University of Stavanger

Faculty of Science and Technology

MASTER'S THESIS

Study program/ Specialization: **MSc, Petroleum Engineering / Production Engineering**	Spring semester, 2011 Open
Writer: **Vadood Azadegan**	………………………………………… (Writer's signature)
Faculty supervisor: **Svein Magne Skjæveland** External supervisor(s): **Clas Normann , Talisman Energy Norge AS**	
Title of thesis: **Alternative Production Scenarios for the Gyda field**	
Credits (ECTS): 30	
Key words: Reservoir Simulation The Gyda field Production scenarios Petrel RE 2010 ECLIPSE 300	Pages: 100 + enclosure: ………… Stavanger, June 14th, 2011

Alternative Production Scenarios for the Gyda field

Department of Petroleum Engineering

University of Stavanger

Supervisors:

Svein Magne Skjæveland, UiS

Clas Normann , Talisman Energy Norge AS

Vadood Azadegan

Spring 2011

Acknowledgement

I would like to express my sincere gratitude to my supervisors Prof. Svein Skæveland and Clas Normann for their continuous support, patience and immense knowledge. Their guidance helped me in all the time of writing this thesis.

I am also thankful to Hening Gilje, subsurface manager of Southern North Sea Area department of Talisman Energy Norge for giving me the opportunity of writing this thesis.

It was my pleasure working with experienced and talented colleagues. Special thanks to Børge Andersen, Bodil Sømme, and all other colleagues in Talisman Energy, Stavanger office.

At the end, I would like to thank my parents and my beloved sister for supporting me spiritually throughout my life.

Vadood Azadegan

June 2011

Abstract

The Gyda field has been on stream since June 1990. Water injection commenced Feb. 1991. Currently Gyda is suffering from high water cuts. Having in mind that water injection is very costly, environmentally pollutant and associates with scale formation problems, the question which arises here is whether water injection (real development scenario of Gyda) was the best choice or not?

This study is not concerning about prediction of future production; rather it is a backward study to see: if we would have implemented other production scenarios, what could be our cumulative productions at present. Alternative production scenarios have been investigated and the results suggest that water injection scenario was indeed the best choice. Further, the real scenario (water injection) has been modified by ESP (Electric Submersible Pump), gas lift, infill drilling and new injectors, which led to 10 MMbbl increase in the historical oil production.

The latest history-matched 2010 Gyda compositional reservoir model was used with Petrel seismic to simulation software, which is served as the front end to the ECLIPSE reservoir simulation software.

Table of Contents

List of Tables

List of Figures

1 Introduction

1.1 Overview

The medium-sized mature oil field, Gyda is located between the Ula oil field and the Ekofisk complex in the central North Sea. It has very weak aquifer support and therefore has been water flooded from early days of its production. With high operating expenditure and complex geology, Gyda is a significant economic challenge for the field partners. After 20 years of production, it is of interest to examine if the selected production scenario was the best one? Or there were other scenarios that could lead to better productions.

In this thesis eight proposed production scenarios have been studied to investigate the best scenario for developing the Gyda reservoir. ESP (Electric Submersible Pump) and gas lift have been deployed as artificial lift methods to increase production rates. VFP (Vertical Flow Performance) tables have been built in PROSPER (from IPM Suit) and imported to Petrel for ESP-lifted wells. Simulation period is from June 1990 (Start of production) till December 2010 (end of history) and Petrel 2010 has been used as the reservoir simulator.

The next chapter (chapter two) gives a short introduction to the Gyda field and some key facts about it. Chapter three has the basic theory of material balance calculations and concept of numerical simulation. In chapter four the simulation results have been presented with detailed description of different production scenarios. Final conclusion and recommendations have been described in chapter five.

1.2 Methodology

The first step in this study was to get a good understanding of the reservoir, in terms of geological aspects, and production history. It was time consuming due to complexity of the Gyda field. Next, some theoretical background studies of numerical simulation and material balance have been carried out.

To investigate alternative production scenarios for Gyda field, first a new development strategy has been built in which all injectors are shut (10 injectors). Table 1.1 shows Gyda's well details.

To improve this no-injection case, a full-field gas lift with gas injection rate of 2 MMscf / day (56635 Sm3 / day) has been set up in all producers (30 wells). Furthermore, the full-field gas lift scenario modified with substituting 10 gas-lifted wells with 10 ESP-lifted wells. ESP technology may not be technically possible to be used in early 1990s; however, it is worth to be investigated as a possible solution.

Next scenario was improving no-injection case with putting 10 new infill producers (equal to the number of shut injectors) but without any artificial lift method. Further improvement of this scenario, was a full-field gas lift (40 wells). The latter case altered with 10 gas-lifted wells substituted by 10 ESP-lifted wells.

In all the above mentioned scenarios, it has been considered that there is no water injector. Therefore, a modified water injection scenario was also conducted to see how Gyda's production could be with water injection, along with artificial methods and more infill producers; the strategy that Talisman is implementing to get more out of Gyda in recent years.

To make the simulations as realistic as possible, some assumptions have been put in place which will be fully explained in chapter 4, Simulation Results.

Table 1.1 Gyda well names and types

	Well Type		
NO.	**Producer**	**Injector**	**Producer converted to Injector**
1	A02H	A17	A04H
2	A07H	A09	A05H
3	A01H	A16	A03H
4	A08H	A24A	A22
5	A06A	A11	A27
6	A23	A24B	A31
7	A19	A12	A32
8	A15	A14C	
9	A26	A09A	
10	A20	A28A	
11	A18T2		
12	A30AT2		
13	A28		
14	A14A		
15	A08A		
16	A17A		
17	A16AY1T2		
18	A31AT2		
19	A02A		
20	A27A		
21	A10		
22	A16B		
23	A07AT2		
Total	23	10	7
	Total 40 wells (including branches of multibranched wells)		

It should be mentioned that Gyda platform has 32 slots. However, here it is assumed that it could have been designed with 40 slots.

2 The Gyda Field

2.1 Introduction

The Gyda field is located in the North Sea Central Trough, offshore Norway, 270 km Southwest of Stavanger, and 43 km North of Ekofisk Center, block 2/1 production license 019 B, in 65- 70 m water depth (Figure 2.1).

The production license was awarded in 1977, the field was discovered in 1980, and declared commercial in 1986, PDO (Plan for Development and Operation) was approved in June 1987. Gyda came on stream in June 1990. At production start-up in1990, it was known as one of the hottest and deepest oilfields in the North Sea, with one of the lowest permeabilities. Because of this, it is considered to be one of the first new generation of challenging and marginal fields. BP was the operator of the field until Talisman Energy took over in 2003. Talisman is the field operator and main shareholder (61%), DONG Energy (34%) and AEDC (5%) are the field's partners.[12].

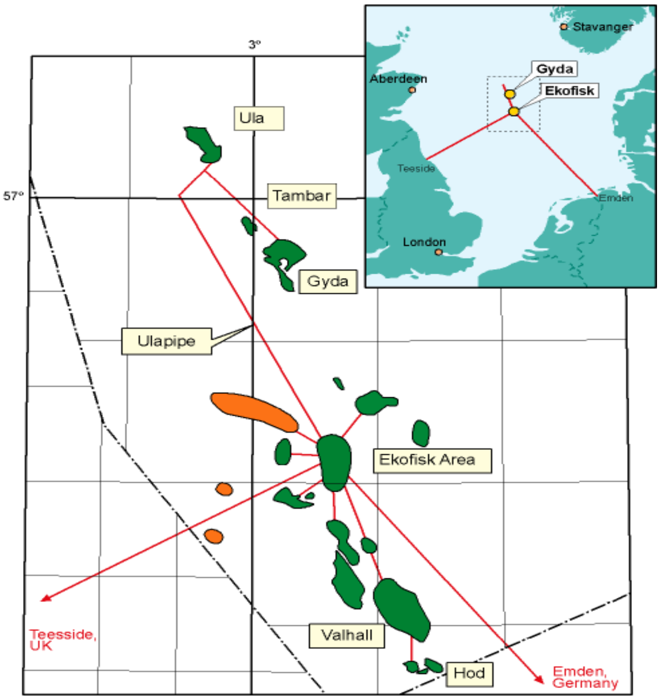


Figure 2.1Gyda field location [11]

Three different fluid types are present in the shallow marine sandstone reservoir, and the crude is asphaltene rich. The depth of the reservoir varies between 3650 and 4165 meters sub surface (mss), and the temperature is about 150 ºC at 4155 mss. The wells, typically, have a measured length above 4000 meter, which involves a noticeable pressure drop along the production path. A majority of the producing wells are producing with relatively low oil rates (below 1000 stb/d) and high watercuts. The field produces with water injection as the drive mechanism for the main part of the field. The connate water/ injection water mix has proved to have a severe scaling tendency. Pressure support from the gas cap and the aquifer are drive mechanisms for other parts of the field. [12, 13]

The total estimated combined recoverable reserves (proved + probable) for the Gyda Main and Gyda Sør reservoirs are shown in Table 2.1 (Remaining Reserves at 01/01/2010).

Table 2.1 Gyda Reserves - [13]

Initial Oil (mmbbl)	Initial LPG (mmbbl)	Inittial Gas (bcf)	Remaining Oil (mmbbl)	Remaining LPG (mmbbl)	Remaining Gas (bcf)
265	27	236	42	2	23

2.2 Geology

The Gyda reservoir is highly compartmentalized and therefore very complex. The Upper Jurassic Kimmeridgian sandstones, which are located at a depth of between 3,650-4,165 meters, are generally poorer in quality than those of the other Jurassic field in the area, Ula. The reservoir varies in thickness and is located in a stratigraphic pinch-out structure. [13]

The field has been divided to five segments: Crest, Downdip, C-sand, Southwest and Gyda South as shown in Figure 2.2 Gyda map with regions. Southwest and Gyda South regions are out of scope of this study.

The Crest was target of the initial development in the early 1990s, and at present all of the wells in the Crest are experiencing a high water-cut.

The Gyda sands are divided into three main units: A-, B- and C-sand. Figure 2.3 depicts the sand unit deposition along west to east cross section. The A-sand is at the bottom with a high permeability zone at the top. The permeability in the top can be as high as 1 D while at the base it can be 1 mD or even lower. The middle sand unit is B-sand, and generally has poor reservoir quality. Permeability in the best part of the B-sand is 30 mD, while mostly it is around 1 mD. The C-sand on the top pinches out towards the crest and varies in reservoir quality. The C-sand deposition is interpreted as a mixture of erosion of A- and B-sand in the crest and additional sediment source in the downdip area. The C-sand is inter-bedded with calcite stringers and reservoir quality in the eastern parts is poorer, despite its western parts of which have very good reservoir quality, up to 800 mD. Porosity of the Gyda field ranges from 10% to 25%. [12]

The oil characteristics vary across the Gyda field. Field characteristics are outlined in Table 2.2.

Table 2.2 Gyda field characterestics [13]

Calorific Value btu/scf	GOR scf/bbl	Gravity °API	Sulphur %	Total Acid No. mg KOH/g	Reservoir Temp °C	Reservoir Depth m
1036,0	1100	39.2 - 48	0,1	0,1	150	3,650 - 4,165

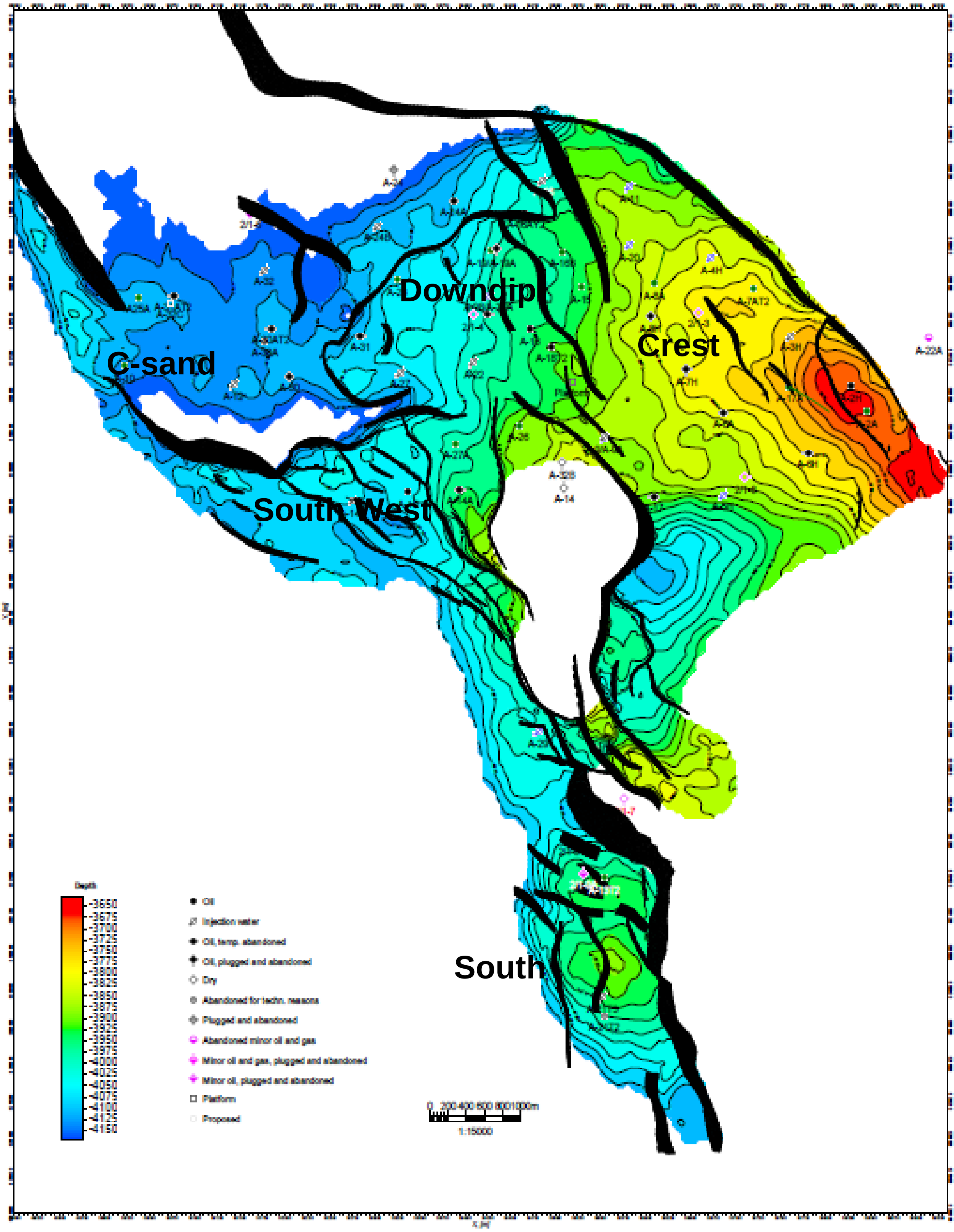


Figure 2.2 Gyda map with regions

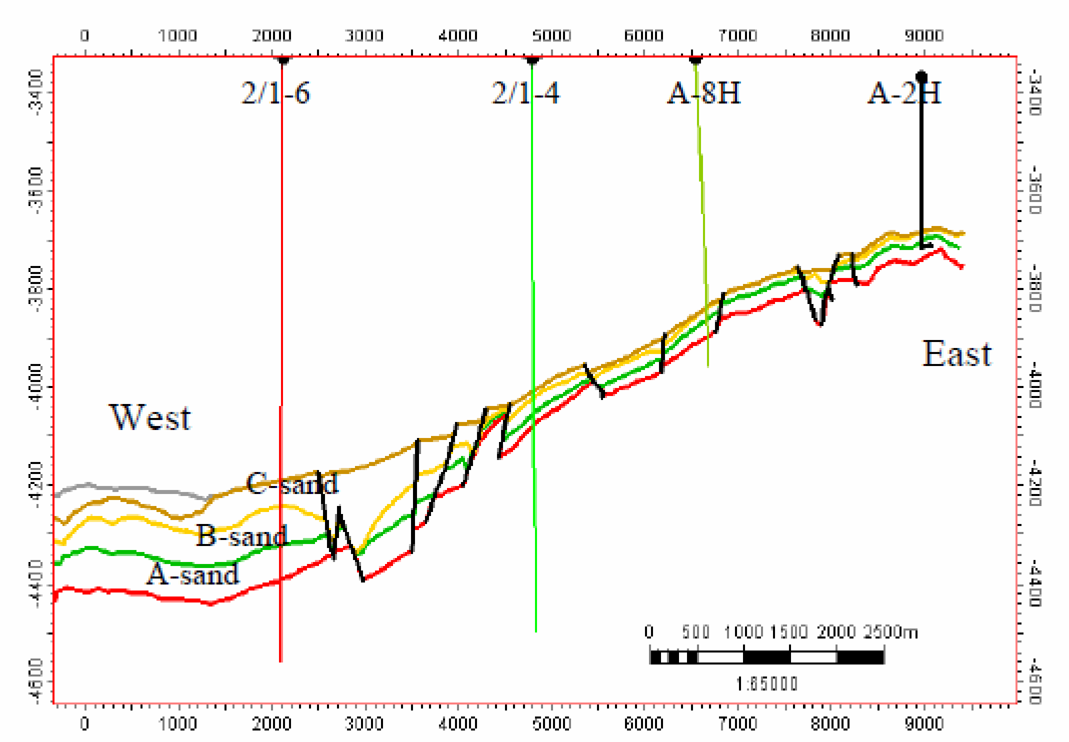


Figure 2.3 Gyda field schematic West (downdip) to East (crest) cross section showing the reservoir sand units [11]

2.3 Development

Gyda is an oil field located between Ula and Ekofisk in the southern part of the North Sea. The field was developed using a single integrated steel platform combining drilling, process and accommodation quarters (PDQ) it has 32 drilling slots. (Figure 2.4)

The oil is transported to Ekofisk via the oil pipeline from Ula and further in Norpipe to Teesside. The gas is transported in a dedicated pipeline to Ekofisk for onward transport in Norpipe to Emden. [13]

Figure 2.4 Gyda Platform

Table 2.3 gives an overview of the Gyda wells at the end of year 2010.

Table 2.3 Gyda active wells [14]

Gyda Wells	
Type	**No.**
Oil Producer	11
Water Injector	6
Shut in	5
Abandoned/suspended	10

2.4 Status

Gyda is in its tail phase and experiences increasing water production and challenges in maintaining the oil production. The production license period has been extended to 2018 and work is ongoing to prolong the lifetime of the field correspondingly.

A new onshore operations room was opened in 2009 to optimize production. Gas lift has increased well production, and the gas lift capacity will be extended. Improved recovery by means of gas injection is being considered. [13]

The field reservoir management strategy is to provide pressure support to producers using sea water injection. Some areas have been significantly depleted due to historic lack of injection well capacity. Activities have been carried throughout 2005, 2006 and 2007 to repair key water injectors and to secure water injection in the field.

The majority of the wells in Gyda produce at moderate (30% - 50%) and high water cuts (>80%). There is a severe scaling potential in the Gyda production wells due to mixing of seawater and formation water, which are incompatible. A program for regular monitoring and scale inhibitor treatment of production wells has been implemented with success. [14]

3 Reservoir Engineering Methods

3.1 Material Balance Equation

3.1.1 Introduction

The material balance equation basically keeps track of input, output and accumulation of materials in the reservoir. This concept has been extensively used in reservoir engineering and is regarded as the fundamental tool of a reservoir engineer for analyzing, basic understanding of the physics, and forecasting reservoirs performance.

Despite the fact that in the powerful numerical simulators era, there is not much applications left for classical material balance methods, but still knowing its concept is worthwhile. In fact, material balance and numerical simulation complete and support each other. Material balance is perfect at history matching of production performance but has substantial drawbacks when it comes to prediction, which is the realm of simulation modeling.

The general material balance equation first was introduced by Schilthuis in 1941 and in simple way it says [2]:

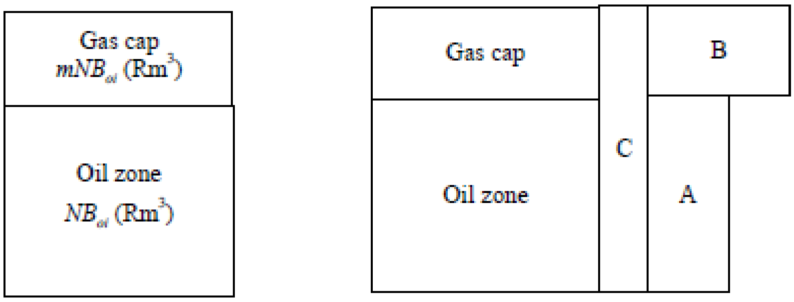
Initial volume= volume remaining + volume removed

In the next section, zero dimensional material balance (i.e. it is evaluated at a point in the reservoir) for a general oil reservoir will be developed.

3.1.2 Material balance equation for a general oil reservoir [1,4]

Generally speaking, in an oil reservoir, we are dealing with oil with/without free gas.

Original reservoir pressure, temperature and fluid composition are main factors contributing in existence of a gas cap over the oil zone in an oil reservoir (see Figure 3.1).



(a) (b)

Figure 3.1 (a): Initial reservoir condition, (b): Present condition [4]

Oil in the oil zone is in equilibrium with gas of the gas cap, and the volume part of the reservoir occupied by gas relative to oil is constant. Before starting it is necessary to define some parameters:

HCPV: Hydrocarbon pore volume

N: Initial oil in place (Sm3)

m: Ratio between the resources of gas in the gas cap and resources of oil in the oil zone (at reservoir conditions)

mNB_{oi}: Initial gas in place (Rm3)

Np: Cumulative oil production (Sm3)

Production from an oil reservoir with a gas cap (Fig. 3.1) can be described as expansion of the oil zone, (volume A), the gas cap expansion (volume B) and as expansion of connate water plus reduction of pore volume because of reservoir formation matrix expansion and likely reduction of bulk volume (volume C). For developing of the material balance equation, it is customary to split the expansion term into its components as following:

A1: Expansion of oil

A2: Expansion of originally dissolved gas

B: Expansion of gas cap gas

C: Reduction in $HCPV$ due to expansion of initial water and decrease in pore volume.

Reservoir expansion is equal to production, therefore we have:

$\Delta Vprod = A1 + A2 + B + C$.

a) Expansion of oil (A1)

The oil expansion in reservoir condition is:

$Vo(p) - Vo(pi) = \Delta Vo(p)$

Where $Vo(pi)$ is the oil volume at initial pressure and $Vo(p)$ is the volume of the oil initial in place at pressure p. ΔVo is the volume of produced oil in reservoir pressure p.

So, oil expansion is:

$$\Delta Vo = N(Bo - Boi) \qquad (3.1)$$

ΔVo is in $Rm3$, N (initial oil in place) is defined as $N = Vp(1 - Sw)/Boi$, where Sw is the average water saturation and Vp is pore volume.

b) Expansion of originally dissolved gas (A2)

In initial condition, oil is in equilibrium with a gas cap. Decreasing the pressure below the bubble point pressure (p_b) causes the liberation of solution gas.

The total amount of solution gas in the oil is $NRsi$, measured in surface volumes. The amount of gas still dissolved in the oil at present reservoir condition (pressure and temperature) is NRs, in surface volumes. Hence, the volume of liberated gas during the pressure drop, from pi to p, is: $NR_{si} - NR_s = N(R_{si} - R_s)$.

This gas volume is measured at surface condition; however, we need to have all expanded volumes in reservoir condition, so, in order to convert it to reservoir volume (at reservoir pressure) B_g (gas volume factor) is multiplied to the gas surface volume, we have:

$$\Delta Vog = N(R_{si} - R_s)B_g \tag{3.2}$$

c) Expansion of gas cap gas (B)

The total volume of gas cap gas is *mNBoi* rb, which in surface condition is

$$G = \frac{mNBoi}{Bgi}$$

The gas production at current reservoir pressure is then:

$$GpBg = \frac{mNBoi}{Bgi}(Bg - Bgi)$$

Therefore, the expansion of the gas cap is

$$\Delta Vgg = mNBoi\left(\frac{Bg}{Bgi} - 1\right) \tag{3.3}$$

d) Change in HCPV due to expansion of connate water and pore volume reduction (C)

Reduction in *HCP*V due to connate water expansion and decrease of pore volume is practically equal to the increase in production volume. Controlling factors of connate water expansion and reduction in pore volume are the compressibility of water (c_w) and pore volume (c_p).

The HCPV compressibility as is defined based on the general law of thermal compressibility:

$$c = \frac{1}{V}\frac{\Delta V}{\Delta P} \qquad \Longrightarrow \qquad \Delta V = cV\Delta P$$

The absolute volume change in the hydrocarbon pore space as a result of connate water expansion and decrease of pore volume is:

$$\Delta V_{HCPV} = \Delta V_w + \Delta V_p$$

ΔVp and ΔVw are the volume changes due to reduction in pore volume and expansion of connate water, respectively. From the definition of compressibility, we have:

$$\Delta V_{HCPV} = c_w V_w \Delta p + c_p V_p \Delta p$$

Where $V_w = S_w V_p$ and $V_p = V_{HCPV} / (1 - S_w)$, substituting them in the above equation we get:

$$\Delta V_{HCPV} = V_{HCPV} \left(\frac{c_W S_W + c_p}{1 - S_W} \right) \Delta p$$

where

$c_p = (c_b - (1+\varphi)c_r) / \varphi$

$V_{HCPV} = V_o + V_g = NB_{oi} + mNB_{oi} = (1+m)NB_{oi}$

Therefore:

$$\Delta V_{HCPV} = (1+\mathrm{m})\mathrm{NBoi} \left(\frac{c_W S_W + c_p}{1 - S_W} \right) \Delta p \qquad (3.4)$$

e) Total underground withdrawal

The surface oil and gas production are *Np* and *Np Rp* respectively. If we take these volumes down to the reservoir, the volume of oil + dissolved gas will be *NpBo*. *Np Rs* of surface gas production dissolves in *Np* of oil, if it is taken back to reservoir condition. The remaining produced gas, *Np (Rp − Rs)* is then, the total amount of liberated and gas cap gas produced and will occupy a volume *N(Rp − Rs)Bg* at the lower pressure. The total underground withdrawal term is (in reservoir condition):

$$\Delta V_{prod} = N_p[B_o + (R - R_s)B_g] \qquad (3.5)$$

Combining Equations (3.1) to (3.5) the material balance equation for a general oil reservoir will become:

$$N_P\left[B_O+\left(R-R_S\right)B_g\right]=NB_{oi}\left[\frac{\left(B_o-B_{oi}\right)+\left(R_{si}-R_S\right)B_g}{B_{oi}}+m\left(\frac{B_g}{B_{gi}}-1\right)+\left(1+m\right)\left(\frac{c_W S_W+c_p}{1-S_W}\right)\Delta p\right]$$
$$+\left(W_e-W_p\right)B_w \qquad (3.6)$$

$[(We - Wp)Bw]$ term takes into account water production and water influx in the reservoir.

It is crucial to bear in mind the assumptions that based on the material balance equation is developed. The equation gives a static representation of the reservoir and it has no term describing the energy loss in the reservoir due to fluid flow behavior. The following characteristics of the material balance equation should be considered:

- It generally exhibits a lack of time dependence; however, the water influx is time dependent.
- Although the pressure only appears explicitly in the water and pore volume compressibility terms, it is implicit in all the other terms of Equation (3.6) because the PVT parameters B_o, R_s and B_g themselves are functions of pressure. Water influx is also pressure dependent.
- Equation (3.6) is evaluated, in the way it was derived, by comparing the current volumes at pressure p to the original volumes at p_i. Note that the material balance equation is not evaluated in a step-wise or differential fashion.

3.1.3 The material balance as a linear equation

The linearized material balance equation is especially interesting regarding to reservoir parameter estimation. Results published in 1963-64 by Havlena and Odeh opened a wide range of applications of the material balance equation to reservoir engineering. The linear form of Eq. (3.6) is:

$$F = N(E_o+mE_g+E_c)+W_eB_w \qquad (3.7)$$

In which, we have used the following definitions:

Underground withdrawal:

$$F = N_p[B_o + (R - R_s)B_g] + W_pB_w$$

Expansion of oil and its originally dissolved gas:

$$E_o = (B_o - B_{oi}) + (R_{si} - R_s)B_g$$

Expansion of the gas cap gas:

$$E_g = B_{oi}\left(\frac{B_g}{B_{gi}} - 1\right)$$

Expansion of the connate water and reduction of pore volume:

$$E_c = (1+m)\left(\frac{c_W S_W + c_p}{1 - S_W}\right)B_{oi}\Delta p$$

Equation (3.7) is particularly important for predicting reservoirs drive mechanisms and estimation of initial oil and gas in place.

3.2 Numerical simulation

3.2.1 What is Reservoir Simulation?

Similar to material balance calculations, Reservoir Simulation is also a form of numerical modeling which is applied to measure and understand physical phenomena, as well as, predicting future performances. The below are some of Material balance limitations which can be covered by reservoir simulation [5]:

- No account of spatial variation (so-called “zero-dimensional”)
- Reservoir and fluid properties as well as fluid flows are averaged over the entire reservoir

- To examine the system at a number of discrete points in time requires a material balance calculation over each time interval.

In Reservoir simulation, the reservoir is divided into a number of discrete elements in 3-D form and the alteration of reservoir and fluid properties through space and time is modeled in a sequence of discrete steps. Like in material balance, the system total mass is conserved. It can be compared to a coupled system of material balance models. It serves the reservoir engineer with much better understanding of recovery mechanisms. However, bear in mind that a simulator is only a tool and needs good engineering judgment in order to obtain sensible results. [5]

Reservoir simulation provides information on the response of the reservoir under alternative production / injection scenarios. Reservoir simulators are extensively utilized by reservoir engineers to better interpret the reservoir, study performance predictions in future and even uncertainty analysis. Besides, it is faster, cheaper and more reliable than other methods. [6]

The most common types of reservoir fluid models are compositional and black oil models. Black oil models are based on the assumption that the saturated phase properties of oil and gas only pressure dependent. Similar to black oil model, compositional models assume two hydrocarbon phases too, however, they include the definition of many hydrocarbon components. In this sense, black oil simulator can be thought of as a compositional simulator with two components. A compositional simulator often has six to ten components [7]. For simulation tasks where changes in fluid composition have primary influence on the results, use of Black Oil model is not accurate enough, such as, modeling of miscibility processes. Therefore, in a compositional modeling of fluid properties, hydrocarbon components (methane, ethane, …) are used in addition to water. Then oil and gas properties will be functions of fluid composition in addition to pressure [6]. Since the reservoir simulation model of the Gyda reservoir is a compositional model, in the next section we take a brief look at this type of model.

3.2.2 Compositional model

Compositional model is different from black oil model from PVT (pressure, volume, temperature) calculation point of view. Black oil model assumes three phases: oil, gas and water. However, in compositional model, hydrocarbons are divided in several components, i.e. we have hydrocarbon components, as well as, water. The components can be pure hydrocarbon components, like methane, ethane, or some components can be grouped and form a pseudo component. If hydrogen sulfide and nitrogen are also present, they will be treated in the same way as hydrocarbon components. It is assumed that hydrocarbon components exist both in oil and gas phase; there is no phase transition between hydrocarbons and water. It is also assumed that temperature is constant (isothermal) and we have instantaneous phase equilibrium. [6]

Correct modeling of PVT-properties for compositional simulation is indeed difficult, especially for complex fluids. Most methods for PVT calculations are on basis of cubic equations of state (Peng-Robinson, Redlich-Kwong, etc.). Using equation of state are time consuming, and some models use lookup tables of K-values instead of equation of state calculations. [6]

Let (*xi*) denote oil composition and (*yi*) the composition of gas. If moles are used as unit for mass, (*xi*) and (*yi*) will be mole fractions, so, densities are mole densities.

The basic equations for compositional simulators express mass conservation for each of the hydrocarbon components and water are [6]:

Water:

$$\nabla . \left[\frac{[k] k_{rw}}{\mu_w} \rho_w \left(\nabla p_w - \gamma_w \nabla d \right) \right] + Q_w = \frac{\partial}{\partial t} \left(\varphi \rho_w S_w \right) \tag{3.8}$$

Hydrocarbons:

$$\nabla . \left[\frac{[k] k_{ro}}{\mu_o} \rho_o x_i \left(\nabla p_o - \gamma_o \nabla d \right) \right] + \nabla . \left[\frac{[k] k_{rg}}{\mu_g} \rho_g y_i \left(\nabla p_g - \gamma_g \nabla d \right) \right] + Q_i = \frac{\partial}{\partial t} \left(\varphi \rho_o x_i S_o + \varphi \rho_g y_i S_g \right)$$

$$i = 1,2,\ldots,n_c \tag{3.9}$$

Where:

[k]: Permeability
K_r : Relative permeability
μ : Viscosity
B: Formation Volume Factor
P: Phase pressure
γ: ρg
ρ: phase density
g: gravity acceleration
d: vertical distance from a reference level to a point
Q: q / ρ^s

q: flow rate

ρ^s: density in standard condition

φ: Porosity
S: Saturation

Subscripts:

o:oil
w: water
g: gas

3.2.3 History matching versus Prediction

3.2.3.1 Introduction

Reservoir simulation is divided into two phases called, history matching and future prediction.

