NTNU – Trondheim
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"Well Placement for maximum production in the Norwegian Sea"

Case Study: Norne C-segment Oil Field

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Master’s Thesis in Reservoir Engineering
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Norwegian University of Science and Technology, NTNU
Department of Petroleum Engineering and Applied Geophysics

“Well Placement for maximum production in the Norwegian Sea”

Case Study-Norne Field C-Segment

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in
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Stella Eyo Akpan
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MASTER OF SCIENCE THESIS

The candidate's name:
Stella Eyo Akpan

Title of Thesis
"Well Placement for maximum production in the Norwegian Sea"
Case Study: Norne Field -C-Segment

Plan and Scope of work:

Make simulation runs with reference case
Forming new case scenarios using the reference case model and placed new wells
Predicting field performance for the duration of 9 years
Estimating production, recovery factor and reserves in the field for all cases.
Calculate the Net present Value (NPV) at cases

Area of specialization: Reservoir Engineering
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Dedication

This thesis work is dedicated to Almighty God who was with me throughout this work. I also dedicate this work to my family members for their support and prayers during this program. I finally dedicate this work to the educational world.

Abstract

In petroleum fields, the essence of well placement is to develop and maintain petroleum reservoirs in order to achieve maximum production for economic benefit. Maximum production can be achieved with more oil wells, but few optimal numbers of wells in good location reduces economic costs and increase recovery. The best location for the placement of oil, gas or water wells depends on reservoir and fluid properties, well and surface equipment specifications, as well as economic parameters [1].

The objective of the study is to determine the net present value from few well placements in the Norne C-segment reservoir by either obtaining the same or more oil production/recovery compared to the base case wells. New well placement in a reservoir simulation model uses an industrial standard ECLIPSE reservoir simulator. Manually simulation approach is used to locate high oil saturation grids for the new well placement. From the base case simulation result, a total number of thirteen wells were discovered, nine producers and four injectors. The production and injection wells were classified with a suffix according to the production templates B, D, K and injection template C respectively.

The base case wells removed and new well placed from exhaustive simulation runs for two different scenario cases. A total number of ten wells, six producers and four injectors were placed in each scenario. In order to obtain maximum oil recovery, the producers are placed horizontally while injectors remain the same as those from the base case. The new well placements in the scenario cases are identified with the suffix “P-H” for producers and “I-H” for injectors. Simulation results, the total oil produced for wells in each field case from the start year 1997 to December 2015, (end of production) can be seen in Table 10, 11 and 12 in chapter 6. The cumulative oil produced from each field case is the same as the total oil produced from all the wells in each case.

The cumulative field oil and gas production from the start of production, November 1997 to December 2015 is 41.3 million Sm^3 oil and 260 million Sm^3 of gas for base case, 42.8 million Sm^3 oil and 269 million Sm^3 of gas for scenario 1case, 43.2 million Sm^3 oil and 272 million Sm3 of gas for scenario 2 case. The recovery factor for base case is 28%, scenario 1 & 2 are 29.0% and 29.3%. Each field case uses drive mechanisms, gas injection and water injection to support oil production and maintain pressure in the each field case. The total gas and water injected in the base case field were 9.6 billion Sm3 and 78.8 million Sm3 respectively**.** In scenario 1, a total of 8.6 billion Sm^3 of gas and 81.6 million $Sm^3$of water was injected and in Scenario 2, 8.6 billion Sm3 of gas and 81.3 million $Sm^3$of water was injected.

The Net present values for the three cases were calculated taking into account the economic costs such as well cost, cost of gas and water injection. Sensitization was done on the oil price ($25, $35 and $45). The NPV results from Table 19 prove that all case projects are acceptable, but scenario 2 is the most economical as it has the highest NPV of $4,026 million based on $35-medium oil price that was considered.

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Chapter One

1. Introduction

Optimal placement of oil, gas or water wells is a complex problem that depends on reservoir and fluid properties, well and surface equipment specifications, as well as economic parameters [2]. Optimum reservoir performance is highly dependent on well locations. Determination of optimal well locations certainly cannot be based on intuitive judgment alone owing to the fact that engineering and geologic variables affecting reservoir performance are not only nonlinearly correlated, but also time and process dependent. Hence, there is the need for an objective well-placement [3].

In 1904, Anthony Lucas, who had discovered Spindle top, spoke about the decline in production. He claimed that "the field had been poked with too many holes and that the cow was milked too hard." Oil operators in that day gave little thought to reservoir depletion as they completed wells. They produced a well at the highest rate they could without regard for well spacing [4]. Drilling of fewer wells appears to be a promising procedure for necessary and important reductions in the cost of producing oil [3].

Development strategies and well placement may significantly depend on field geology, maturity of the depletion stage, technological factor, drive resources and other parameters. Optimum well placement most of the time is done based on a deterministic (most likely) case. The definition of a well placement is a key aspect with major impact in a field development project. In this sense, the use of reservoir simulation allows the engineer to evaluate different placement scenarios. However, the current industry practice is still, in most cases, a manual procedure of trial and error that requires a lot of experience and knowledge from the engineers involved in the project. Considering that, the development of well placement optimization tools which can automate this process is a high desirable goal.

The definition of a production strategy is one of the most important tasks in reservoir management, since it will affect the reservoir behaviour, which influences future decisions, economic analysis and, consequently, attractiveness of projects. It involves variables like well placement, number and type of wells, operational conditions, reservoir characteristics and economic scenario. The analysis becomes more complex when horizontal wells are considered in production strategy, due to their interaction with reservoir, which demands tools to assist the decision-making process by discarding less attractive alternatives and providing analysis of a reduced number of solutions [4].

The main activity is the planning of strategies for the development and management of petroleum fields. The determination of well location is one of the most important aspects in production strategy definition, and the optimization procedure related this problem is complex. The analysis becomes harder when horizontal wells are considered, due to its interaction with the reservoir. The process of choosing the best location for horizontal wells demands time-consuming and computational efforts, since its productivity depends on many variables related to reservoir and fluid properties, and well characteristics.

Optimal placement of oil, gas or water wells is a complex problem that depends on reservoir and fluid properties, well and surface equipment specifications, as well as economic parameters. Before strategies for the development and management of petroleum fields, it is better to know the life cycle of hydrocarbon field. Reservoir Management begins with exploration leading to discovery followed by appraisal of the reservoir, development of the field under primary and secondary means, IOR and EOR, and finally to abandoned.

1.2. Research Objectives

Reservoir engineering is the application of scientific principles to develop and maintain petroleum reservoirs to maximize economic benefit. For example, carefully spacing out wells over a reservoir and restricting production rates can make a difference in the overall productivity of the reservoir. Base on maximize economic benefit from well placement, the objective of this study will involved to:

- Make simulation runs with reference case
- Form new case scenarios using the reference case model and placed new wells
- Predict field performance for the duration of 9 years
- Estimate production for the field in all cases
- Estimate recovery factor in the field for all cases.
- Estimate the reserves in the field for all cases.
- Calculate the Net present Value (NPV) for all field cases

1.3. Research Outlines

The research outline of this work contains 7 chapters in total; chapter 1 provides an overview of the theoretical foundations on which this work is based. This chapter gives an underlying introduction to this work and the objectives of this work.

Chapter 2 gives a literature review on well placement theory and procedure from different researchers regarding well placement.

Chapter 3 gives an overview description of Norne field, such as the field segment and subsea system. Beside this, the chapter explain other vital field information such as field geology, the reservoir formation/communication, wells/drainage strategy, resources, recoverable and unrecoverable reserves.

Chapters 4 explain the case study, “The Norne C-segment Field” with Eclipse reservoir model application on the field; illustration on method used to separate and C-segment field from the whole Norne field. This chapter also gives an explanation on the simulation grids, properties, fluid contacts, fault/barrier and wells in the located in the reservoir from the model Eclipse simulation model.

Chapter 5 explain the simulation carryout on the field on the references case which a base case or which in this content is used as on this study, but first work flow is presented. In this chapter, the base case wells are defined and the new wells placement is performed for two scenario cases.

Chapter 6 is segmented into three parts; the first part give results profile on the simulation model with the base case and the new well placement cases and discussed. The second part gives the reserve estimation. Finally, the last part gives the results from NPV calculation exported fron excel spread sheet and discussion.

Chapter 7 gives summary of conclusions drawn from the best and the cheapest well case and recommendation for further study. The final stage of this chapter, present the nomenclature, reference, and some appendix developed in this research.

2. Research Literature

Placing too many wells in oil reservoir is known to have tremendous effect in oil recovery. This has also cause increase in economic cost in the oil industry for many years now. In the early days the belief was widely held that the more wells completed in a given reservoir the higher would be the ultimate recovery. With the growth of the science of reservoir engineering, it was realized that ultimate recovery can be achieve with minimal wells through simulation study. In field development, new well placement involves the determination of the optimum number, type, location, trajectory, well rates, and drilling schedule of new wells such that oil recovery will be achieved.

The study objective to considered in the well placement include cumulative oil (or gas) produced and net present value (NPV). The new well placement task is challenging, because the related literature is very expensive due to the required well types (vertical, horizontal, deviated; producer or injector). The incorporation of geological uncertainty, treated by considering multiple realizations of the reservoir, further increases the complexity of the placement problem.

2.2. Well Placement

For this work, well placement will be done manually using an industry standard ECLIPSE simulator. The vertical and horizontal producers will be placed manually by assigning well values after locating grid blocks with high oil saturation. After generate simulation output, the required result is extract to a user friendly spread sheet for NPV calculation. In cited studies on well placement, many researchers have used different experimental or simulation approach for new well placement. These researchers include;

Aanonsen *et al.* (1995)[4] optimized well locations under uncertainty using a response surface methodology, incorporating experimental design and a kriging proxy. Their approach used both a simple analytical flow model and a numerical simulator.

Seifert *et al*. (1996)[5] presented an approach for defining optimum high-angle development wells. They investigated a large variety of trajectories that varied in terms of inclination, azimuth, length, and position within the geologic zone.

Güyagüler and Horne (2000)[6] optimized well-location problems based on maximization of NPV. They developed the Hybrid Genetic Algorithm (HGA) involving genetic algorithm, polytope algorithm together with kriging and neural network proxies to reduce the number of simulation runs. Güyagüler and Horne found kriging a good alternative to the flow simulator but the neural network proxy still had some issues to be addressed.

