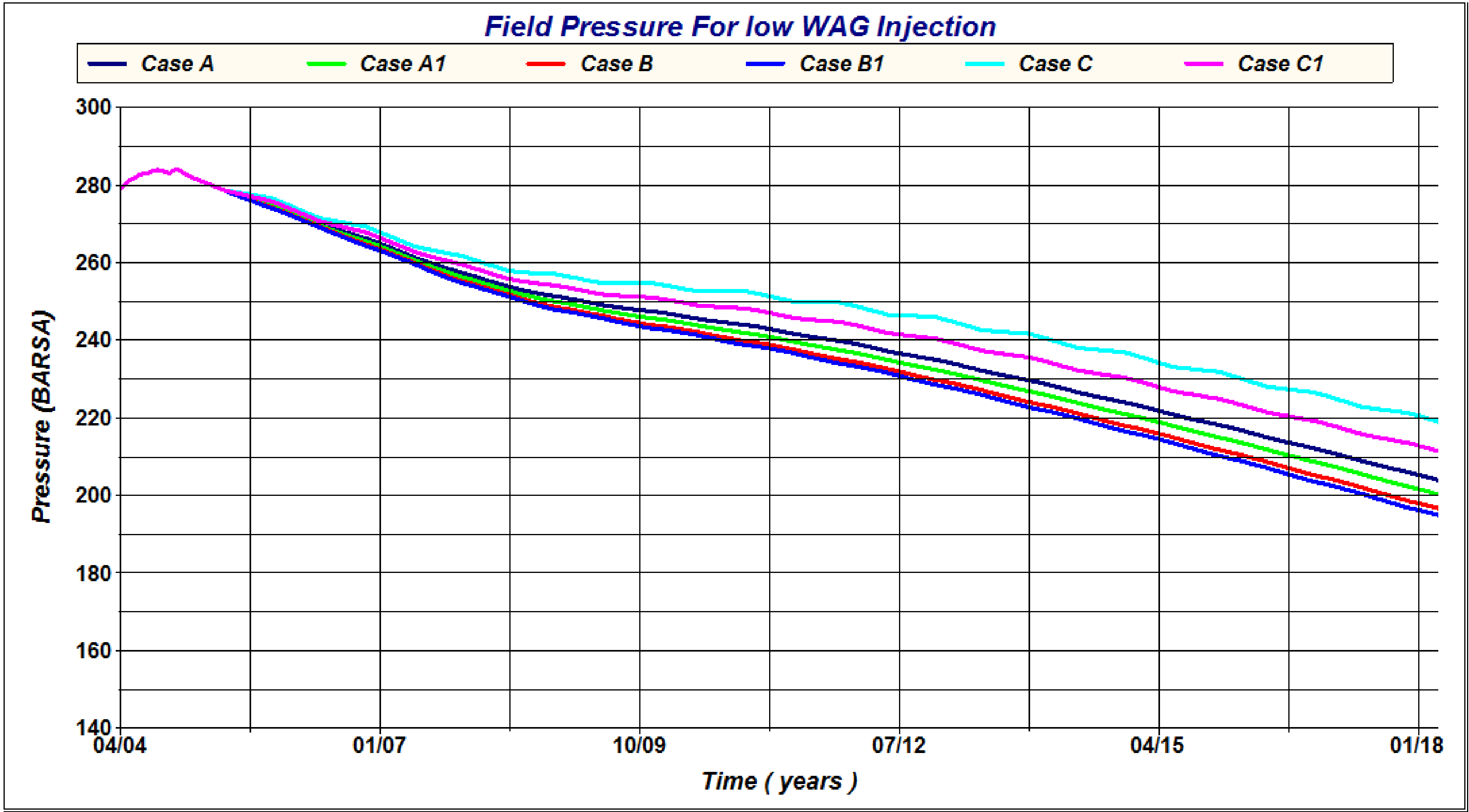

Figure 29- Field Pressure for WAG low injection rate

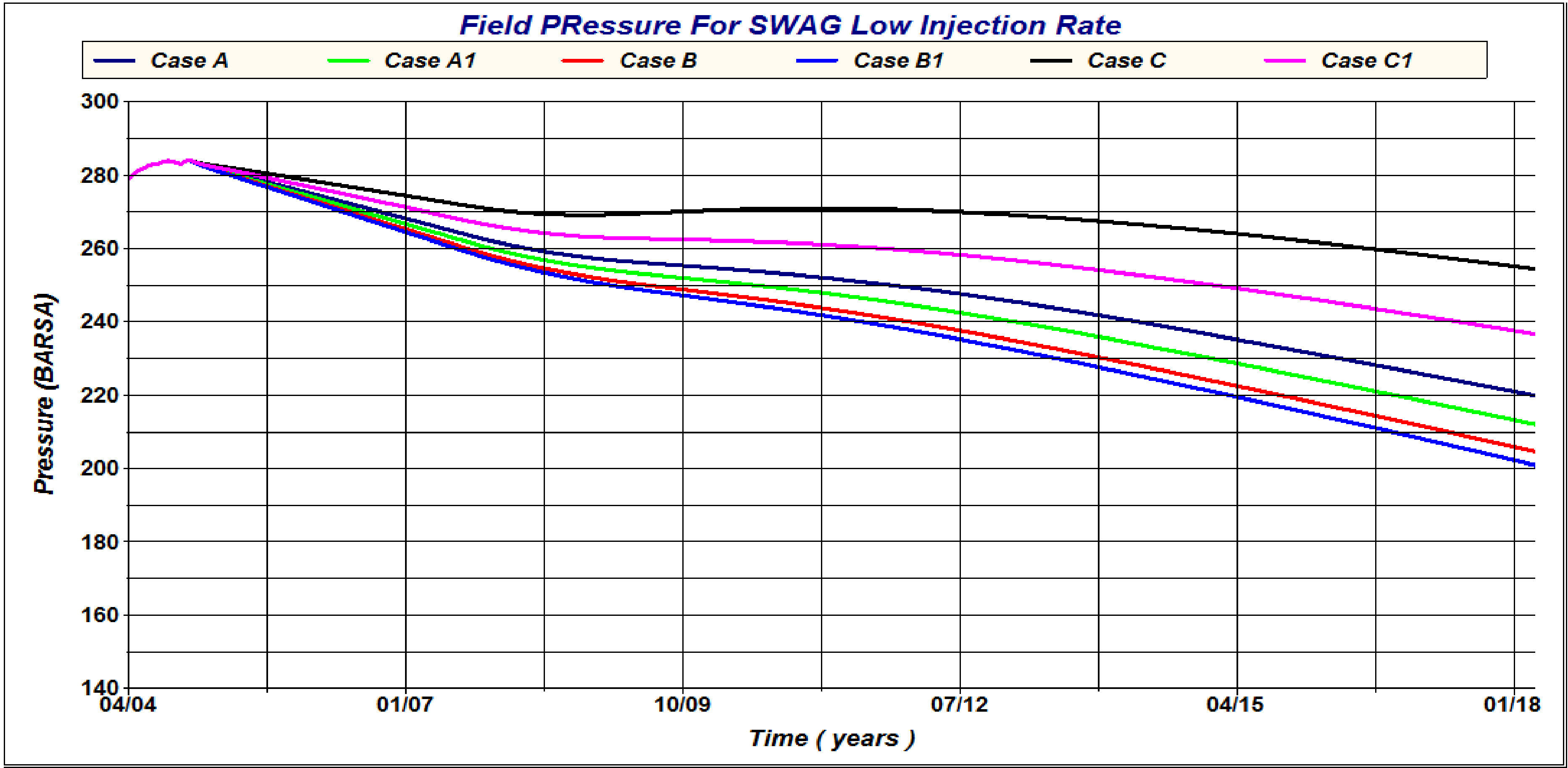

Figure 30- Field Pressure for SWAG low injection rate

In order to see the effect of the volume of water and gas injected for a period of time into the Norne E-segment using SWAG injection technique, different injection cases were modelled with same values used for WAG injection technique (see table 5). However, it doesn't make sense to determine SWAG cycle time because of the fact that in this technique gas and water are injected into the reservoir at the same time continuously. As a result, it showed concordance with WAG injection results (figures 28 e 30).

From the plots (figures 27-30), we can see that, the case C had better performance in terms of residual oil recovery for both SWAG for injection or WAG injection technique. The main difference in implementing the two techniques is related to the pressure profile of the reservoir. When SWAG injection is considered, the pressure profile for the case C lies between 250 and 290 BARA, instead WAG injection pressure profile decrease rapidly with time, achieving the minimum pressure value of 220 BARA approximately for case C and the minimum pressure values for cases different from case C are below 220 BARA.

In fact, Norne E-segment didn't respond positively for very low injection rates, since the pressure still decreasing rapidly. Therefore, high injection rates (see table 6) values were suggested in order to improve the pressure profile keeping it higher than minimum miscible pressure in order to decrease the residual oil production within the field. The simulation results can be verified in Figures 31-33.