In this section the focus is on the definition of history matching and prediction concepts in reservoir modeling. History matching and prediction are essentially different. The goal of history matching is to refine reservoir characterization. This improves production estimates during the prediction phase. In history matching reservoir characteristics are undetermined, and well rates are known but in prediction the reservoir has been characterized but future well rates are just estimates from simulation results. Figure 3.2 shows the relation between prediction and history matching. [5]

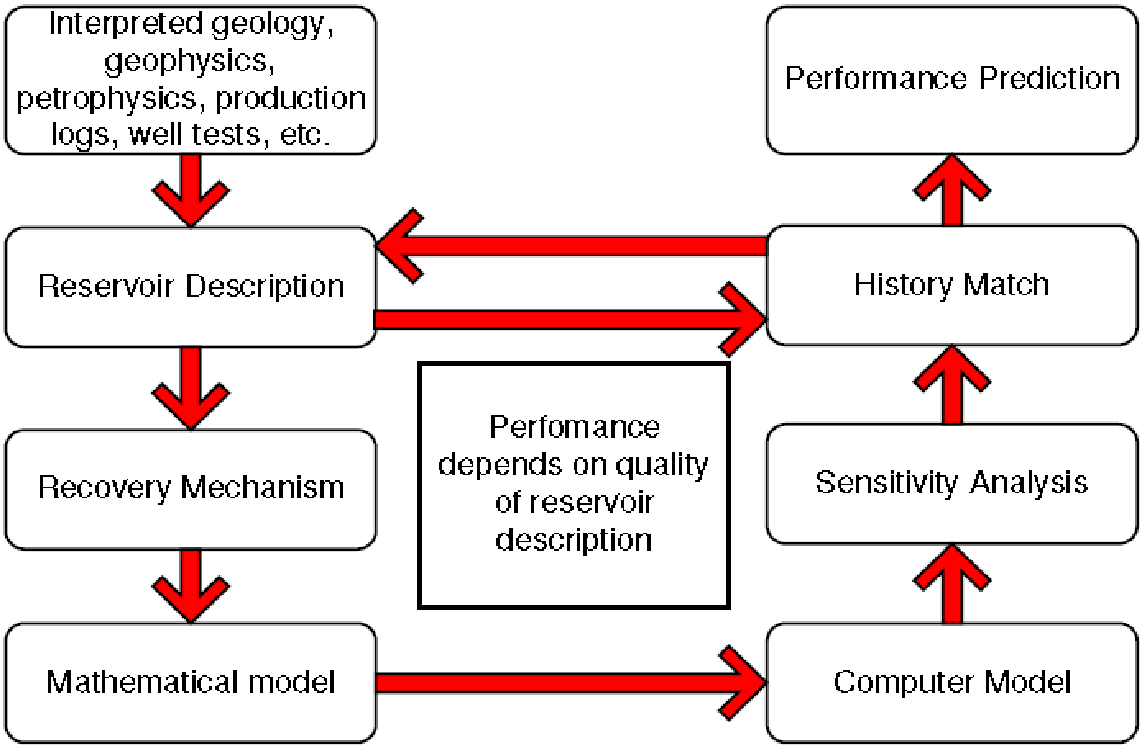


Figure 3.2 History matching versus prediction [5]

3.2.3.2 History matching

Reservoir simulation firstly concerns, tuning uncertain parameters of the reservoir to dynamic data and, then, using the tuned model to predict future performances of the reservoir under different production scenarios. This tuning process is called *history matching* and usually takes many simulation runs in order to specify the results sensitivity to the uncertain parameters [8]. History matching is therefore the practice of determining the reservoir properties subject to the highest uncertainty and modifying them to get an acceptable match between the simulated and measured rates [5].

When the sensitivities have been set up, the next step is adjusting of the model input parameters' values to refine the match between the history field data and the simulation results. Now the history matched model can be used to examine alternative production scenarios and find the one with the best reservoir performance. [8]

The main purpose of doing a history match is improving and verifying the reservoir simulation model. The below are the matching data

1. Observed gas/oil ratios and water/oil ratios
2. Observed average pressures (shut-in pressures) or pressures at observation wells
3. Observed flowing well pressures
4. Observed oil production rates.

Normally history matching is the most time consuming part of a simulation study and it often accounts for a big portion of the cost of a reservoir study [8].

History matching is often a repetitive process, in which steps are reiterated a number of times with alterations in reservoir characterization. There are no exact rules for a history matching but the methodology is well known [8].

3.2.3.3 Prediction

As previously discussed, the main objective of reservoir modeling is to produce a tool which helps us with giving some recommendations on a reservoir management plan. The main goal of reservoir management is to find the optimum operating conditions required to maximize the commercial recovery of hydrocarbons. The economical effect of a simulation study is the development of a cash flow prediction from estimated field performance. So, the model study is usually completed by making field performance predictions to be utilized in economic analysis of possible production strategies [7].

During history matching, the simulator tries to meet the historical reservoir performance. In the prediction mode, the matched simulation case is utilized to predict future performance of a well or a reservoir undergoing various operating strategies (see Figure 3.3). The reservoir engineer examines a range of scenarios and selects a strategy that expected to give the most favorable performance.

The engineer can also to show the potential advantages of a new idea and give results of high interest to a company. The prediction process consists choosing of prediction scenarios, input data preparation for the cases, proper use of history matching, assessment and analysis of predicted performance, and report of the predicted performance. [8]

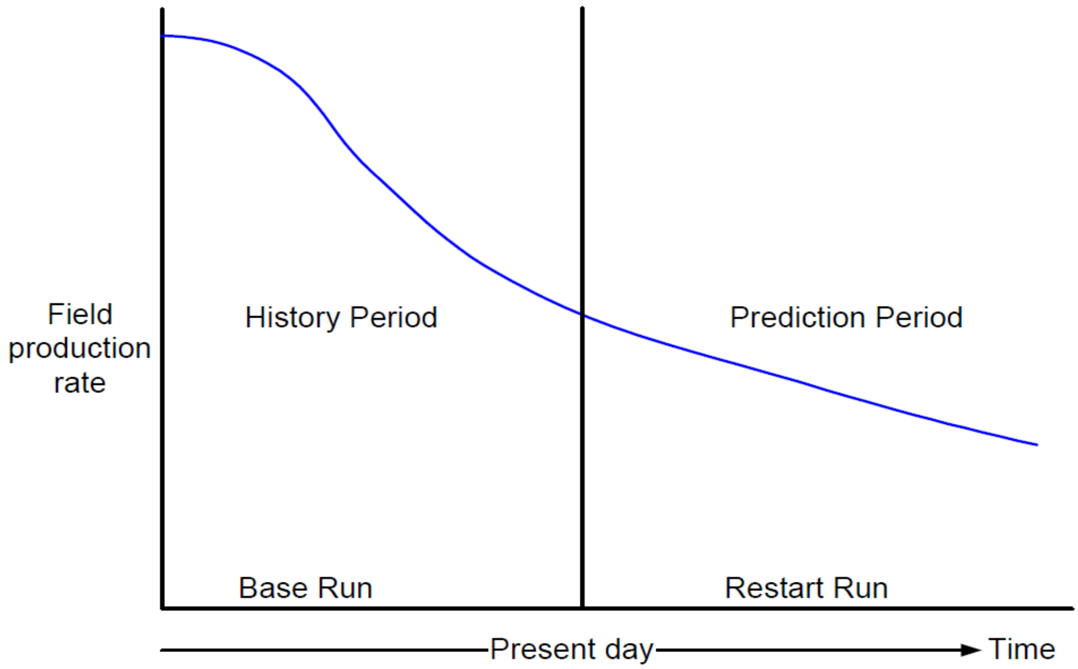


Figure 3.3 History and prediction periods [9]

3.2.4 Simulation with Petrel RE 2010

In conventional reservoir simulation the engineer had to use a range of different softwares, thus, data had to be exported / imported between the different applications. Besides, feedback to the geological model used to be hard to implement. The vision for Petrel RE is to make all of these tools available from Petrel User interface. [10]

Classically the geoscientists supplied input to the reservoir simulation model. Since Petrel gives one tool for the whole workflow, it is easier for the different professionals to work in an interrelated way. Since the modeling and simulation tools are accessible in one single application, it is easier for the engineer and the geologist to collaborate (see Figure 3.4) [10].

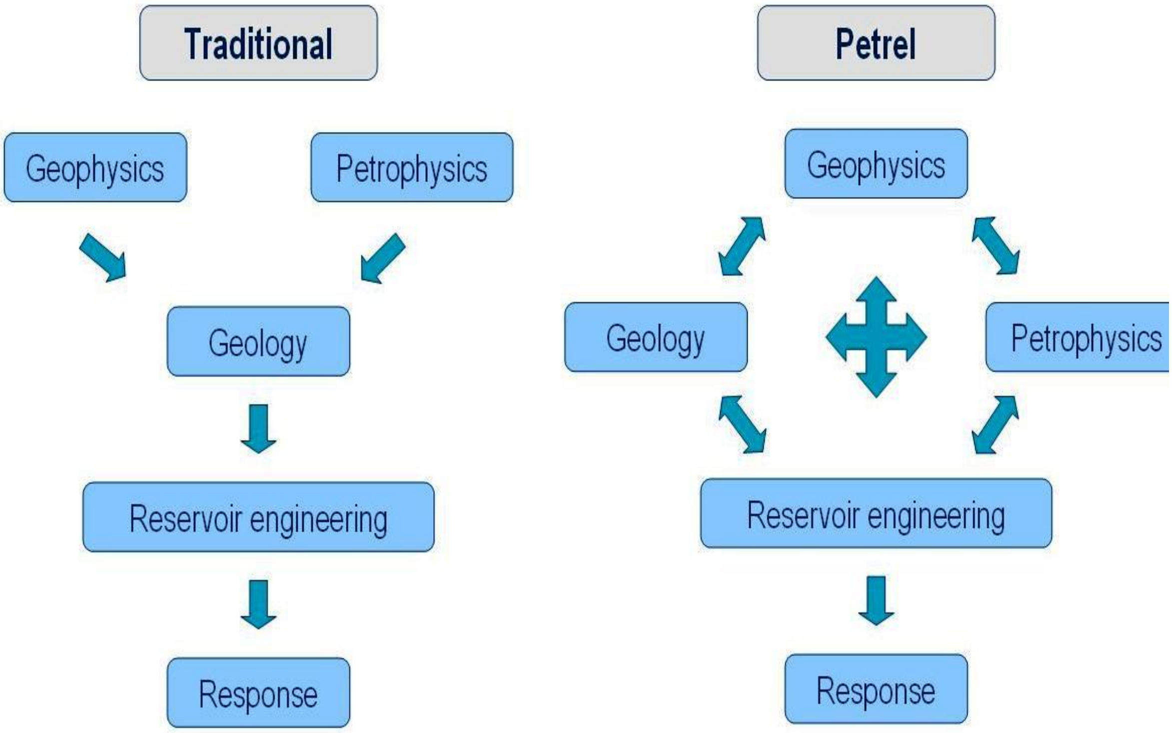


Figure 3.4 Petrel enables feedback between disciplines [10]

The reservoir engineer used to needs on a range of softwares to set up, run and view the simulation results. The traditional reservoir engineering workflow is depicted in Figure 3.5.

Petrel offers one combined user interface for workflows from seismic interpretation to reservoir simulation. The vision of Petrel is to embody all of those tools into one common user interface to stay away from challenges and time spent on import / export (see Figure 3.6) **[10].**

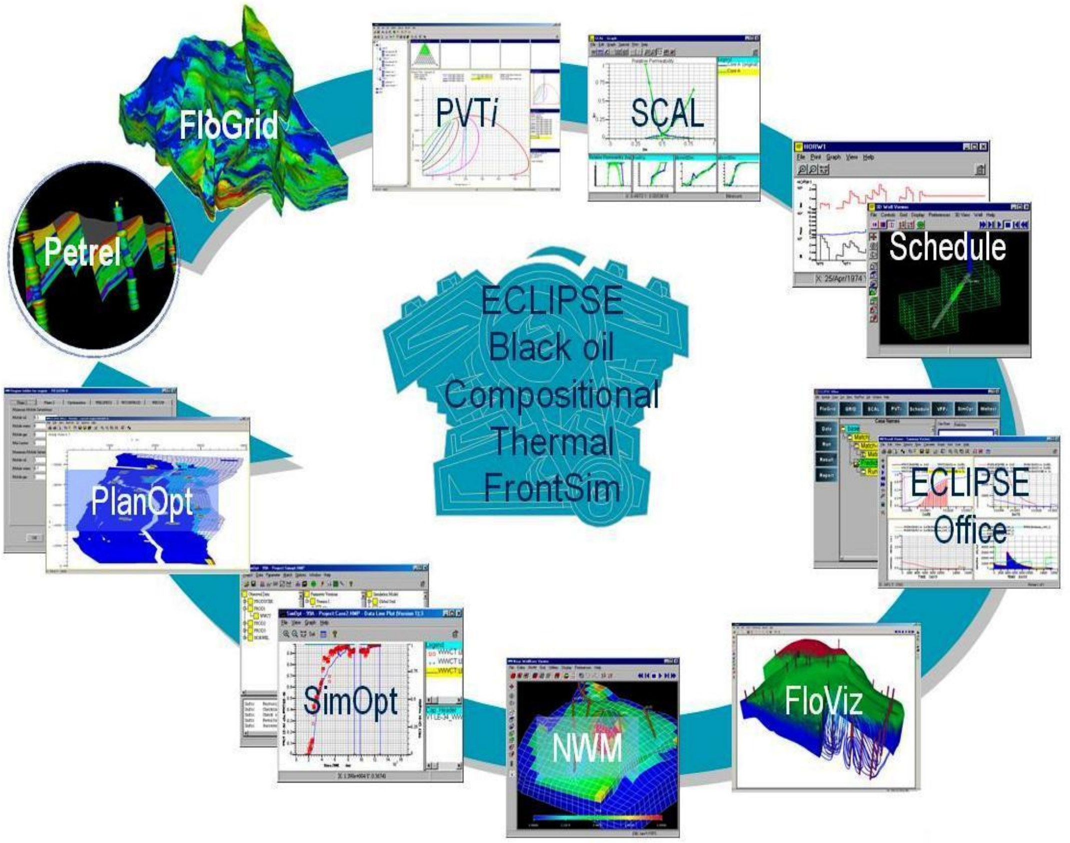


Figure 3.5 Traditional reservoir engineering workflow [10]

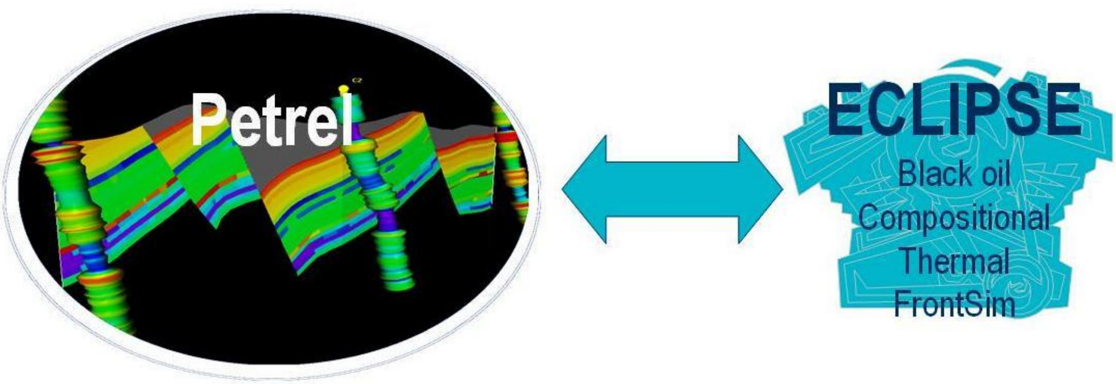


Figure 3.6 Petrel Reservoir Engineering – One application [10]

Since Petrel 2010 uses ECLIPSE as its reservoir simulator, it is customary to give a brief description about ECLIPSE data file structure [5]:

RUNSPEC

The RUNPSEC section describes general model characteristics. It is used to assign memory to the different elements of the simulation. This section is compulsory, except for fast restarts.

GRID

The GRID section includes the specification of the static reservoir description, like the grid geometry data, porosities, permeabilities, net to gross values and numerical aquifer specification. The GRID section is required, except for fast restarts.

EDIT

The EDIT section is optional. It is used to adjust the grid geometry data to a form more suitable for use in flow calculations (after ECLIPSE processed GRID section).

PROPS

The PROPS section consists of the fluid PVT properties, relative permeabilities and capillary pressure data. PROPS section is compulsory.

REGIONS

This section is optional. It is used to group cells together into regions of different reservoir characteristics, for example, rock compressibility or initial oil density and viscosity. Regions may also be defined for reporting purposes. The REGIONS section is mandatory, except for fast restarts.

SOLUTION

The SOLUTION section defines the conditions at the start of the simulation run. It is required, except for fast restarts.

SUMMARY

This section is optional. It is used to specify the data output for line plots.

SCHEDULE

The SCHEDULE section includes all the data on wells, surface facilities, flow correlations and simulation advance and termination. Without a SCHEDULE section, **ECLIPSE** does not output restart files. To output the initial conditions, a SCHEDULE keyword is required and the simulation have to be run for at least one time step.

Figure 3.7 shows ECLIPSE data file format [5]

```
123456789012345678901234567890                                   132
--This comment denotes the beginning of the data file proper
--Keywords must start in the first column read, which is 1 by default
RUNSPEC Can place comments in the 8th column following the keyword
--This is a comment
--followed by another comment
EDIT        This section is optional

PROPS       This section is compulsory
DENSITY
--Oil       Water      Gas
  45     63         0.07       /    Comments can be placed after
-- the terminating slash
REGIONS        This section is optional
--This is another comment
SOLUTION
columns        Eclipse keywords are not case sensitive
--First   Last
  1      33  /              | Anything beyond the final column is a comment
SUMMARY                     |
                            |
SCHEDULE                    |
                            |
END                         |
```

Figure 3.7 ECLIPSE data file format [5]

4 Simulation results

4.1 Introduction

As it is mentioned before Gyda came on-stream in June 1990, water injection commenced Feb. 1991. Original pressure was 595 bar and bubble point pressure was 200 bar. The study covers Region 1: Downdip, Region 4: Crest and Region 5: C-sand, other regions are excluded from the study, since, those regions are not included in the dynamic reservoir model.

The following production scenarios have been investigated and the results are presented in this chapter.

1. Water injection (Real scenario)
2. No water injection
3. No water injection – Gas Lift
4. No water injection – ESP & Gas Lift
5. No water injection– Infill wells
6. No water injection– Infill wells & Gas Lift
7. No water injection– Infill wells, Gas Lift & ESP
8. Modified water injection

First the base case is introduced and then the alternative scenarios are discussed, at the end a modified version of base case is studied to show how the base case could be modified.

To make the simulation more realistic the below measures have been put in place (Simulation period: **June 1990** – **Dec. 2010**):

- Well minimum production rate set to **16** Sm3 ~ **100** bbl (Economical Limit)
- Minimum THP (tubing head pressure) set to **14** bar (Imposed by surface facilities)
- Minimum BHP (bottom hole pressure) set to **50** bar
- Well Efficiency set to **0.95** (5% downtime) for ordinary producers
- Well Efficiency set to **0.8** for ESP wells (20 % downtime)
- An average of **90 days** is considered for drilling a well
- Water cut maximum limit is **0.95**

4.2 Production Scenarios

4.2.1 Scenario 1: Water injection (Real scenario)

This scenario is the one which has been performed on Gyda during its life. The model is history matched and therefore all the mentioned figures are the real data.

Figure 4.1 shows field oil production rate:

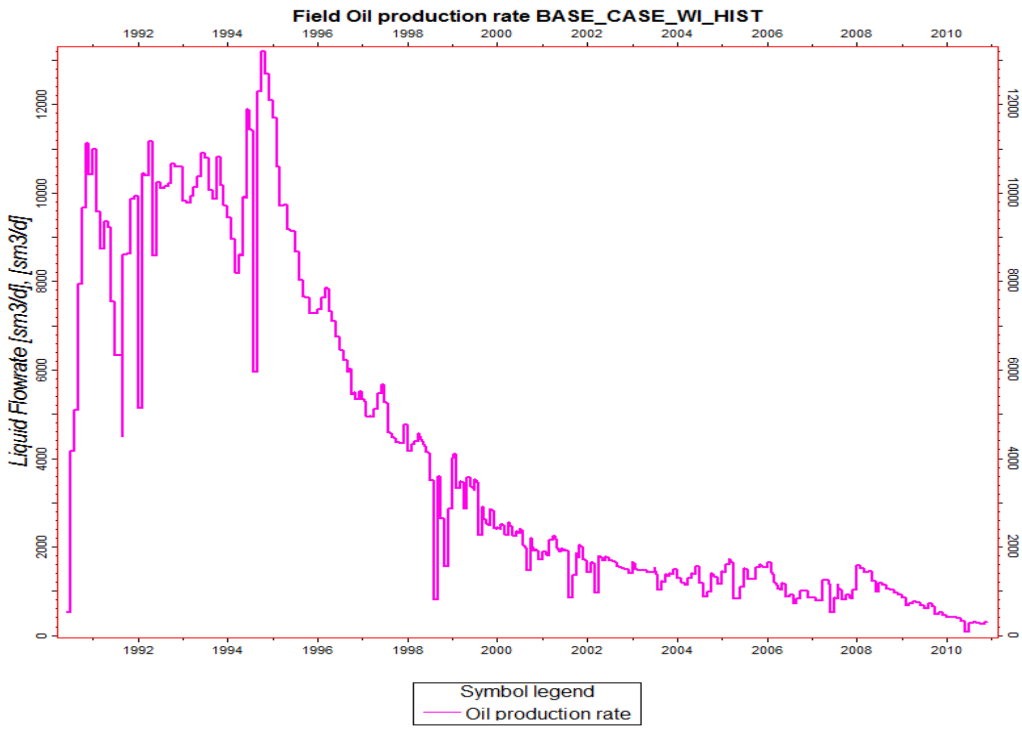


Figure 4.1 Field oil production rate (water injection)

As it is expected in the early days of production, oil production increases to reach a plateau and after that the rate decreases towards the end of the field's life.

Figure 4.2 shows gas production of the field, as it can be seen, field gas production also follows almost the same trend as field oil production.

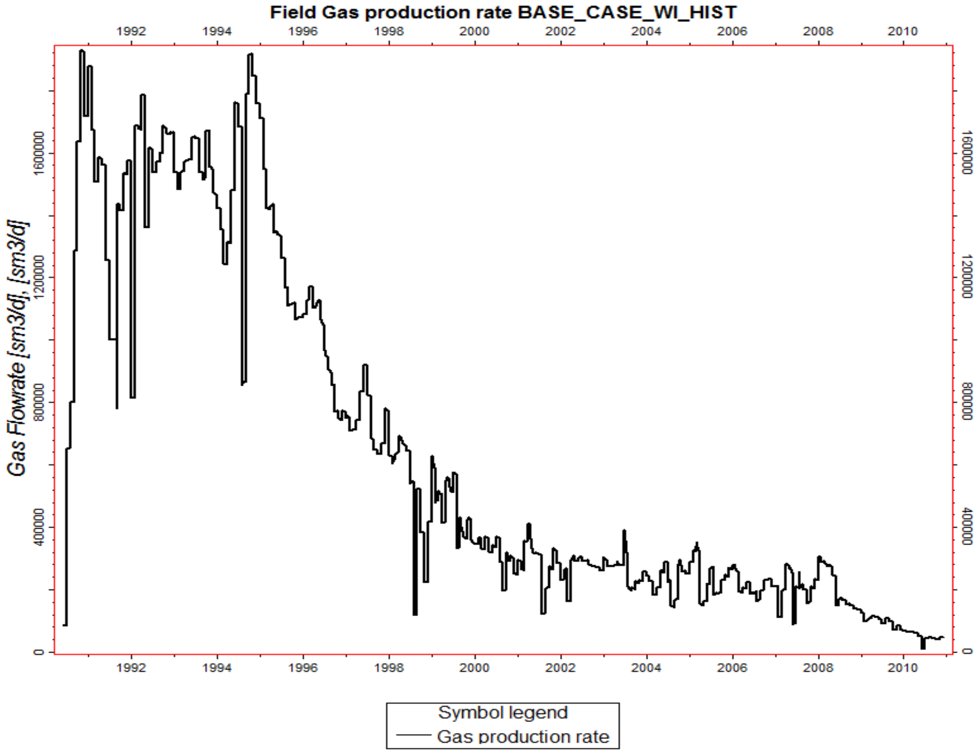


Figure 4.2 Field gas production rate (water injection)

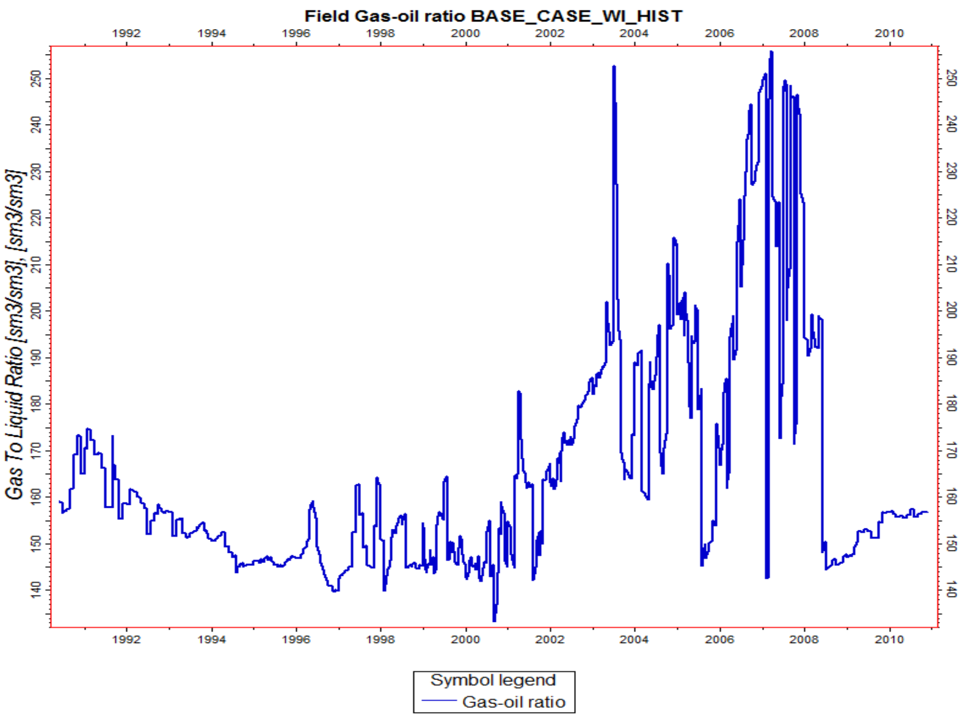


Figure 4.3 Field gas oil ratio (water injection)

Field gas oil ratio is depicted in Figure 4.3 which does not show any specific trend in the early days of production. Since normally field gas oil ratio is influenced by many parameters, it does not exhibit a simple trend in early phase. However, it increases toward the end of the field's life which is an indication of reservoir depletion.

Water cut is showed in Figure 4.4. As it is predictable, in water flooding scenarios the water cut rapidly increases. Here it reaches around 88 % at the end of simulation period.

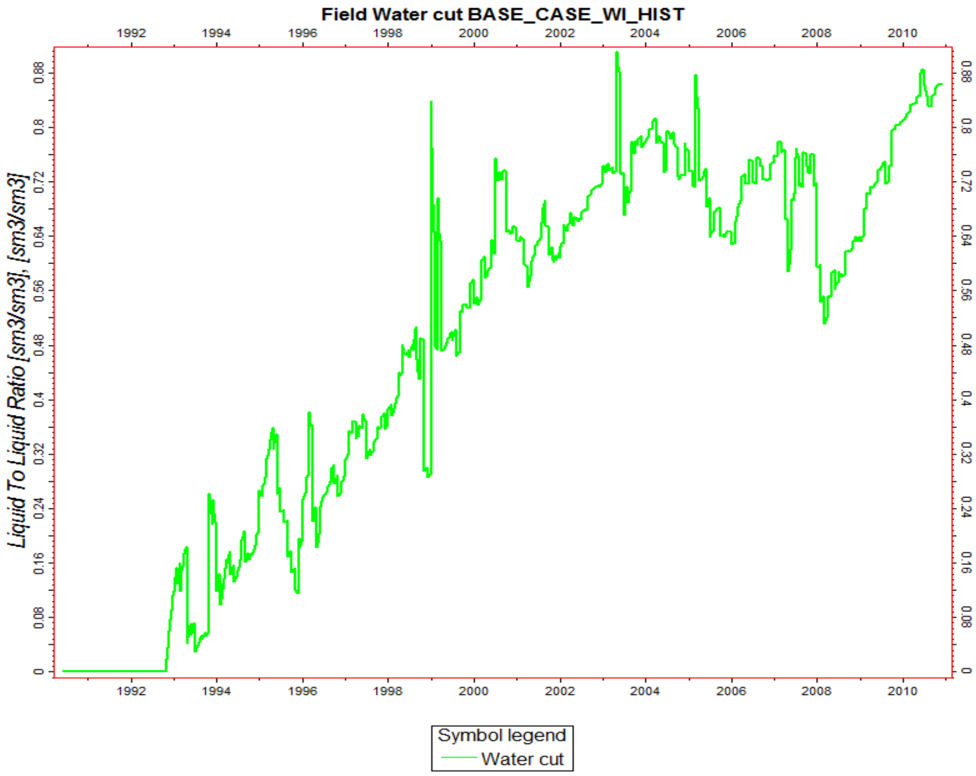


Figure 4.4 Field water cut (water injection)

As it was mentioned earlier, three regions of the Gyda, Downdip, Crest and C-sand are under this study, and therefore here reservoir pressure changes in these regions are depicted in

Figure 4.5, Figure 4.6 and Figure 4.7 respectively. Figures show that in the early phase there was a sharp decline in pressure, but after start of water injection the pressure again increases toward the end of the simulation period. It says that the pressure maintenance by water injection has been successful.