Badru et al. (2003)[7] uses the Hybrid Genetic Algorithm (HGA) to determine optimal well locations. They used this technique to optimize both vertical and horizontal wells for both gas injection and water injection projects using NPV as the objective function. They compared the results obtained from the optimization of well placements proposed by the HGA method with those selected by engineering judgment. The optimized placement results obtained using HGA showed a significant increase in cumulative production of about 70% more than that proposed by engineering judgment

Bittencourt and Horne (1997)[8] also used a hybrid genetic algorithm, coupled with polytope algorithm and a Tabu search method to determine the optimal layout of wells for an oil field development project.

Bittencourt and Horne developed a hybrid algorithm based on direct methods such as genetic algorithm, Polytope search and Tabu search to obtain the optimal solution for problems related to reservoir development. Simulator was used as a data generator for the evaluation of the objective function, which involved an analysis of cash flow.

Yenten*et al*. (2002)[9] showed how the use of GAs, a hillclimbing search algorithm, and artificial neural networks could be used in optimizing not only well locations but also well trajectories.

Güyagüler and Gümrah (1999)[10] optimized production rates for a gas storage field using GAs. The focus of a large number of well-placement optimization studies has been numerical simulation, coupled with an automated optimization algorithm. Most of the proposed algorithms have been demonstrated to be very reliable. However, a significant number of 17 they are CPU-intensive. As a result, studies have been carried out on ways of reducing the number of simulation runs. The use of a proxy in place of the numerical model has particularly evoked considerable interest. Neural networks and kriging have shown promise as proxies, but before they can be reliably used, a significant initial investment in simulation runs is required.

Pan and Horne (1998)[11] investigated the use of kriging in solving multivariate optimization problems, particularly in field development scheduling and well-placement design. Their objective was also NPV maximization and from their studies, kriging led to a significant reduction in the number of simulation runs.

Johnson and Rogers (2001)[12] also used neural networks in lieu of the numerical model for a water-injection optimization project. The quality map used in this study is itself a proxy and it is an extension of the work of da Cruz *et al*. who introduced the method as a possible well-placement optimization tool in 1999 (Cruz *et al*., 1999)[13].

Handels et al. (2007)[14] and Wang et al. (2007)[15] proposed different approaches for well placement optimization using gradient-based optimization techniques by representing the objective function in a functional form. They then calculated the gradient of this function and used a steepest ascent direction to guide the search. For the examples they considered, these methods seemed promising due to their efficiency in terms of number of simulation runs. The techniques were only applied to vertical wells and they expected more difficulty in applying them to problems with arbitrary well trajectories in complex model grids.

Montes et al. (2001)[16]optimized the placement of vertical wells using a GA without any hybridization. They tried to discern the effects of internal GA parameters, such as mutation probability, population size, initial seed, and the use of elitism. Their tests were applied on two synthetic rectangular models (a layer cake model and a highly heterogeneous one). For the tested cases, they found that the ideal mutation rate should be variable with generation. Using random seeds for their problem showed little sensitivity while the use of elitism showed significant improvement. The population size study they performed suggested that an appropriate size was equal to the number of the variables in the problem. When they used very big populations, solution convergence was deterred as more poor quality chromosomes had to be evaluated. They also drew attention to issues like absolute convergence and stability of the optimization algorithm.

Nogueira and Schiozer (2009)[17] proposed a methodology to optimize the number and placement of wells in a field through two optimization stages. The procedure started by creating reservoir sub-regions equal to the maximum number of wells. Then, a search for the optimum location of a single well was performed in each sector.

The second stage aimed to optimize well quantity through sequential exclusion of wells obtained from the first stage. After a new optimum number of wells were reached, the first stage is performed again until no improvement in the objective function is observed. This strategy showed efficiency when tested on a heterogeneous synthetic model with light oil. They optimized both vertical and horizontal wells in separate studies. They also concluded that the proposed modularization of the problem speeds up the optimization process for their problem of consideration.

Yeten et al. (2002)[9] applied a bGA to optimize well type, location, and trajectory for nonconventional wells. Along with that, they developed an optimization tool based on a nonlinear conjugate gradient algorithm to optimize smart well controls. Several helper functions were also implemented including ANN, the Hill Climber (HC).

In addition, they applied near wellbore upscaling, which approximately accounts for the effects of fine scale heterogeneity on the flow that occurs in the near-well region by calculating a skin factor for each well segment. The results of this study were presented on fluvial and layered synthetic models, as well as a section model of a Saudi Arabian field. An experimental design methodology was introduced to quantify the effects of uncertainty during optimization. The study also conducted sensitivity analysis in a similar manner to Guyaguler's study [2].

Rigot extended the optimization engine developed by Yeten et al. (2002) [9] implementing an iterative approach to improve the efficiency of multilateral well placement optimization. He divided the original problem into several single well optimizations to speed-up the optimization process and improves results. He also applied a proxy to avoid running numerical simulation if the expected productivity of a certain well was within the range of validity of the proxy.

3. The Norne Field

The Norne field is situated in the southern part of the Nordland II area in the Norwegian Sea precisely on blocks 6608/10 and 6508/1. Its location, relative to other fields is shown in Figure 1. The field is located 85 kilometres from Heidrum and roughly 200 km from the north of the Norwegian coast. This area has a water depth of 380 meters. Hydrocarbons in the Norne field are located in the lower-to Middle-Jurassic sandstones, which are of a good reservoir quality. Norne lies in a license which was awarded in 1986[18]. Hydrocarbons in the Norne field are located in the Lower- to Middle-Jurassic sandstones, which is of a good reservoir quality [18].

The Norne field

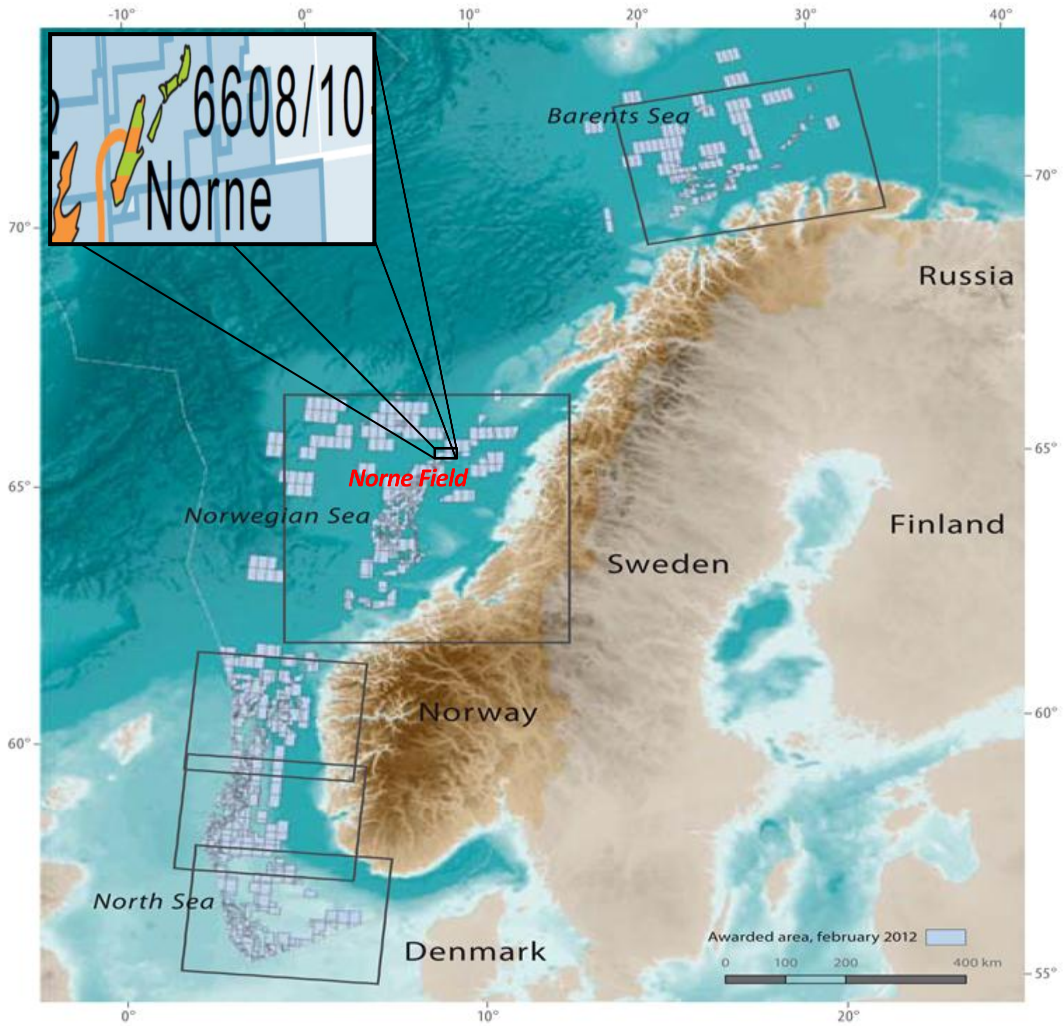


***Figure1 - Norne Field on the Norwegian continental shelf* [19]**

The Norne field is owned by a partnership of Petoro AS (54.0%), Statoil (39.1%) and EniNorge AS (6.9%). Statoil is the operator [20].

The well 6608/1 0-2 first penetrated the Norne reservoir in December 1991. Appraisal well 6608/1 0-3 was drilled in 1993 and proved the field's northerly extension. Based on results from those two wells, a development project began in 1993. Exploration well 6608/1 0-4 was drilled in a separate smaller structure north-east of Nome and proved some additional reserves.

An oil zone of 110 meters thick with an overlying gas cap makes up the hydrocarbon column. The reservoir is a flat structure with the crest about 2,525m below mean sea level (MSL). Reservoir pressure is close to hydrostatic, with a formation pressure of 273bar and a temperature of 98°C at a reference depth of 2,639m below MSL. The oil/water contact is defined at 2,688m. Reserves in-place is estimated at one billion barrels (160 million m^3) of oil and 29 billion m^3 of free and associated gas. Reservoir simulations and risk analysis suggest that the most likely estimate for recoverable reserves is 450 million barrels of oil and 15 billion m^3 of gas.

Production from the Norne field in the Norwegian Sea began on 6 November 1997.Recoverable reserves originally present were 89.2 million Sm3 oil, 14.billion Sm^3 gas and 1.7 million tonnes NGL. Out of which according to reports, remaining at 31.12.05 were 21.4 million Sm3 oil, 9.4 billion Sm^3 gas and 1.2 million tonnes of NGL. Estimated production in 2006 was 76,000 bbl/day oil, 1.2 billion Sm^3 gas and 0.16 million tonnes of NGL [20].