Table 6. WAG rate sensitivity analyses using high injection Rates

Cases	Water rate (sm^3/day)	Gas rate (sm^3/day)
Case (1:1)	430414.393	430414.393
Case (1:2)	430414.393	860828.786
Case (1:3)	430414.393	1291243.185
Case (2:1)	860828.786	430414.393
Case (3:1)	1291243.185	430414.393

After injecting high rate in 2004, there was significant increase in oil production rate compared with low injection rates were the production rates went down instantaneously. The maximum value of field oil production rate is above 1500 Sm^3/ day. However, it is important to find out which is better – WAG injection at 1:1 slug, 1:2 slug or injection at 1:3 slug. Embora a pressão do reservatório aumente com o aumento do caudal de gás injetado a quantidade de petróleo residual produzida se mantem constante, o que parece que o varrido de petróleo residual não depende do aumento do caudal de gás injetado no intervalo de tempo considerado.

Figure 31 shows the oil production rate with an increased water injection for 2:1 and 3:1. Since we expect to get a better performance, from the graph, it can be seen that the oil production rate performance match with 1:1 injection slug size.

The Next step is to compare all the new cases made in terms of residual oil recovery (figure 33). However, considering the different cases proposed, residual oil recoverability reaches the same maximum final value, about 67%. Field oil efficiency doesn't change with different injection slug size what make optional to choose.

Considering the analysis made concerning WAG cycle and WAG ratio, the option for water alternating gas injection into the reservoir with high injection slug size, will be performed using 1:3 WAG ratio at intervals of 6 months. However for low injection rate, water alternating gas injection technique will be applied using 1:2 slug size (2000 Sm^3/day of gas and 4500 Sm^3/day of water).