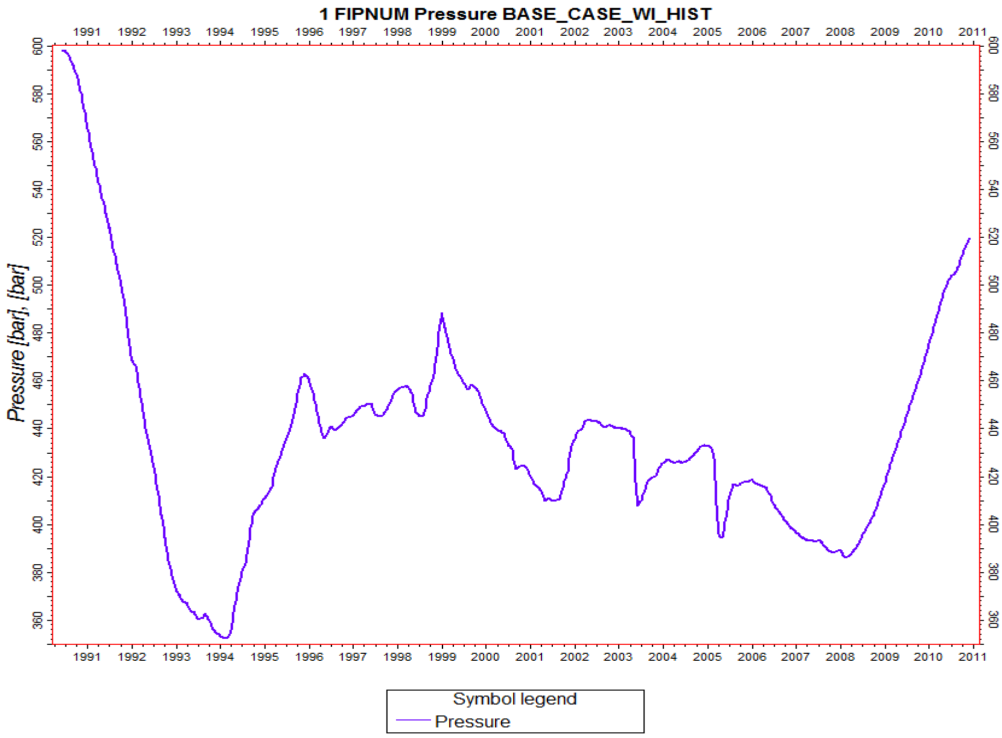


Figure 4.5 Region 1 (Downdip) Pressure (water injection)

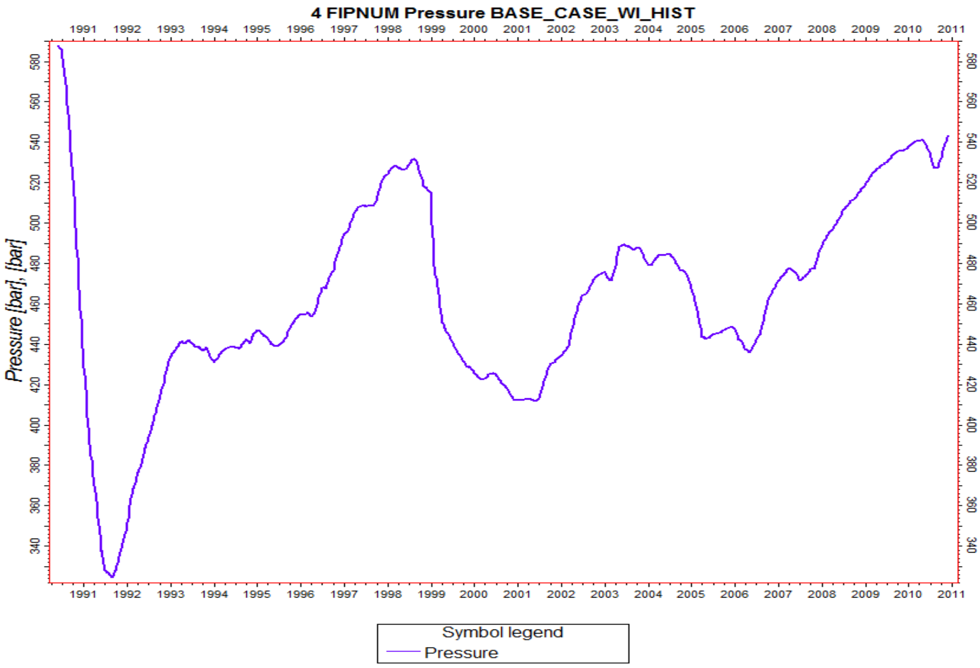


Figure 4.6 Region 4 (Crest) Pressure (water injection)

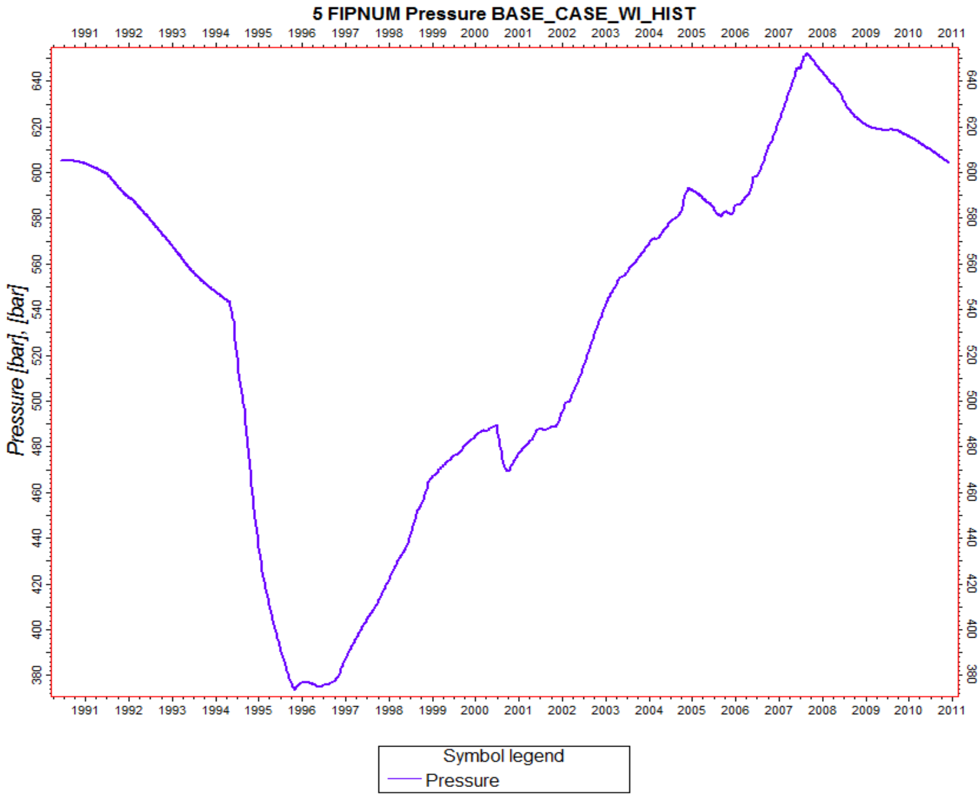


Figure 4.7 Region 5 (C-sand) Pressure (water injection)

After looking through the various diagrams depicting the main parameters of this production scenario, it is time to look at some important facts and figures:

- Field Total Oil Production (at Dec. 1st , 2010):
  30,584,716 Sm3 ~ 192.4 MMbbl

- Field Total Gas Production (at Dec. 1st , 2010):
  4,795,150,336 Sm3 ~ 169.3 Bcf

- Field Total Water Production (at Dec. 1st , 2010):
  18,555,854 Sm3 ~ 116.7 MMbbl

Since this scenario is the real case, it has been chosen as the base case, and now on, other cases will be compared toward this case.

4.2.2 Scenario 2: No water injection

In this scenario, all injectors (10 wells) have been shut from day first; the producers which converted to injectors in real case (7 wells) remain producer in this scenario. Therefore, the model has been run without any injection.

To begin with, Figure 4.8 shows field oil production rate of "No water injection" scenario (red line) versus the base case (black line). As it can be seen, in the early days "No water injection" scenario has higher oil rate (blue circle), it is due to oil production from wells A03H and A05H which here they are still producing, but in the base case, they have been converted to injectors at this time. However, after a short time, due to sharp decrease in reservoir pressure because of lack of pressure maintenance by water flooding in this scenario, we can clearly see the lower oil production rate of "No water injection" case.

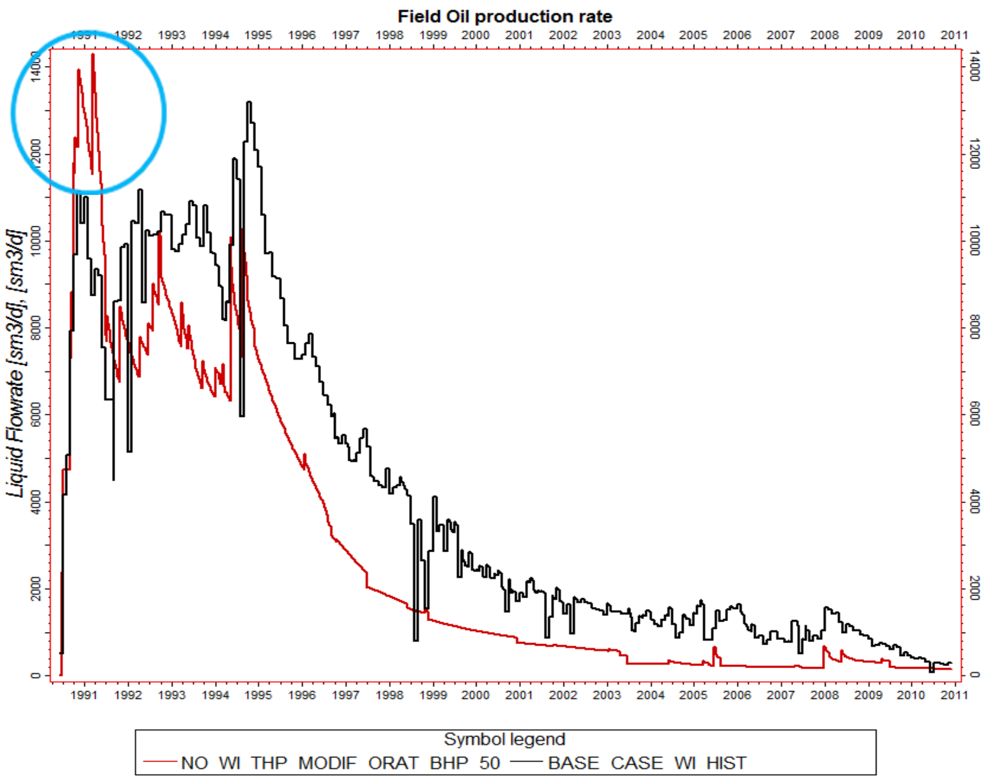


Figure 4.8 Field Oil Production Rate of "No water injection" vs. Base Case

Figure 4.9 shows field gas production rate of “No water injection” scenario (red line) versus the base case (blue line). As it can be seen, similar to Figure 4.8 in the early days “No water injection” scenario has higher oil rate (green circle), however, towards the end of simulation period, due to lack of pressure maintenance and further decrease of reservoir pressure under bubble point pressure (around 200 bar), the amount of free gas increases in the reservoir which leads to increase in gas production rate, higher than the base case.

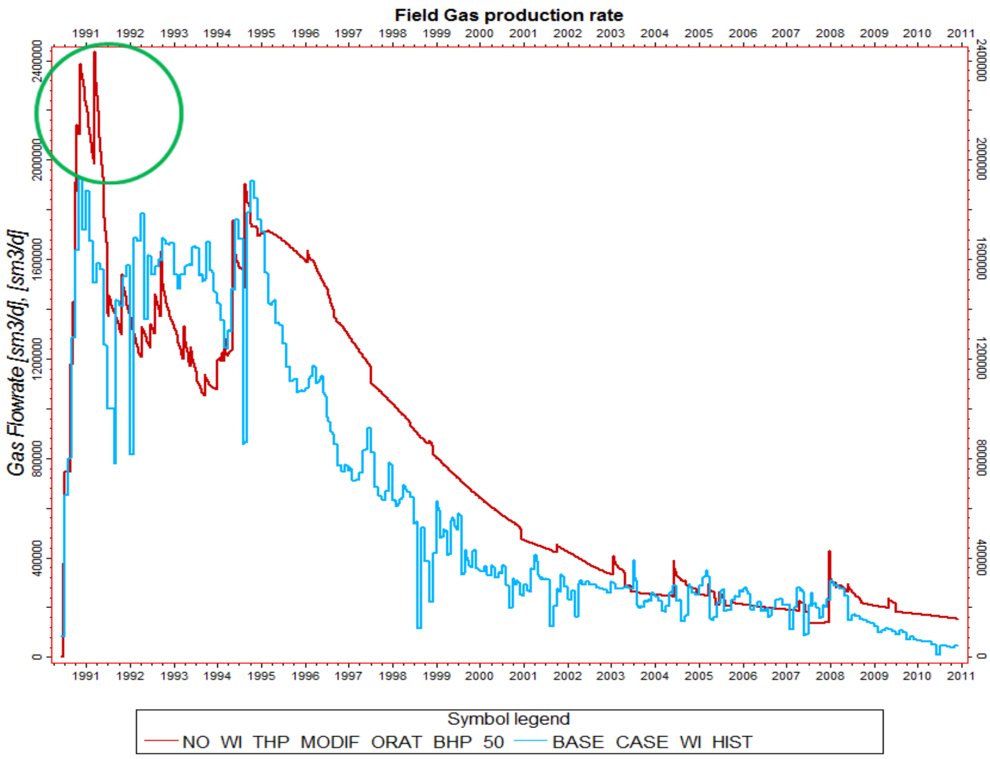


Figure 4.9 Field Gas Production Rate of "No water injection" vs. Base Case

Field gas oil ratio is depicted in Figure 4.10. In the early years of production gas oil ratio of “No water injection” scenario (red line) follows the base case (blue line). Nevertheless, after this short period a dramatic increase in gas oil ratio of “No water injection” is noticeable which is because of the fact that reservoir pressure went under bubble point pressure and free gas has evolved in the reservoir and resulted in producing more gas and increasing gas oil ratio.

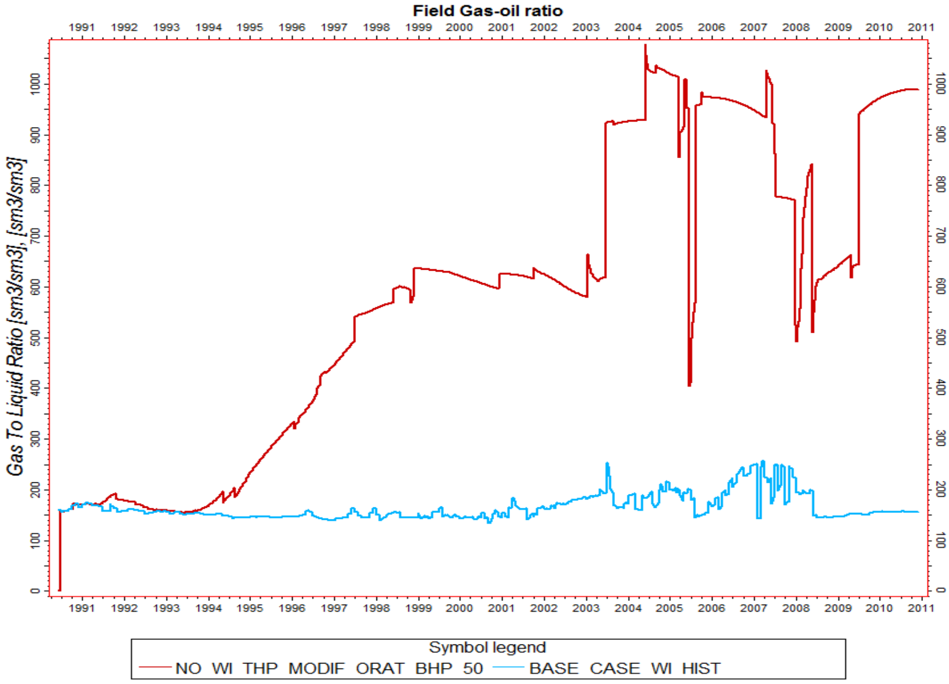


Figure 4.10 Field Gas oil ratio of "No water injection" vs. Base Case

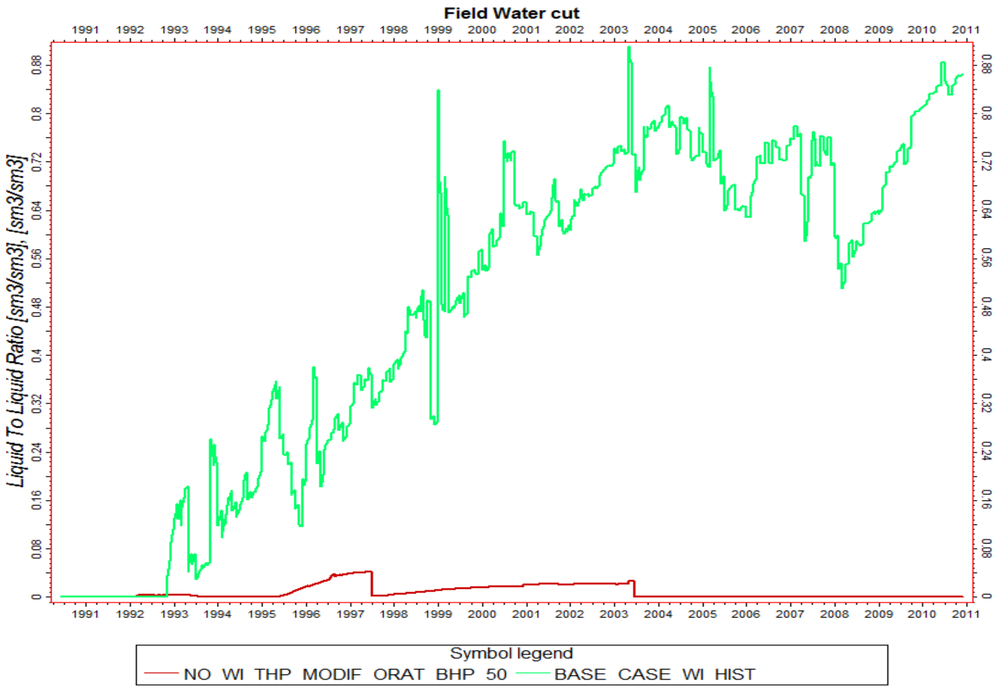


Figure 4.11 Field water cut of "No water injection" vs. Base Case

Field water cut of “No water injection” scenario (red line) and the base case (green line) is indicated in

Figure **4.11**. Obviously, water cut in the base case is much higher than “No water injection”, since in the latter no water has been injected into the reservoir and consequently the water cut is significantly lower than the base case which was water flooded.

Below are figure 4.12- 4.14 showing reservoir pressure of Downdip, Crest and C-sand regions of Gyda respectively, for both “No water injection” scenario (red line) and the base case (green line). Figures suggest that in the early phase there was a sharp decline of pressure in both scenarios, however, in the base case due to water injection the pressure starts to build up but in “No water injection” due to lack of pressure maintenance, the pressure continues to decrease till very low pressures. The highest pressure drop is in the region 4 (Crest), since, there are more producers in that region and they produce longer than producers of other regions.

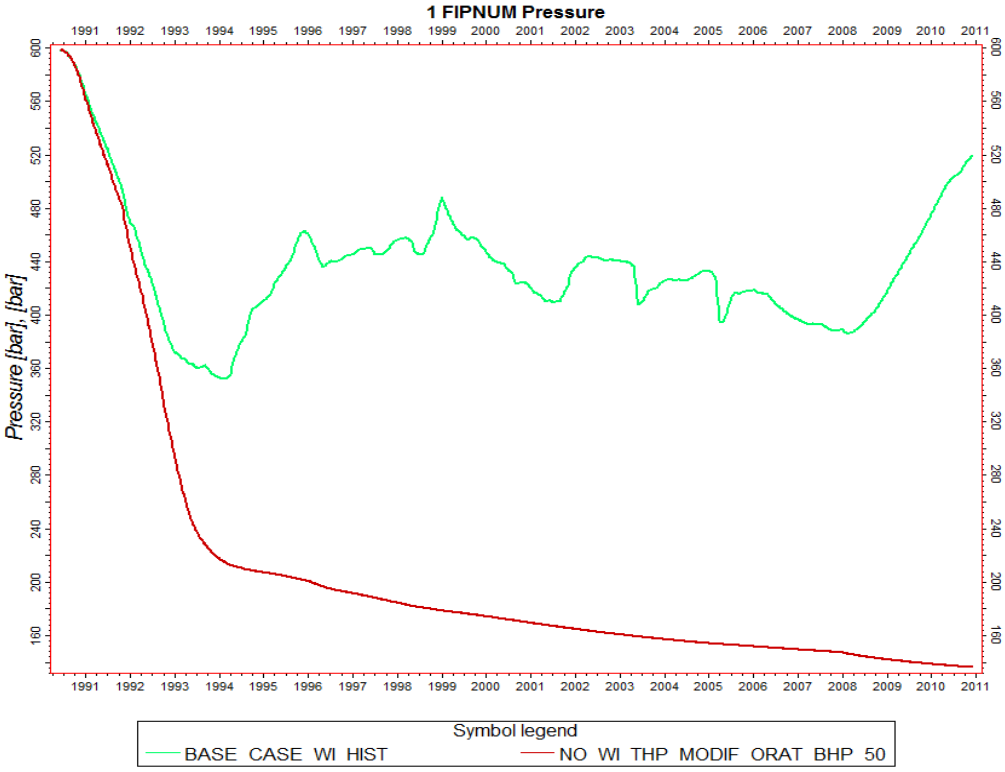


Figure 4.12 Region 1 (Downdip) Pressure of "No water injection" vs. Base Case

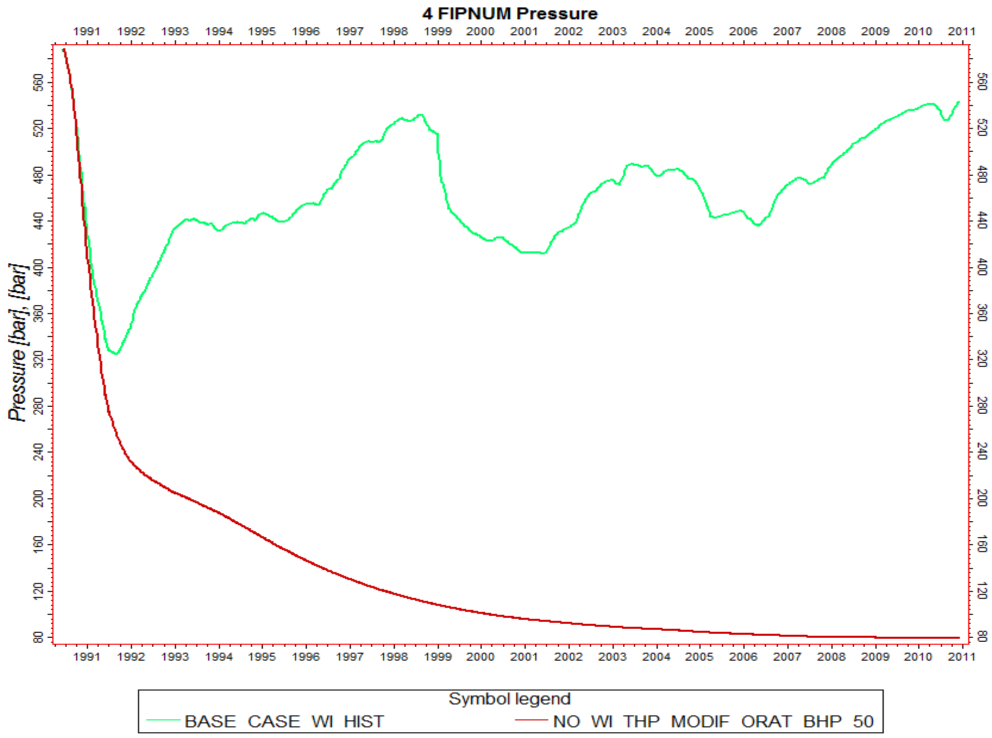


Figure 4.13 Region 4 (Crest) Pressure of "No water injection" vs. Base Case

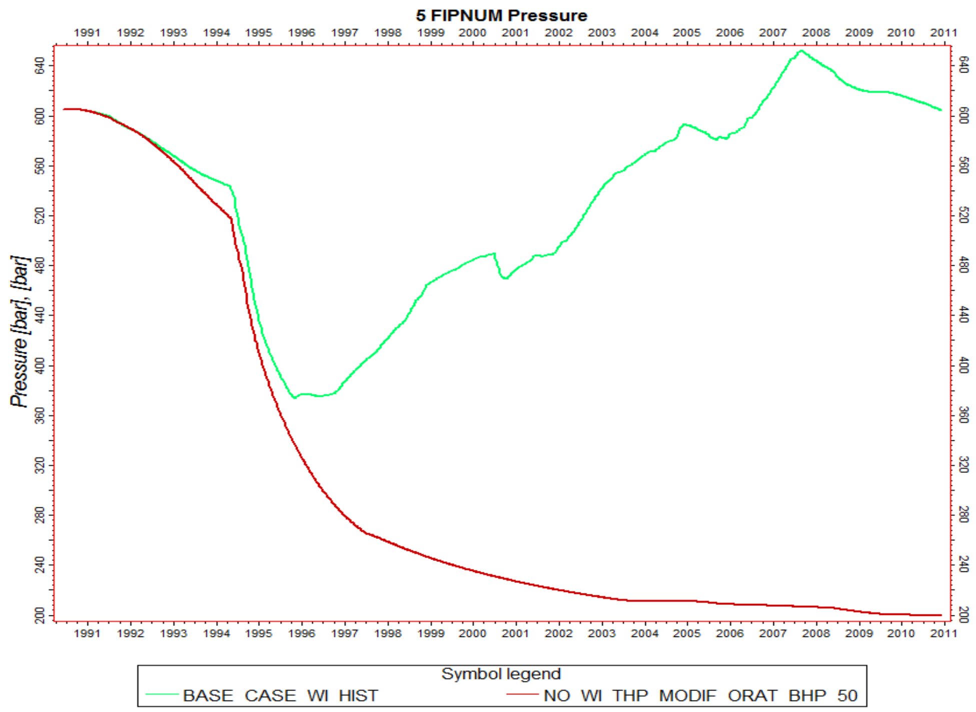


Figure 4.14 Region 5 (C-sand) Pressure of "No water injection" vs. Base Case

Below is total productions of "No water injection" scenario, you can also find a visual comparison of these productions with corresponding values in the base case, in Figure 4.15, Figure 4.16 and Figure 4.17 all at Dec. 1st , 2010.

- Field Total Oil Production:
  20,906,056 Sm3 ~ 131.5 MMbbl
  68.5 % of base case production

- Field Total Gas Production:
  5,720,444,416 Sm3 ~ 202 Bcf
  119.5 % of base case production

- Field Total Water Production:
  114,660 Sm3 ~ 0.72 MMbbl
  0.6 % of base case production

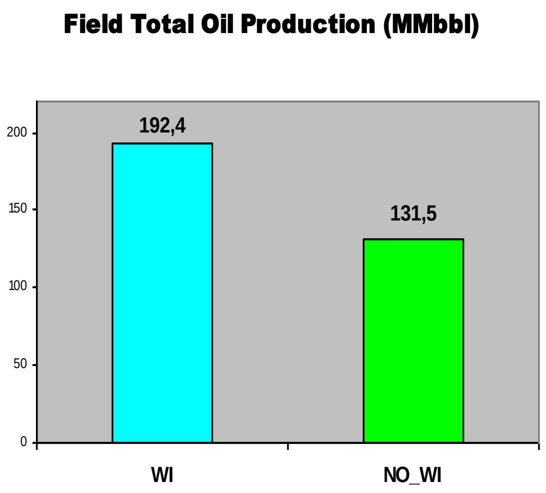


Figure 4.15 Field total oil production- “No water injection"

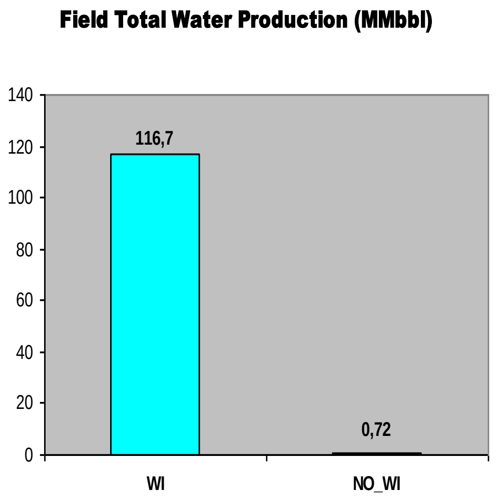


Figure 4.16 Field total water production- “No water injection"

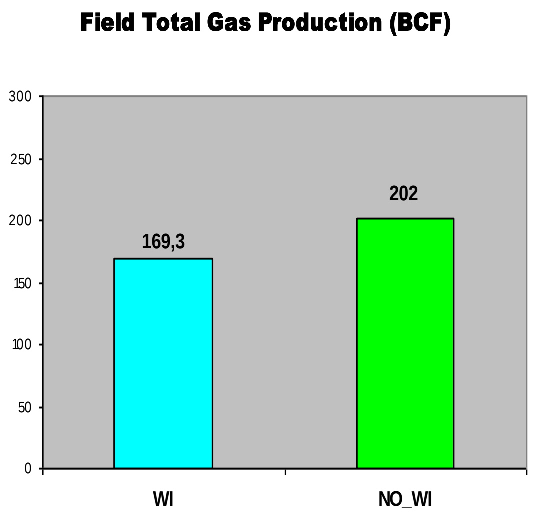


Figure 4.17 Field total gas production- “No water injection"

4.2.3 Scenario 3: No water injection – Gas Lift

This scenario is further modification of the previous scenario by implying gas lift as an artificial lift method. Full field gas lift has been set up with all producers being gas lifted (30 wells). Gas lift quantity is 2 MMscf / day approximately 56635 Sm3 / day.

In Figure 4.18 field oil production rate of "No water injection – Gas Lift" scenario (black line) versus the base case (green line) is showed. Similar to "No water injection" case, in the early phase we can see higher oil production rate in "No water injection – Gas Lift" scenario in comparison with the base case, but again because of rapid pressure depletion of the reservoir, the production rate from this scenario falls below the production rate seen in the base case.

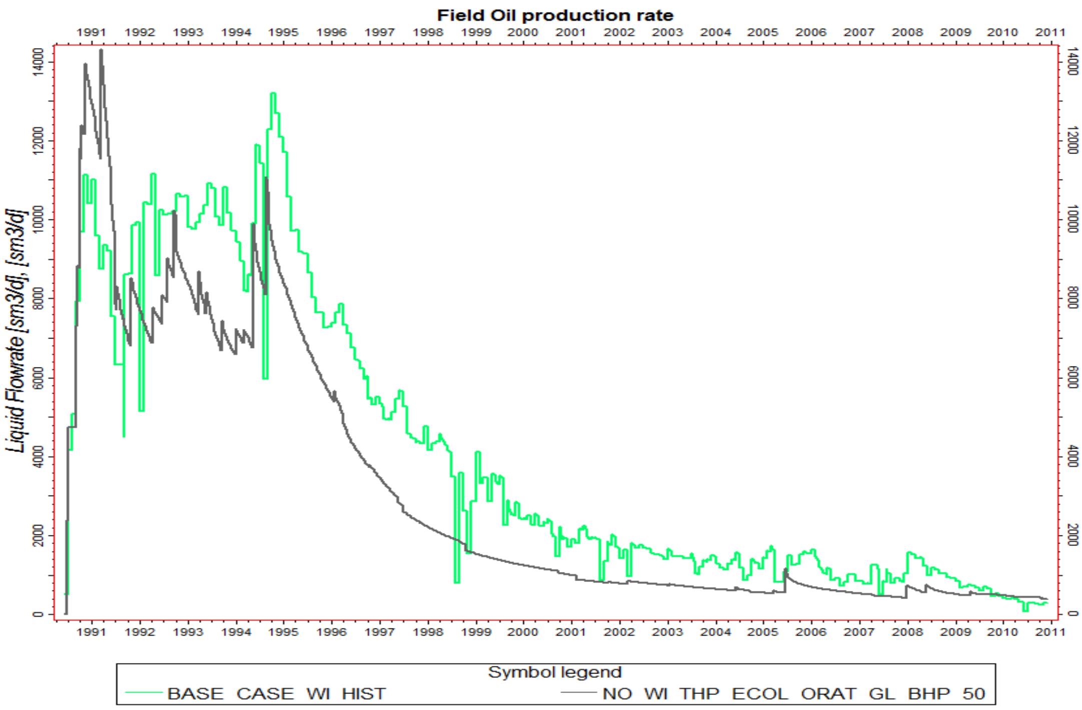


Figure 4.18 Field oil production rate of "No water injection-GL" vs. Base Case

Figure 4.19 illustrates field gas production rate of this scenario (dark blue line) versus the base case (green line). Higher gas production rate in "No water injection-GL" scenario in comparison with base case is clear. The reason is because of 1) Reservoir presser drops below bubble point pressure and free gas develops in the reservoir and 2) gas is injected into wells because gas lift is used as artificial method which itself increase gas production.

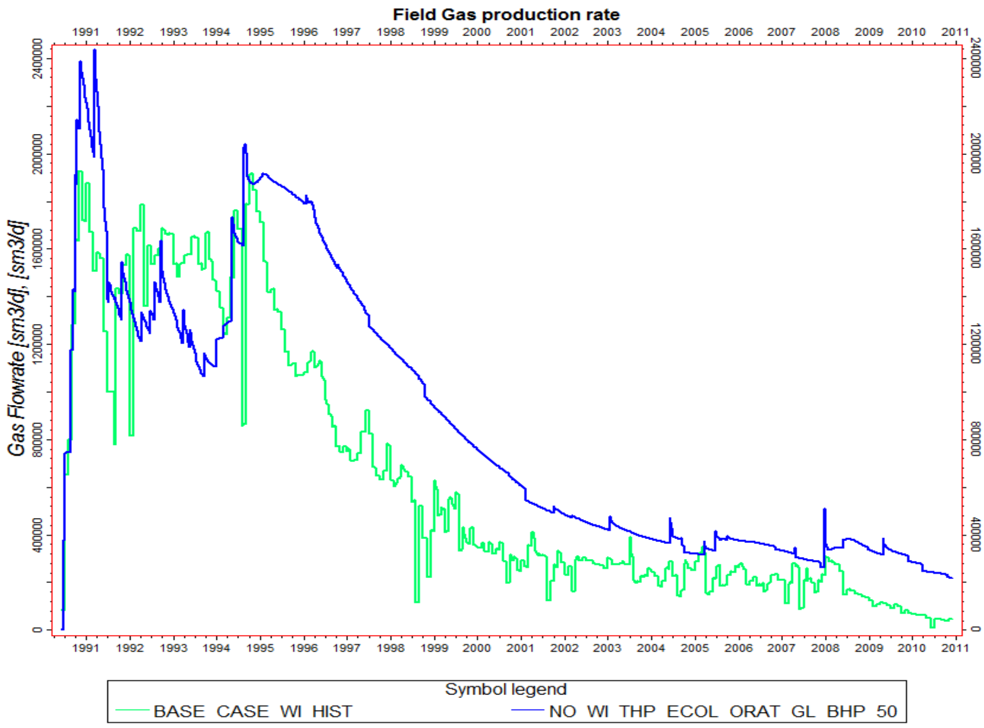


Figure 4.19 Field gas production rate of "No water injection-GL" vs. Base Case

Field gas oil ratio of "No water injection-GL" case (pink line) and the base case (green line) are presented in **Figure 4.20**. As the figure suggests, in the early phase, both scenarios more and less follow each other, after this phase, gas oil ratio in "No water injection-GL" increases to a much higher level than gas oil ratio of the base case.