3.2. General Field Information

The field has two separate compartments: [21]

- Norne Main Structure (Norne C, Norne D and E-segment). Relatively Flat with generally a gas filled Garn Formation and the gas oil contact in the vicinity of the Not formation clay stone. The Norne main structure includes 97% of the oil in place.
- Northeast Segment (Norne G-Segment)(Figure 2)

The northern flank dips towards north-northwest with an oil leg in the Garn Formation.

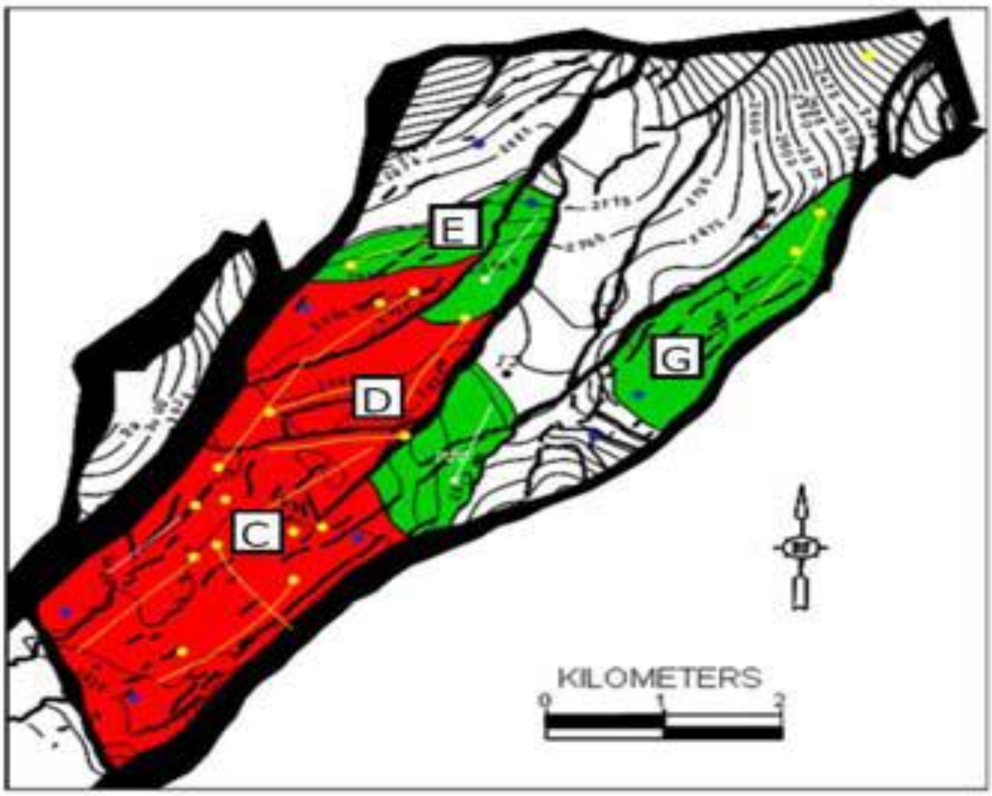


***Figure2 - Map of Norne field separated by four main fault blocks of C, D, E and G segment* [22]**

3.3. Field Geology

The reservoir is around 3 x 9 km in extent, at a depth of approximately 2.5 km bellow the sea surface at its shallowest; it comprised of lower and middle Jurassic sandstones in a NE/SW trending horst block. The gas cap is approximately 75 m thick with an oil column of 110 meters. Sub-horizontal shale and calcite permeability barriers and faulting have a major impact on gas and water injection and on reservoir production. The reservoir blocks are separated by 4 main fault blocks.

The Oil and gas is contained in Jurassic sandstones with good reservoir qualities; porosity ranges from 20-30% and permeability ranges from 50-1000md. Oil is mainly found in the Ile and Tofte formations, and the gas in the Garn formation. The cap rock which seals the reservoir and keeps the oil and gas in place is the Melke formation. The Not formation also behaves as a cap rock, preventing communication between the Garn and the Ile Formations.

The present geological model consists of 17 reservoir zones. Today's reservoir zonation is slightly altered from earlier subdivisions. An illustration of the zonation from 2001 can be seen in Figure 4. Figure 3 shows the geological zonation from 2002 and 2006.

Norne 2002		Norne 2006		
Lower Melke		Not 3	Upper Not Shale	
Garn 3		Not 2	Not 2.3	Not Sist
Garn 2			Not 2.2	
Garn 1			Not 2.1	
Not		Not 1	Lower Not Shale	
Ile 2	Ile 2.2	Ile 2	Ile 2.2	Ile 2.2.2
				Ile 2.2.1
	Ile 2.1		Ile 2.1	
Ile 1	Ile 1.3	Ile 1	Ile 1.3	
	Ile 1.2		Ile 1.2	
	Ile 1.1		Ile 1.1	
Tofte 2	Tofte 2.2	Tofte 2	Tofte 2.2	
	Tofte 2.1		Tofte 2.1	
Tofte 1	Tofte 1.2	Tofte 1	Tofte 1.2	
	Tofte 1.1		Tofte 1.1	

Figure3- Old and new zonation of the Norne Field [23]

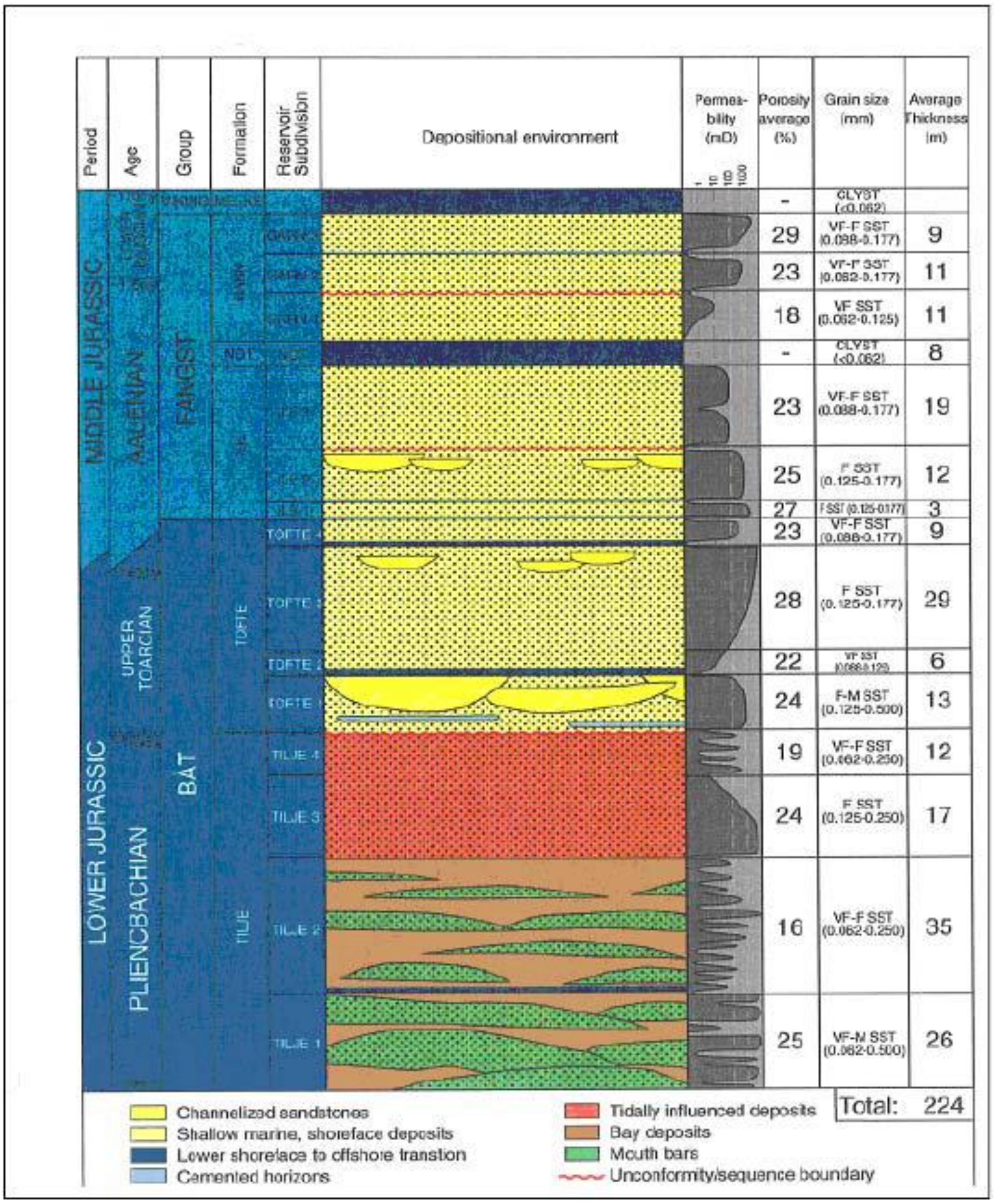


Figure4- Stratigraphical sub-division of the Norne reservoir [18]

The entire reservoir thickness, from Top Åre to Top Garn Formations, varies over the Norne Field from 260 m in the southern parts to 120 m in the northern parts. The reason for this difference is the increased erosion to the north, causing especially the Ile and Tilje Formations to decrease in thickness. Some of the formation encountered are in two major categories, the fangst which consists of the Garn, Not and Ile Formations and the BÅT which includes the Tofte, Tilje and Åre Formations (Figure 4)

3.4. Reservoir Formation [25]

- **The Garn Formation**

The garn formation was deposited during the Late Aalenian and the Early Bajocian, and is 35 m thick sandstone. The depositional environment was near shore with some tidal influence. Reservoir quality is increasing upward within the formation, from pretty good in the lower parts to very good in the upper parts. This formation is divided into reservoir zones based on differing properties and deposits. For the

Garn Formation the number of reservoir zones is three. Garn 1 is a sandstone unit which is coarsening upward, from very fine to fine grained sand.
The lower part is muddy and bioturbated, as it is the continuance of the Not Formation, while the upper part has an increased sand content. At the top of Garn 1 a course to very coarse grained, garnet rich bed is found. Garn 2 is a transgressive deposition consisting of fine grained sandstones, where some layers are bioturbated while others are laminated. The lower part of Garn 3 is not cored in any of the wells. A coarse grained bed is located in the top of Garn 3.