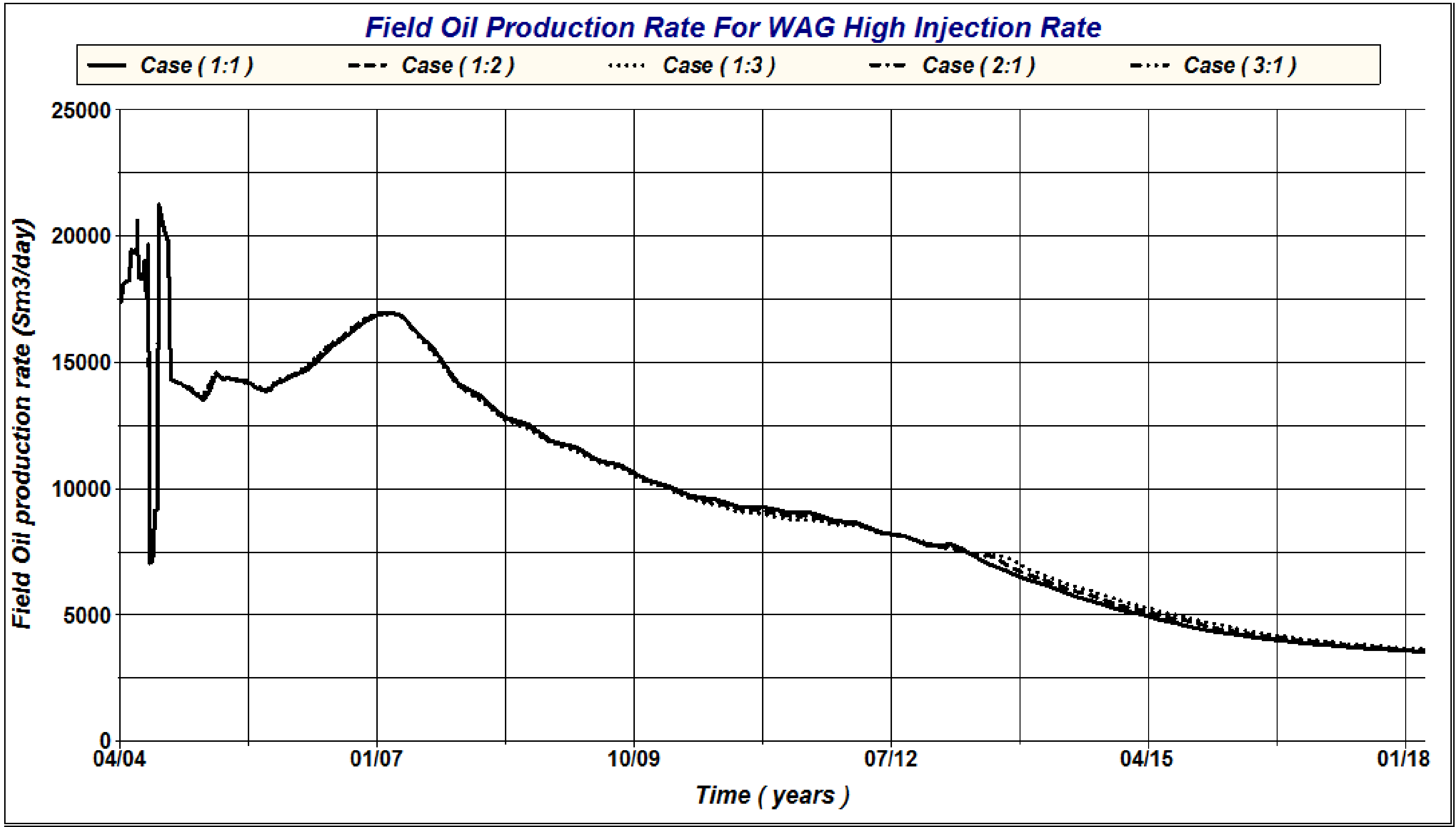

Figure 31- Field Oil Production Rate for different Wag slug injection

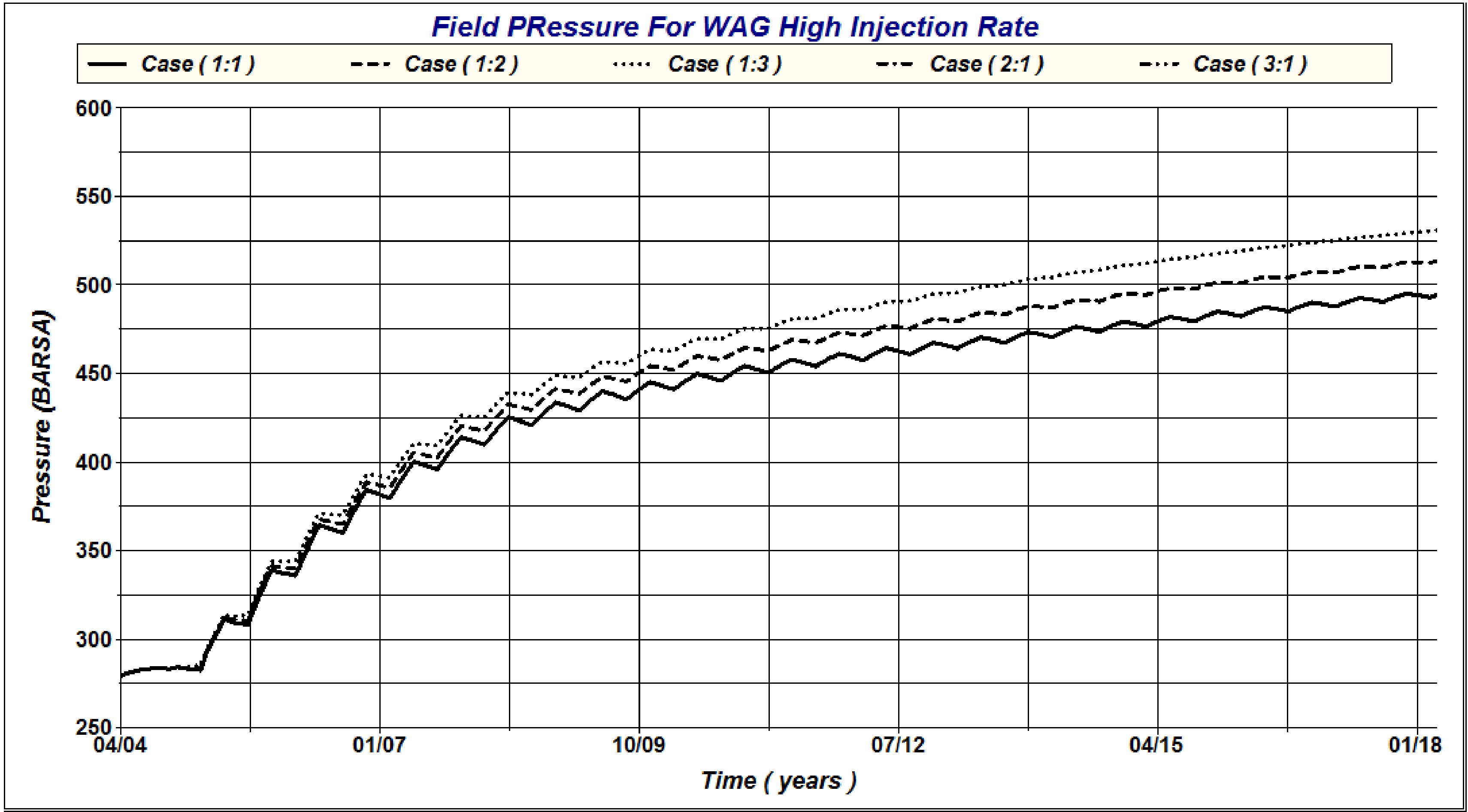

Figure 32- Field Pressure for different Wag slug injection

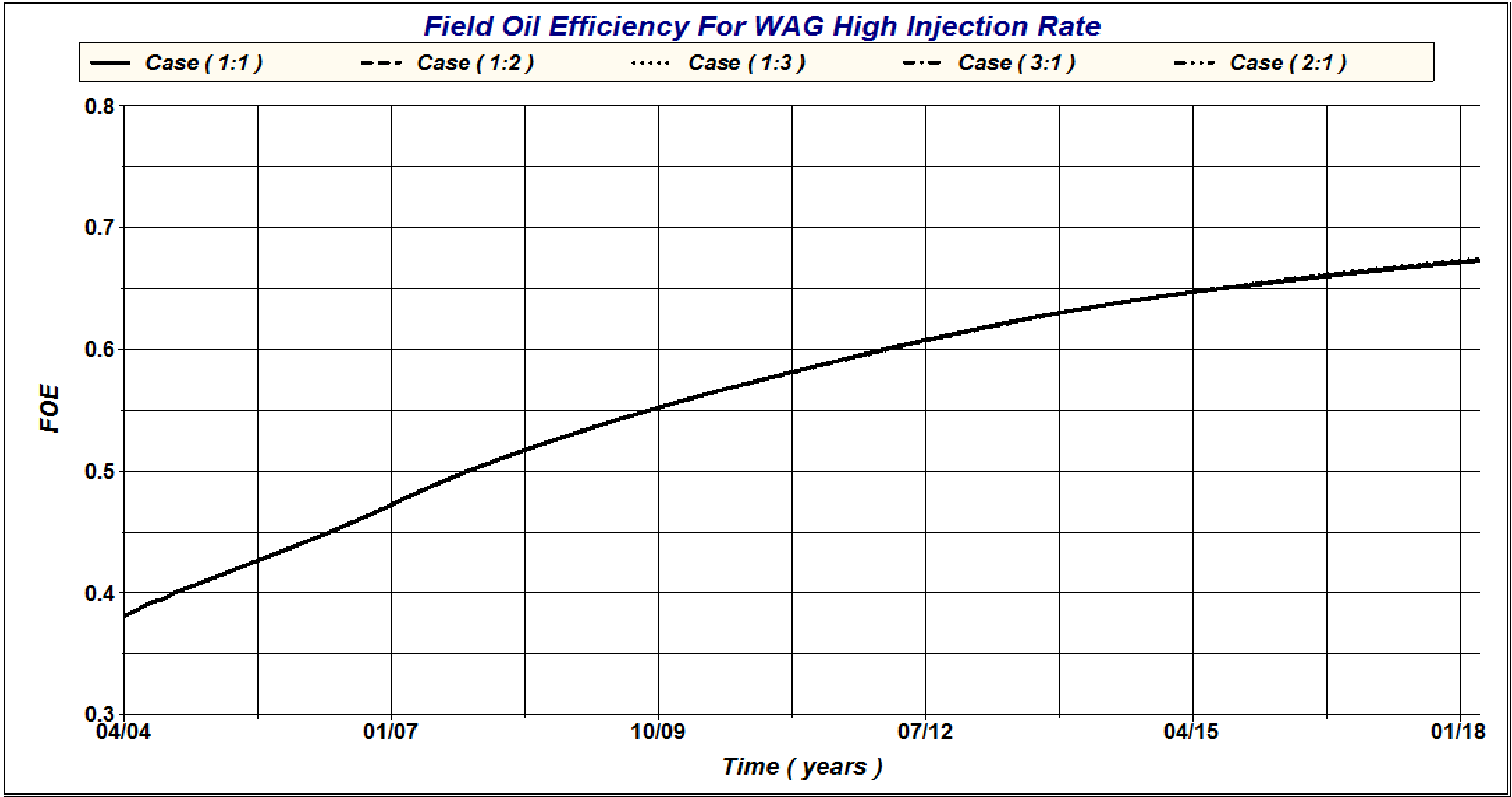

Figure 33- Field Oil Efficiency for different Wag slug injection

5.2. MODIFICATION OF THE WELLS INTO THE NORNE E-SEGMENT

To efficiently increase the recovery of residual oil tank, after a certain time of production, it is necessary often make various modifications to the original modelling of the wells. Among the modifications made, the longer stand out usually applied in re-completion, addiction of new wells, shutting the well that is producing a lot of water at surface etc.

More specifically, the well configuration that would guaranties the greatest oil recovery into the Norne E-Segment proposed by the present master thesis are re-completion and addiction of new injection well. Late on, the following scenarios will be studied and compared among them in terms of the best oil recovery applying WAG and SWAG techniques into the E-segment:

1. Injecting into the reservoirs and producing using the original wells.
2. Additional well is introduced; the originals injectors and producers remain as they are but a new injection well is added in the Ile formation.
3. Adding a new well and re-completion of the existing water injectors; the water injectors were modified in order to make a completion operation in the Ile and Tofte formations.

One of the following options will guarantee the highest efficiency, in terms of oil recoverability. Economic analyses are not the scope of this project, therefore, it will not be considered as a decisive parameter to choose the best scenario.

5.2.1. CONFIGURATION OF THE ORIGINAL WELLS INTO THE E-SEGMENT

According to the Eclipse simulation model DATA file, Norne E-segment is originally composed by five wells, being two inject wells (F-3H and F-1H) and three production wells (E-3AH, E-2H and E-3H), as we can see in the figure 33. Wells F-3H was perforated in the Tofte and Tilje formations. It was originally designed to sweep oil in the south-western part of the Norne E-segment. The northern part of these segment, is swept by F-1H injector, completed in the Garn, Ile, Tofte and Tilje formations.

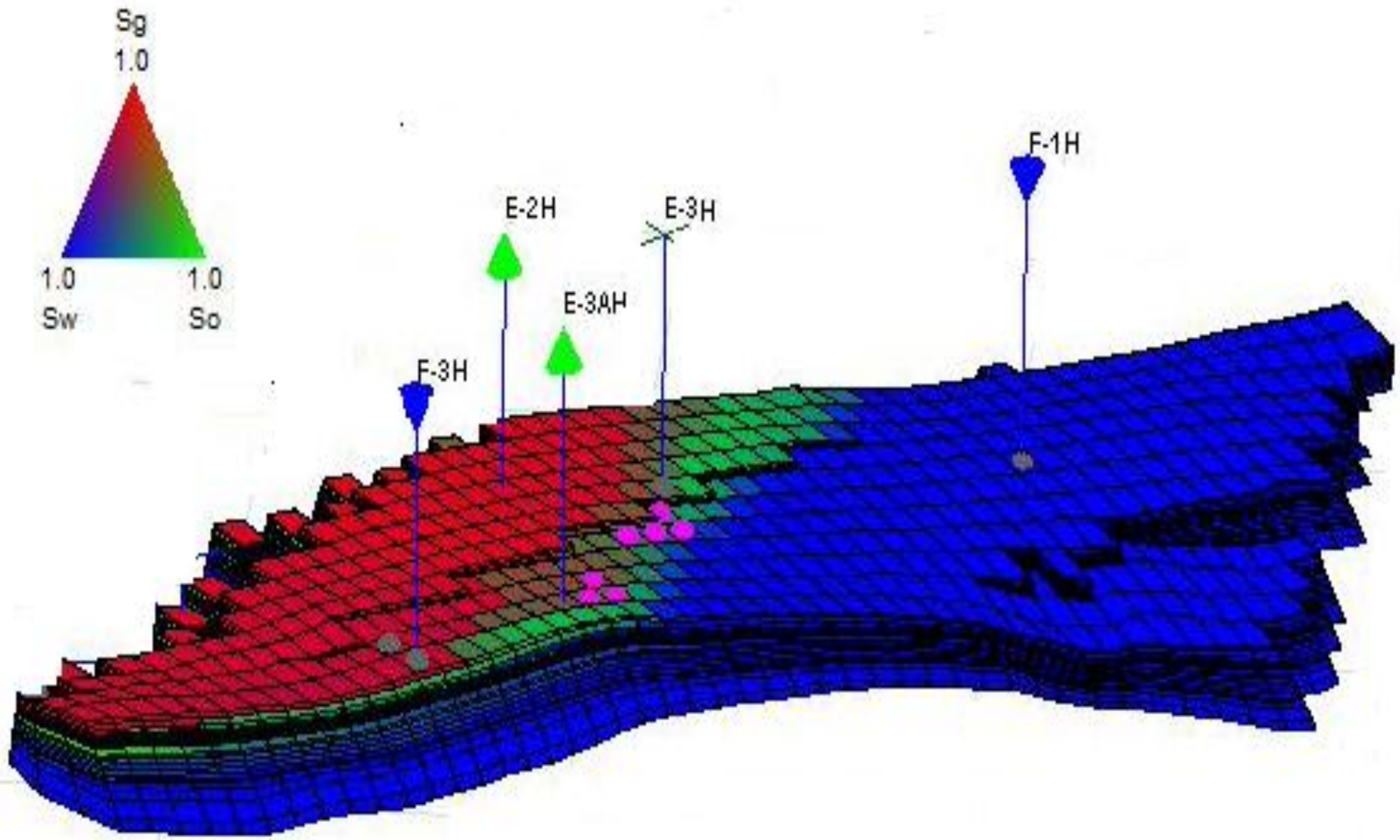

Figure 34. Original Wells in the Norne Field E-Segment

5.2.2. CONFIGURATION OF THE NEW INJECTION WELL

In this particular case, the original injection and production wells remain as the base model. Additionally, a new injection well is introduced, named N-3H, to drain a critical part of the Norne E-segment that is not being swept. In order to increase the sweep area, a horizontal well has been drilled through Ile and Tofte formation with following location:

Table 7. New Injection well new completions data

N-3H			
I	**J**	**K1**	**K2**
14	67	1	1
14	67	2	2
14	67	3	3
14	67	4	4
14	67	5	5
14	67	6	6
14	67	7	7
14	67	8	8
14	67	9	9
14	68	10	10
14	69	10	10
14	70	10	10
14	71	10	10
15	71	10	10

In the figure 35, the well N-3H is represented clearly in conformity with table presented above. The new injection well is able to sweep oil from the northern part of the reservoir to the southern part of the E-segment.

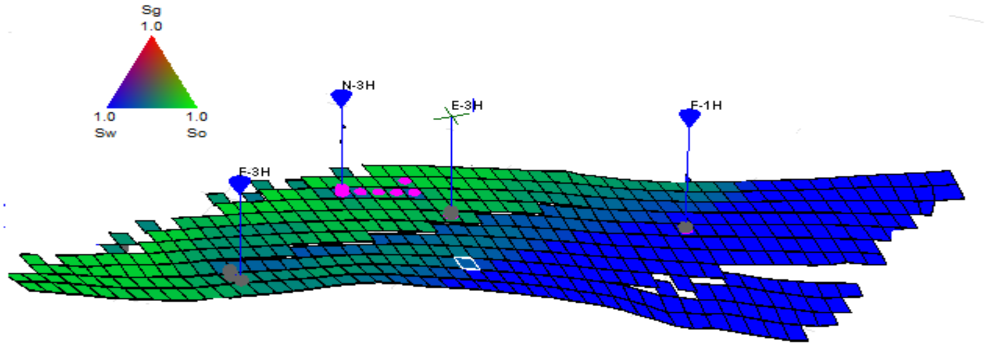

Figure 35. Shows Original Wells in Addition to a new well

5.2.3. CONFIGURATION OF THE RE-COMPLETED WELLS AND A NEW WELL LOCATION

With intention to avoid water to come out abundantly through the injection wells in a specific time period, and consequently decrease the oil production, a combination of re-completion of the injection and production wells and new well were implemented into the E-segment, as shown in figure 36;

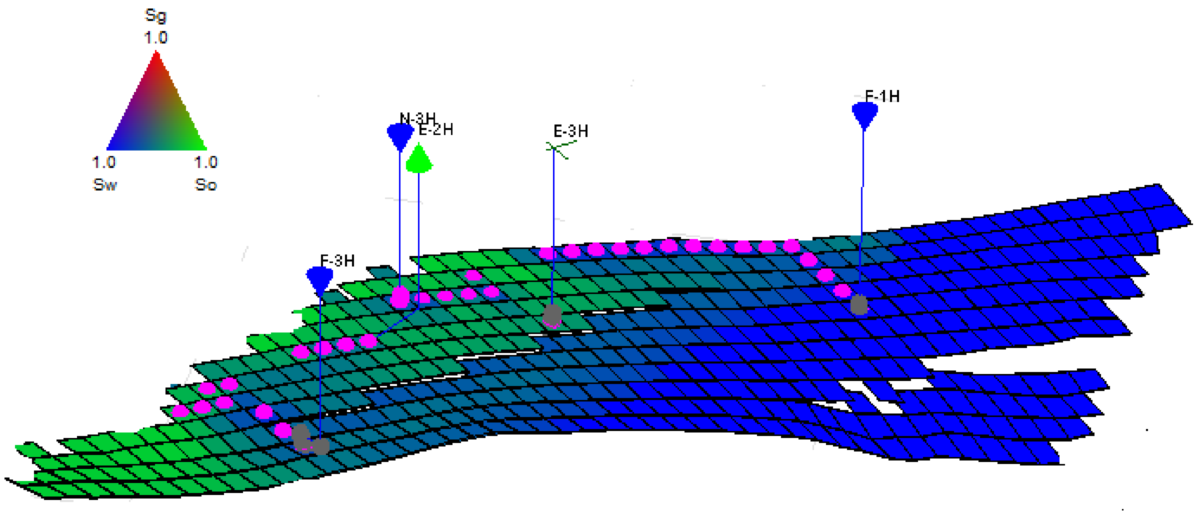

Figure 36- Well Re-completion of the injectors with an additional new injection well included.

According to the proposed scenario, oil sweep from different parts of the E-Segment is believed to be covered and is expected to achieve oil residual recovery higher than the base case. The main attention as to be cared out to the production wells (E-2H, E-3H…), maybe some production wells can produce significant amount of gas and water and very less amount of oil. In this case, optimization action has to be performed in a way to improve the production performance. Is very important to be in mind that E-segment is invaded by two well from C-segment but it's coursed and the Eclipse model doesn't take that wells in account.

The new well, N-3H, was introduced in the scenario three with injection wells F-1H and F-3H re-completed in the Ile and Tofte formations. The new Completion location details, for F-1H and F-3H injection well, are presented in the table 8.

Table 8. Original Injection wells new completions data

F-1H				F-3H			
I	**J**	**K1**	**K2**	**I**	**J**	**K1**	**K2**
12	85	8	8	7	57	7	7
13	85	8	8	7	57	7	7
14	85	8	8	8	57	7	7
15	85	8	8	9	57	7	7
16	85	8	8				
16	84	8	8				
16	83	8	8				
16	82	8	8				
16	81	8	8				
16	80	8	8				
16	79	8	8				
16	78	8	8				
16	77	8	8				
16	76	8	8				
16	75	8	8				

Normally this optimization study of the production process in real life should be studied in detail, so it takes some time to be drawn, as are many factors that directly or indirectly interfere to reduce residual oil. The E-segment fluid flow in a vertical direction is affected by stratigraphy barriers composed by cemented layers, in other words, the permeability in a vertical direction is poor and partly is responsible for the precarious sweep efficiency, By this motive, injection of polymer and surfactants have been part of studies (Clara thesis, 2010) so as to increase the permeability of the vertical segment and in the Norne field. Faults in some way are considered semi-sealing according to Erik (2010) and in the E segment faults affects the vertical sweep efficiency. However, during WAG injection technique stratigraphy barriers cannot be changed, but viscous and capillary forces can be mitigated.

5.3. Comparison of WAG and SWAG Recovery Techniques applied into the Norne E-segment

Taking into account the different injection patterns modelled and presented in the previous sections, WAG and SWAG injection techniques are applied into the Norne E-segment for 6 months interval during 14 years for low injection rate and for high injection rate, 3 months injection interval. However, is recommended to use 2000 Sm^3/day of water and 4500 Sm^3/day of gas for both WAG and SWAG for low injection rate and 430414.393 Sm^3/day of water and 1291243.185 Sm^3/day of gas for both WAG and SWAG for high injection rate.
In figure 37 is presented the oil production rate for low injection rate using three different scenarios proposed to optimize the residual oil production.