Figure 4.21 shows field water cut of "No water injection-GL" case (yellow line) and the base case (green line) are presented in **Figure 4.20**. The interesting point to mention is that although water cut in this scenario is lower than water cut of the base case, however, it is much higher than water cut in previous scenario (No water injection). The reason could be due to the fact that when an artificial method is used, higher pressure drop imposed in the vicinity of wellbore; this can lead to higher water production, especially, in wells which are completed near to water oil contact.

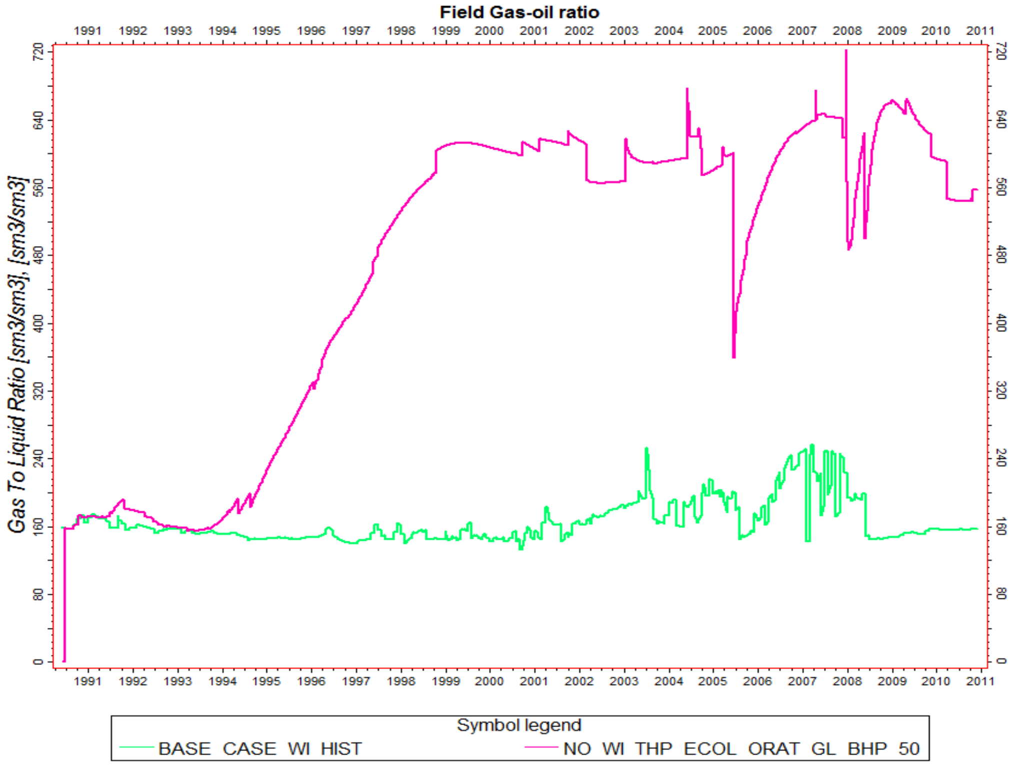


Figure 4.20 Field gas oil ratio of "No water injection-GL" vs. Base Case

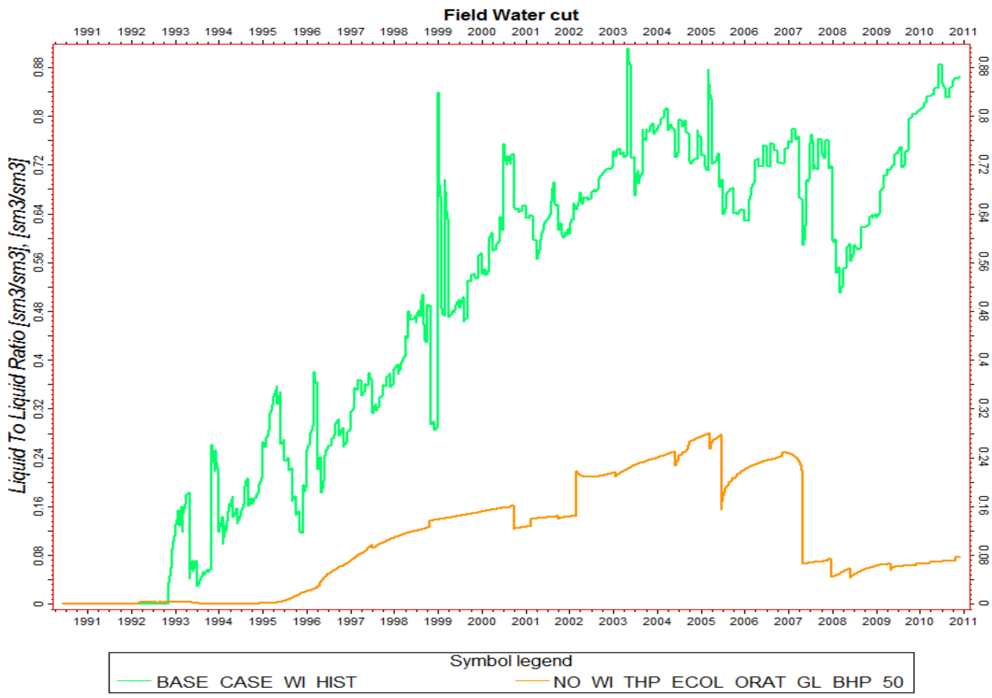


Figure 4.21 Field water cut of "No water injection-GL" vs. Base Case

Reservoir pressure of Downdip, Crest and C-sand regions of Gyda are depicted in Figure 4.22, Figure 4.23 and Figure 4.24 respectively, presenting both “No water injection-GL” scenario (dark blue line) and the base case (green line). The general trend as it was discussed previously, is sharp pressure decline in the early phase, and continues with a less steep until the end of simulation period.

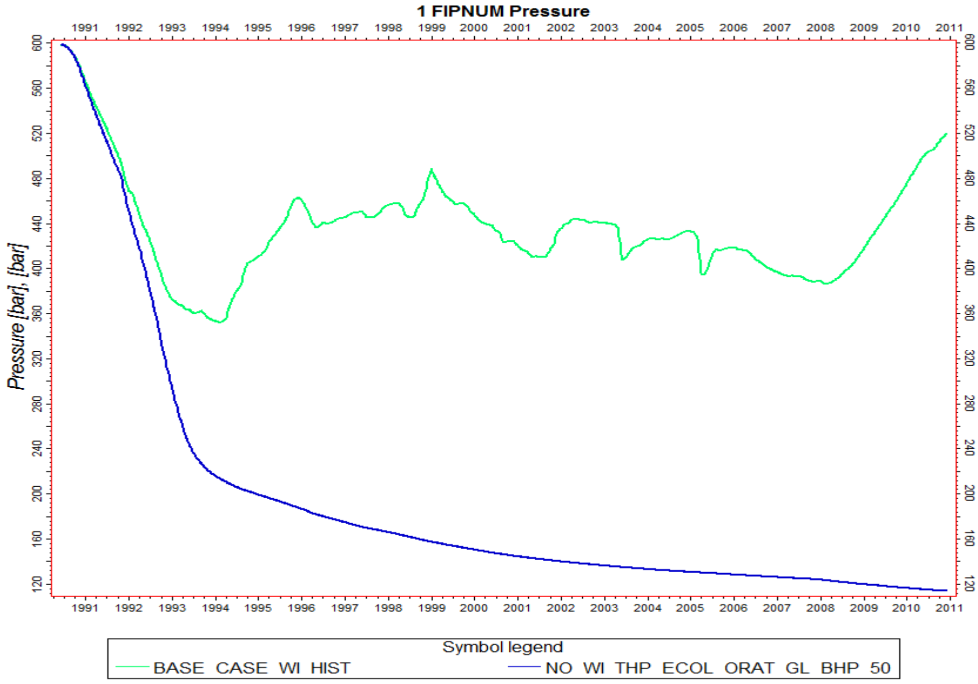


Figure 4.22 Region 1 (Downdip) Pressure of "No water injection-GL" vs. Base Case

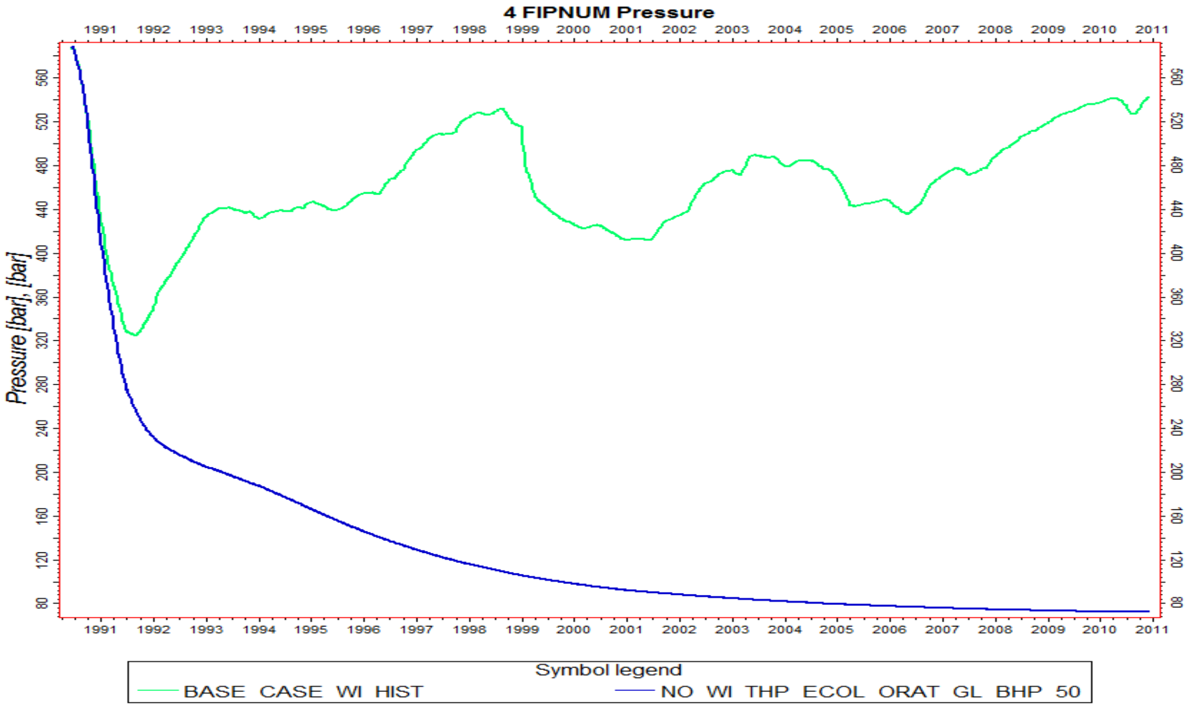


Figure 4.23 Region 4 (Crest) Pressure of "No water injection-GL" vs. Base Case

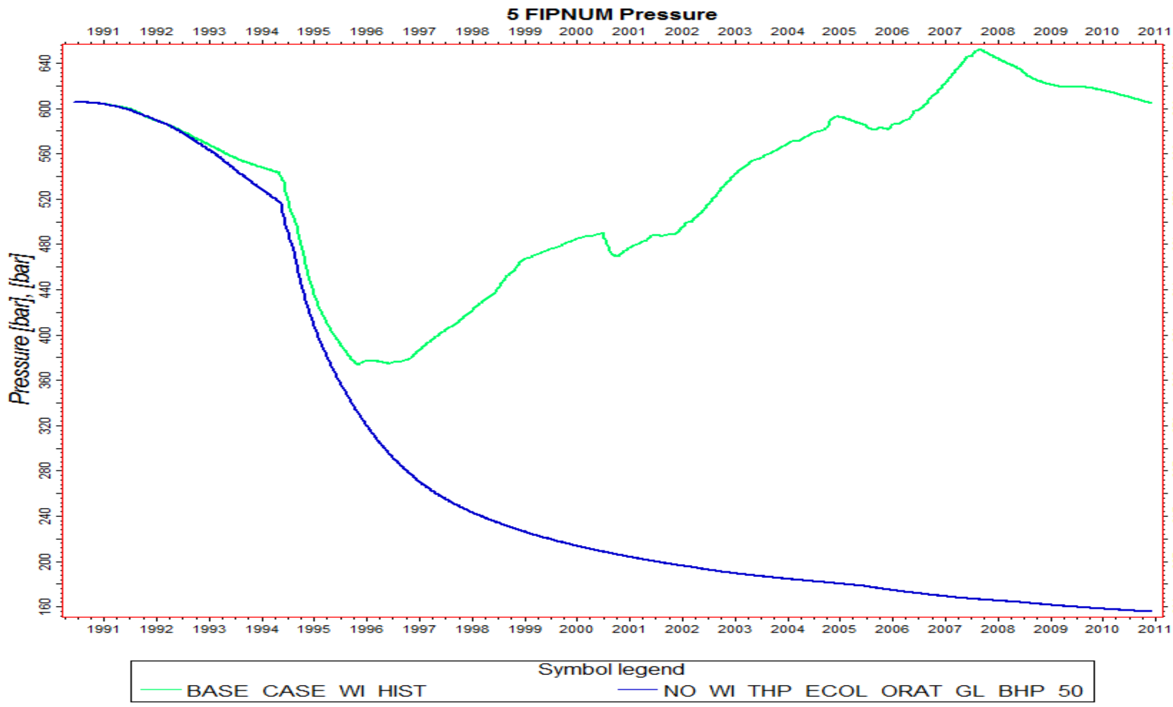


Figure 4.24 Region 5 (C-sand) Pressure of "No water injection-GL" vs. Base Case

Total oil, water and gas productions of "No water injection- GL" scenario, versus base case and “No water injection” case are presented in figure 4.25 - 4.27 (at Dec. 1st, 2010).

- Field Total Oil Production:
  23,113,824 Sm3 ~ 145.4 MMbbl
  75.7 % of base case production

- Field Total Gas Production:
  6,500,506,624 Sm3 ~ 229.5 Bcf
  135.8 % of base case production

- Field Total Water Production:
  945,194 Sm3 ~ 5.9 MMbbl
  5.1 % of base case production

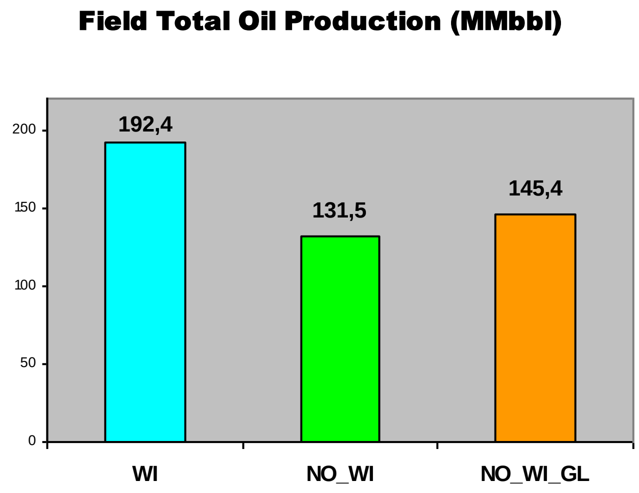


Figure 4.26 Field total oil production- “No water injection-GL"

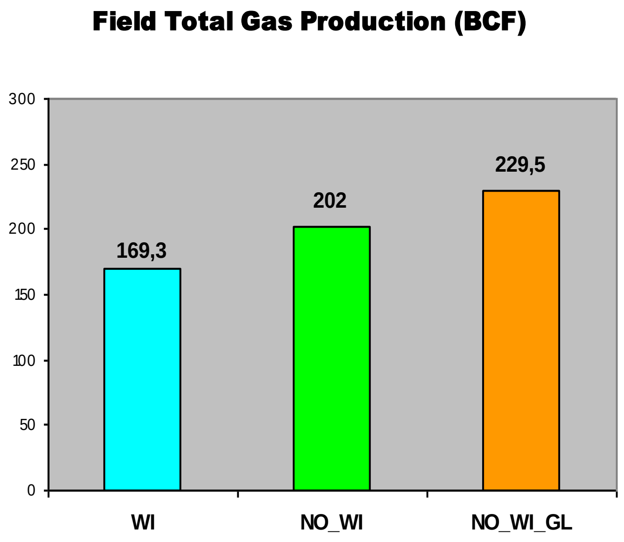


Figure 4.25 Field total gas production- "No water injection -GL"

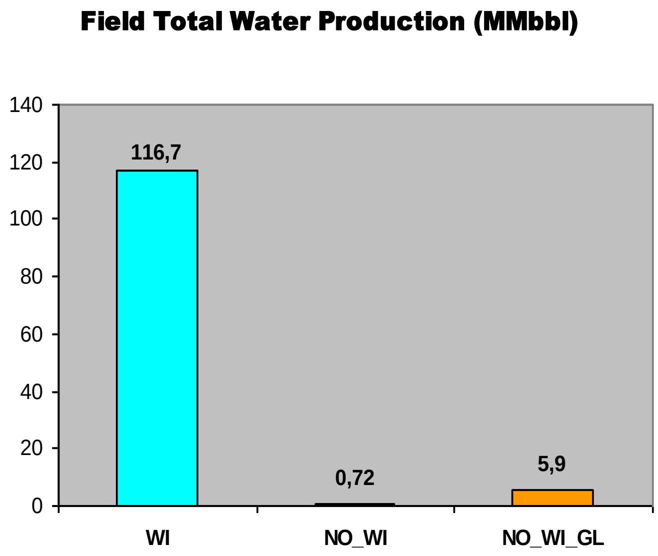


Figure 4.27 Field total water production- "No water injection -GL"

4.2.4 Scenario 4: No water injection – ESP & Gas Lift

In this scenario, both gas lift (Gas lift quantity is 2 MMscf / day approximately 56635 Sm3 / day) and ESP (Electric Submersible Pump) are used to improve production from Gyda reservoir which has no water injection. For simplicity, this scenario will be called “No water injection-ESP&GL” now on.

The below points have been considered for designing this scenario

- 10 ESP producers, and 20 gas lift producers
- Max well rate in ESP wells is set based on ESP Performance Curve
- ESP depth in all wells is considered **2500**m **TVD**
- Gas Separator Efficiency assumed to be **0**
- Each ESP has 84 stages
- ESP- VFP tables have been built in PROSPER

Also for selecting 10 wells to be lifted by ESP the following selection criteria have been used:

- Stable and good reservoir pressure support
- Longer time of BHP > P_b (bubble point pressure)
- High Productivity Index
- Lower Decline Rates

Figure 4.28 illustrates field oil production of “No water injection-ESP&GL” scenario (blue line) and oil production of the base case (green line). Again, in this figure it can be noticed that in “No water injection-ESP&GL” scenario, first few years oil production rate is higher than the base case, but it does not last long and in the late phase oil production if base case which has water flooding and pressure maintenance is higher than the case of no water injection.

Field gas production is depicted in **Figure 4.29**. The purple line is for “No water injection-ESP&GL” scenario and the green line for the base case.

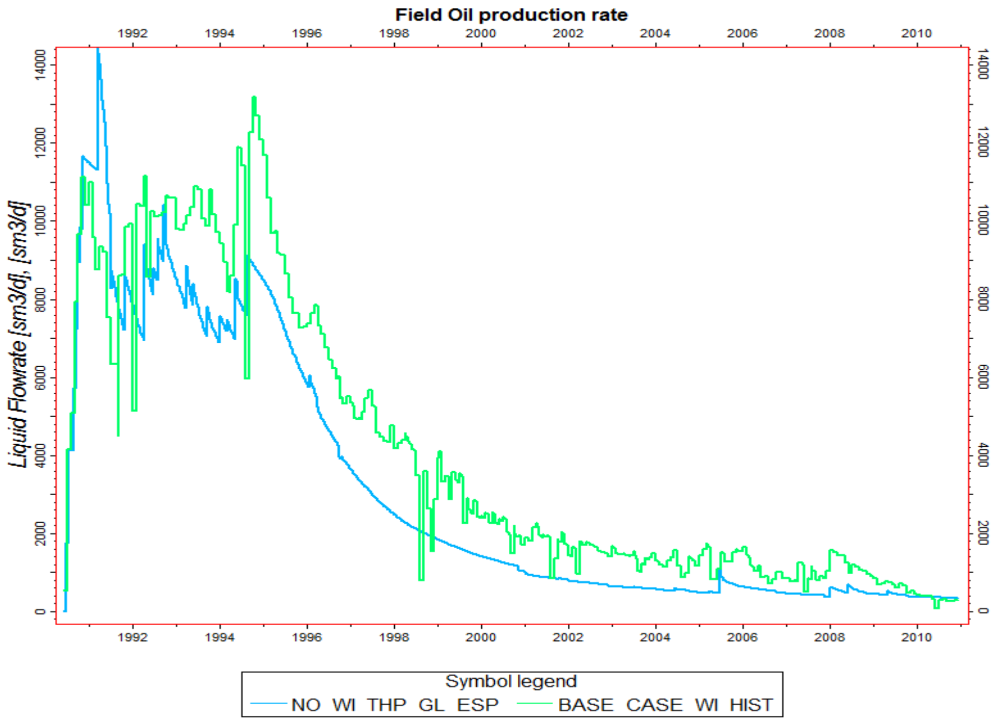


Figure 4.28 Field oil production rate of "No water injection-ESP &GL" vs. Base Case

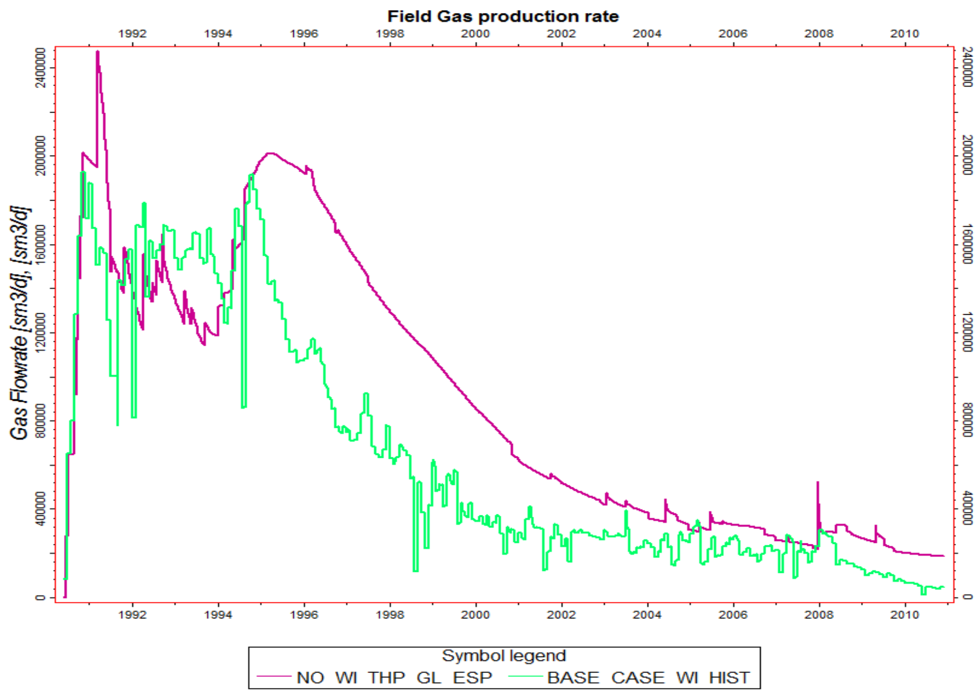


Figure 4.29 Field gas production rate of "No water injection-ESP &GL" vs. Base Case

Field gas oil ratio is outlined in Figure 4.30. From the figure we can see the effect of water injection and its importance. In water injection scenario (green line) much lower gas oil ratio develops till the end of simulation (except the early phase), however, in "No water injection-ESP &GL" (black line) similar to other scenarios without water injection very high gas to oil ratio develops throughout the reservoir life.

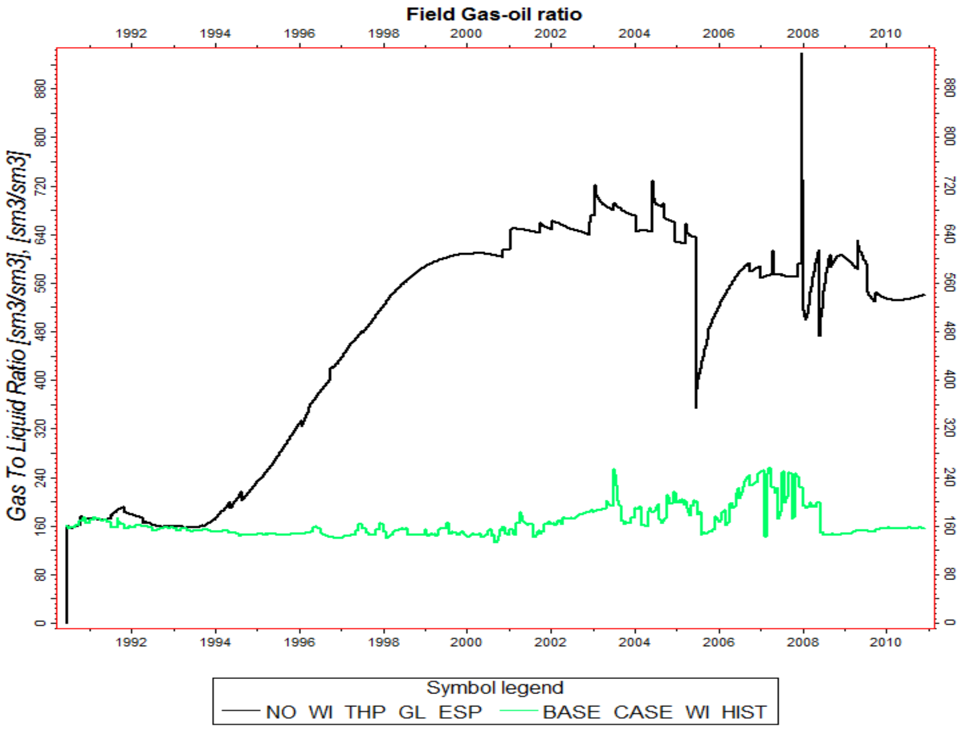


Figure 4.30 Field gas oil ratio of "No water injection-ESP &GL" vs. Base Case

In Figure 4.31 field water cut for "No water injection-ESP &GL" scenario (dark blue line) and for the base case (green line) are showed. As it was stated before, water cut in base case is much higher because of water breakthrough in production wells. However, in "No water injection-ESP &GL" case no water has been injected and, consequently, much lower water cut has been seen in the simulation result.

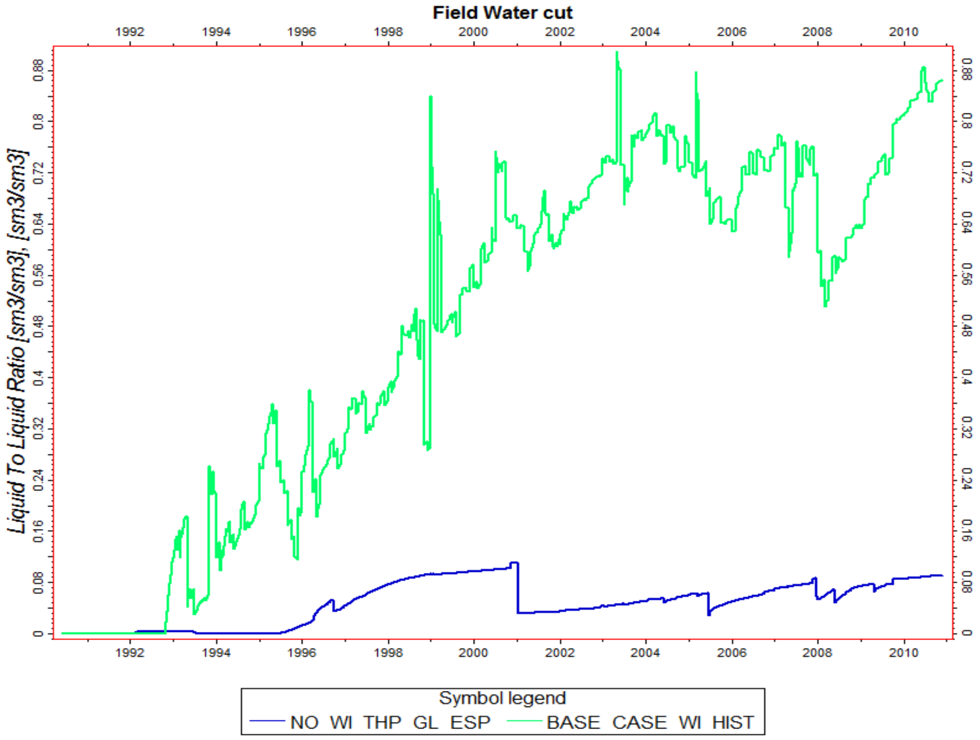


Figure 4.31 Field water cut of "No water injection-ESP &GL" vs. Base Case

Figures 4.32 -4.34 pressures of Downdip, Crest and C-sand regions have been presented. The green line is the corresponding pressure of the base case scenario. Due to lack of water injection and pressure maintenance in "No water injection-ESP &GL" scenario in all three regions reservoir pressure quickly declines and goes below bubble point pressure (approximately 200 bar). In Crest region, at the end of simulation period pressure is even less than 80 bar. In practice it is not applicable, however, in simulation because of using both ESP and gas lift we could decrease the pressure till even those low values.