- **The Not Formation**

The Not Formation was also deposited during Aalenian time. It is a 7.5 m thick, dark grey to black claystone with siltstone lamina. The depositional environment was quiet marine, probably below wave base. However, palynological findings indicate that there was freshwater influencing the environment. This is explainable if one assumes that the water column in the basin was stratified, hence preventing the water from mixing before it reached far into the basin. The Not Formation has a coarsening upward trend which continues into the Garn Formation. Therefore, it can be found a layer of very fine grained, bioturbated sandstone in the upper part of the formation. The upward coarsening indicates deposition during a regression.

- **The Ile Formation**

The Ile Formation was deposited during the Aalenian, and is 32-40 m thick sandstone. The depositional environment was in the shore-face. This formation is divided into three reservoir zones; Ile 1, Ile 2 and Ile 3. The separation between Ile 1 and Ile 2 is the same as the boundary between the Ror and Ile 1 Formations, a cemented calcareous layer. These layers are probably the result of minor flooding events in a generally regressive period. Both the calcareous layers are correlative in the wells 6608/10-2 and 6608/10-3, and are assumed to be continuous throughout the Norne Field.

Ile 2 and Ile 3 are separated by a sequence boundary, which is an indicator of the change from regressive to transgressive environment. The reservoir quality of the Ile Formation is generally good, especially in the regressive depositions, whereas the reservoir properties are decreasing toward the top of the formation. Ile 1 and Ile 2 both consist of fine to very fine grained sand which is coarsening to the north. Bioturbation, glauconites and plenty of calcareous shell fragments are all evidence of the depositional environment. The coarser grained sequence boundary that was mentioned above is at the top of Ile 1. Ile 3 lies above the sequence boundary and is an extensively bioturbated, upward fining sandstone of fine to very fine grains. This zone also contains glauconites, phosphorite nodules and clay clasts, which are signs of periods of starvation during the transgression.

- **The Tofte Formation**

The Tofte Formation was deposited on top of the unconformity mentioned above during the Late Toarcian. Mean thickness of the Tofte Formation across the field is 50 m. The depositional environment was marine from foreshore to offshore. To the east of the Nordland Ridge the depositions from this age are mostly shales, whilst sand were deposited to the west. In addition, there is proof of minor erosion at the top of the ridge. It is therefore assumed that the Nordland Ridge was a barrier for sand transportation to the east.

The Tofte Formation is divided into three reservoir zones. Tofte 1 consists of medium to coarse grained sandstones with steep dipping lamina. The lower parts are more bioturbated and have finer grains. The dip of the layers suggests that the source area for sediments was to the north or northeast of the field.

Another important issue related to Tofte 1 is the limited distribution in the east-west or northeast-southwest direction. Tofte 2 is an extensively bioturbated, muddy and fine grained sandstone unit. Floating clasts can be found in the lowermost part of the section, which is coarsening upward. Tofte 3 consists of very fine to fine grained sandstone where almost none of the depositional structures are visible because of bioturbation. Some low angle dipped layers occur in the upper part.

- **The Tilje Formation**

Tilje Formation was deposited in a marginal marine, tidally affected environment. Sediments deposited are mostly sand with some clay and conglomerates. The source of the sediments was located west of the Norne Area. The formation is thinning to the north due to decreased subsidence rate during the deposition, along with increased erosion to the north/northeast at the base of the overlying Tofte Formation. An unconformity is discovered at the top of the Tilje Formation.

The Tilje Formation is divided into four reservoir zones based on bio-stratigraphic events and similarities in log pattern. Tilje 1 is not cored in either of the wells 6608/10-2 nor 6608/10-3, but it is believed to consist of two sequences of sand that are coarsening upward and more massive sand at the top. Tilje 2 has a heteroclitic composition consisting of; sandstone layers of variable thicknesses, heavily bioturbated shales, laminated shales and conglomeratic beds.

A varying depositional environment is characteristic for Tilje 2 deposits. Tilje 3 consists of fine grained sand which has a low degree of bioturbation. It is therefore possible to see mud drapes, cross bedding and wave ripples in the depositions. Implications of the presence of fresh water are also found. Tilje 4 is a fine grained, bioturbated and muddy sandstone in the lower parts, while upper parts have conglomeratic beds inter-bedded with thin sandstone and shale layers.

3.5. Reservoir communications [25]

Vertical and lateral flow in the Norne Field is affected by both faults and stratigraphic barriers. Although these barriers are not expected to be important in a field-wide scale, it is important to consider the effect they have on the fluid flow to enhance the drainage strategy.

3.5.1. Faults

Faults, especially major faults, can be discovered by studying the seismic data. Each sub-area of the fault planes has been assigned transmissibility multipliers. To describe the faults in the reservoir simulation model, the fault planes are divided into sections which follow the reservoir zonation. These are functions of fault rock permeability, fault zone width, the matrix permeability and the dimensions of grid blocks in the simulation model. Several stratigraphic barriers are present in the field. Their lateral extent and thickness variation are assessed using cores and logs.

3.5.2. Stratigraphic barriers

Several stratigraphic barriers are present in the field. Their lateral extent and thickness variation are assessed using cores and logs. Continuous intervals which restrict the vertical fluid flow within the Norne Field are listed below in Table 2. Core photography's has been used to select representative core plugs. To determine average vertical permeability for each barrier, k_v measurements are used. Pressure development in the field clearly indicates what influence the stratigraphic barriers have on flow within the reservoir. Most prominent barriers to flow are the Not Formation, the carbonate cemented layers which separate Ile 1 and Tofte 4 Formations, and the claystone which separate Tilje 3 and Tilje 2 Formations.

Table1 - Location of the stratigraphic barriers in the 1999 and 2004 geological zonation [24][25].

Geological zonation		Comment
1999 model	**2004 model**	
Garn 3/Garn 2	Garn 3/Garn 2	Carbonate cemented layer at top Garn 2
Not Formation	Not Formation	Claystone formation
Ile 3/Ile 2	Ile 2.1.1/Ile 1.3	Carbonate cementations and increased clay content at base Ile 3
Ile 2/Ile 1	Ile 1.2/Ile 1.1	Carbonate cemented layers at base Ile 2
Ile 1/Tofte 4	Ile 1.1/Tofte 2.2	Carbonate cemented layers at top Tofte 4
Tofte 2/Tofte 1	Tofte 2.1.1/Tofte 1.2.2	Significant grain size contrast
Tilje 3/Tilje 2	Tilje 3/Tilje 2	Claystone formation

3.6. Main Processing System

The well stream will be transferred via the swivel mounted in the turret to the inlet separator, operating at 15-20bar. Oil from this separator is stabilized in a second separation unit, operated at 1.5-2bar, before it is transferred via a coalescer to a storage tank. Gas from the second-stage separator is compressed in two stages, and then mixed with gas from the inlet separator. All the gas is then compressed in three stages to 280bar, for its reinjection into the reservoir [24][26].

3.7. Water Injection

Normally, only 30% of the oil in a reservoir can be extracted, but water injection increases that percentage (known as the recovery factor) and maintains the production rate of a reservoir over a longer period. The injection of waters, both aquifer and seawater, is extensively used to support and maintain the production of oil in the C-segment field. Pressure in the reservoir is maintained by reinjection of produced gas in the gas cap and water injection in the water zone.

De-aeration of the injection water has been eliminated, since the presence of oxygen in the injected seawater is expected to stimulate reservoir productivity. Reinjected of produced water into the reservoir together with the reduced use of chemicals owing to the elimination of de-aeration, this solution will help to safeguard the environment. Injecting raw seawater, together with the produced water, has simplified the water-injection system, but has also required the extensive use of high-quality materials.

3.8. Subsea System and producing wells

Subsea production facilities will comprise five well templates - three for production, one for water injection and one for combined gas and water injection. Each template has four slots and the capacity to tie in additional satellite wells. Flexible flow lines and risers are specified. A multifunctional umbilical will be used to control and monitor the subsea system, to distribute chemicals and hydraulic fluid, as well as to supply power. The templates are being installed in northern and southern groups, placed about 4,000m apart. Water depth varies between 370-390m.

One production and one water-injection template will make up the northern group. These installations are tied back to the production ship by two nine-inch production lines, one nine-inch water-injection line and one control and service umbilical. The southern group comprises two production templates, a combined water-/gas-injection line and two control and service umbilical's. The templates in each group are positioned so that the rig can enter all the slots without the need for anchor handling [26][27].

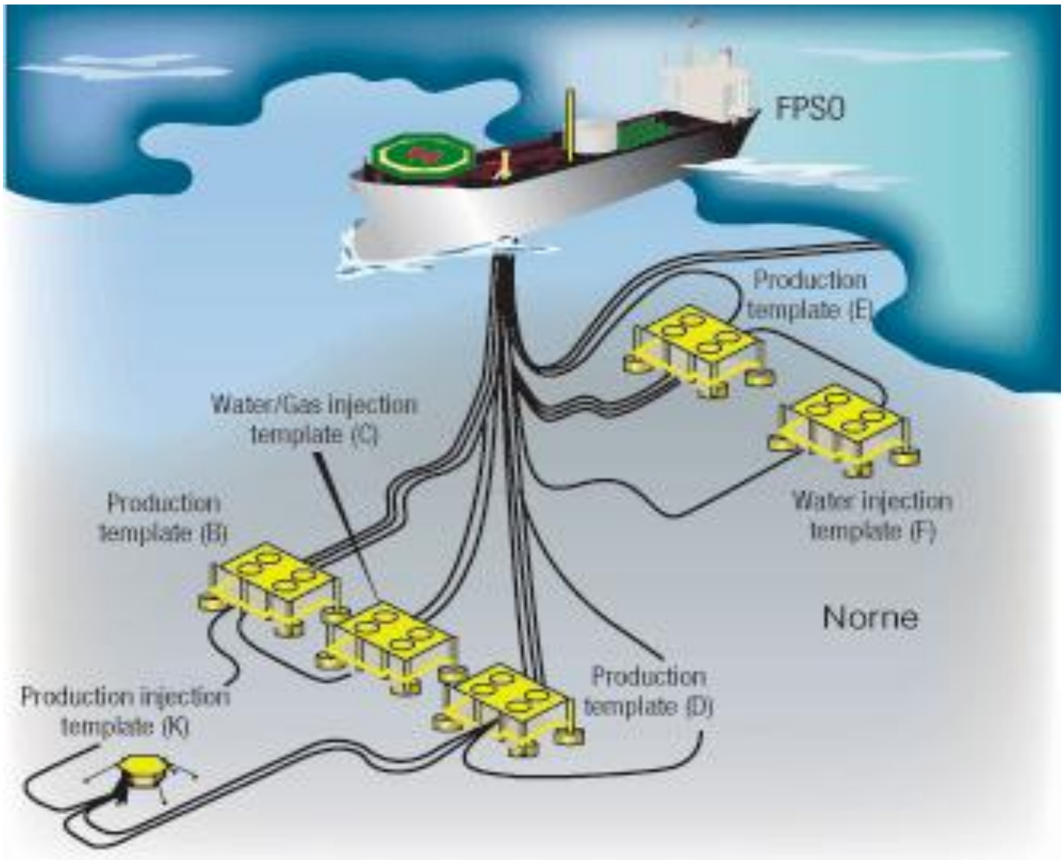


Figure5 - The subsea template for Norne field [28]

The field is being developed with five templates (B, C, D, E and F) at the sea bottom connected to a floating production vessel shown in Figure 5. In 2005 an extra template K was placed on the sea bottom 150-200 meters south of B, C and D templates. The K-template has 4 slots available; 3 for producer and 1 for injector or producer. The first production well K-3 H in Figure 6 is planned to be drilled during summer of 2006 [26].