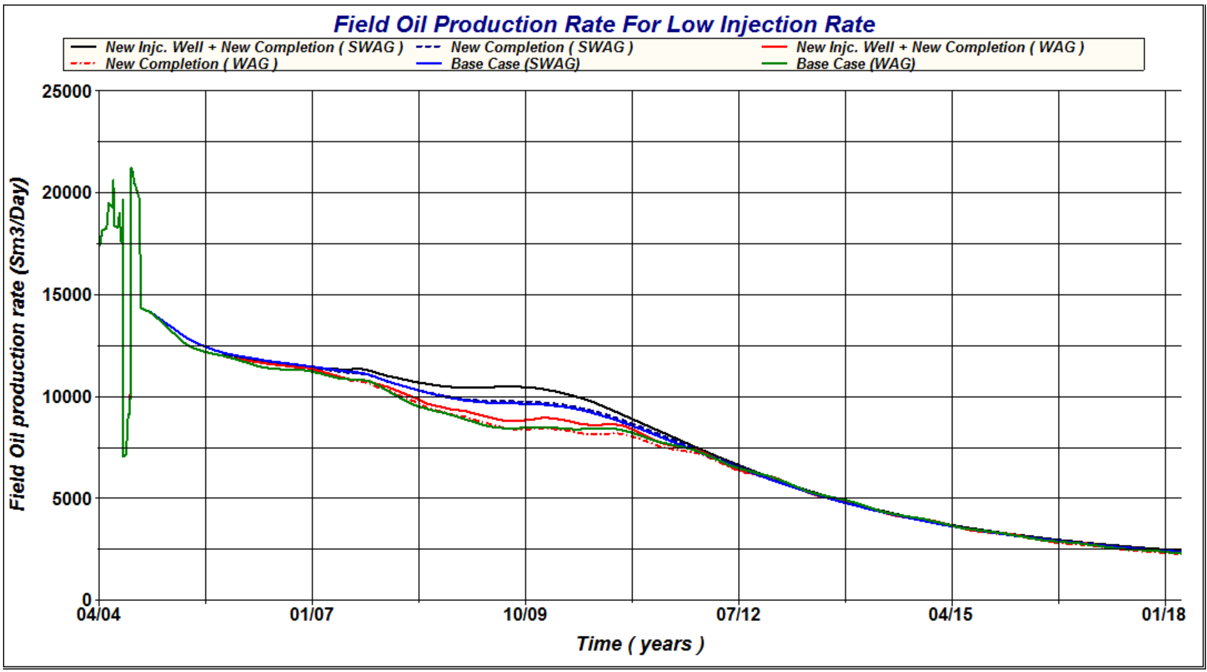

Figure 37. Comparison of Field Oil production rate for low injection rate

It can be seen that the scenario with new completion adapted to a new injection well led to increase in the production oil rate when WAG or SWAG injection techniques are applied into the E-segment. Considering SWAG injection scenarios, clearly from the figure 37, we can see that the base case has a rate approximately 10000 Sm^3/day in year 2009, instead, scenario with new well and new completion, gave production rate of 10500 Sm^3/day in the same date; comparatively it was 500 Sm^3/day less than oil rate produced from the base case. Therefore we can conclude that even though the production rate increases with increment in the changes on the reservoir development, the increment on oil recoverability might not really be very substantial and it decreases gradually with time until achieve constant stage.

For high injection rate, oil production rate detail can be found in the figure. 38 with different scenarios proposed at the top of this theme.

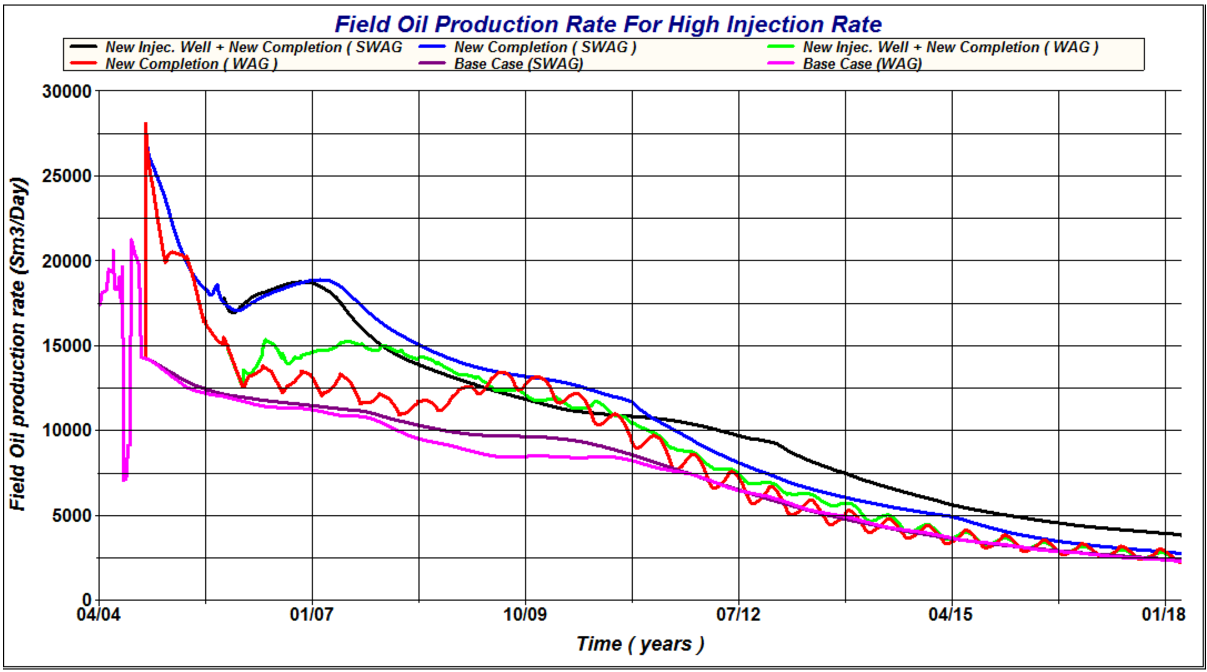

Figure 38. Comparison of Field Oil production rate for high injection rate

For high injection rate, the oil production rate increase significantly when compared with base case. The maximum peak of oil production rate (27,500 Sm^3/day) exceeds the value of the maximum peak (21,000 Sm3/day) reached in 2004. When compared with injection scenarios from low injection rate, the increment on oil production rate is clearly seen until 2018.

At the beginning (2004), considering SWAG scenario, new well plus new completion scenario presents the same behaviour as scenario with only new completion (figure. 38) until 2007, and then scenario with new completion results in higher oil production rate until year 2010. Subsequently, new well plus new completion scenario increased the oil production rate, keeping it at higher oil production rate until 2018.

The cases with new wells plus new completion have more cumulative oil than the case with just the original wells. The case with recompleted wells has cumulative production of $1.05*10^8$ Sm^3 for low injection rate while scenario three has a cumulative of $1.2*10^8$ Sm^3 for high production rate (figures 41, 42).

Figure 43-44 (appendix) shows water production total, which is 3 times higher for scenarios using high injection rate when compared with low injection rate scenarios. This number represent cumulative of water production from the producers wells contidos dentro do E-Segment. The increase could be attributed to the fact that more water has been injected to aid the effectiveness of the WAG injection to perform better.

Field Gas-Oil ratio is presented in the figures 47 and 48 (appendix) for low injection rate and high injection rate. Scenario with new completion plus new injection well produced less amount of gas during productive time of the Norne E-segment. For low injection rate, the minimum value was 750 Sm^3/Sm^3 (new well + new completion _SWAG), instead, for high injection rate; the minimum value was 900 Sm^3/Sm^3 (base case _SWAG). For WAG scenarios, a fluctuated variation is noticed for high injection rate with a maximum peak in 2500 Sm^3/Sm^3 (new inj. Well+ new completion_WAG).

The pressure profile (Figure 45 and 46), for low injection rate is stable for the range of time chosen, when SWAG scenarios are taken in account, in general, it vary above the bubble point pressure until 2018. For high injection rate, the pressure profile reaches values of reservoir pressure very high (490 BARA). This increasing in pressure is due to the higher water injection rate. However, gas rate also contribute for the pressure stability in the reservoir.

The Field Oil efficiency (FOE) is shown in the figure 39 and figure 40, for low and high injection rates respectively. The increment does not seem noticeable at the beginning, but in 2009, a slightly difference among them starts to be notable. However, for low injection rate scenario the maximum value achieved for oil recovery was 63% (new well + new completion _SWAG). For high injection rate, the maximum value of residual oil recovered was 73%. Considering high injection rate but using SWAG injection technique, field oil efficiency has only 5% of difference when compared with WAG (68%) injection technique.