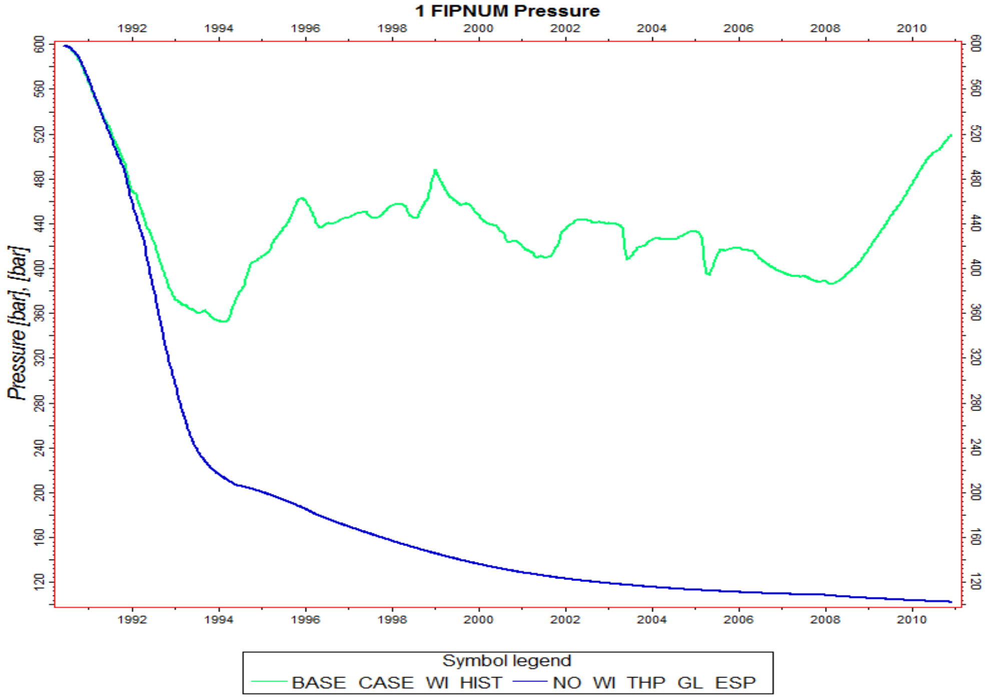


Figure 4.32 Region 1 (Downdip) Pressure of "No water injection-ESP & GL" vs. Base Case

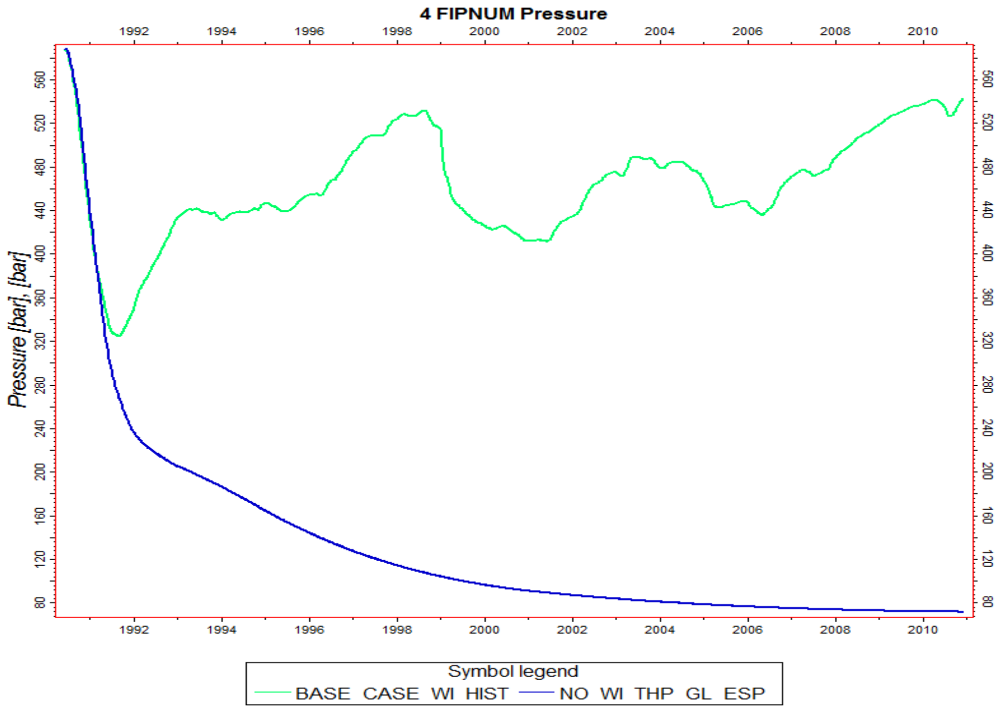


Figure 4.33 Region 4 (Crest) Pressure of "No water injection-ESP & GL" vs. Base Case

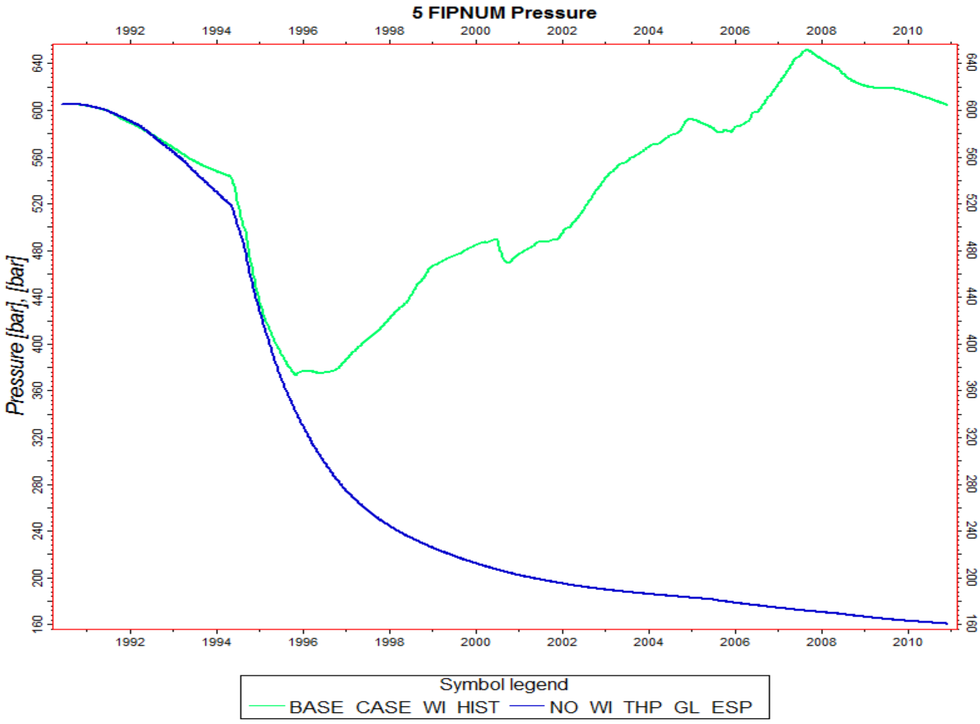


Figure 4.34 Region 5 (C-sand) Pressure of "No water injection-ESP & GL" vs. Base Case

Now let us look at some facts and figures related to this scenario (at Dec. 1st , 2010):

- Field Total Oil Production:
  23,358,836 Sm3 ~ 146.9 MMbbl
  76.5 % of base case production

- Field Total Gas Production:
  6,669,263,872 Sm3 ~ 235.5 Bcf
  139.3 % of base case production

- Field Total Water Production:
  452,291 Sm3 ~ 2.8 MMbbl
  2.4 % of base case production

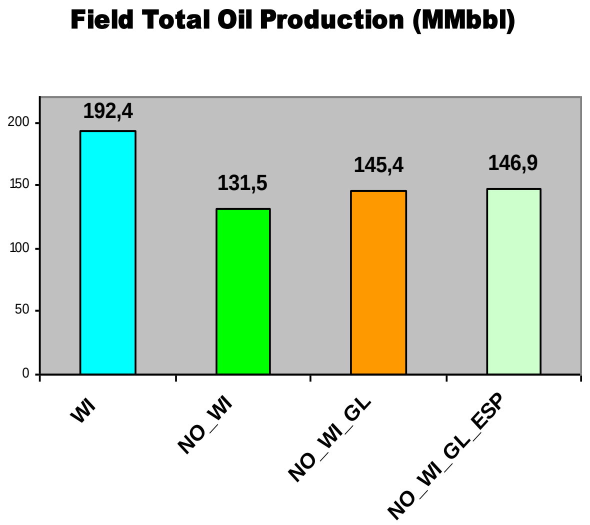


Figure 4.35 Field total oil production- "No water injection-ESP & GL"

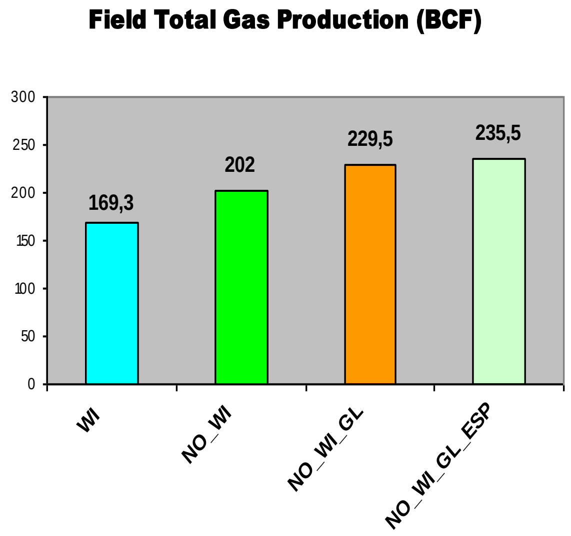


Figure 4.36 Field total gas production- “No water injection-ESP & GL"

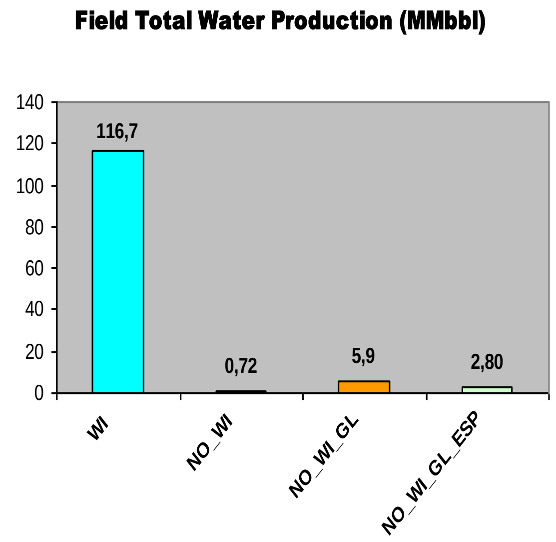


Figure 4.37 Field total water production- “No water injection-ESP & GL"

From Figure 4.35 can be seen that using ESP here does not have any significant effect and only increases oil production by 1.5 MMbbl from “No water injection-GL” scenario. The reason is maybe because ESP is mostly used for high water cut wells, however, in this scenario we do not have any injected water, and very low water cut wells which makes ESP not very applicable and useful as the results suggests.

4.2.5 Scenario 5: No water injection – Infill wells

In this scenario we further modify “No water injection” case with drilling new infill wells. It was decided to put 10 new infill wells in the model (instead of 10 water injectors of the real scenario).

Table 4.1 contains drilling start dates of all 10 new infill wells, as well as, their production start dates. It is considered that drilling of a well lasts an average of 60 days. The production start dates have been selected in a way that allows 60 days for drilling and time and do not have any conflict with history wells. Gantt chart of the new infill wells is indicated in figure 4.38.

Table 4.1 New infill wells- Drilling and Start of production date

Well name	*Drilling start date*	*Drilling duration (days)*	*Start of production*
Well 1	02/11/1991	60	01/01/1992
Well 2	21/05/1993	60	20/07/1993
Well 3	02/09/1994	60	01/11/1994
Well 4	02/04/1996	60	01/06/1996
Well 5	02/10/1997	60	01/12/1997
Well 6	02/04/1999	60	01/06/1999
Well 7	02/10/2000	60	01/12/2000
Well 8	02/04/2002	60	01/06/2002
Well 9	02/10/2003	60	01/12/2003
Well 10	02/11/2004	60	01/01/2005

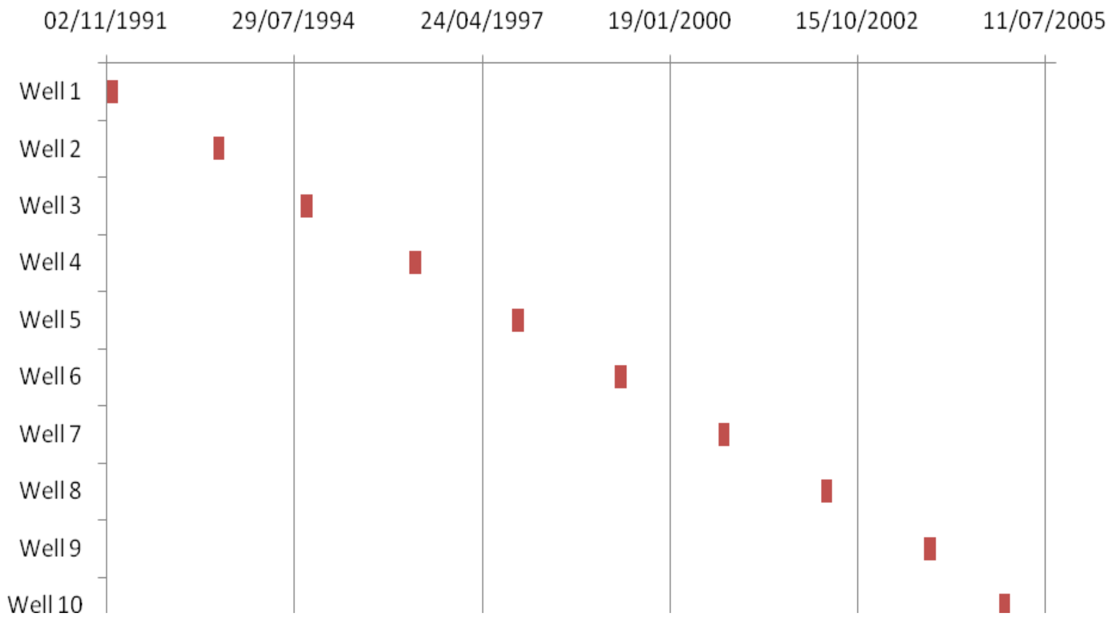


Figure 4.38 Gantt chart of new infill wells

From 10 new infill wells, 7 are drilled in Crest region and 3 in Downdip. Below are the well placement criteria which have been used for drilling these wells:

- High Oil Saturation (Soil > 0.4) @ 1st, Dec. 2010
- High Reservoir Pressure @ 1st, Dec. 2010
- High Porosity & Permeability

- High Net to Gross Ratio (NTG)
- High Transmissibility (I, J, K)

Location of these new infill wells are showed in figure 4.39. The yellow area is Crest region and the blue area is Downdip region.

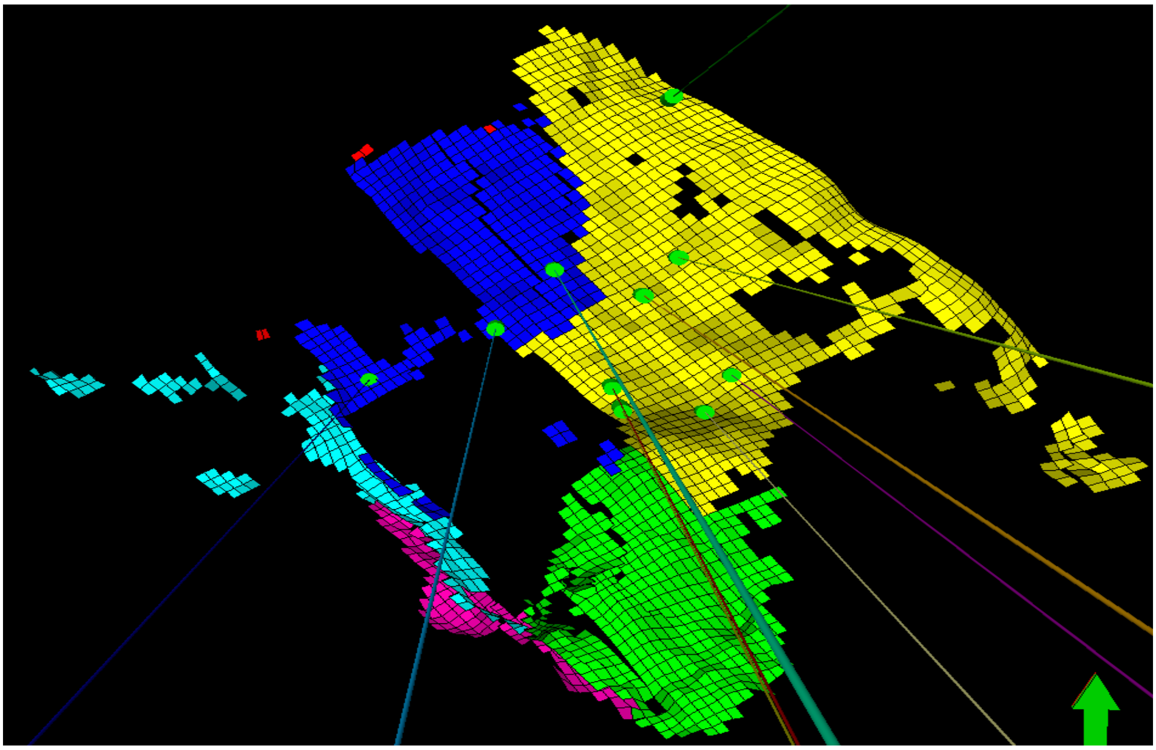


Figure 4.39 New infill wells location (yellow: Crest, blue: Downdip)

Figure 4.40 shows field oil production rate of "No water injection – Infill wells" scenario (black), along with production rate of the base case (green line). Higher production of the early phase in "No water injection – Infill wells" is because of production from wells A03H and A05H. We can also see that well 1 which came on stream 1st Jan. 1992 improves the early field oil production to some extent. However, even these 10 wells cannot improve the production rate as such.

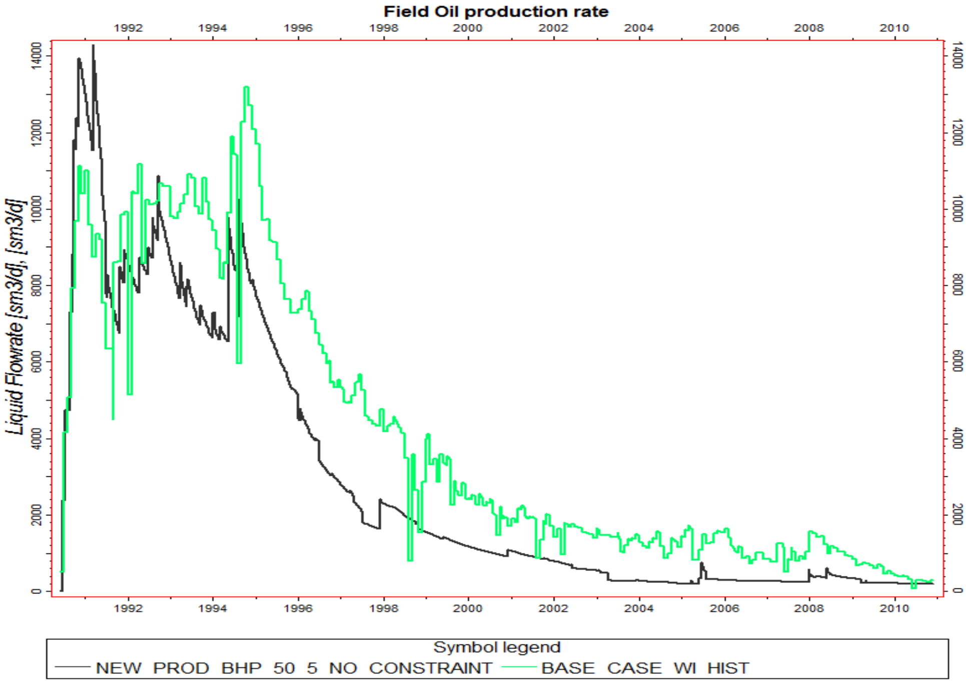


Figure 4.40 Field oil production rate of "No water injection-Infill wells" vs. Base case

Field gas production rate of “No water injection – Infill wells” scenario (purple line) versus the base case (green line) is illustrated in figure 4.41. The figure exhibits the same trend of gas productions of previous scenario; high early phase gas production, presumably because of high early phase oil production, a short period of reduction in gas production which can be because of reduction in oil production. At last, high gas production rate, because of reservoir pressure went below bubble point pressure.

Figure 4.42 shows field gas oil ratio of “No water injection – Infill wells” scenario (blue line) and the base case (green line). In this scenario like previous scenarios higher field gas oil ratio can be clearly seen, it is because of the fact that in this scenario and all other scenarios which do not have water flooding, early reservoir pressure drop below bubble point causes this high gas oil ratio.

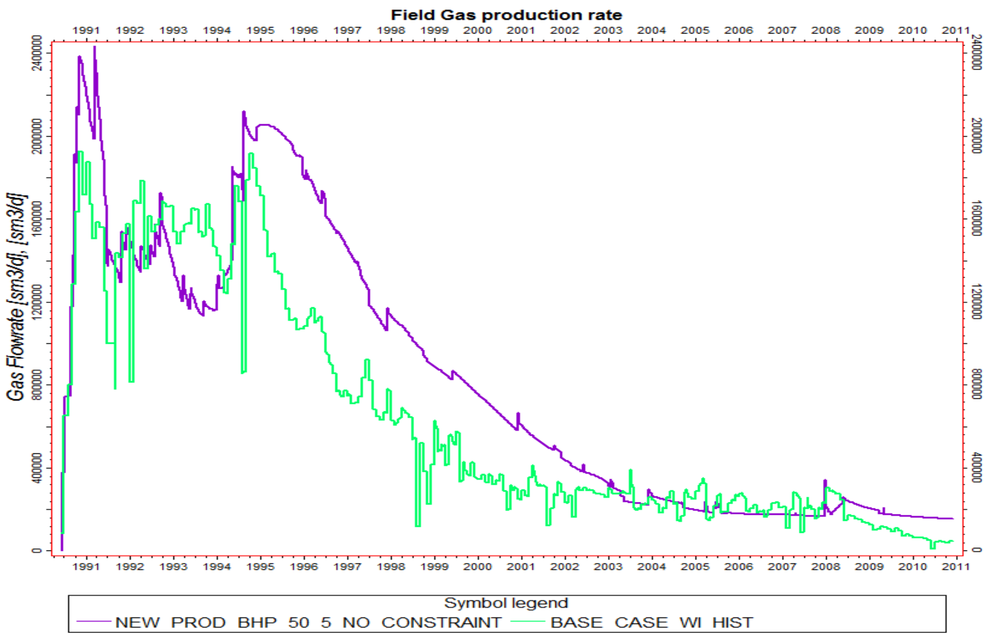


Figure 4.41 Field gas production rate of "No water injection-Infill wells" vs. Base case

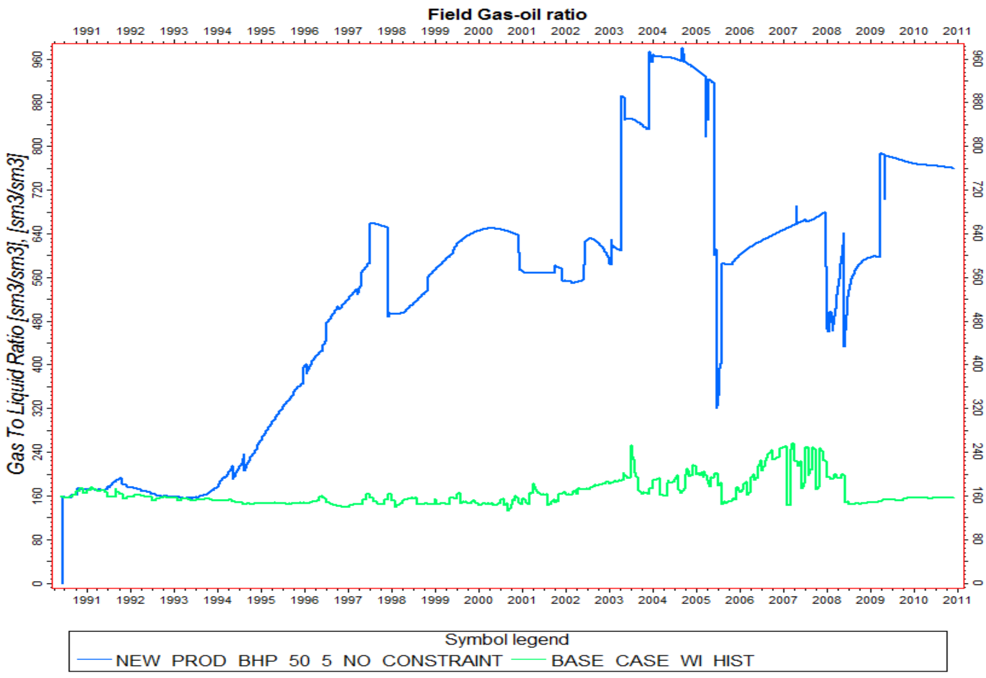


Figure 4.42 Field gas oil ratio of "No water injection-Infill wells" vs. Base case

Field water cut is depicted in figure 4.43. The figure suggest very low water cut in case “No water injection – Infill wells” and very high water cuts in the base case, the reason is the same as it was previously discussed .

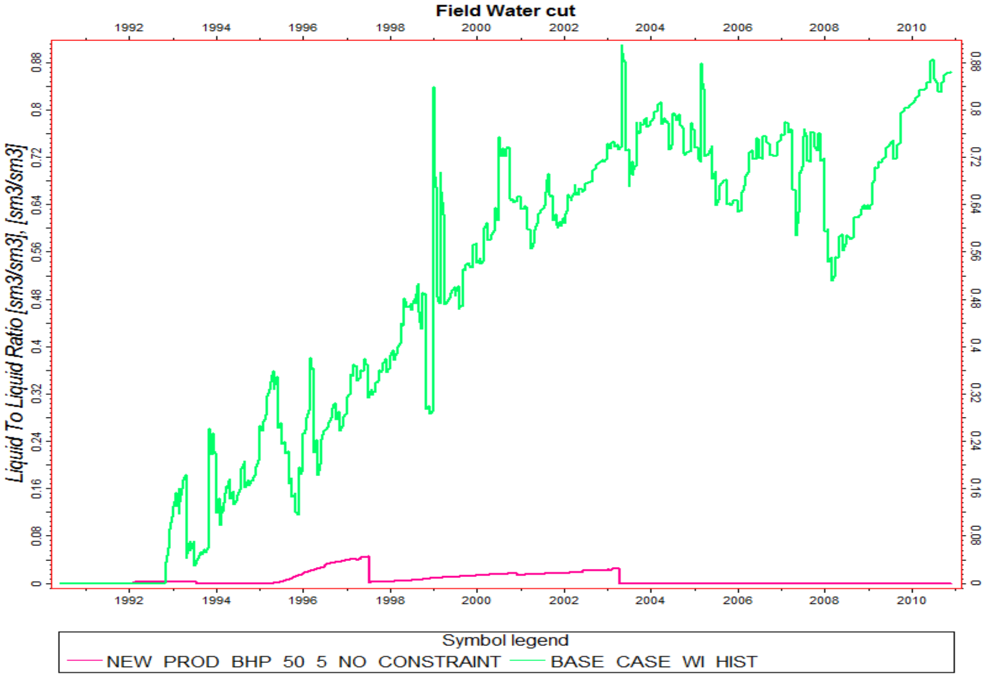


Figure 4.43 Field water cut of "No water injection-Infill wells" vs. Base case

Figures 4.44 - 4.46 illustrate reservoir pressure of “No water injection – Infill wells” (black line), as well as, reservoir pressure of the base case (green line) for the three regions (Downdip, Crest and C-sand). In this scenario the reservoir pressure is decreases even more, since, we have 10 more producers, which impose higher pressure drop.

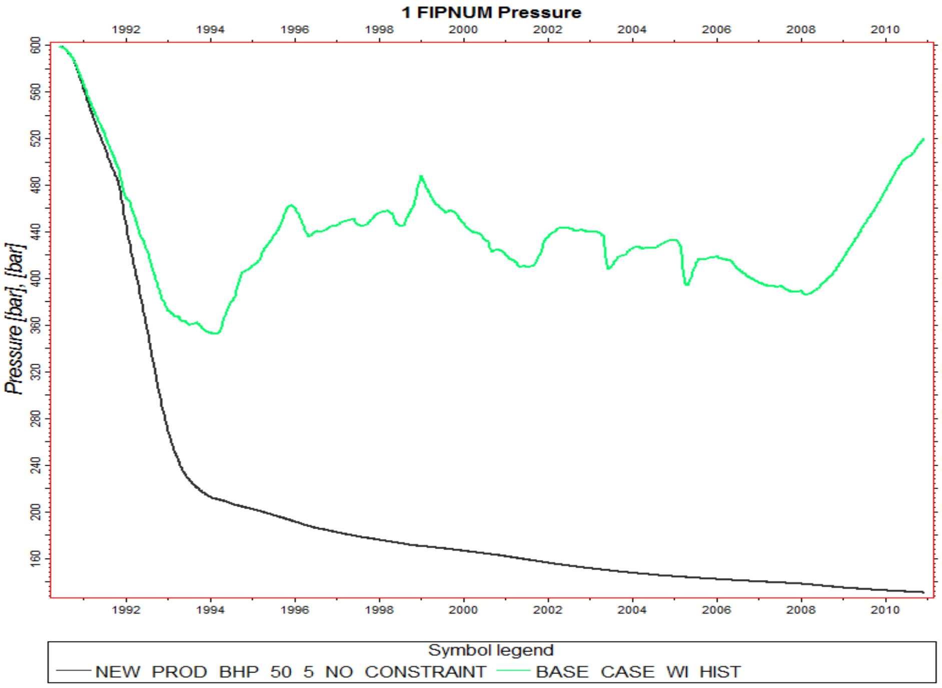


Figure 4.44 Region 1 (Downdip) Pressure of "No water injection- Infill wells" vs. Base Case

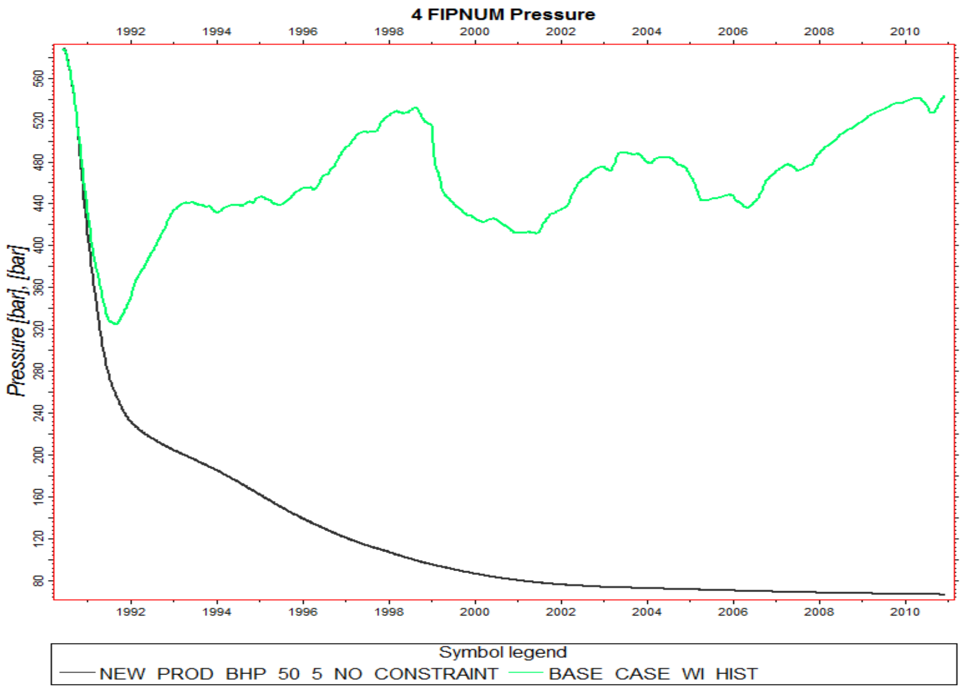


Figure 4.45 Region 4 (Crest) Pressure of "No water injection- Infill wells" vs. Base Case

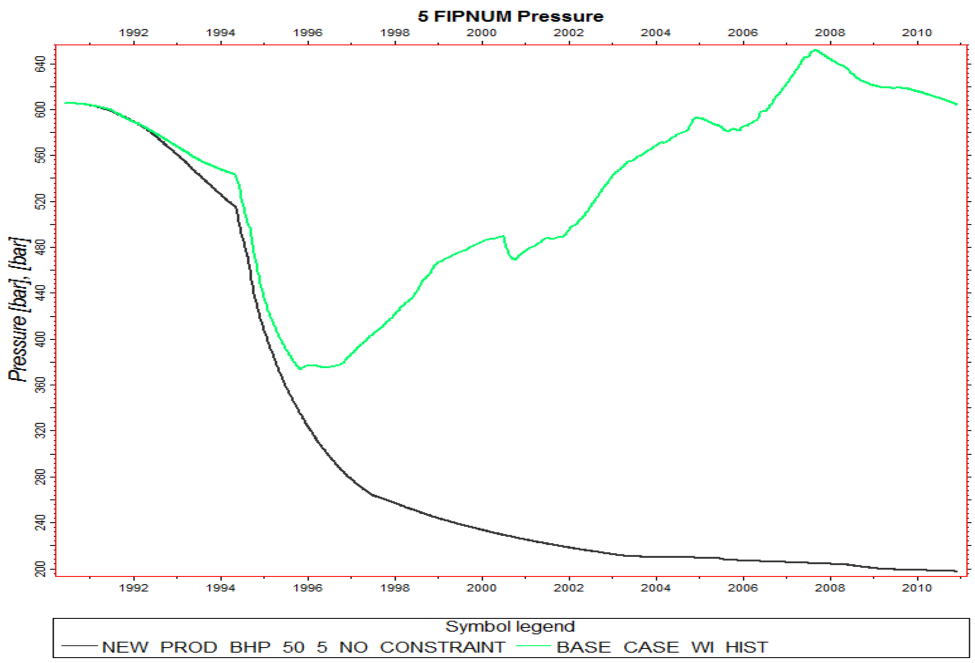


Figure 4.46 Region 5 (C-sand) Pressure of "No water injection- Infill wells" vs. Base Case

At this point it is necessary to look at the total productions to see how much these 10 infill wells were able to help the field's production (at Dec. 1st , 2010):

- Field Total Oil Production:
  21,734,482 Sm3 ~ 136.7 MMbbl
  71% of base case production

- Field Total Gas Production:
  6,146,389,504 Sm3 ~ 217 Bcf
  128.2 % of base case production

- Field Total Water Production:
  109,253 Sm3 ~ 0.68 MMbbl
  0.58 % of base case production

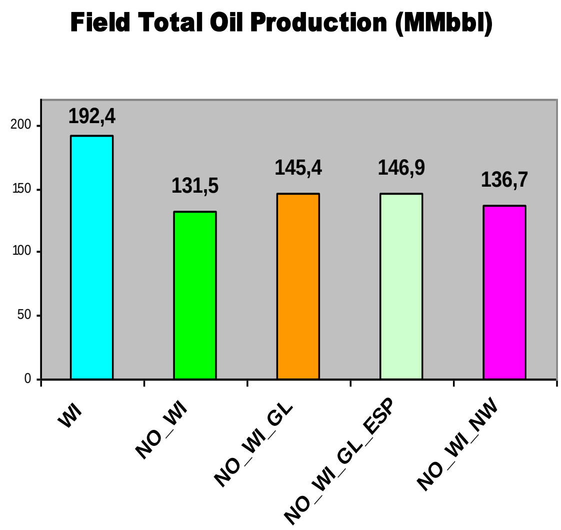


Figure 4.47 Field total oil production- "No water injection- Infill wells"

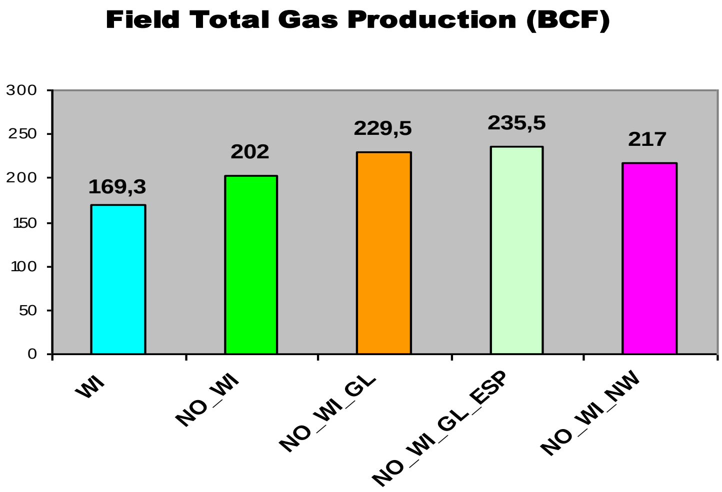


Figure 4.48 Field total gas production- “No water injection- Infill wells"

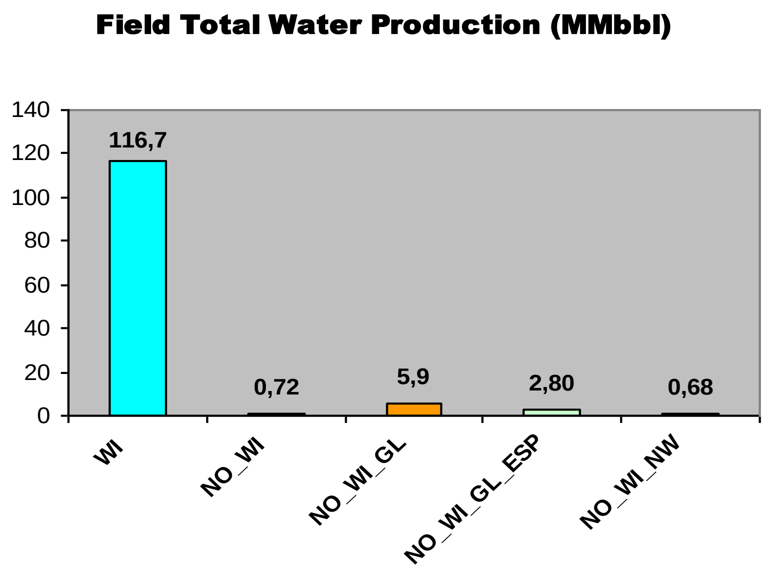


Figure 4.49 Field total water production- “No water injection- Infill wells"

Figure 4.47 shows 5.2 MMbbl increase in “No water injection” scenario because of the ten new infill wells. Although, it is not a significant increase but it represents that the new infill wells are participating in the production and they have increased the total field oil production. From graph 4.48 we can also see 15 BCF higher total gas production of this scenario due to the new infill wells.