In January 2006 the Norne Field is producing oil from all 12 well slots, approximately 15000 Sm3/d. 8 injectors have been drilled, and water is injected in all 8 wells. 68 million Sm3 oil has been produced since the production started, which is approximately 43% of the oil in place or 76% of recoverable reserves.

3.8.1. Development of the Norne Field

The Exploration wellbores for the Norne Field is presented in Appendix A. The active development wells are shown below in Table 2.

Table2 - Active development wells in the Norne Field [19]

Well Names	Completion date	Drill Permit	Wellbore Purpose	Wellbore Contents
6608/10-B-1 BH	2006	2634-P	Production	Oil
6608/10-B-2 H	1997	1239-P	Production	Oil
6608/10-B-3 H	1999	1590-P	Production	Oil
6608/10-B-4 DH	2004	2423-P	Production	Oil
6608/10-C-1 H	1998	1422-P	Injection	Water
6608/10-C-2 H	1998	1501-P	Injection	Water
6608/10-C-3 H	1999	1570-P	Injection	Water
6608/10-C-4 AH	2004	2342-P	Injection	Water
6608/10-D-1 CH	2003	2335-P	Production	Oil
6608/10-D-2 H	1998	1249-P	Production	Oil
6608/10-D-3 BY2H	2005	2580-P2	Production	Oil
6608/10-D-3 BY1H	2005	2580-P1	Production	Oil
6608/10-D-4 AH	2003	2218-P	Production	Oil
6608/10-E-1 H	1999	1591-P	Production	Oil
6608/10-E-2 CH	2008	2915-P	Production	Oil
6608/10-E-3 CH	2005	2551-P	Production	Oil
6608/10-E-4 AH	2000	1727-P	Production	Oil
6608/10-F-1 H	1999	1584-P	Injection	Water
6608/10-F-2 H	1999	1638-P	Injection	Water
6608/10-F-3 H	2000	1669-P	Injection	Water
6608/10-F-4 AH	2007	2898-P	Injection	Water
6608/10-K-1 H	2006	2772-P	Production	Oil
6608/10-K-3 H	2006	2743-P	Production	Oil
6608/10-K-4 H	2007	2830P	Production	Oil
6608/10		3103-P	Production	Oil
6608/10		3106-P	Production	Oil

3.9. Resources and Recoverable Reserves of Norne Field

The most likely in place volumes and official recoverable reserves for the Norne Field are presented in Table 3 below.

Table3 - Initial volumes in place Oil and Gas

Description	Units	PDO	Official RNB 2004
Oil in Place, STOIIP	X 10^6 Sm^3	164.2	157.0
Gas in Place (free & Solution)	X 10^9 Sm^3	29.9	29.8
Recoverable oil Reserves	X 10^6 Sm^3	72.4	89.24
Recoverable gas reserves	X 10^9 Sm^3	-	13.00

The updated estimate made by the Directorate for the total petroleum resources on the Norne Field is presented in Table 4-5.These are resources that are discovered and undiscovered, recoverable resources, including quantities that have already been produced.

Table4 - The NPDs Original Reserves in Norne Field [19]

Recoverable Reserves in Norne Field					
	Original reserves				
Recoverable reserves	**Oil (mill.Sm^3)**	**Gas (bil.Sm^3)**	**NGL (mill.tons)**	**Cond (mill.Sm^3)**	**Total o.e (bill.Sm^3)**
1997	72.4	-	-	-	72.4
1998	80.4	15.0	1.4	0.0	97.3
1999	80.4	15.0	1.4	0.0	97.3
2000	84.8	15.0	1.4	0.0	102.5
2001	84.8	13.5	1.3	0.0	100.8
2002	87.4	13.7	1.4	0.0	103.8
2003	87.4	13.7	1.8	0.0	104.4
2004	88.5	13.8	2.5	0.0	107.1
2005	89.2	14.0	1.7	0.0	106.4
2006	90.0	10.7	1.2	0.0	103.0

Table5 - The NPDs Remaining Reserves in Norne Field [19]

Recoverable Reserves in Norne Field					
	Remaining reserves				
Recoverable reserves	**Oil (mil.Sm^3)**	**Gas (bill.Sm^3)**	**NGL (mill.tons)**	**Cond (mill.Sm^3)**	**Total o.e (bill.Sm^3)**
31.12.1997	72.0	-	-	0.0	72.0
31.12.1998	73.9	15.0	1.4	0.0	90.8
31.12.1999	65.4	15.0	1.4	0.0	82.2
31.12.2000	59.4	15.0	1.4	0.0	77.0
31.12.2001	47.9	12.5	1.2	0,0	62.7
31.12.2002	40.4	11.8	1.3	0,0	54.5
31.12.2003	31.8	11.0	1.6	0.0	45.8
31.12.2004	25.9	10.2	2.1	0.0	40.1
31.12.2005	21.4	9.4	1.2	0.0	33.1
31.12.2006	17.3	5.7	0.7	0.0	24.3

3.10. Drainage strategy and well plans

The Norne Field should be regarded as a mature reservoir and plateau rates will definitely not be achieved anymore. The reservoir performance is in major parts of the field as expected. Water cut is rising in most of the wells. Drainage from the upper Ile reservoir has started in 3 wells, two of them performing well. The reserve estimate in base case has been increased from 88.5 to 89.2 million Sm^3.

This is based on investment of the K-template and the verification of TTRD Technology in 2005. However, the increase in reserves is less than the increase due to these IOR measures due to a reduction of the estimate for reserves. The Field is now developed only with horizontal producers as shown in Figure 7. However, to accelerate the build-up of well potential until plateau production was reached, some of the first producers were drilled vertical to some deviated. All these wells have been side-tracked to horizontal producers.

The drainage pattern in the Norne Field can be seen in Figure 8.The pre-start drainage was to maintain the reservoir pressure by re-injection of produced gas into the gas cap and water injection into the water zone. However, during the first year of production it was experienced that the Not shale is sealing over the Norne Main Structure, and the gas injection has been changed to inject in the water zone and the lower part of the oil zone, and in 2005 the gas injection was ended. The horizontal oil producers in Tofte and Lower Ile formation will be plugged and side-tracked and drilled horizontal in upper Ile Formation just below the Not Formation shale when the water cut becomes high (>90%) resulting in problems to lift the liquid.

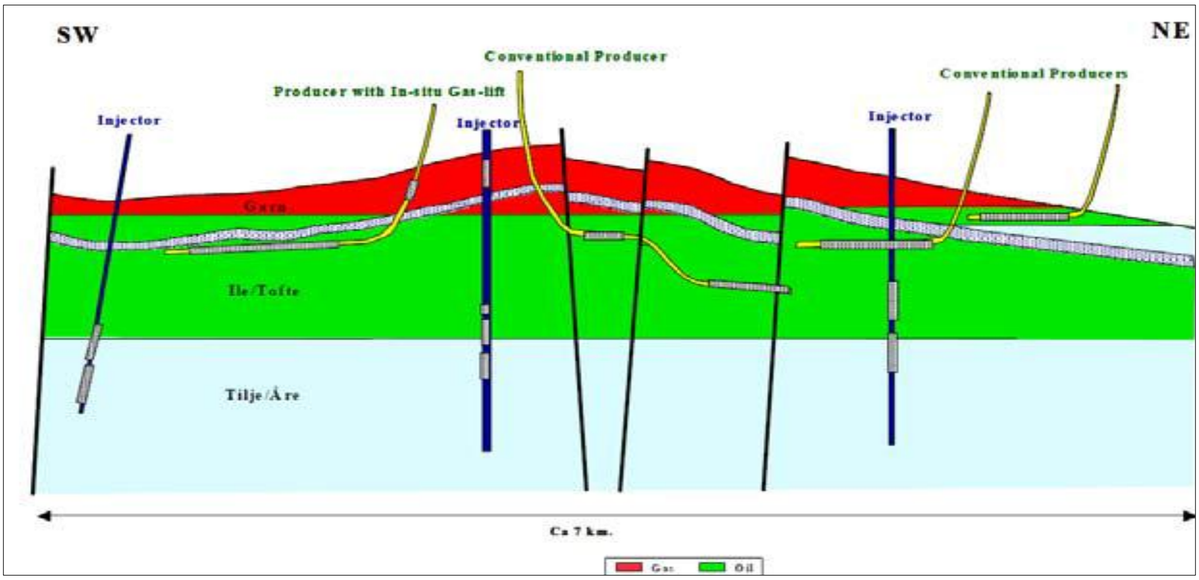


Figure6 -Cross-Section Area of the Norne field [19]

The Norne field is a flat horst structure and a change in fluid contacts during production has to be monitored by the difference is seismic signals from the reservoir zone from year to year. In this context it is very important for repeatability that the seismic lines are acquired at the same geographical position each time and the seismic acquisition parameters are identical to the previous surveys. For the 4D surveys on the Norne Field, WesternGeco Q-marine active streamer steering have been used, allowing accurate positioning of streamers for reliable repeat surveys[30][31].