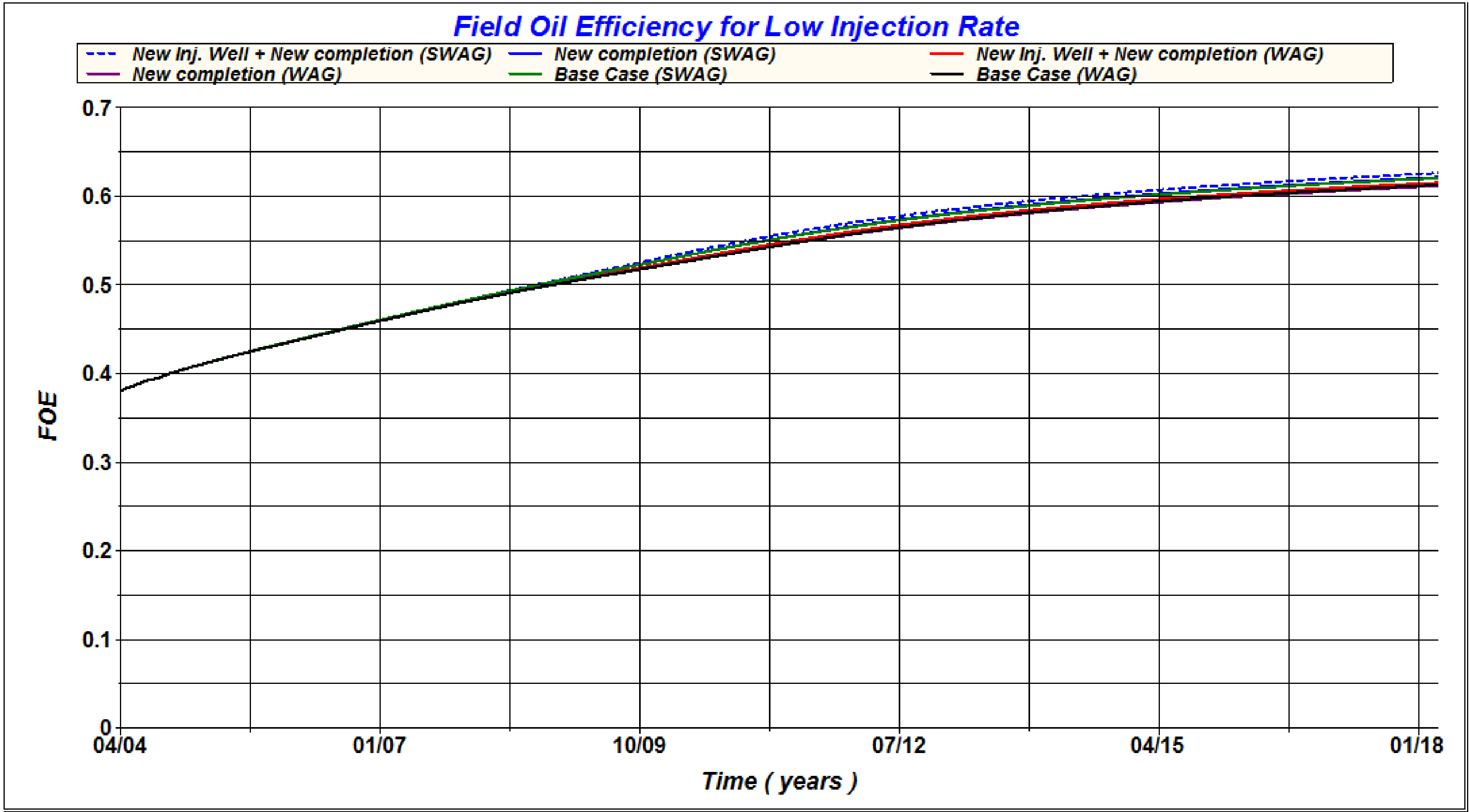

Figure 39. Comparison of the field oil efficiency for WAG and SWAG low injection rate

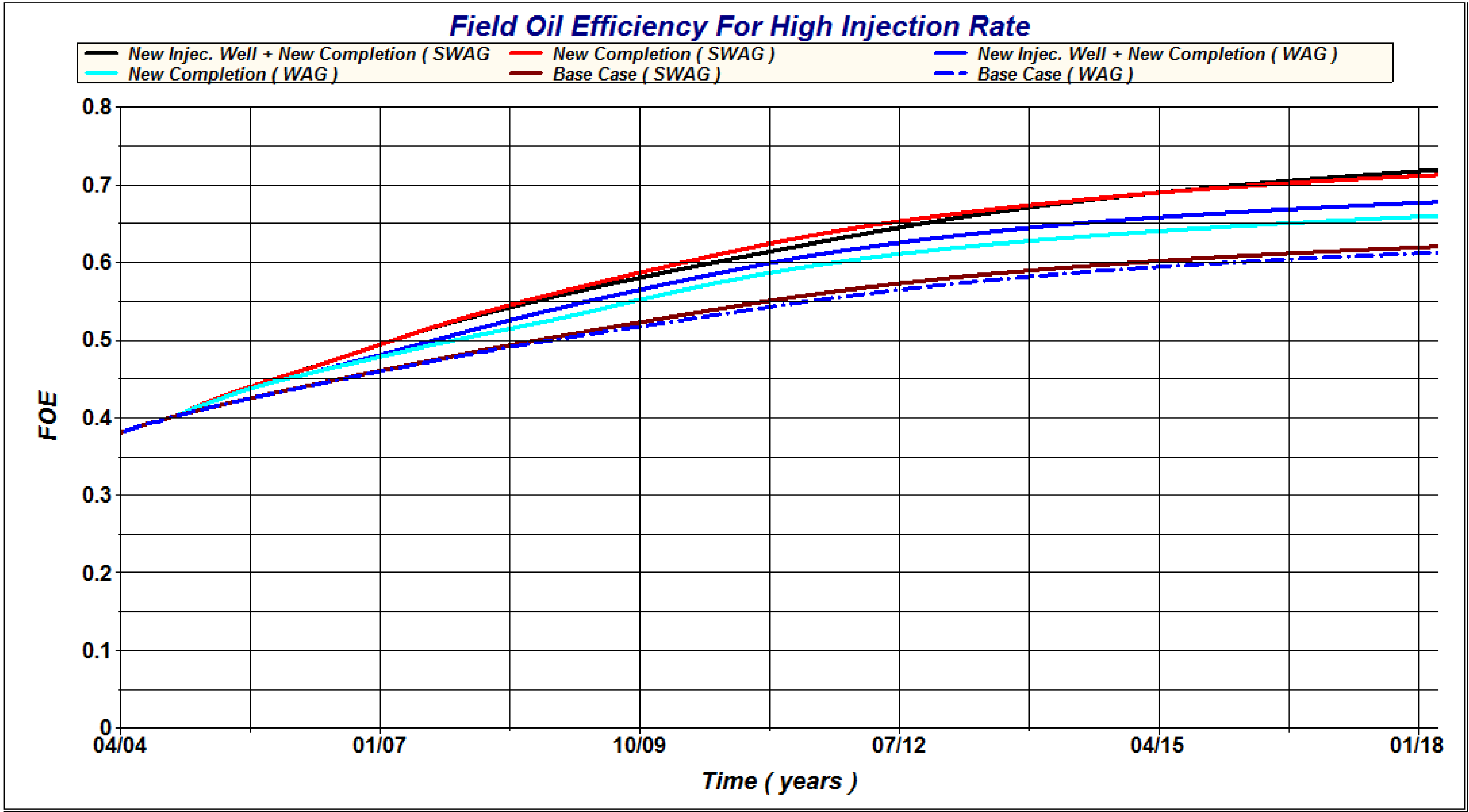

Figure 40. Comparison of the field oil efficiency for WAG and SWAG high injection rate

CHAPTER VI
CONCLUSIONS

1. Recovery from a WAG process isn't a function of cycle time when low injection rate is used, instead, when high injection rate is used 3 months cycle results in a slightly higher residual oil recovery.

2. For low injection rate, injection of 2000 Sm^3/day of water and 4500 Sm^3/day of gas when WAG or SWAG injection technique is implemented constitute the best option.

3. For high injection rate, injection of 430414.393 Sm^3/day of water and 1291243.185 Sm^3/day guarantee the best oil recoverability.

4. Even though the production rate increases with increment in the changes on the reservoir development, the increment on oil recoverability might not really be very substantial and it decreases gradually with time until achieve constant stage.

5. Modelling suggests that new completion plus new injection well improves the production oil rate in 5%, resulting the best scenario in terms of oil recoverability, considering high injection rate.

6. Simulation results showed that Norne E-segment would have a maximum recovery of 73% at a 1:3 SWAG ratio when high gas injection rates are considered.

7. The implementation of SWAG injection (73%) gave the best oil recovery when compared with WAG injection technique (63%) with approximately 5% of difference.

Nomenclature

Parameter	Designation	Unit
v	Darcy velocity	(m/s)
M	displacing fluid viscosity	(Pa.s)
σ	interfacial tension	(N/m)
Nc	Capillary number	-
Ca	Capillary number	-
λ_{ing}	mobility of the displacing fluid (e.g. Water)	-
λ_{ed}	Mobility of the displaced fluid (oil).	-
R_f	oil recovery factor	%
E_v	vertical sweep efficiency	%
E_{h}	horizontal sweep efficiency	%
E_m	microscopicefficiency	%
S_{oI}	Initial oil saturation	-
S_{or}	Residual oil saturation	-
OIIP	Initial oil in place	(%)
SSWAG	Selective simultaneously water alternating gas	-
SWAG	simultaneously water alternating gas	-
WAG	water alternating gas	-
WF	water flood	-