4.2.6 Scenario 6: No water injection – Infill wells & Gas Lift

In this scenario "No water injection – Infill wells" case is modified with setting up a full field gas lift strategy i.e. having gas lift in all 40 wells (30 history wells and 10 new infill wells). Now on for simplicity we call this scenario "No water injection-NW & GL". Gas lift quantity is 2 MMscf / day approximately 56635 Sm3 / day.

Figure 4.50 illustrates file oil production rate of "No water injection-NW & GL" scenario (red line) versus the base case scenario (green line). It can be seen the simultaneous use of gas lift and new infill wells increase the oil production rate from the field, however, still the water injection case produces much better than this scenario.

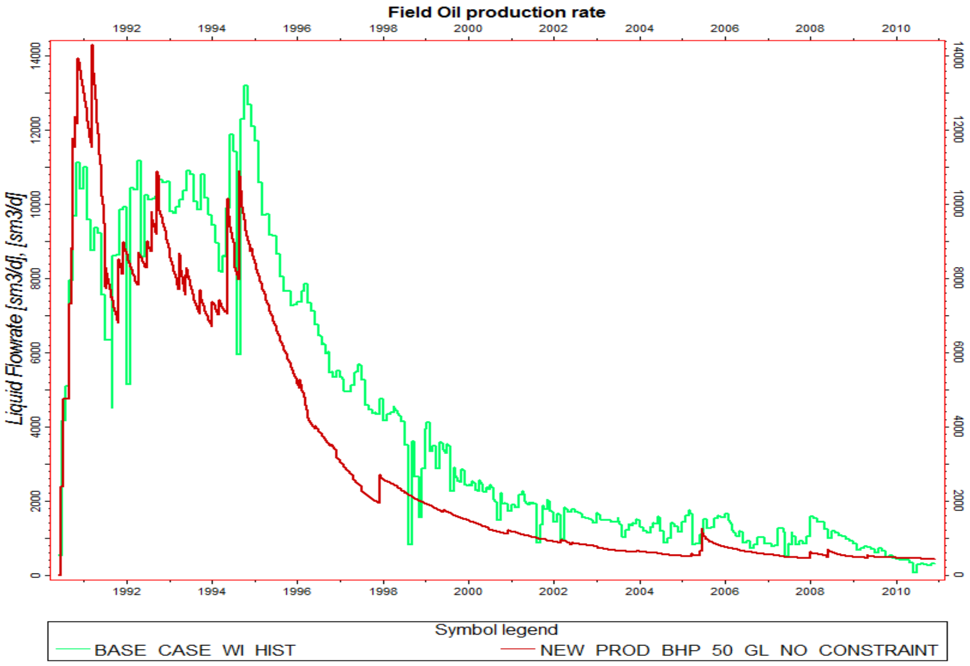


Figure 4.50 Field oil production rate of "No water injection-NW & GL" vs Base case

Field gas production rate of "No water injection-NW & GL" scenario (purple line) and the base case (green line) are shown is figure 4.51. It has similar trend as the previous no water injection scenario.

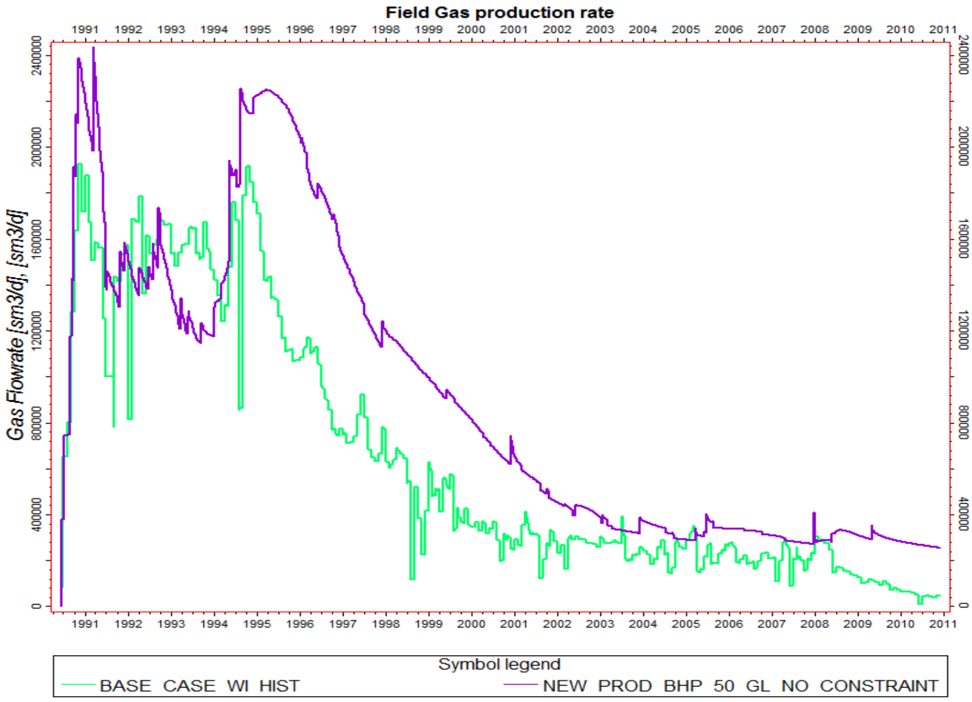


Figure 4.51 Field gas production rate of "No water injection-NW & GL" vs Base case

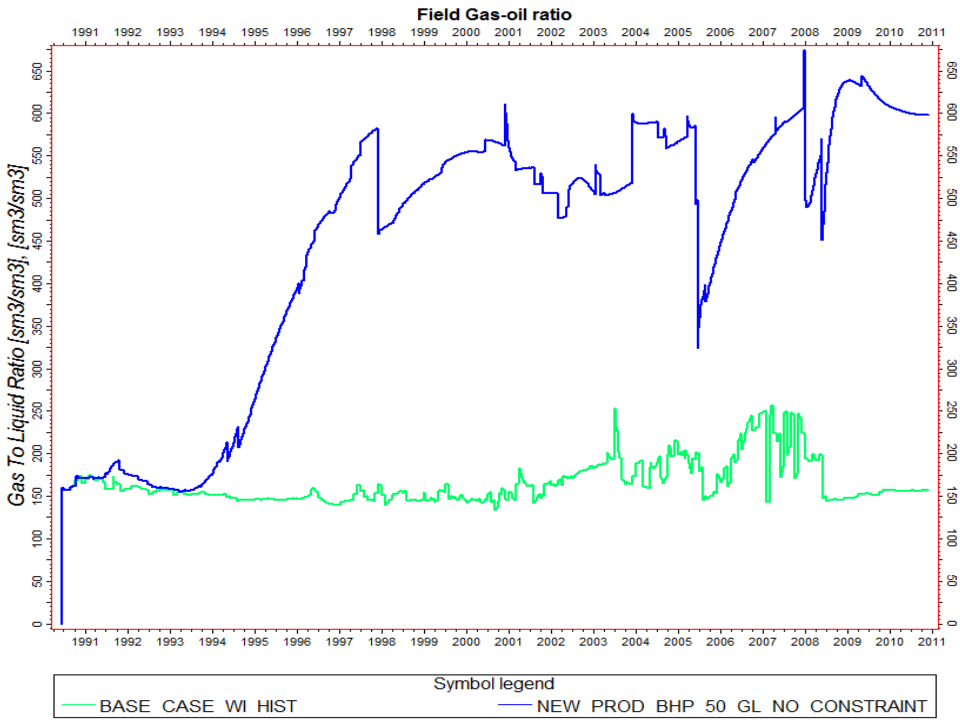


Figure 4.52 Field gas oil ratio of "No water injection-NW & GL" vs Base case

Field gas oil ratio of "No water injection-NW & GL" scenario (dark blue line) and the base case (green line) are shown is figure 4.52. Higher field gas oil ratio of "No water injection-NW & GL" case in comparison with the water injection case (real scenario) is totally visible. It shows the effectiveness of the real scenario.

Figure 4.53 depicts field water cut of "No water injection-NW & GL" case (purple line) along with water cut of the base scenario (green line). From the figure it can be seen that when gas lift is being used, it leads to higher water cuts. As it was stated in section 4.2.3 a possible answer could be because while gas lift is utilized, pressure drop in the wellbore region is higher which may cause higher water production, especially, in wells which are completed near to water oil contact.

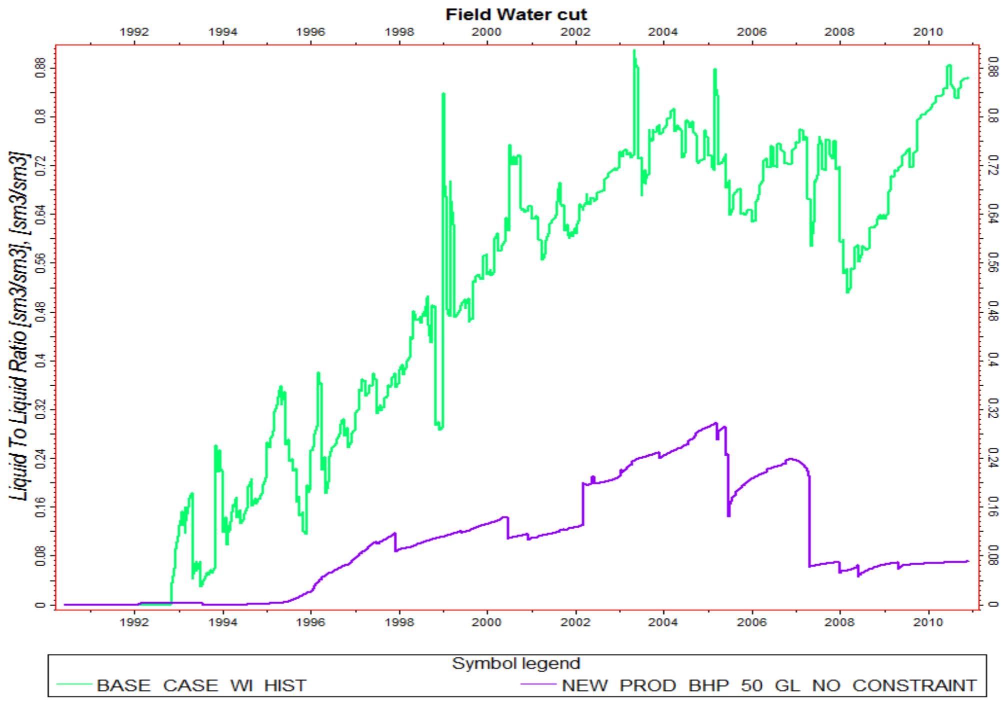


Figure 4.53 Field water cut of "No water injection-NW & GL" vs Base case

Downdip, Crest and C-sand regions pressures are showed in figures 4.54, 4.55 and 4.56 respectively. As previously mentioned, in practice one may not decrease the reservoir pressure as low as 80 bar (figure 4.55), however, in this case simulator was able to go down that far since we have gas lift.

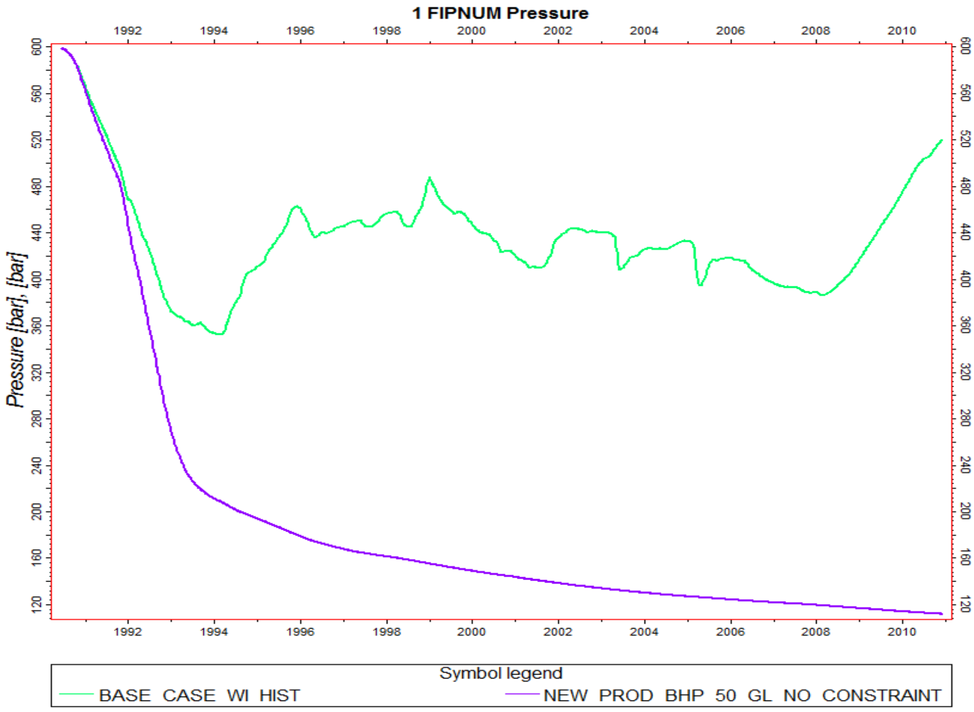


Figure 4.54 Region 1 (Downdip) Pressure of "No water injection- NW & GL" vs. Base Case

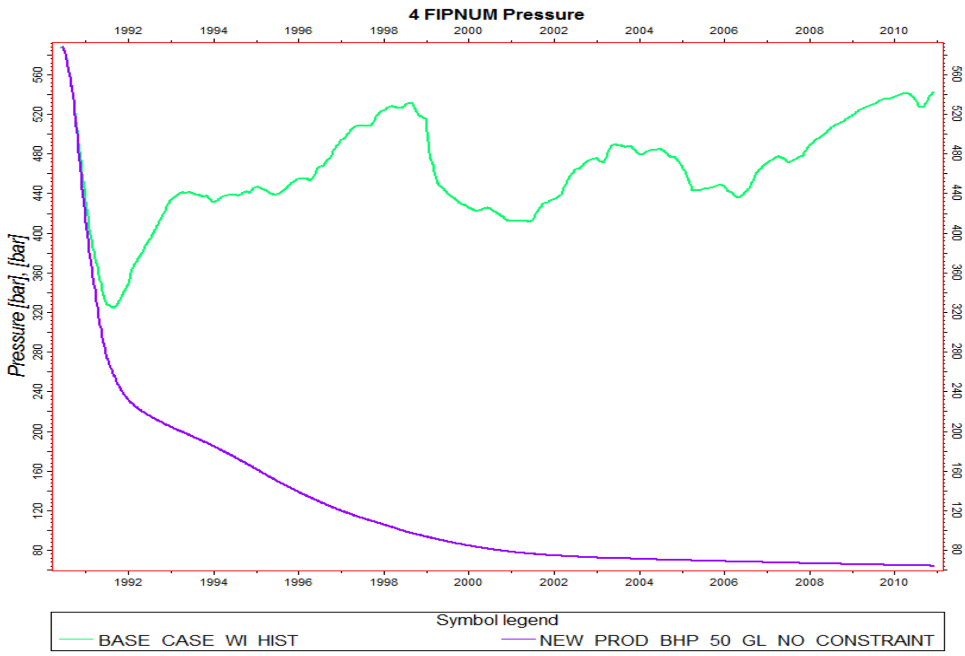


Figure 4.55 Region 4 (Crest) Pressure of "No water injection- NW & GL" vs. Base Case

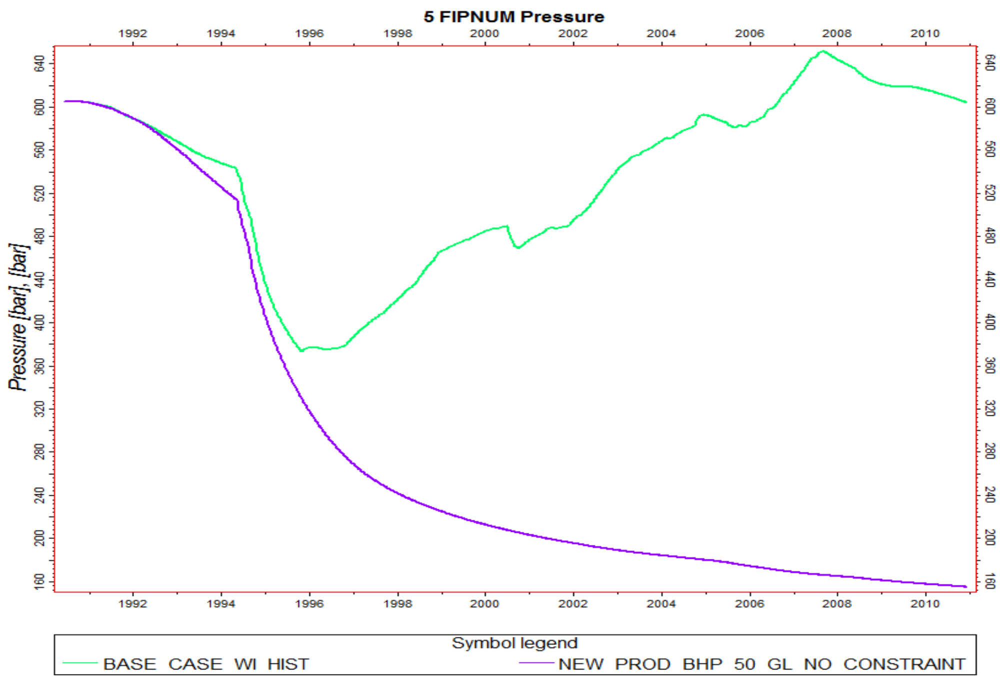


Figure 4.56 Region 5 (C-sand) Pressure of "No water injection- NW & GL" vs. Base Case

To further investigate this scenario, we look through field total productions at the end of simulation period (at Dec. 1st , 2010):

- Field Total Oil Production:
  23,575,960 Sm3 ~ 148.3 MMbbl
  77.1 % of base case production

- Field Total Gas Production:
  6,769,709,568 Sm3 ~ 239.1 Bcf
  141.2 % of base case production

- Field Total Water Production:
  927,342 Sm3 ~ 5.8 MMbbl
  5 % of base case production

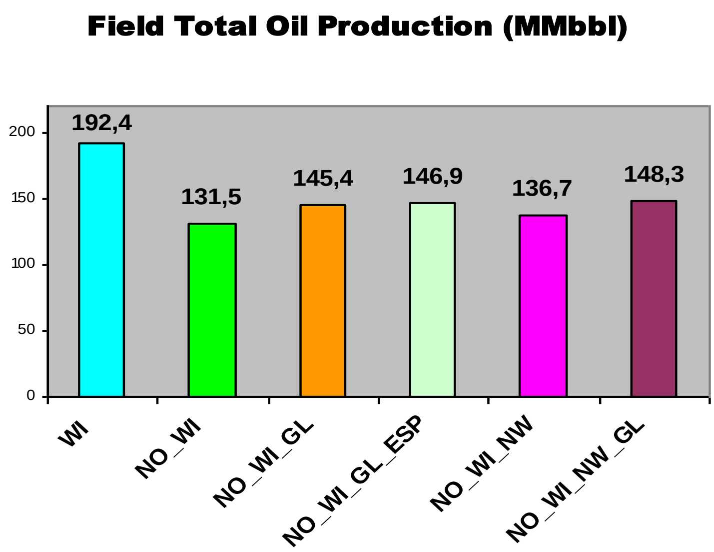


Figure 4.57 Field total oil production- “No water injection- NW & GL"

Field total oil production of “No water injection- NW & GL" scenario, as well as, the previously studied scenarios is depicted in figure 4.57. It can be clearly seen that using gas lift increases the total oil production by 11.6 MMbbl which shows a successful use of artificial lift in this case.

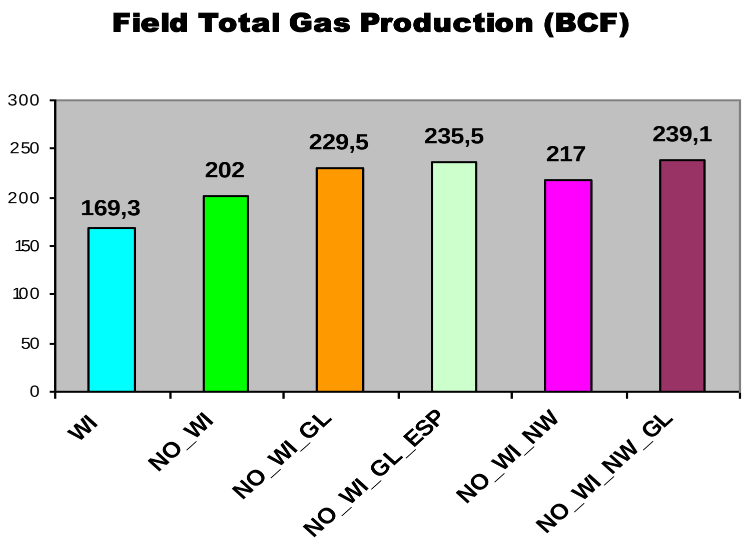


Figure 4.58 Field total gas production- “No water injection- NW & GL"

Figure 4.58 shows total gas production of the Gyda field under “No water injection- NW & GL" scenario. Other scenarios also are put in the figure to give a better comparison between alternative scenarios. Gas lift gives 22.1 BCF extra gas production in this scenario comparing “No water injection-Infill wells” case.

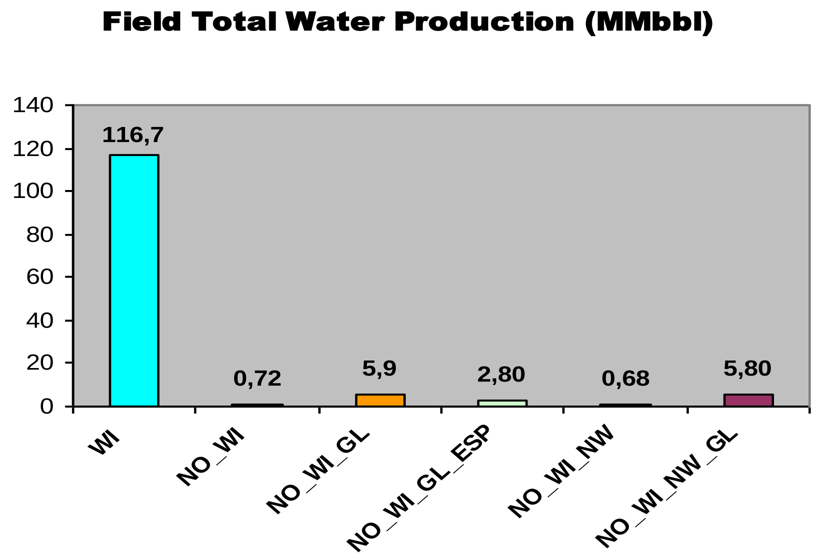


Figure 4.59 Field total water production- “No water injection- NW & GL"

Field total water production is illustrated in figure 4.59. All scenarios without water injection have very small total water production in comparison with the real scenario in which water flooding has been implemented.

4.2.7 Scenario 7: No water injection – Infill wells, Gas Lift & ESP

This scenario is the final modified version of “No water injection “scenario. In this case, we have altogether 40 producers (30 history wells and 10 new infill wells), 30 wells under gas lift and 10 wells have ESP. Similar to the previous cases Gas lift quantity is 2 MMscf / day approximately 56635 Sm3 / day. It is customary to call this scenario “No water injection-NW, GL & ESP”

Figure 4.60 and 4.61 show field oil and gas production rates of this scenario respectively.

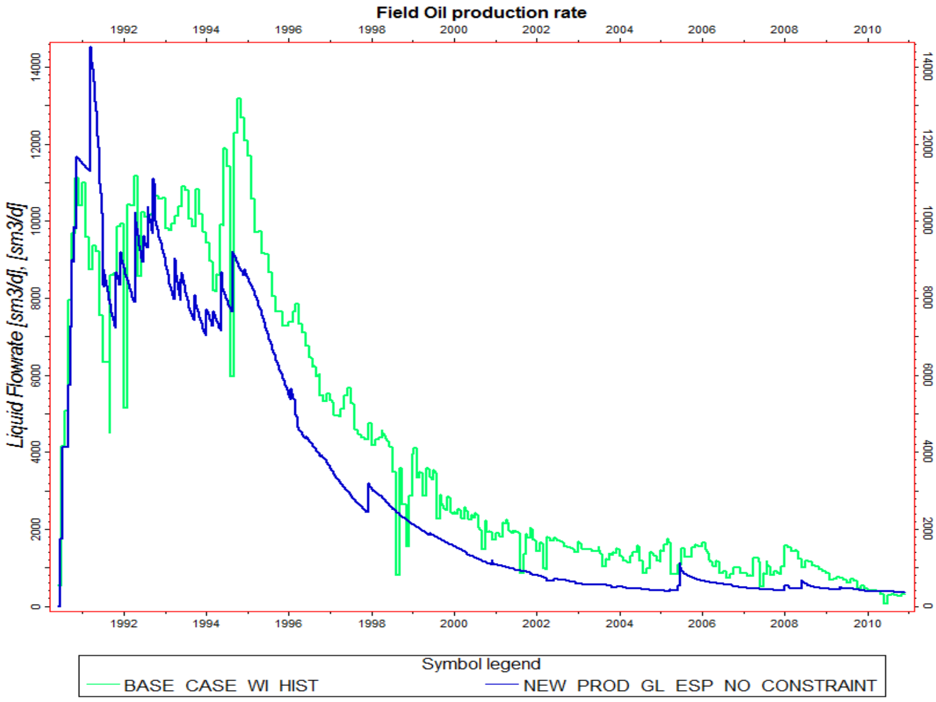


Figure 4.60 Field oil production of “No water injection- NW, GL & ESP” vs. Base Case

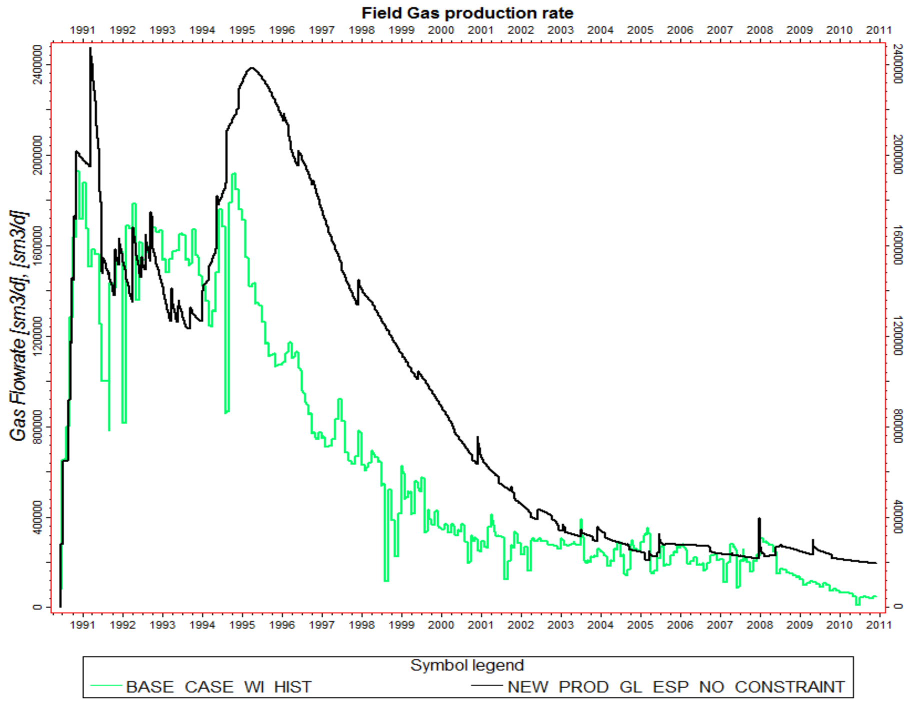


Figure 4.61 Field gas production of “No water injection- NW, GL & ESP” vs. Base Case

Gas oil ratio of "No water injection- NW, GL & ESP" scenario (purple line) versus the base case scenario (green line) is depicted in figure 4.62. Water cut is also showed in figure 4.63.

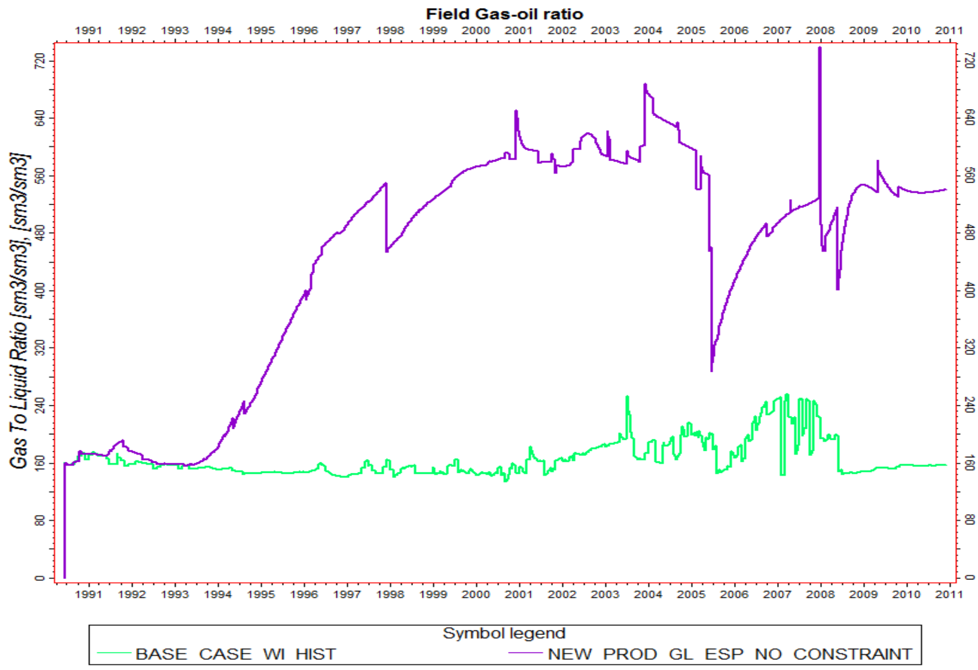


Figure 4.62 Field gas oil ratio of "No water injection- NW, GL & ESP" vs. Base Case

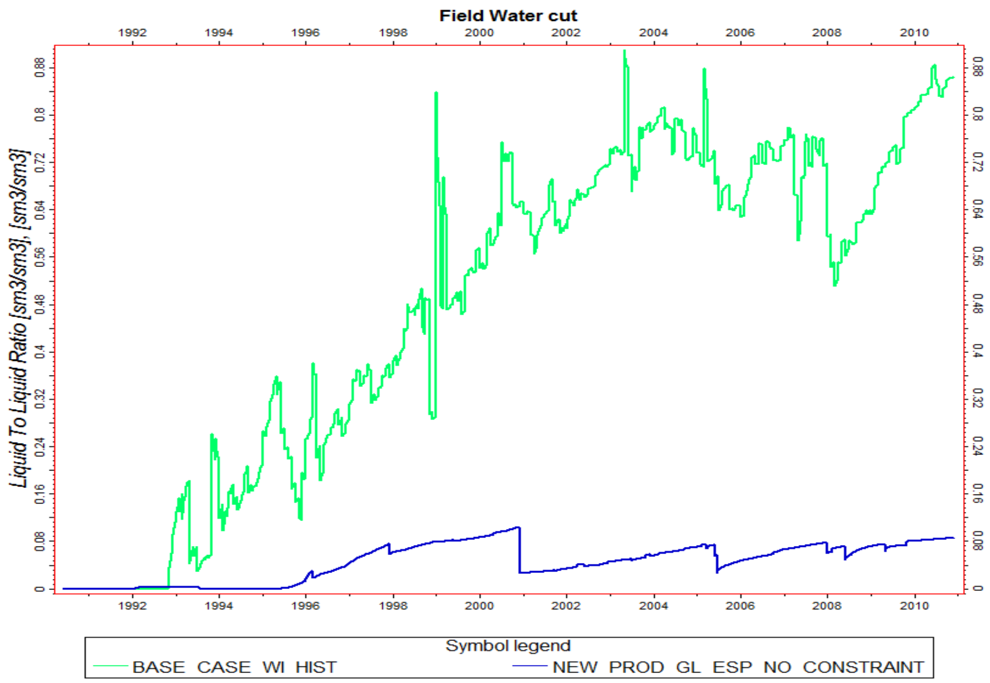


Figure 4.63 Field water cut of "No water injection- NW, GL & ESP" vs. Base Case

Regions pressure of "No water injection- NW, GL & ESP" can be seen in figures 4.64 -4.66.