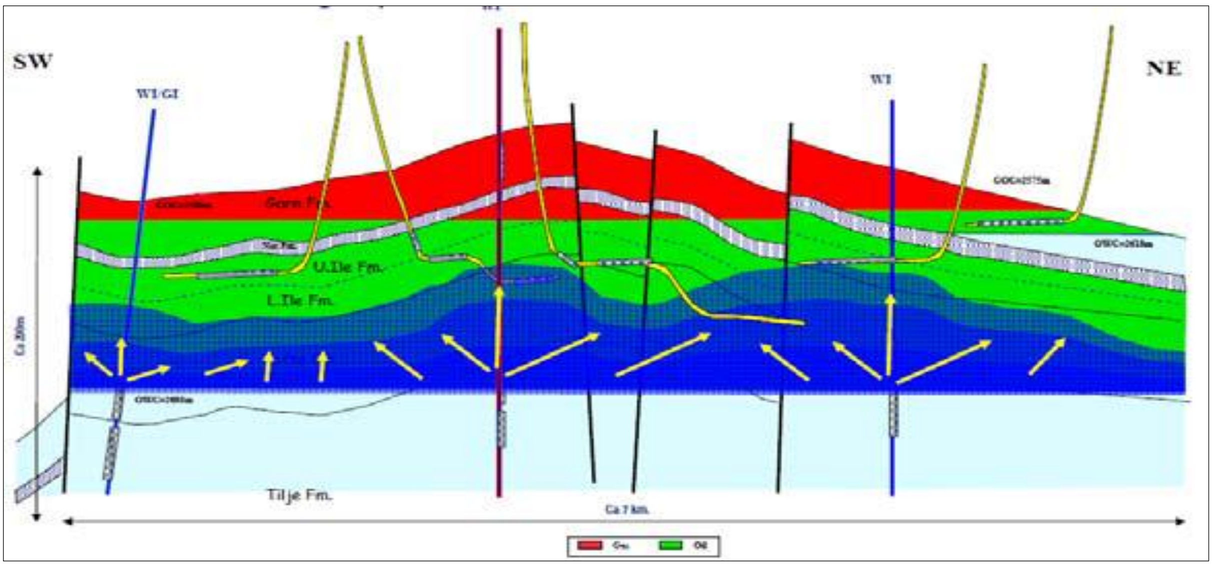


Figure7 - The Norne Field drainage pattern [29]

4. The Eclipse Simulator

ECLIPSE from Schlumberger is one of the leading reservoir simulators in oil industry. It is a batch program. As an input user creates text file with a set of keywords that must be located in particular section. Such data file gives complete description of a reservoir. The following section describes shortly the model built in ECLIPSE simulator. An eclipse tool was used to build four different black-oil models from the Norne field.

The use of reservoir simulation is very important to provide reliable production/injection forecast and correct predictions for field recovery potential. However, during the initial field development phase the amount of available information for the reservoir is very restricted and it is very difficult to obtain a correct reservoir model. Therefore, the use of simplified simulation models provides more appropriate and lead to better results.

4.2. The Norne Field Simulation model

The Norne field has been simulated by four different Eclipse black-oil models, from oldest to newest: *[30][31]*

- The PDO model has grid dimensions of 40x70x16 and is based on a 1994 interpretation of the 3D seismic survey ST9203.
- The 1998 model has grid dimensions of 56x124x24 and is based on a 1998 interpretation of the 3D seismic survey ST9203.
- The 2004 model has grid dimensions of 46x112x22 and is based on a 2004 interpretation of the 4D seismic surveys ST0103, ST0305, ST0409.
- The 2006 model this model has grid dimensions 55x136x32 and is based on a 2006 interpretation of the 4D seismic surveys ST0103, ST0305, ST0409 and ST0603.

New simulation models are built when significant updates of the geological model are done, or if certain formations need refinement. The reservoir model used on this study is currently based on 2004 geological model with 3D three-phase full field black-oil model. The Norne full field model consists of 49080 active grid cells. DX & DY~ 80-100 m is shown in Figure 9.

Field information used is generated from the Norne model. Information such as data set and includes file which consists of the faults, grids, properties, productivity index, relative permeability, and summary. The reservoir parameters used in the simulation model are based on results from two wells namely 6608/10-2 and 6608/10-3. The fluid analyses from both wells indicate one common fluid system over the main structure in the field. Water compressibility used in the eclipse model was 4.67 X 10^{-5}/bar at 277 bars while the formation volume factor used was 1.038Rm^3/Sm^3.

The rock compressibility of 4.84 X 10^{-5}/bar was used in the entire reservoir while the water viscosity is 0.318cp *[32].*

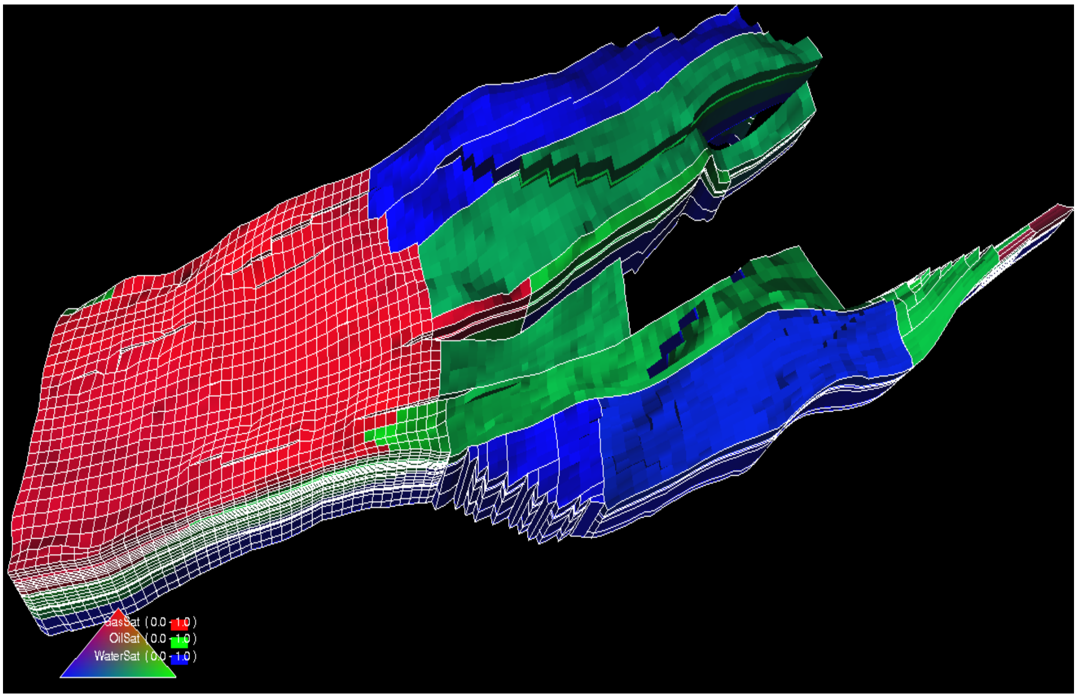


Figure8 - The 2004 Norne Field Reservoir Simulation Model

The pressure and temperature used in the simulation model is 273.2 bar and 98.3°C respectively at 2639m. It is assumed that three different equilibrium regions exist in the reservoir (including the Northeast segment).

Table6 - Characteristic Fluid Parameter for Norne Field [32]

	Units	Norne Main Structure	Norne G-Segment
Bubble point	bar	251	216
Gas Oil Ratio	Sm^3/Sm^3	111	96
Oil Formation Volume Factor At bubble point	Rm^3/Rm^3	1.347	1.3
Oil density at bubble point	g/cm^3	0.712	0.729
Oil Viscosity at bubble point	cp	0.58	0.695
Oil formation Volume factor at initial conditions	Rm^3/Sm^3	1.3185	
Formation volume factor for gas	Rm^3/Rm^3	4.74 10E-3	

4.3. The Case study - Norne C-Segment

The Norne C-segment is part of the full Norne Field which was separated from it for different study purposes by the Integrated Operations Centre IOC at NTNU to be used in the Petroleum Industry. Production data from the reservoir is available. The production data comprises of wellbore, production rate, and water-cut and reservoir pressures.

4.4. Norne C-Segment Simulation model

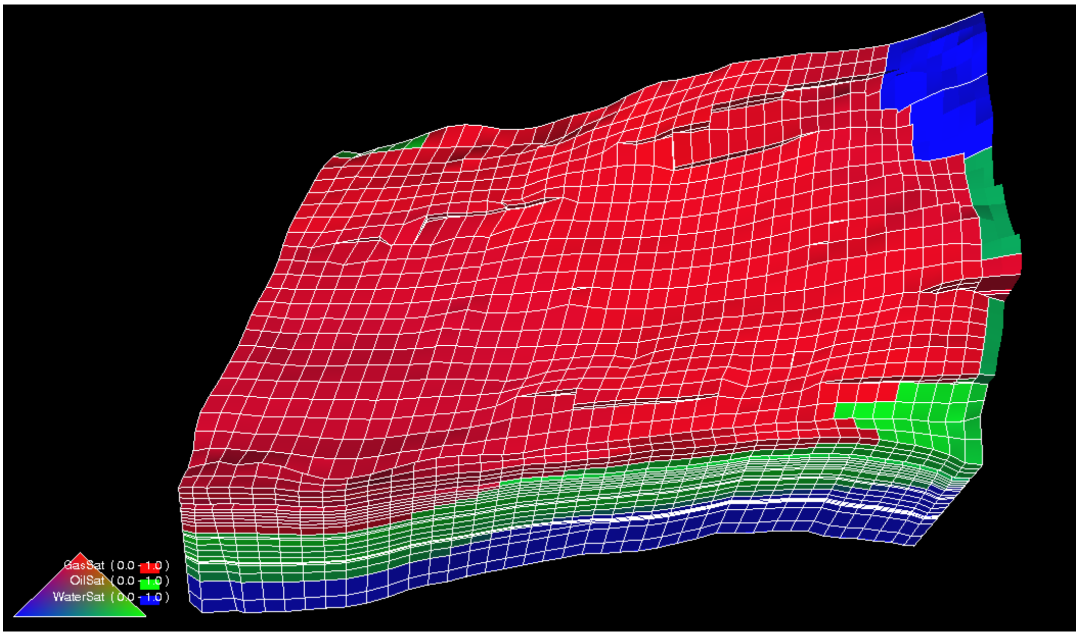


Figure9 -The C-Segment Simulation Model Separated from the whole Norne Field

4.4.1. Simulation grids in the Coarsen Model

The C-segment coarsened grid model was separated from the rest of field by keeping the C-segment coarsened model with 29x49x22 grid blocks. Only 19911 active grid blocks are active. The active grid blocks are displayed in Figure 9 &10. The simulation grid is generated by the Eclipse 100. The layer number with formation names can be seen in Table 7.