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Appendix

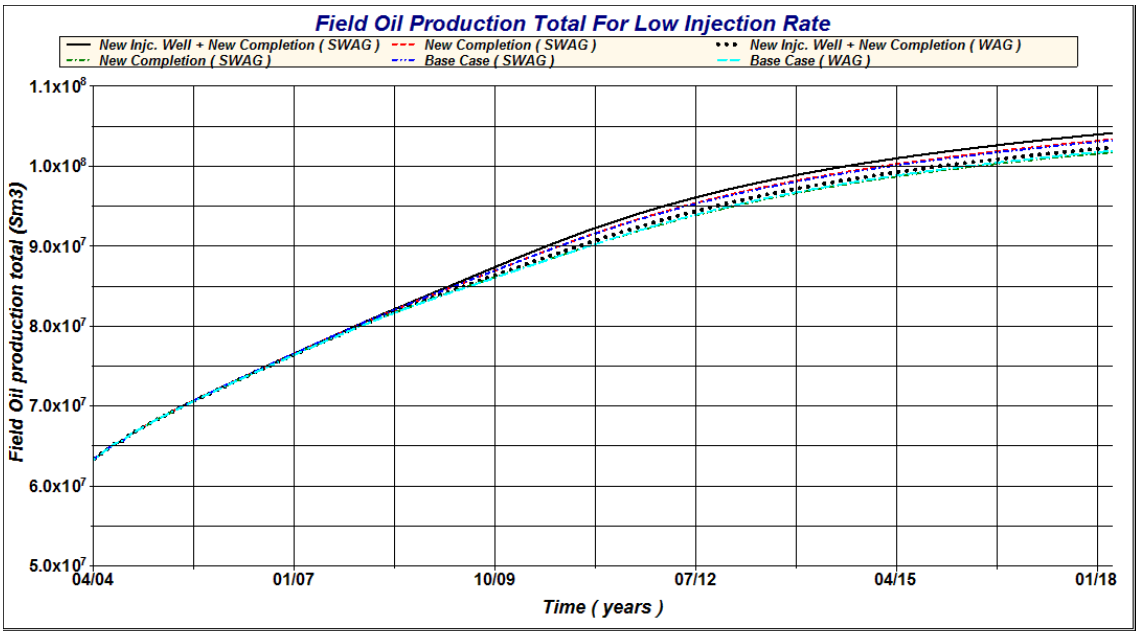

Figure 41. Comparison of Field Oil production total for low injection rate

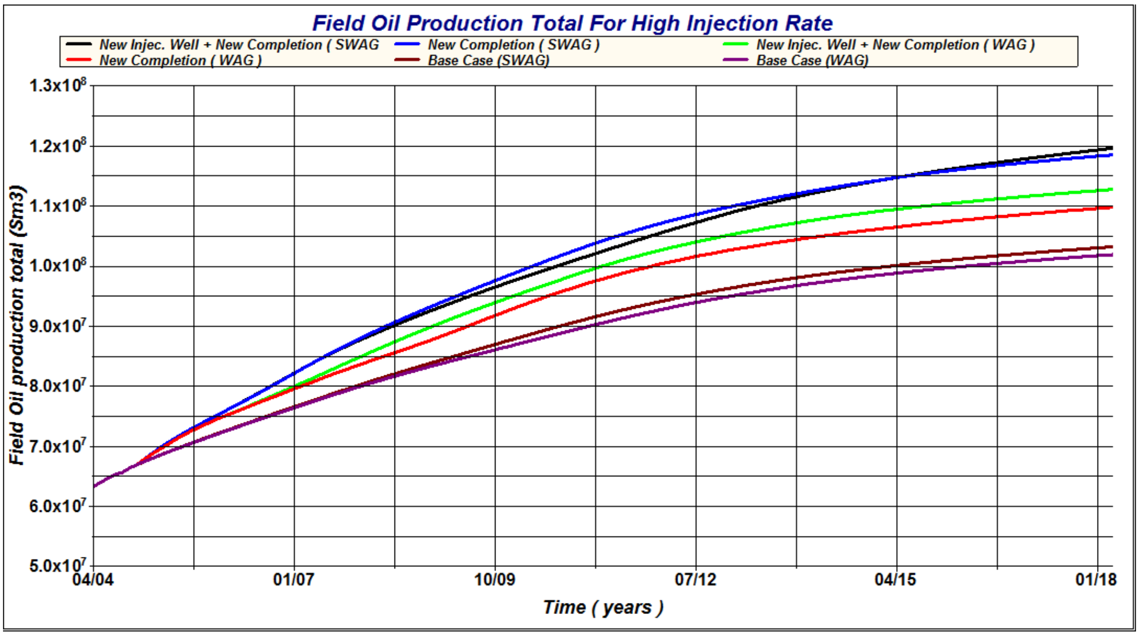

Figure 42. Comparison of Field Oil production total for high injection rate

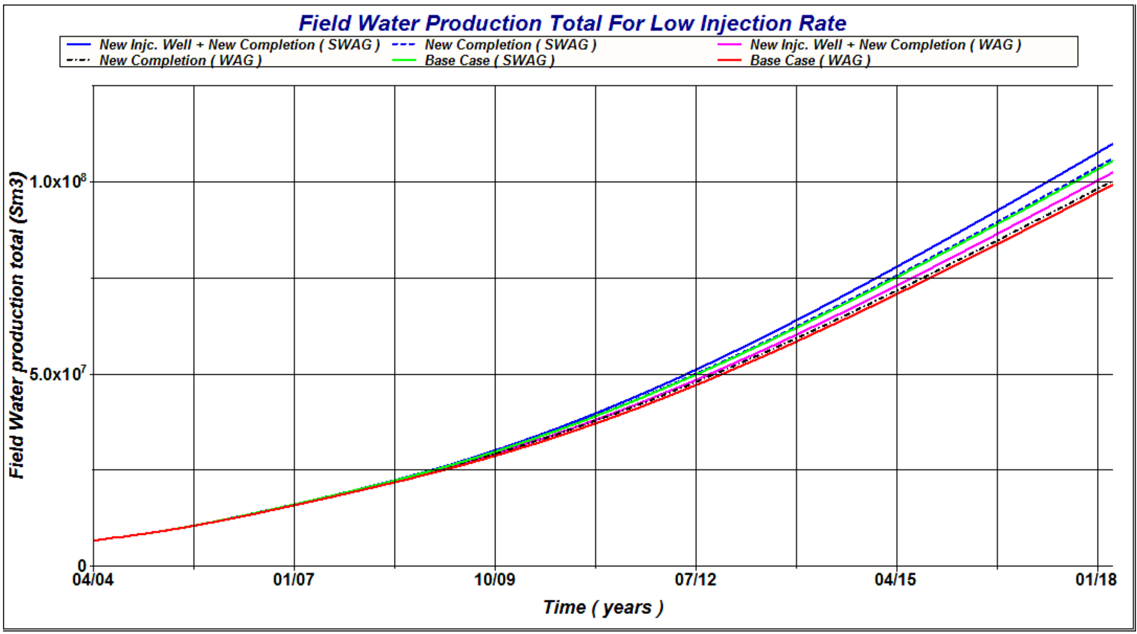

Figure 43. Comparison of Field Water production total for low injection rate

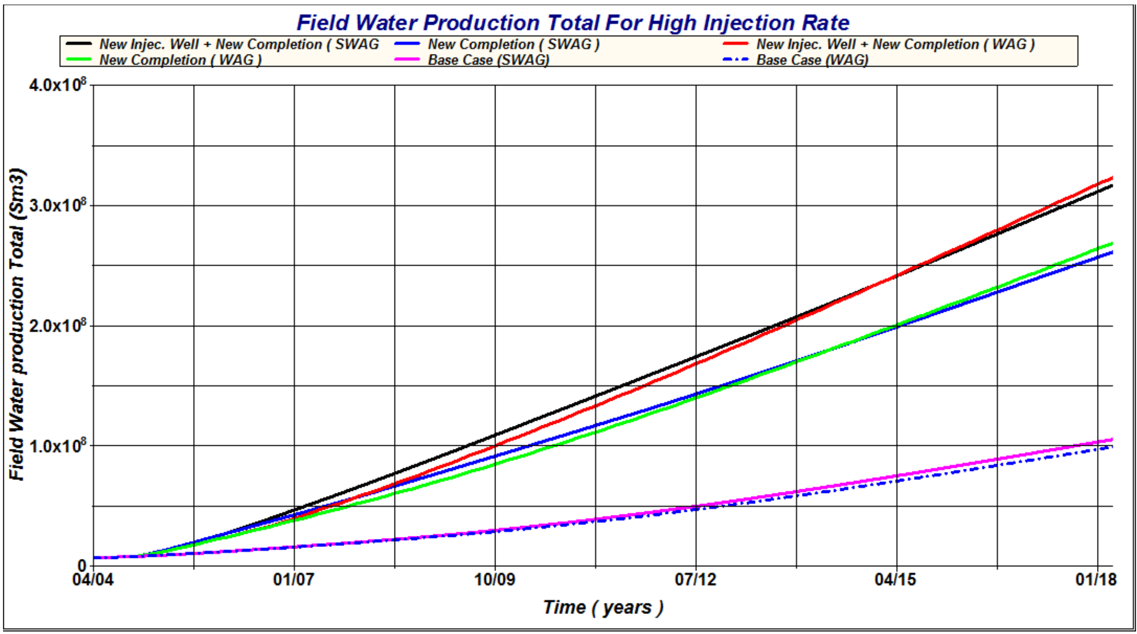