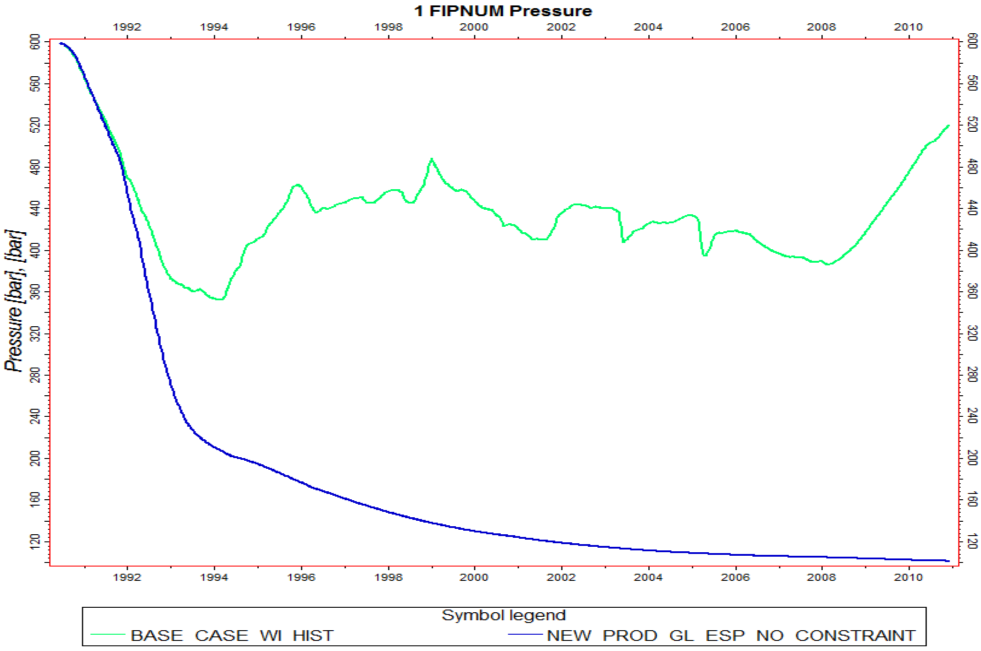


Figure 4.64 Region 1 (Downdip) Pressure of "No water injection- NW, GL& ESP" vs. Base Case

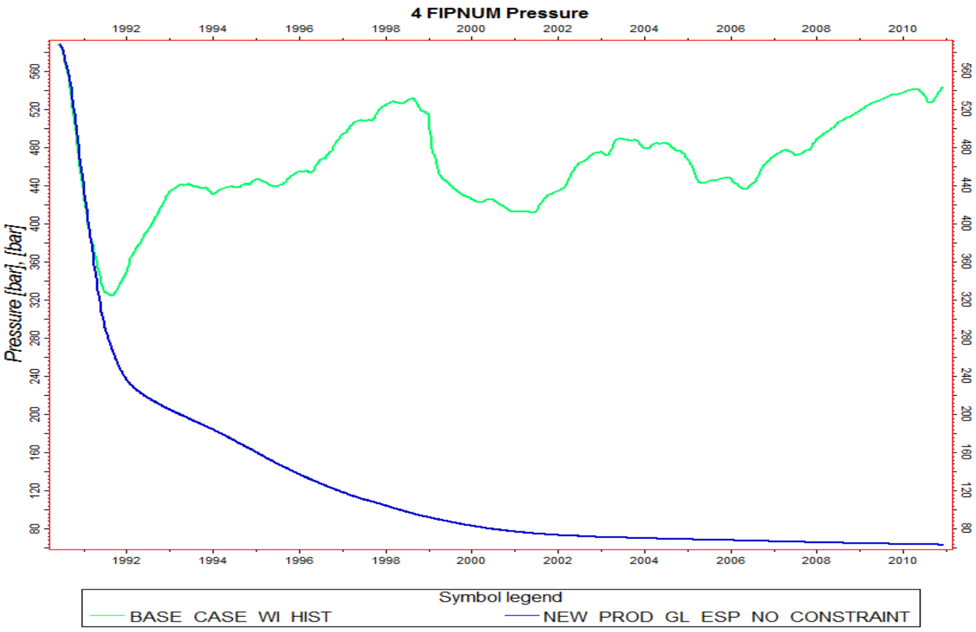


Figure 4.65 Region 4 (Crest) Pressure of "No water injection- NW, GL& ESP" vs. Base Case

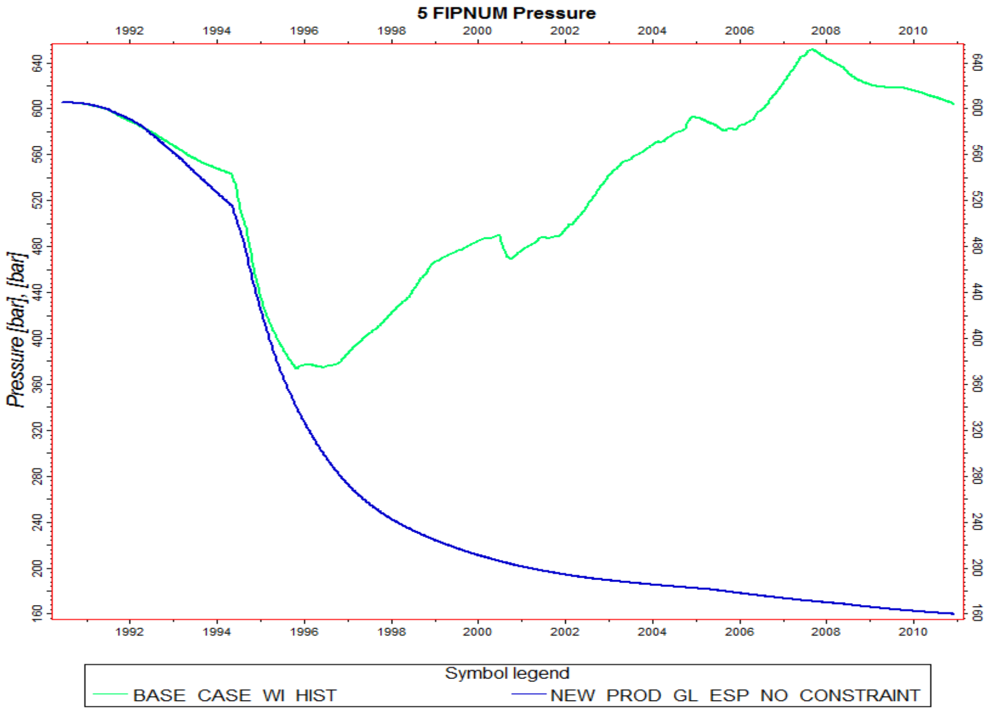


Figure 4.66 Region 5 (C-sand) Pressure of "No water injection- NW, GL& ESP" vs. Base Case

Let us look at the total oil, water and gas productions at the end of simulation period (December, 1st, 2010) of this scenario:

- Field Total Oil Production:
  23,832,976 Sm3 ~ 149.9 MMbbl
  77.9 % of base case production

- Field Total Gas Production:
  6,930,578,432 Sm3 ~ 244.7 Bcf
  144.5 % of base case production

- Field Total Water Production:
  427,959 Sm3 ~ 2.7 MMbbl
  2.3 % of base case production

Figure 4.67 shows total oil production of "No water injection- NW, GL& ESP" scenario, the figure includes all previously discussed scenarios for the ease of comparison. It can be noticed that changing the artificial lift method of 10 wells from gas lift to ESP accounts for 1.6 MMbbl increase in total oil production. This suggests that in scenarios which do not have water flooding and consequently have wells with lower water cuts, ESP cannot be very successful.

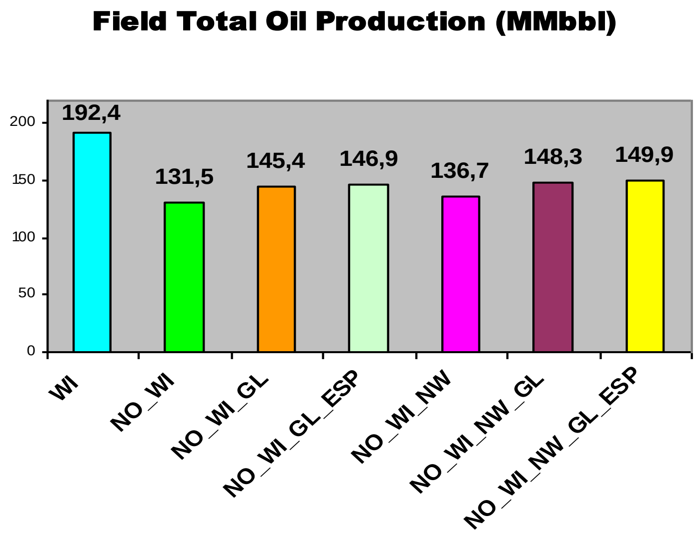


Figure 4.67 Field total oil production- "No water injection- NW, GL & ESP"

Total gas and water production of "No water injection- NW, GL& ESP" scenario and all the earlier cases are depicted in figures 4.68 and 4.69.

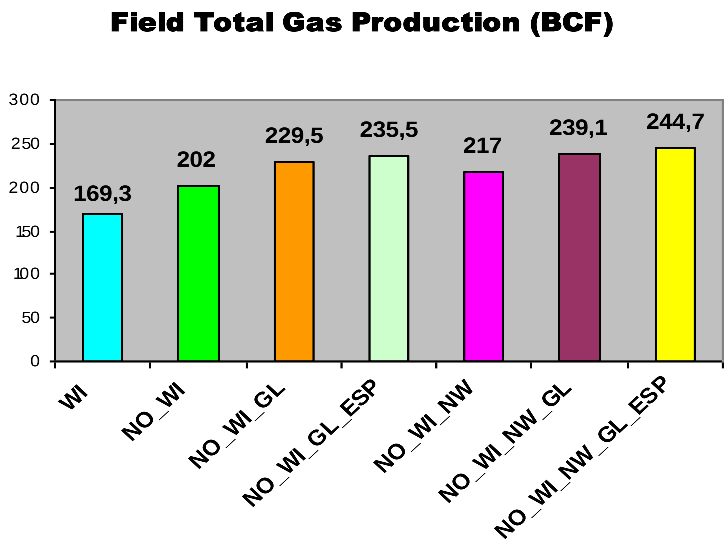


Figure 4.68 Field total gas production- “No water injection- NW, GL & ESP"

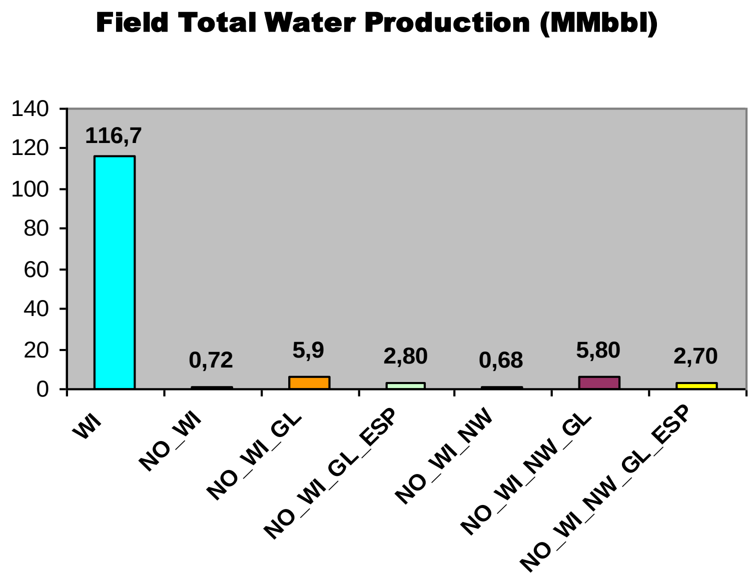


Figure 4.69 Field total water production- “No water injection- NW, GL & ESP"

4.2.8 Scenario 8: Modified water injection

Having looked at all scenarios without water injection, it can be very interesting to see what could be the outcome if we were able to go back in time and improve the real scenario i.e. water injection scenario. In this section "Modified water injection" scenario will be introduced and the results will be presented.

In order to imitate the base case (water injection) we should have all history producers producing and all history injectors injecting. For the producers which have been converted into injectors, the production and injection period is introduced as it was in the history. Production wells follow the assumptions mentioned in section 4.1 (Introduction) and for injection wells the below assumptions have been used:

- THP (Tubing Head Pressure) of an injector is set at 220 bar
- BHP (Bottom Hole Pressure) of an injector is set at 620 bar
- Well Efficiency set to **0.95** (5% downtime) for each injector

Now after applying all the above we should make some modifications in the base case, the following have been carried out in order to modify the real scenario:

a) 2 inefficient injectors will be replaced
b) 2 wells will be gas lifted
c) 2 wells will be lifted by ESP
d) 2 new infill wells will be drilled

a) Injectors to be replaced:

Wells A24A and A14C has been removed from the scenario and replaces by two new injectors, because they have had the lowest injection rate, shorter injection period and lower total water injection volume (see figure 4.70). The location of new injectors kept close to the real ones in order to prevent changing the injection pattern used by the operator; however, the new injectors are placed in new locations where there is more injectivity.

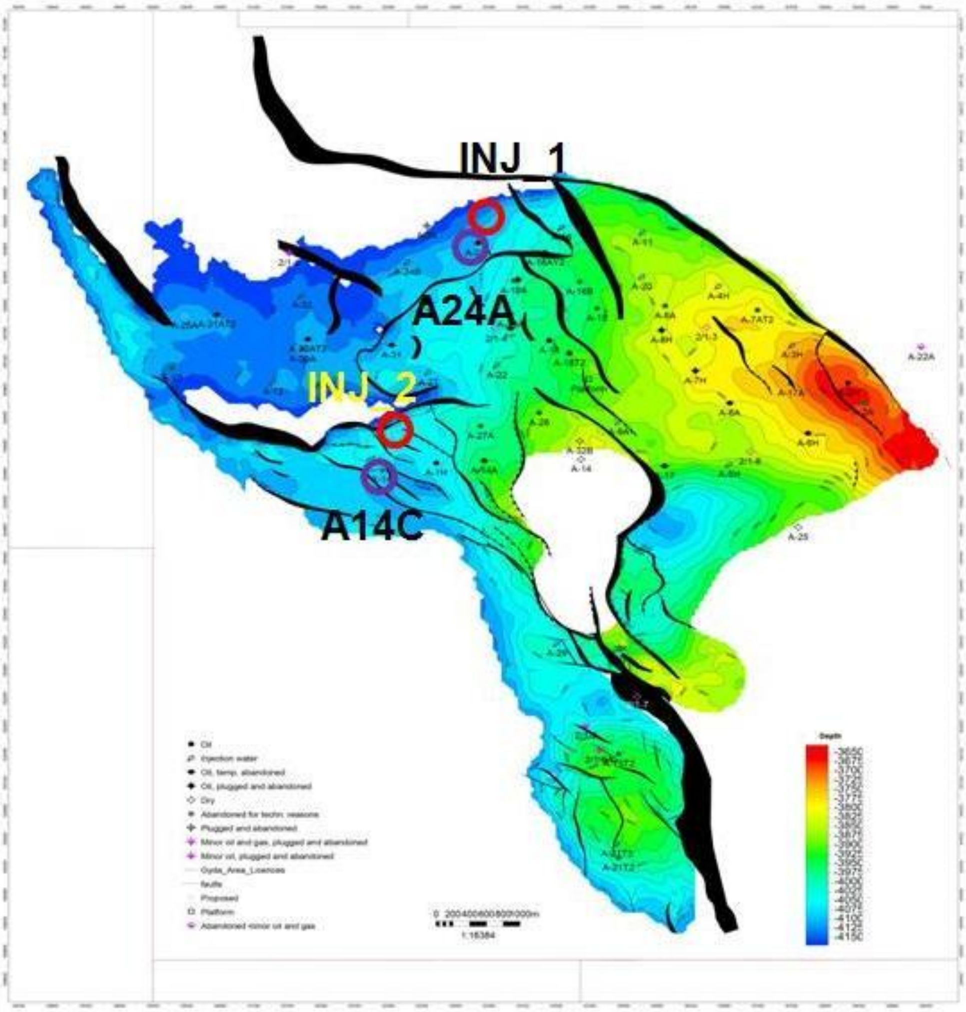


Figure 4.70 Gyda map marked with injectors to be replaced and new injectors

b) Wells to be gas lifted:

Wells A08H and A26 have been selected to be gas lifted because they have higher gas utilization factor (GUF), higher productivity index (PI) and Better performance under gas lift scenarios (comparison between “No water injection” & “No water injection- Gas Lift” cases).

c) Wells to be ESP lifted

Wells A04H and A30AT2 are selected to be ESP lifted, because they have higher production rate, longer production period, higher productivity index and finally lower GOR.

d) New infill wells

The below criteria have been taken into consideration while placing the new producers:

- High Oil Saturation (Soil > 0.4) @ 1st, Dec. 2010
- High Reservoir Pressure @ 1st, Dec. 2010
- High Porosity & High Permeability
- High Transmissibility (I, J, K)
- High Net to Gross Ratio (NTG)

New producers are named **Prod_1_1** (On-stream 01.06.1996) and **Prod_2** (On-stream 01.06.2002). “Prod_1_1” is in Crest region and “Prod_2” in Downdip area (see figure 4.71).

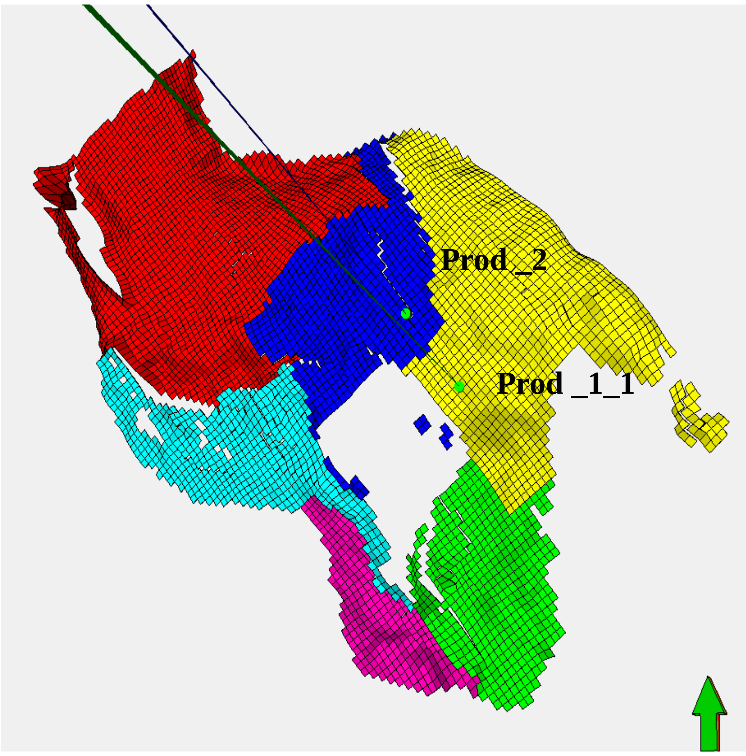


Figure 4.71 Gyda new producers, "Modified water injection" scenario

Figure 4.72 and 4.73 show field oil and gas production rate of “Modified water injection” scenario (red line) versus “Water injection” case (green line). We can see pretty good match between the scenarios.

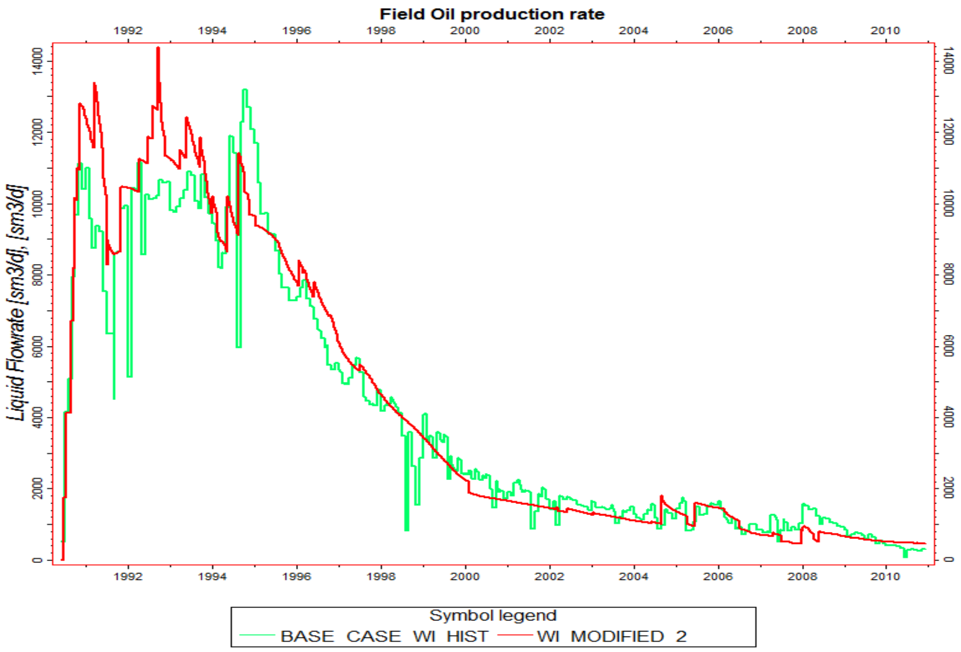


Figure 4.72 Field oil production of "Modified water injection" vs. Base Case

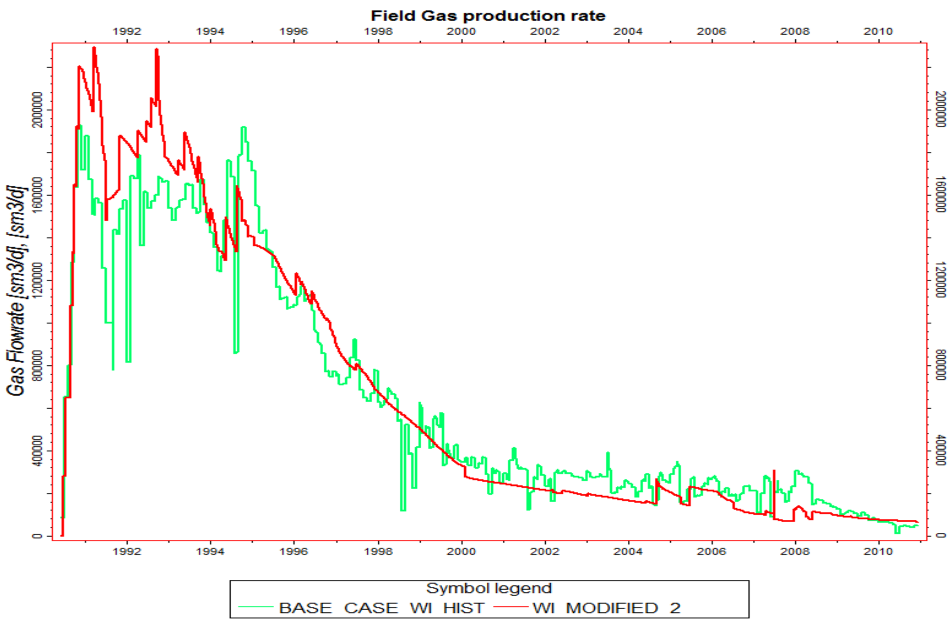


Figure 4.73 Field gas production of "Modified water injection" vs. Base Case

Field gas oil ratio of “Modified water injection” scenario (red line) versus “Water injection” case (green line) is depicted in figure 4.73. In the early phase we have a good match between the scenarios, however, in the late phase “Modified water injection” scenario gives lower gas oil ratio presumably because of better pressure maintenance of “Modified water injection” case .

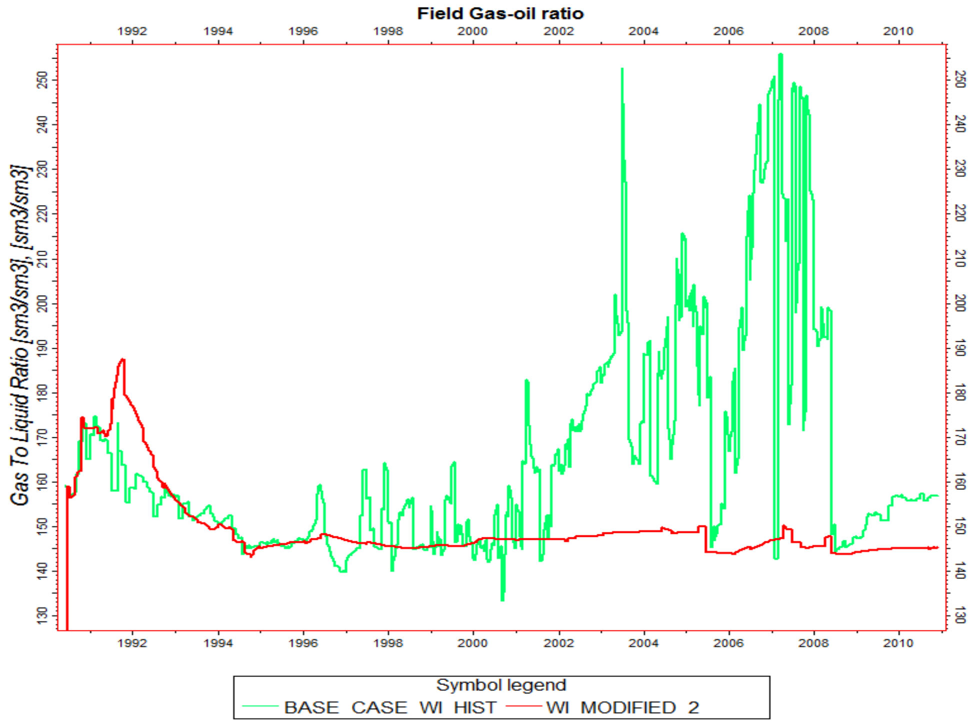


Figure 4.74 Field gas oil ratio of "Modified water injection" vs. Base Case

Figure 4.75 shows field water cut of “Modified water injection” scenario (red line) versus “Water injection” case (green line). The scenarios pretty much match each other, however, “Modified water injection” case gives higher water cut at the end of simulation period which can be because of higher injected water. It is an indication that the new injectors are effective. To back up this claim figures 4.76 and 4.77 show the water injection rate of wells “INJ_1” and “INJ_2”.

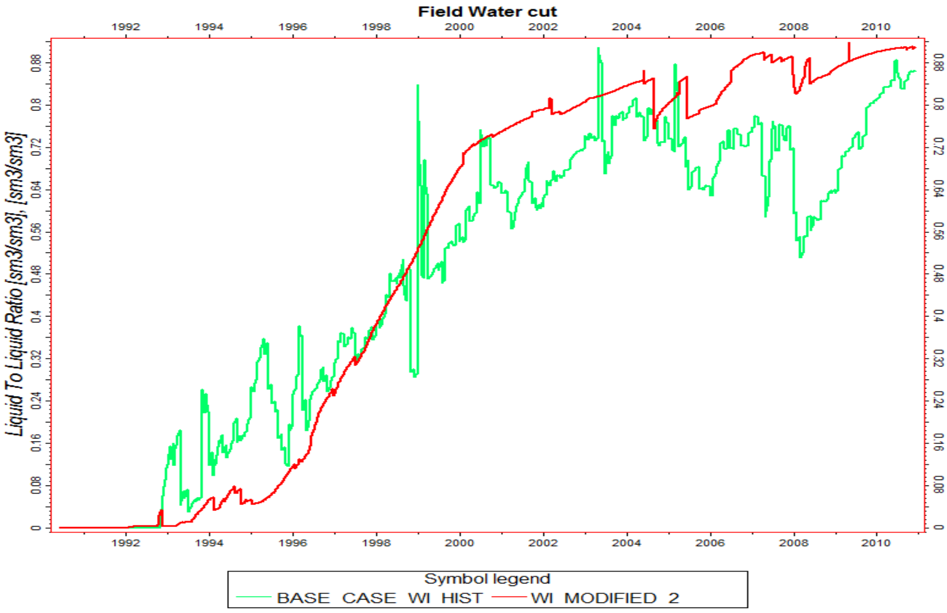


Figure 4.75 Field water cut of "Modified water injection" vs. Base Case

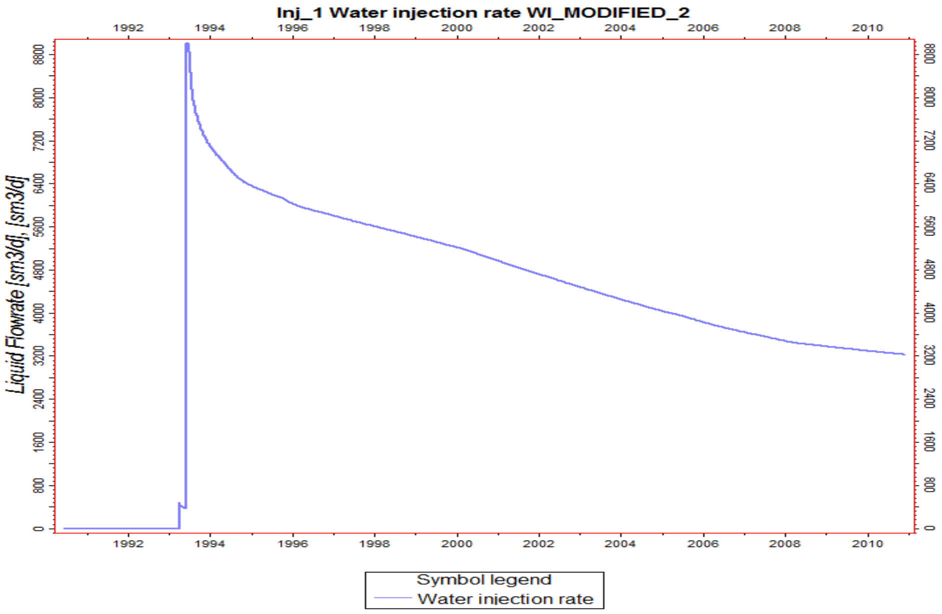


Figure 4.76 Water injection rate of well "INJ_1"

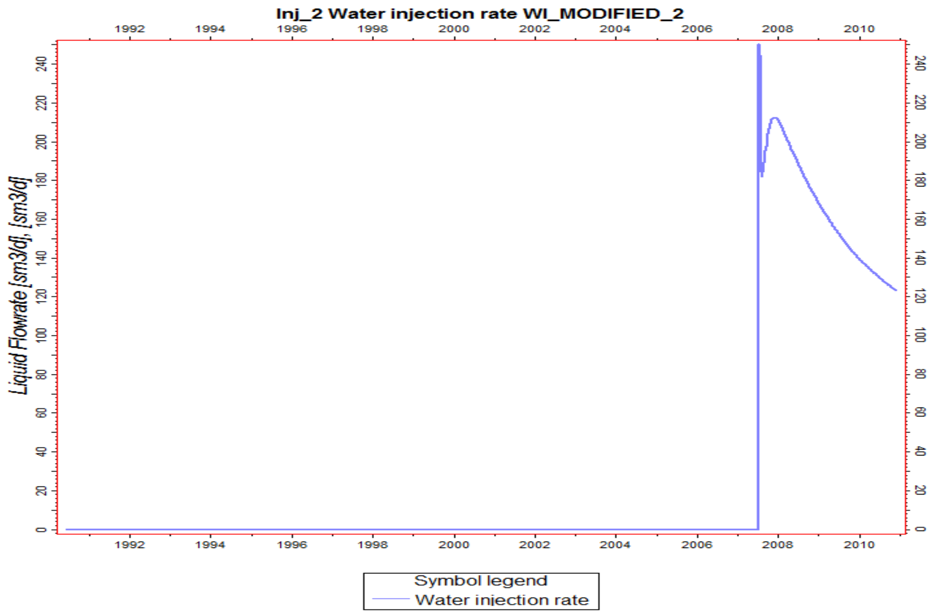


Figure 4.77 Water injection rate of well "INJ_2"

To see the effectiveness of the new producers, Prod_1_1 and Prod_2, figures 4.78 and 4.79 illustrate oil production rate and cumulative oil production of these well respectively.