4.5. Reservoir Properties and Saturation

Porosity, permeability and net-to-gross are imported from the geological model, and vertical permeability is given as a ratio of horizontal permeability [25], Figure 11 shows a reservoir model with different properties.

Porosity: The porosities used in the reservoir simulation model are from the porosity maps. The calculation of porosity is based on the density log where the total porosity has been estimated from the equation:

$$\Phi = \alpha + \beta \rho_b \qquad (1.1)$$

Where, α and β are found from cross plots of the overburden corrected core porosity verse the density log. The porosity is modelled as a constant average value for each reservoir zone since all the wells are quite the same with respect to porosity. The average values of the porosity in the simulation model of ranges from 20-30 precents.

Net-to-gross: Map of net-to gross sand for each reservoir zone in the geological model have been used in the reservoir simulation model. Same as the porosity, the parameter is constant to all wells with the average value ranges of 0.7-1.0.

Permeability: Permeability values ranging from the simulation model ranges from 20-2500 mD. The value used for each layer was constant in the simulation model. The permeability Figures used were obtained as an average from the two wells mentioned previously. These permeability Figures were obtained from logs based on the relationship between core porosity and core permeability. There is a reasonable agreement between the permeability calculated from the well test and the permeability calculated from log.

Saturation: The initial oil, gas and water saturation in the Norne C-segment model is shown in Figure11. The initial water saturation of the simulation model is a sampled from the geological model. The calculation is based on the Archie's equation. The Archie equation:

$$Sw = (R_w\, a / R_c \Phi_m)^{1/n} \qquad (1.2)$$

was used to evaluate Sw assuming clean sand.

Table7 - Average values of porosity, permeability and net-to-gross in modeling [32]

Layer Number	Formation Name	Depth	Porosity	Permeability	Net/Gross
		M TVD /MSL	**(Fraction)**	**mD**	**(Fraction)**
1	Garn 3	2553	0.29	813.9	0.94
2	Garn 2	2562	0.23	518.6	0.86
3	Garn 1	2570	0.18	44.5	0.78
4	Not	2581	0.12	0	
5	Ile 2.2	2591	0.23	137.6	0.89
6	Ile 2.1.3	2601	0.23	87.6	0.92
7	Ile 2.1.2	2614	0.26	723.9	0.99
8	Ile 2.1.1	2622	0.22	508.1	0.8
9	Ile 1.3	2630	0.27	793.5	0.97
10	Ile 1.2	2628	0.23	108.8	0.93
11	Ile 1.1	2637	0.31	1348.2	1
12	Tofte 2.2	2641	0.3	1063.7	1
13	Tofte 2.1.3	2645	0.28	590.7	1
14	Tofte 2.1.2	2649	0.27	375.3	1
15	Tofte 2.1.1	2653	0.26	255.9	1
16	Tofte 1.2.2	2663	0.26	166.7	1
17	Tofte 1.2.1	2679	0.24	971.6	0.9
18	Tofte 1.1	2686	0.23	819.6	0.89
19	Tilje4	2694	0.19	308.7	0.83
20	Tilje3	2709	0.24	555.4	0.87
21	Tilje2	2731	0.16	212.4	0.72
22	Tilje1	2771	0.25	1614	0.9

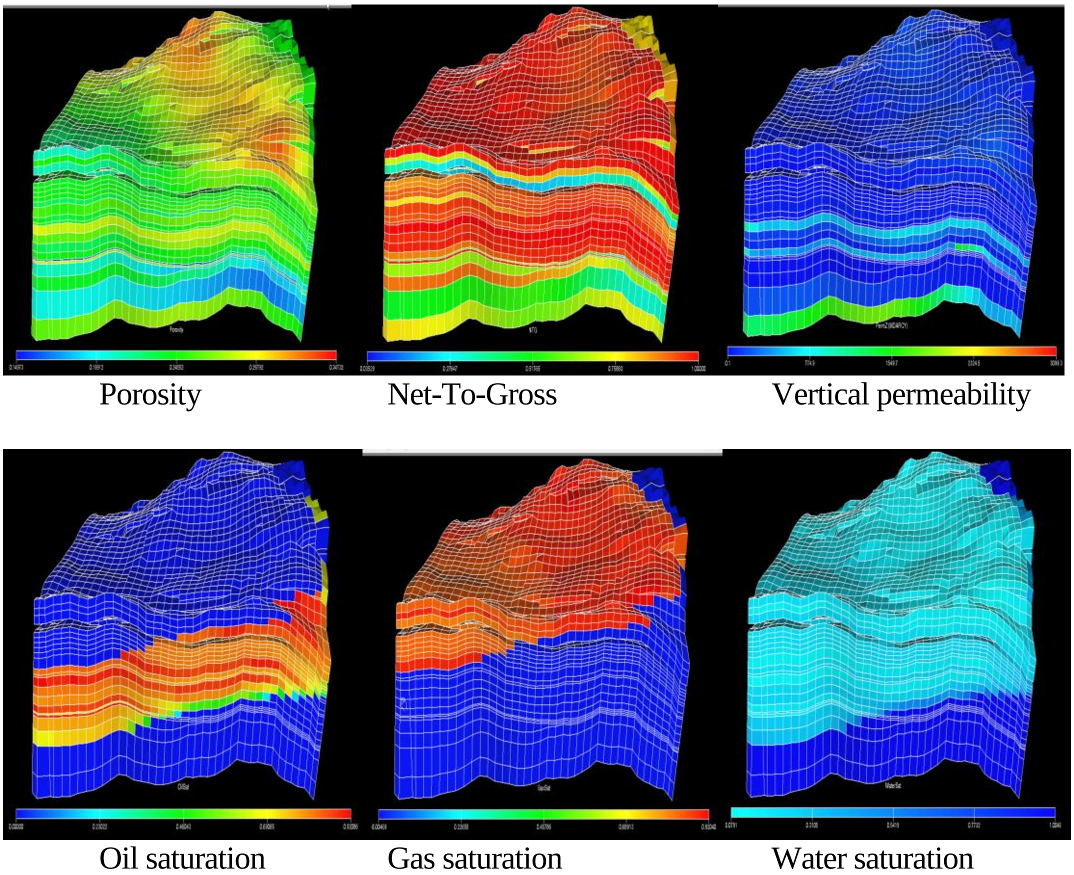


Figure10 - Reservoir Properties and Saturation

4.5.1. Fluid contact

The fluid contact in Norne C-segment simulation model is presented in Table 8 below.

Table8 - Fluid contacts in Norne C-segment simulation model

Formation	C-segment	
	OWC in Depth (m)	**GOC in Depth (m)**
Garn	2692	2582
Ile	2693	2585
Tofte	2693	2585
Tilje	2693	2585

4.5.2. Faults and barriers

Communication across faults and stratigraphic barriers are considered to be sensitive, with respect to history matching in the Norne C-segment simulation model. Meaning that the C-segment faults act as barriers to or conduits for fluid flow, and are included in reservoir simulation models by grid offset.

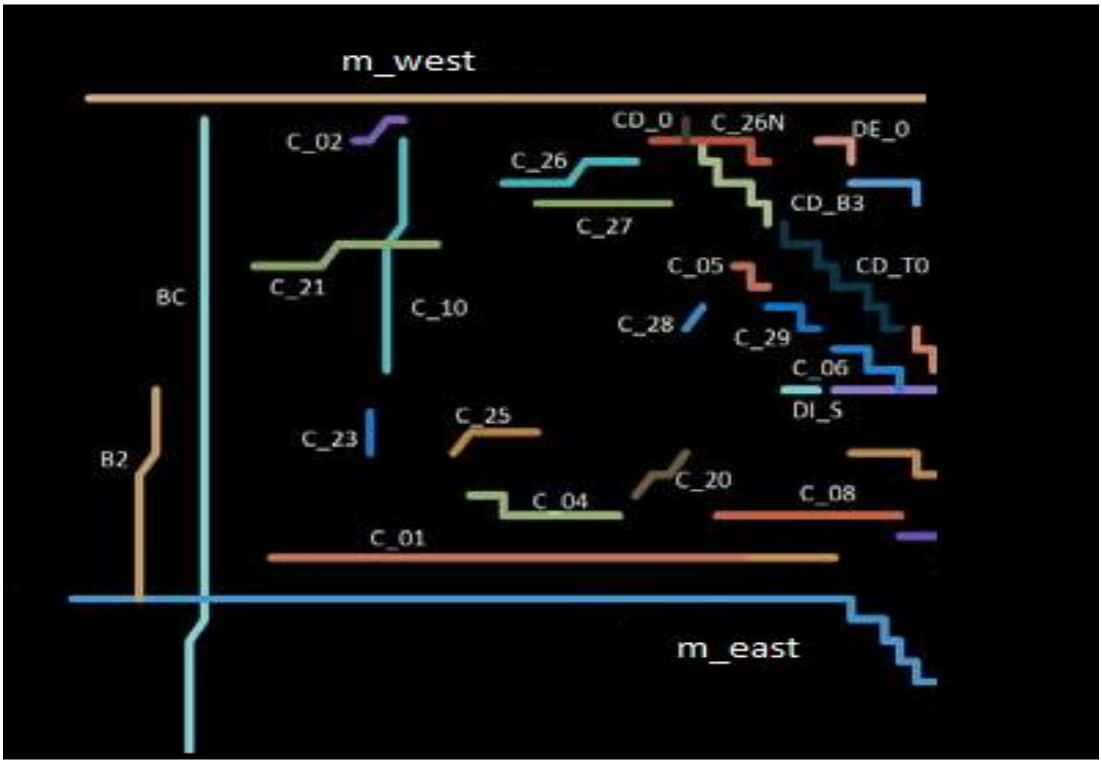


Figure11 - Faults zonation in C-segment simulation model in Eclipse

Fault zonation and fault transmissibility are used to control flooding from the injectors. Vertical transmissibility in the stratigraphic barriers is used to control the oil-water contact rise. Figure 12, shows the fault zonation for 2006 Norne C-segment models. The fault-transmissibility multiplier ranges from a value of 0 (complete flow barrier) to 1 (an open fault).