Figure 44. Comparison of Field Water production total for high injection rate

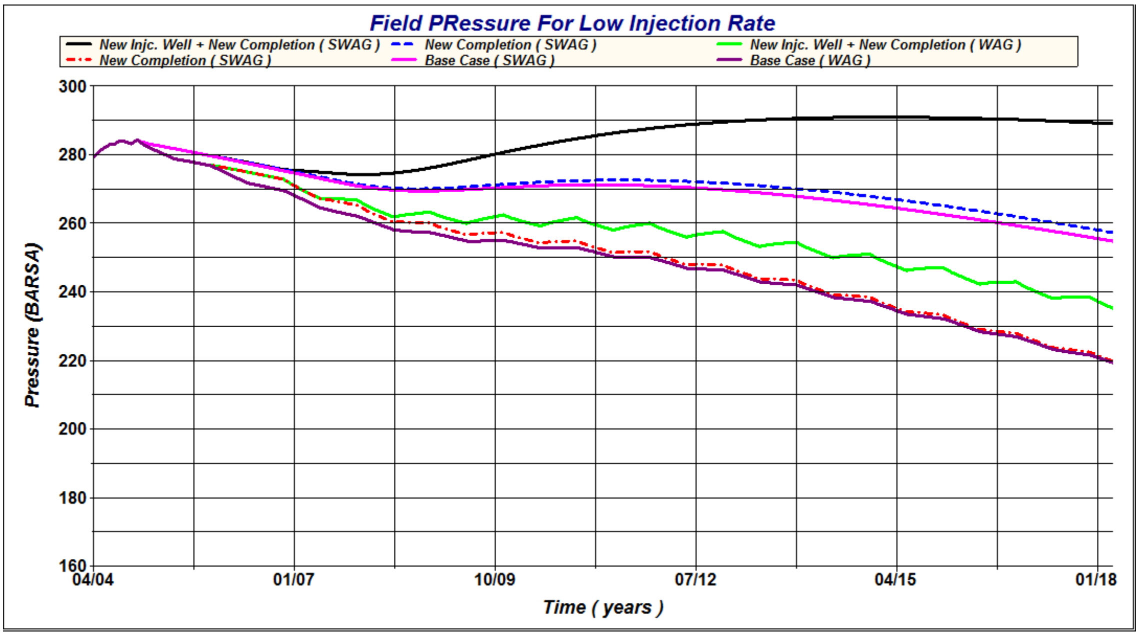

Figure 45. Comparison of Field Pressure for high injection rate

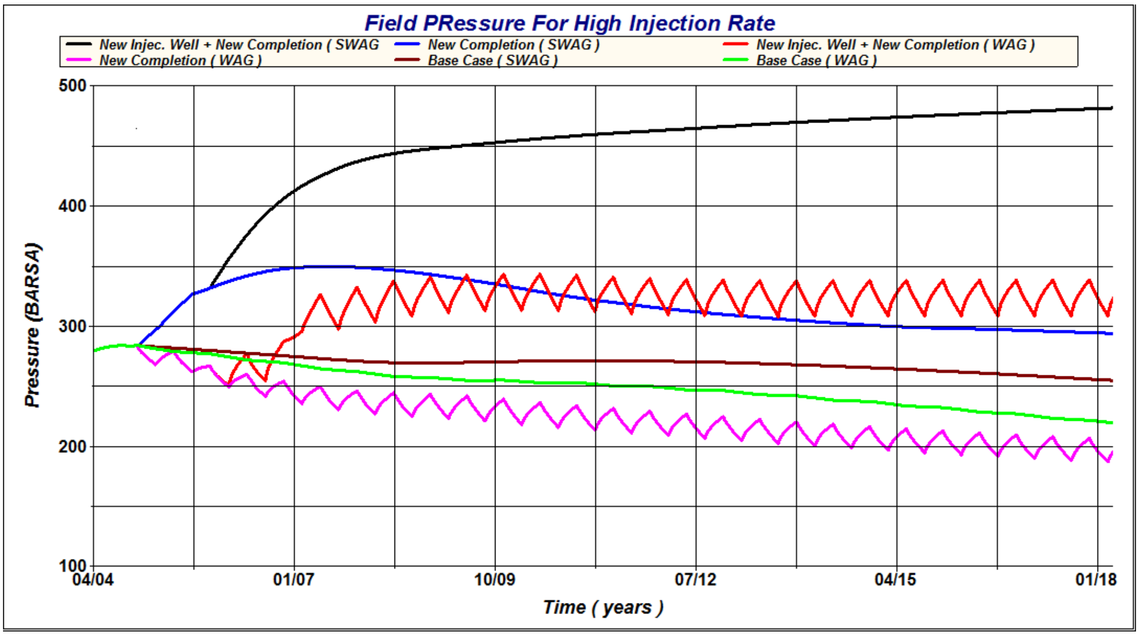

Figure 46. Comparison of Field Pressure for high injection rate

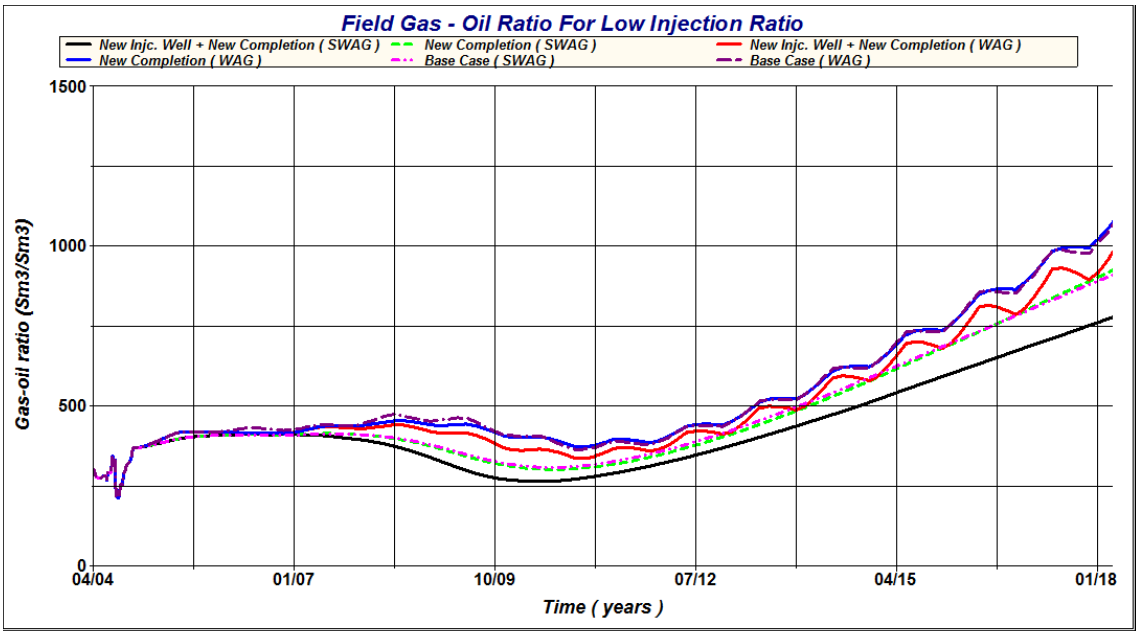

Figure 47. Comparison of Field GOR for high injection rate

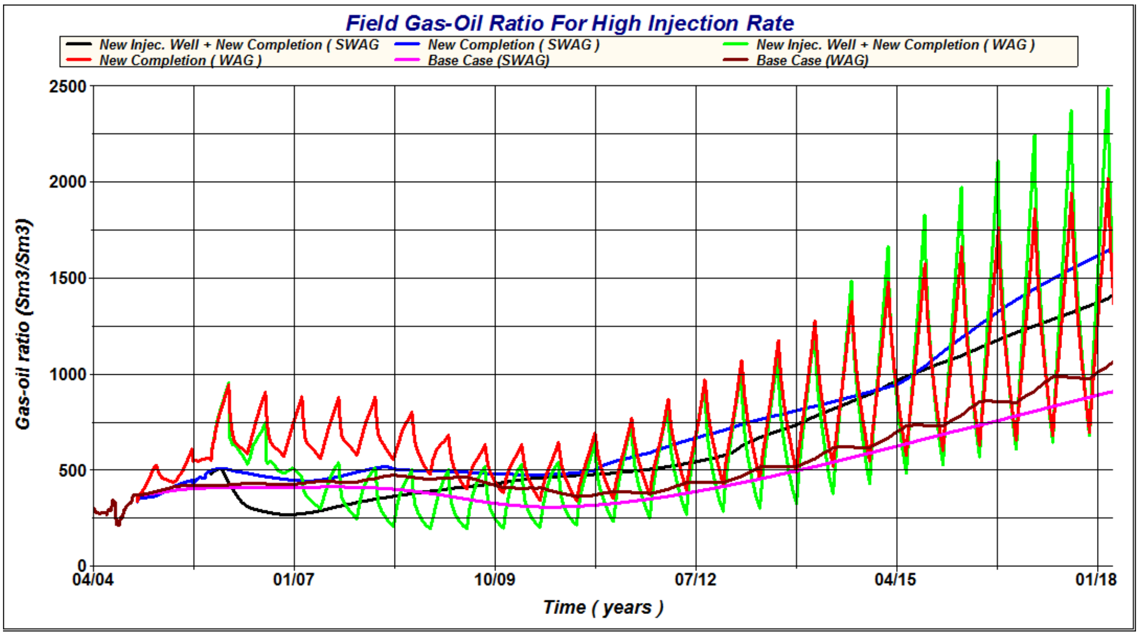

Figure 48. Comparison of Field GOR for high injection rate