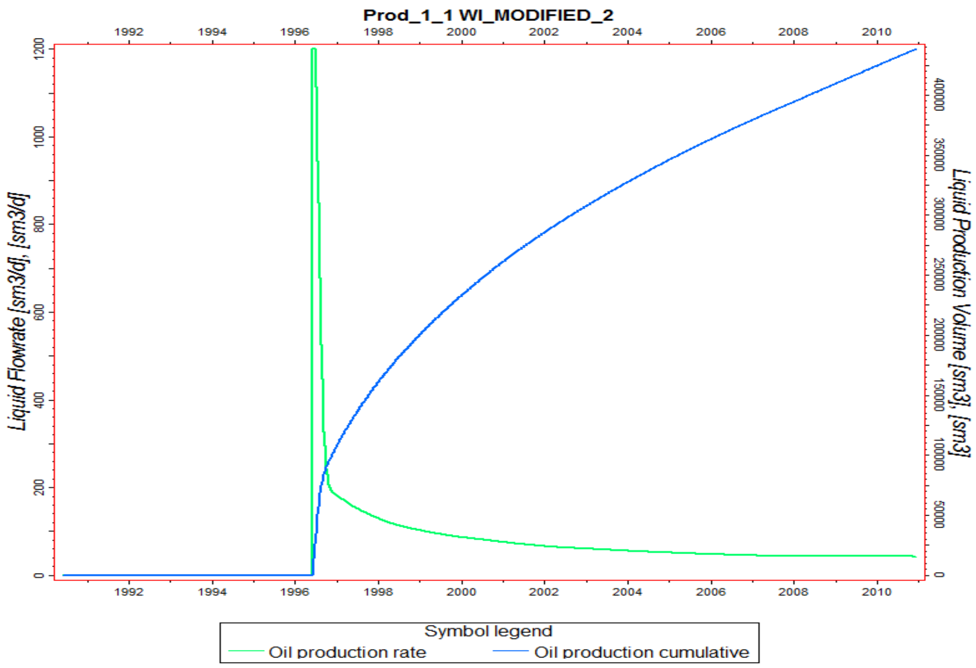


Figure 4.78 Oil production rate and cumulative oil production of well "Prod_1_1"

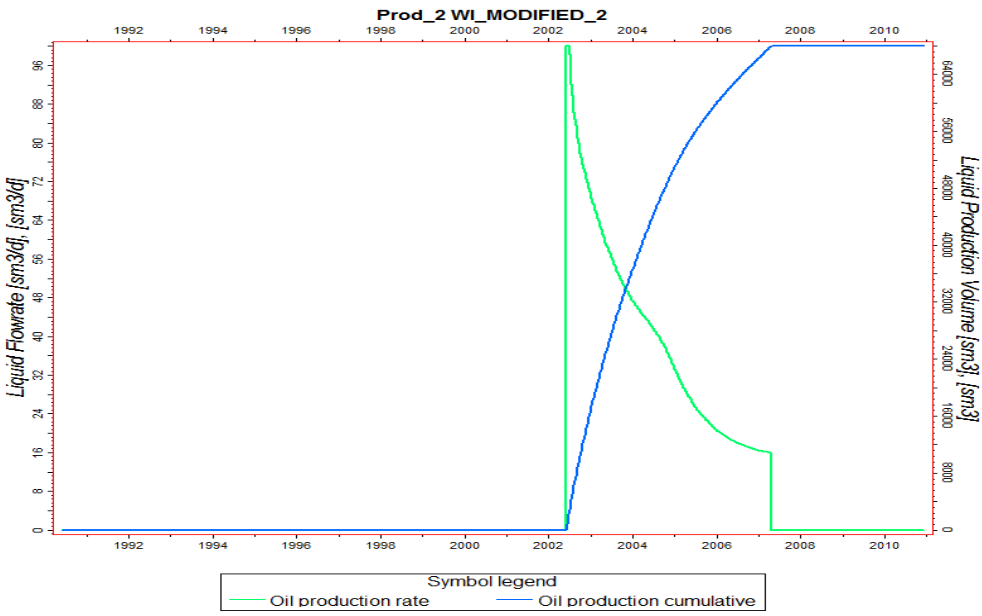


Figure 4.79 Oil production rate and cumulative oil production of well "Prod_2"

Figure 4.80 – 4.82 show Downdip , Crest and C-sand regions pressure of "Modified water injection" scenario (red line) versus "Water injection" case (green line).

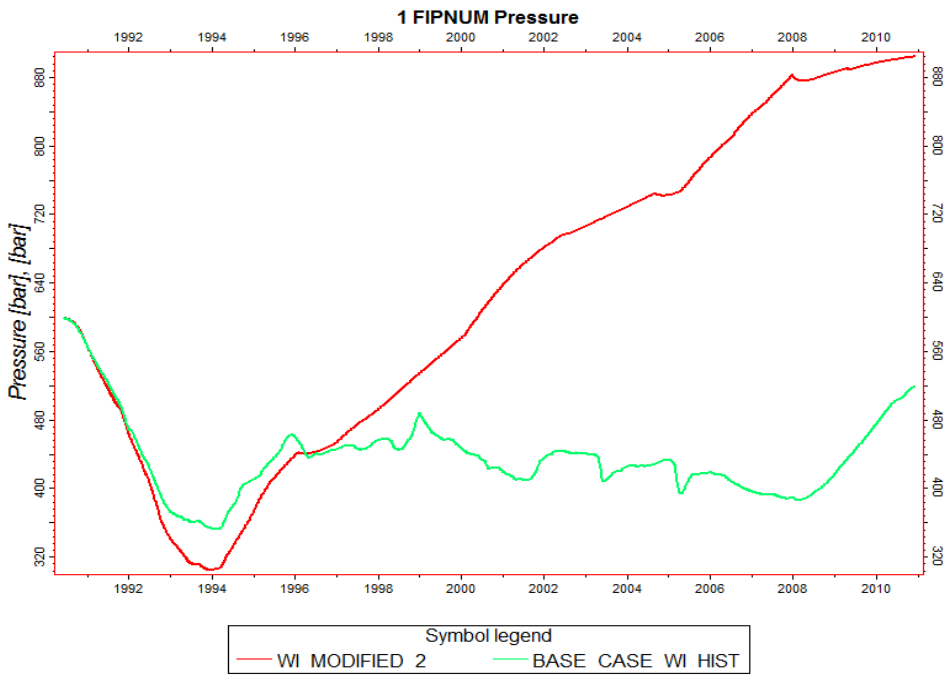


Figure 4.80 Region 1 (Downdip) Pressure of "Modified water injection" vs. Base Case

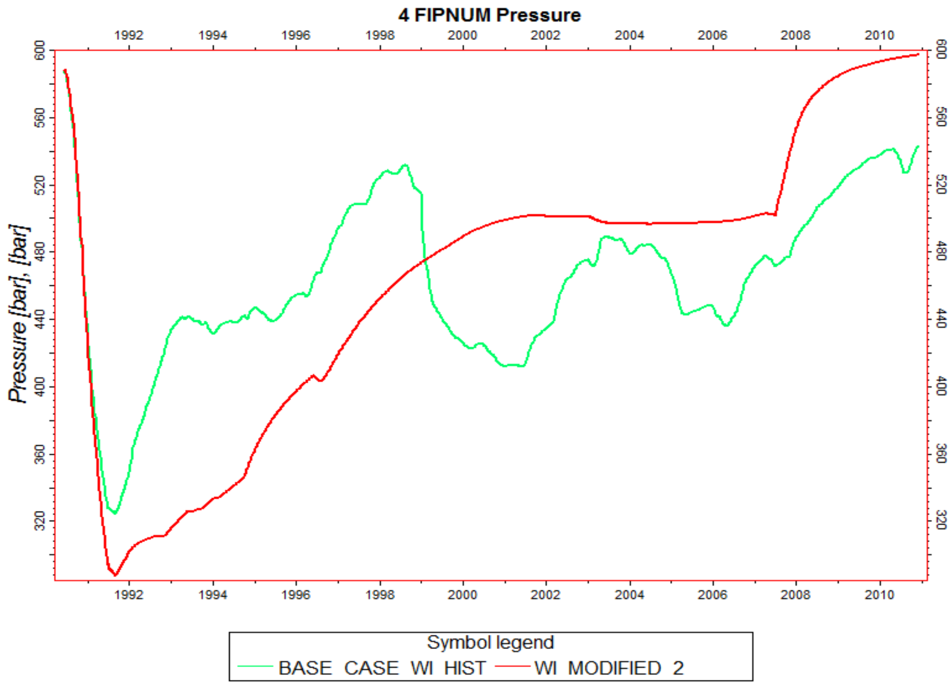


Figure 4.81 Region 4 (Crest) Pressure of "Modified water injection" vs. Base Case

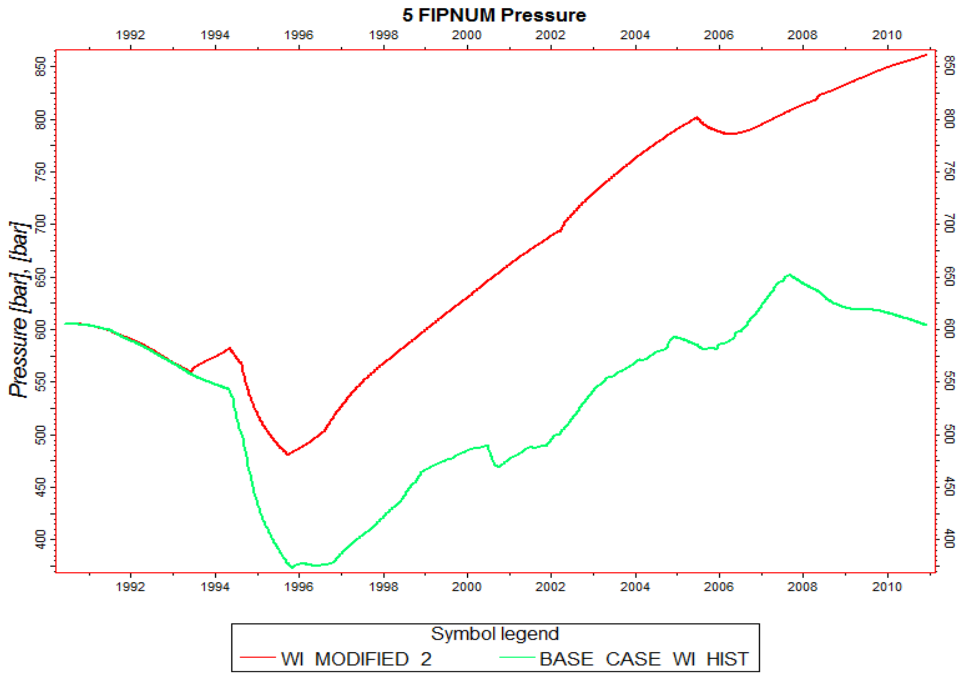


Figure 4.82 Region 5 (C-sand) Pressure of "Modified water injection" vs. Base Case

At this point we should look at the total oil, gas and water productions and compare it with the base case. Visual comparisons of these values, for both scenarios are depicted in figure 4.83 – 4.85 (December, 1^{st}, 2010).

- Field Total Oil Production:
  32,150,382 Sm3 ~ 202.2 MMbbl
  105.1 % of base case production
  Incremental increase: 9,8 MMbbl

- Field Total Gas Production:
  4,956,088,832 Sm3 ~ 175 Bcf
  103.4 % of base case production
  Incremental increase: 5.7 Bcf

- Field Total Water Production:
  25,316,606 Sm3 ~ 159 MMbbl
  136.2 % of base case production
  Incremental increase: 42.3 MMbbl

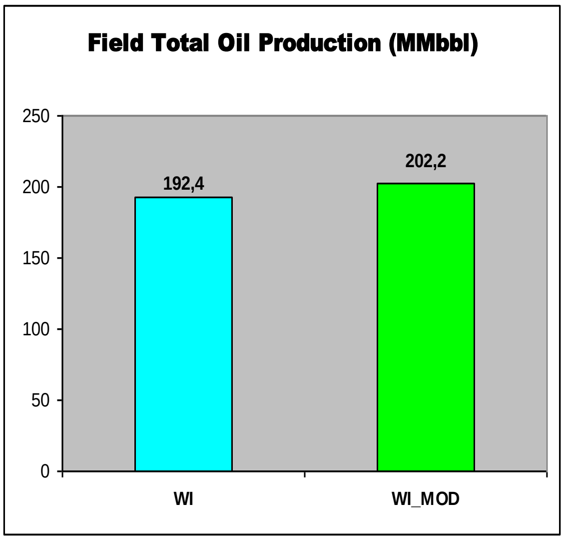


Figure 4.83 Field total oil production of "Modified water injection" vs. Base Case

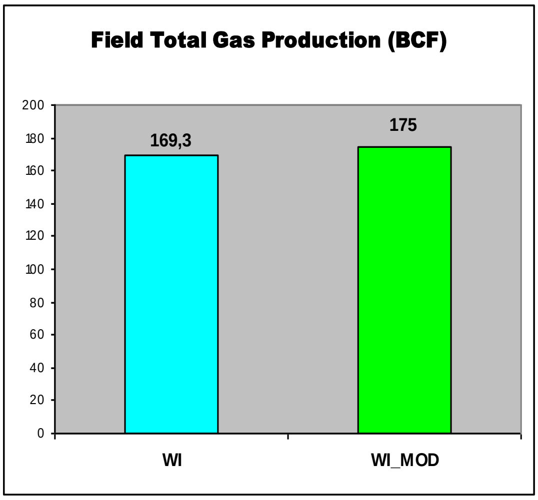


Figure 4.84 Field total gas production of "Modified water injection" vs. Base Case

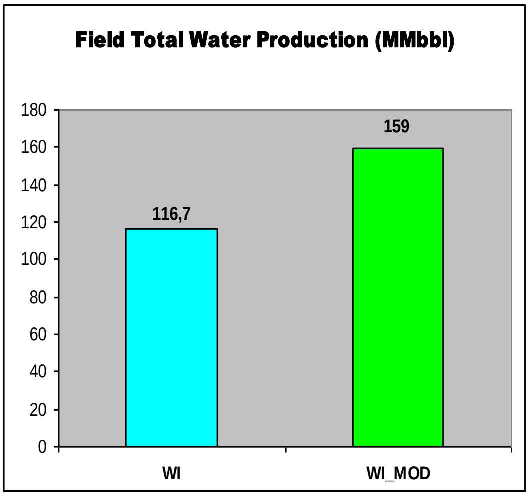


Figure 4.85 Field total gas production of "Modified water injection" vs. Base Case

5 Conclusions and Recommendations

5.1 Conclusions

To conclude which scenario is the best one, the below parameters will be studied for all scenarios:

- Total field oil production (@ Dec., 1st, 2010)
- Total field gas production (@ Dec., 1st, 2010)
- Total field water production (@ Dec., 1st, 2010)
- Regions pressure (@ Dec., 1st, 2010)
- Recovery factor (@ Dec., 1st, 2010)

a) Total field oil production (@ Dec., 1st, 2010)

Figure 5.1 gives a clear comparison between total oil productions from the Gyda field under various production scenarios. A significant difference between water injection scenarios ("Modified water injection" and "Water injection") and no water injection cases can be seen.

Also "No water injection" scenario successfully modified to produce **18.4** MMbbl more oil by using artificial methods, along with, infill drilling ("No water injection-NW, GL & ESP" scenario).

b) Total field gas production (@ Dec., 1st, 2010)

Total gas production from the Gyda field under the studied scenarios is depicted in figure 5.2. As the figure suggests the water injection scenarios have the lowest produced gas. The reason is due to better pressure maintenance in these scenarios, in comparison with no water injection cases. Therefore, reservoir pressure stays above the bubble point pressure and consequently lower gas is produced.

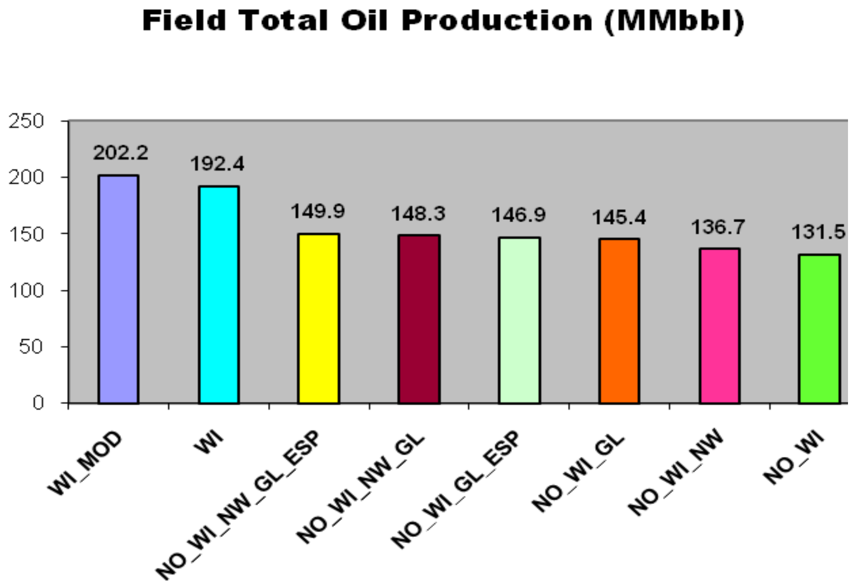


Figure 5.1 Total field oil production (All Scenarios)

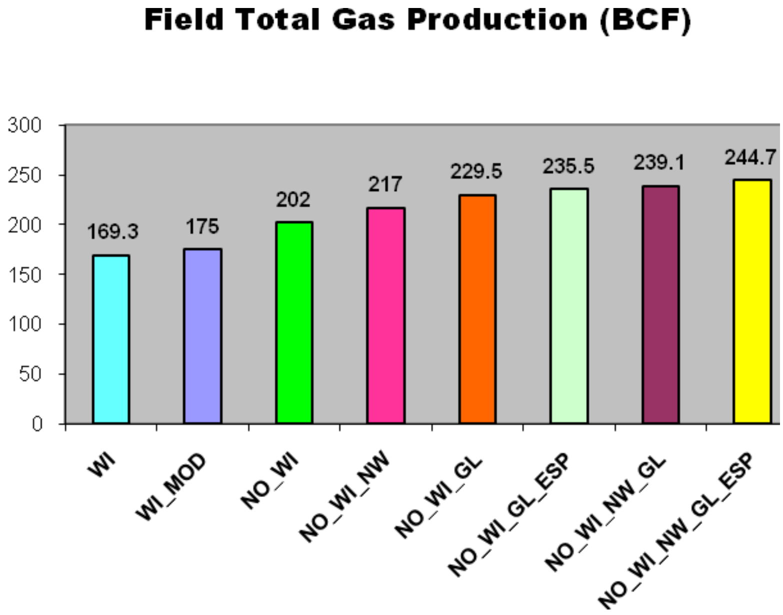


Figure 5.2 Total field gas production (All Scenarios)

c) **Total field water production (@ Dec., 1st, 2010)**

Figure 5.3 shows total water production of all under studied scenarios. From the figure it can be noted that water injection scenarios lead to much higher water production which is the nature of water flooding strategy. Although these scenarios make much higher oil productions in comparison with no water injection case, however, high water production is not of interest, because of costs associated with handling of the produced water, as well as, the fact that there are certain rules and regulations about dumping water offshore Norway.

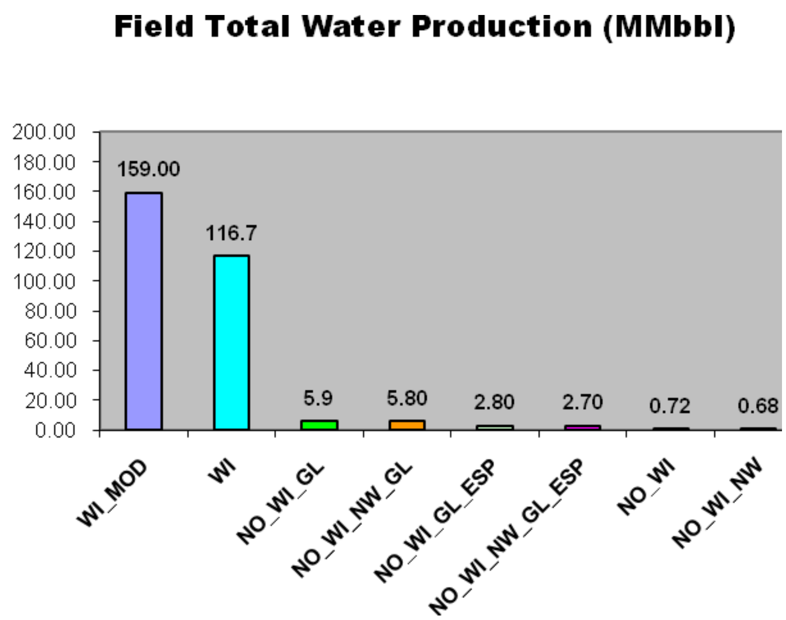


Figure 5.3 Total field water production (All Scenarios)

d) **Regions pressure (@ Dec., 1st, 2010)**

Reservoir pressure in region 1 (Downdip), region 4 (crest) and region 5 (C-sand) at the end of simulation period (Dec, 1st, 2010) are illustrated in figures 5.4 – 5.6. From the figures one can easily seen the importance of water flooding in pressure maintenance of different regions of the field.

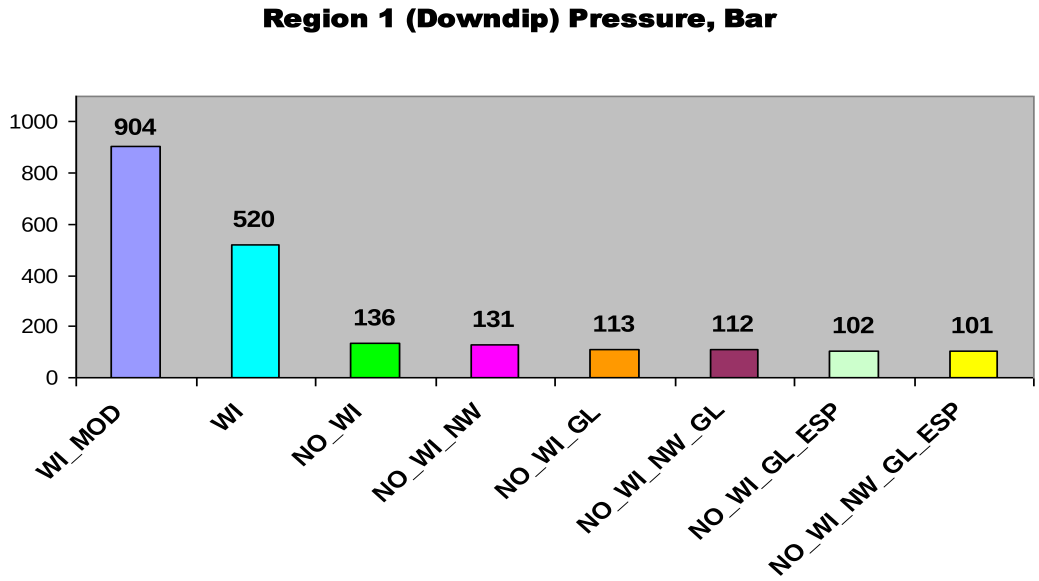


Figure 5.4 Region 1 (Downdip) pressure (All Scenarios)

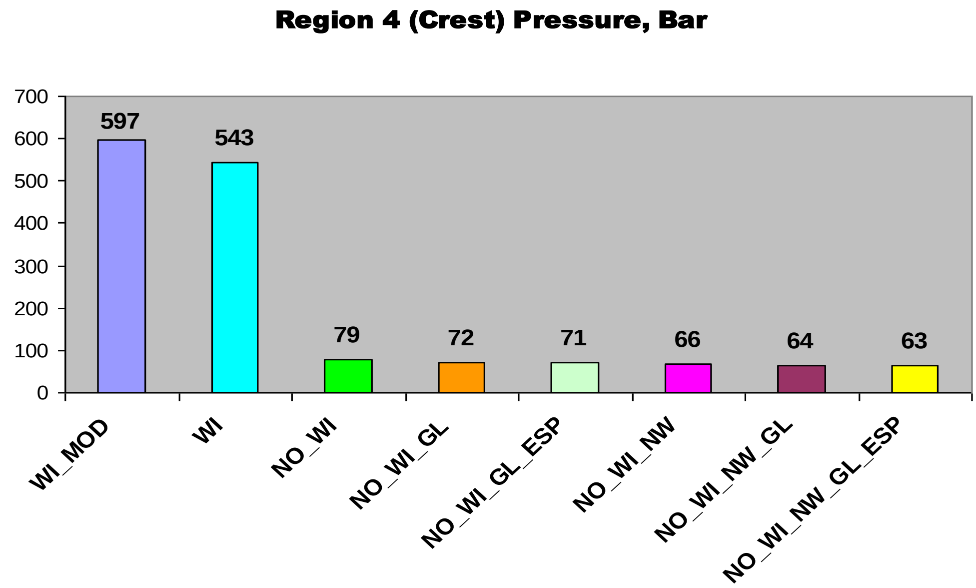


Figure 5.5 Region 4 (Crest) pressure (All Scenarios)

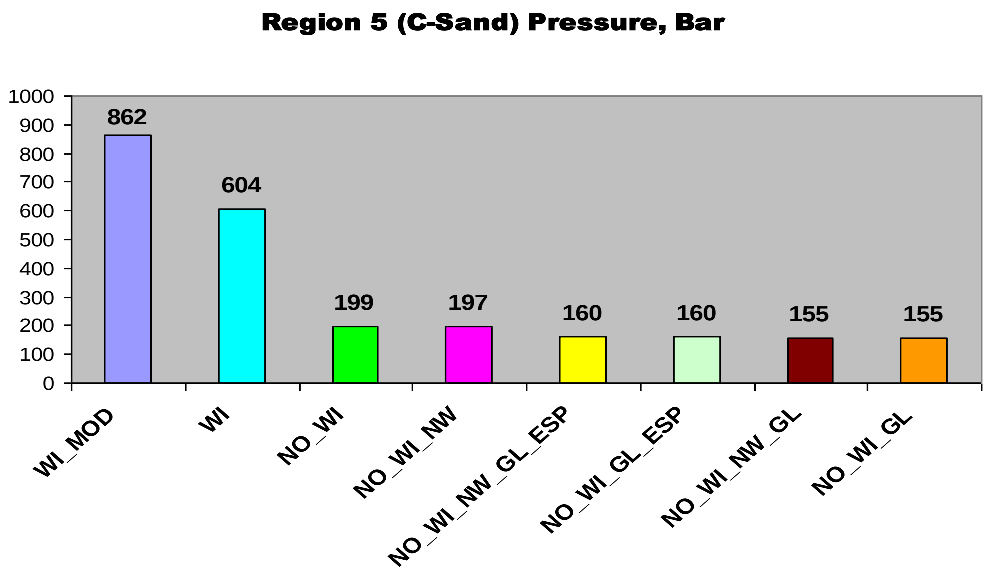


Figure 5.6 Region 5 (C-sand) pressure (All Scenarios)

e) Recovery factor (@ Dec., 1st, 2010)

First we start with stating recovery factor formula:

$$RF = \frac{Field\ Initially\ Oil\ In\ Place - Field\ Ultimate\ Oil\ In\ Place}{Field\ Initially\ Oil\ In\ Place} \qquad (5.1)$$

After introducing the recovery factor formula, now we can take a look at recovery factor of all scenarios to see which one gives us the highest recovery factor. Figure 5.7 gives the recovery factor of the studied scenario.

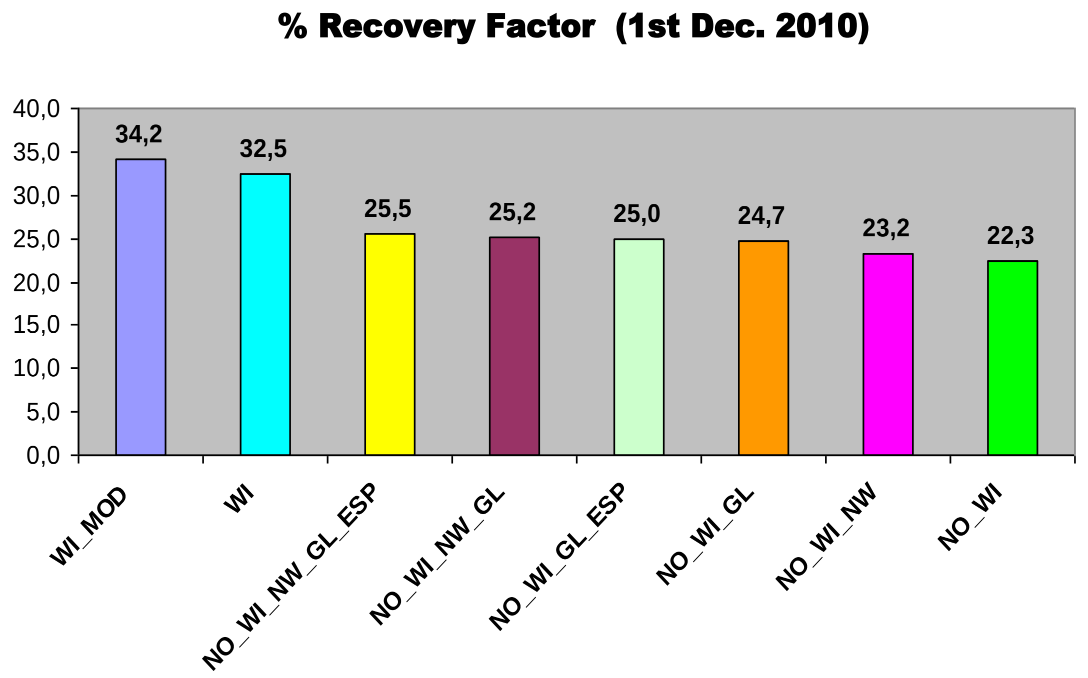


Figure 5.7 Recovery factor on December, 1st, 2010 (All Scenarios)

Having looked at all the above mentioned results and comparisons water injection scenario which is the real developing scenario of the Gyda field is the best production scenarios because:

- Gives the highest recovery factor
- Excellent pressure maintenance
- Has the lowest GOR
- Extending the field’s life

Water injection scenario is modified as presented in the above, which suggests simultaneous use of gas lift, ESP and infill drilling can increase oil production from the field. It should be mentioned that Talisman Energy Norge, the operator of Gyda is currently utilizing all these measures to increase oil production from the Gyda field.

5.2 Recommendations

Further work is recommended. It is recommended to take a study about the financial aspect of the investigated scenarios in which all CAPEX (capital expenditure) and OPEX (operating expense) of alternative scenarios are calculated. Therefore one can find out whether the income from additional oil production which water injection scenario gives can compensate the extra expenses of drilling injection wells and handling the produced water or not.

6 References

1. Dake, L.P, “Fundamental of Reservoir Engineering”, Developments in Petroleum Science 8, Amsterdam, the Netherlands, 1998.
2. Ahmed, Tared H., “Reservoir Engineering Handbook”, second edition, Gulf Publishing Company, Houston, Texas, 2001.
3. Dake, L.P, “The Practice of Reservoir Engineering”, (revised edition), Developments in Petroleum Science 36, Amsterdam, the Netherlands, 2001
4. Ursin, J. R. & Zolotukhin, A. B., “Introduction to petroleum reservoir engineering”, Høyskoleforlaget, 2000.
5. “Eclipse 100 User Course”, Schlumberger – GeoQuest.
6. Kleppe, H., "Reservoir Simulation", course material, University of Stavanger, 2010.
7. Fanchi, J.R., “Principles of Applied Reservoir Simulation”, second edition, Gulf Professional Publishing, USA, 2001.
8. Zhangxin, C., “Reservoir Simulation: Mathematical Techniques in Oil Recovery”, CBMS-NSF Regional Conference Series in Applied Mathematics, Society for Industrial and Applied Mathematics, University of Calgary, Alberta, Canada, 2007
9. “Applied Reservoir Simulation- History Matching” course material, Schlumberger, Denver and Houston, March 2006
10. “Reservoir Engineering Course”, Petrel 2010, Schlumberger Publication, 2010
11. Nishikiori, N., Sugai, K., Normann, C., Onstein, A., Melberg, O., & Eilertsen, T., “An Integrated Workflow for Gas Injection EOR and a Successful Application to a Heterogeneous Sandstone Reservoir in Southern North Sea”, IPTC 12025, 2008.
12. Rothwell, N.R., Sørensen, A., Peak, J.L, Byskov, K., & McKean, T.A.M, BP Norway Ltd, U.A. “GYDA: Recovery of Difficult Reserves by Flexible Development and Conventional Reservoir Management”, SPE 26778, 1993.
13. Wood Mackenzie, Upstream Service, Gyda , < http://www.woodmacresearch.com>
14. Normann, C., “Norway Asset Reserves Report”, Talisman Energy Norge, internal document, 2010.