Table9 - Fault names/transmissibility multipliers for the Norne C-Segment

Fault name	MULTFLT	Fault name	MULTFLT	Fault name	MULTFLT
'BC'	0.1	'C_08_S_Ti'	1	'C_23'	0.1
'CD'	0.1	'C_02'	0.01	'C_24'	0.1
'CD_To'	0.01	'C_04'	0.05	'C_25'	0.1
'CD_B3'	0.1	'C_05'	0.1	'C_26'	0.1
'CD_0'	1	'C_10'	0.01	'C_26N'	0.001
'C_01'	0.01	'C_12'	0.1	'C_27'	0.05
'C_01_Ti'	0.01	'C_20'	0.5	'C_28'	1.0
'C_08'	0.01	'C_20_LTo'	0.5	'C_29'	0.1
'C_08_Ile'	0.1	'C_21'	0.001	'DI_S'	0.1
'C_08_S'	0.01	'C_21_Ti'	0.001	'm_east'	1.0
'C_08_Ti'	1	'C_22'	0.001	'm_west'	1.0

4.6. Wells

The Norne C-segment wells are located in only 4 subsea wellhead templates which are developed with a floating production and storage vessel. The templates are B, C, D, and K Development drilling started with well 6608/10-D-1 H in August 1996 [27].

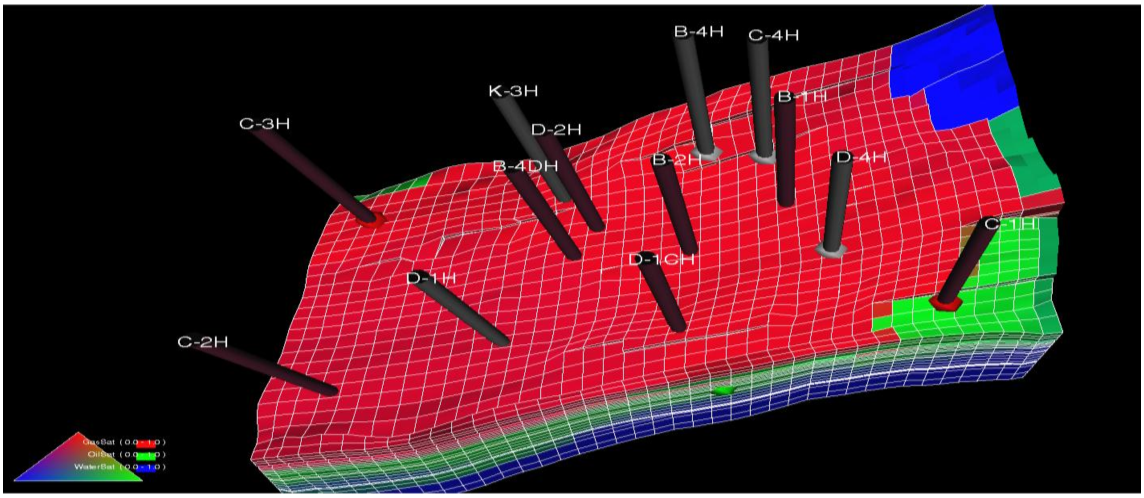


Figure12 - Base case wells in the Norne field C-segment

4.6.1. Producer [31]

Well D-1H:

Well D-1H was the first development well to be drilled on the Norne Field. The plan was to drill it as a producer in the Ile, Ror and Tofte Formations in the southern part of the field. Average inclination of the well from top Ile to total depth was 440. The production start in this well marks the start of the life of the Norne Field; the production start date was the 7th of November 1997. The well was shut the 1st of September 2002.When well D-1Hwas shut, a side-track was planned. A pilot, D-1AH, was to be drilled first to log the formation, find fluid properties and the oil-water contact in the southern part of the C-segment.

Well B-2H:

As the third development well to be drilled, well B-2 H started to produce the 9th of December 1997. It produces from the eastern part of the C-segment with a horizontal section from northwest to southeast in the top of the Ile Formation.

The horizontal section of the well is 850 m long and is completed in the Ile Formation for production. At a later stage the whole reservoir can be completed for production, from top Garn to total depth. This will allow for both oil and gas production.

Well D-2H:

The plan for well D-2Hwas to drill a horizontal producer through the Ile Formation in the C-segment. Because of lost cones in the hole, the first track was plugged back soon after entering the Ile reservoir. The second track, D-2T2H, was more successful and reached its target in Ile 2 and Ile 3 with a near horizontal section of almost 1.1 km. This well was abandoned for a short while with the plan of perforating it in Ile 2 for production. The well started producing the 24th of December 1997.

Well B-4H:

Well B-4H was the fifth development well drilled on the field. It was a vertical producer, drilled through Garn, Ile, Ror, Tofte and Tilje Formations. The well was planned to drain the western part of the C segment and started producing the 27th of April 1998. It was perforated only in the Tofte 3 Formation, while the whole interval is available for perforation, and modifications have been performed. The well was shut May 31st 2001.

Well D-4H:

This well was the sixth development well to be drilled on the Norne Field, D-4 H, was a deviated production well with an inclination of 400 through the Garn, Not, Ile, Tofte, Tilje and Åre reservoir intervals. The purpose was to drain the eastern part of the C-segment and to contribute to a rapid build-up to plateau production. At first, the well was perforated in the Ile and Tofte reservoirs and started production the 17th of June 1998. At a later stage, the entire reservoir section can be completed for production or the well can be side-tracked to a more north-eastern prospect. Production from D-4 H was shut the 16th of November 2002 because of water breakthrough.

Well B-1H:

The tenth development well to be drilled on the Norne Field was well B-1 H. This was a horizontal well, producing from Ile 2 and Tofte 3 Formations. The purpose was to drain oil from the C-segment, mainly the north eastern parts. Reasons for drilling this well was the desire to achieve low GOR and at the same time rapidly build up to plateau production. Production start was 1st of April 1998. Further completions were possible and also side-tracking toward the northern parts as a horizontal producer in the Ile Formation. The well was plugged in October 2005.

Well B-4DH:

Well B-4DH was planned and drilled as a pilot for well B-4DH to verify the fluid contacts in the location where B-4DH was planned. The pilot was drilled because of uncertainties about location of the gas-oil and oil-water contacts in the C-segment. In addition to this, a calibration of the contacts to the 2003 4D seismic was important in order to place B-4DH in the optimal position. Two different gas-oil systems with different levels of the fluid contacts were discovered in the pilot drilling. Some were higher than expected and some lower. Residual gas was found below the Not Formation in addition, this came from the C-3H injector.

Well K-3H:

This well started to produce oil 15th of October 2006. It was the first production well drilled from the K-template. This well was also used to drill the exploration well 6608/10-11 S Trost, before proceeding down, deviated to horizontal, to the base of the Melke Formation. The well was completed in the Ile 2.2 Formation. The primary objective of the well was to drain the remaining oil in the Ile Formation in segment C. The well can be side-tracked at later stages from the Not Formation or Melke Formation.

Well D-1CH:

This well started to produce oil 1st of November 2003. The well is completed in Ile 3.2, through to Ile 2.2 formation. In addition, **Well B-1H,** *i*s produced from both C-segment (90%) and D-segment (10%) and perforation of this well was changed in a way that the well is only produced from C- segment. This well is produced 90% from C-segment and only 10% from D-segment. B-3Hwas removed from C-segment since only the wellhead is located at C-segment and the well is produced from D-segment.

4.6.2. Injector [31]

Well C-1H:

Well C-1H was the seventh development well and the first water injection well drilled on the Norne Field. It injects water into the water leg. This well could also inject gas at a later stage if needed. An inclination of 120was used and the well was drilled through Garn, Ile, Ror, Tofte, Tilje and Åre Formations.

Completion of the well was performed with a perforated cemented liner within the base Tofte and upper Tilje Formations, and the injection started the 21st of July 1998. The well can be perforated through the whole interval later if needed. Side-tracking of the well in north-east direction is also possible if water support is required in the Norne G-segment.

Well C-2H:

Well 6608/10-C-2H was the second water injector drilled on the Norne field. The plan was that this injector should support the already existing injection into the southern part of the field provided by C-1 H. This well can also easily be converted to a gas injector if needed. It was drilled through the Garn, Ile, Tofte, Tilje and Åre Formations with an inclination of 50-450. The well was perforated within the Tilje 3 and 4 Formations. The entire reservoir interval is available for perforation at a later stage and there is a possibility of side-tracking toward the southern parts of the C-segment. The injection started the 21st of January 1999.

WellC-3H:

The plan for this well was to support the existing injection from C-1 H and C-2 H in the southernpart of the field, by injecting water into the water leg. The C-3 H well can easily be converted from water injection to gas injection. The well was drilled through the Garn, Ile, Tofte, Tilje and Åre reservoir intervals with an inclination of 15-100. Injection start was on the 21st of May 1999.

The well is located in the south-western part of the C-segment with the bounding faults of the main field to the north and southwest. When the well was pressure tested it was discovered that there were poorer communication between Ile, Tofte and Tilje than expected.

WellC-4H:

Well C-4H Was drilled in the north-western part of the C-segment as the second development well. The well penetrates the Garn Formation and is a vertical gas injector. Perforations are made with a cemented liner in Garn 3. The injection started the 22nd of November 1997 and lasted until the well was shut the 18th of November 2003. Well C-4H was then plugged and side-tracked to **Well C-4AH**. The reason for shutting well C-4H was that it contributed to a high gas-oil ratio and water cut in the neighbouring production wells. The injection from C-4AH started the 20th of January 2004.

5. Simulation Study

This chapter will explain the simulation carryout on the field on the references case which a base case or which in this content is used as on this study, but first work flow is presented.

5.2. Work Flow

The proposed work flow is simulation run with the Eclipse 100 to generate the reference case. A base case is defined as the initial case; the base case is simulated to obtain production data at the initial state of the field from 1997 to 2006. Afterwards a restart is created for production forecast until 2015. The simulated result on the field show 13 numbers (9 producers and 4 injectors) of wells placed in different location. Duration of wells placed was from the start year of field 1997 to 2006.

After defining the base case, a new field case will be formed without wells. Two scenarios are created Scenario 1 & 2, with 10 new well placements (6 producers and 4 injectors) on each from the start date of the field till 2006. The field will start oil production from 1997 to 2006. As in base case, production forecast will perform till 2015.

5.3. Defining the Base case

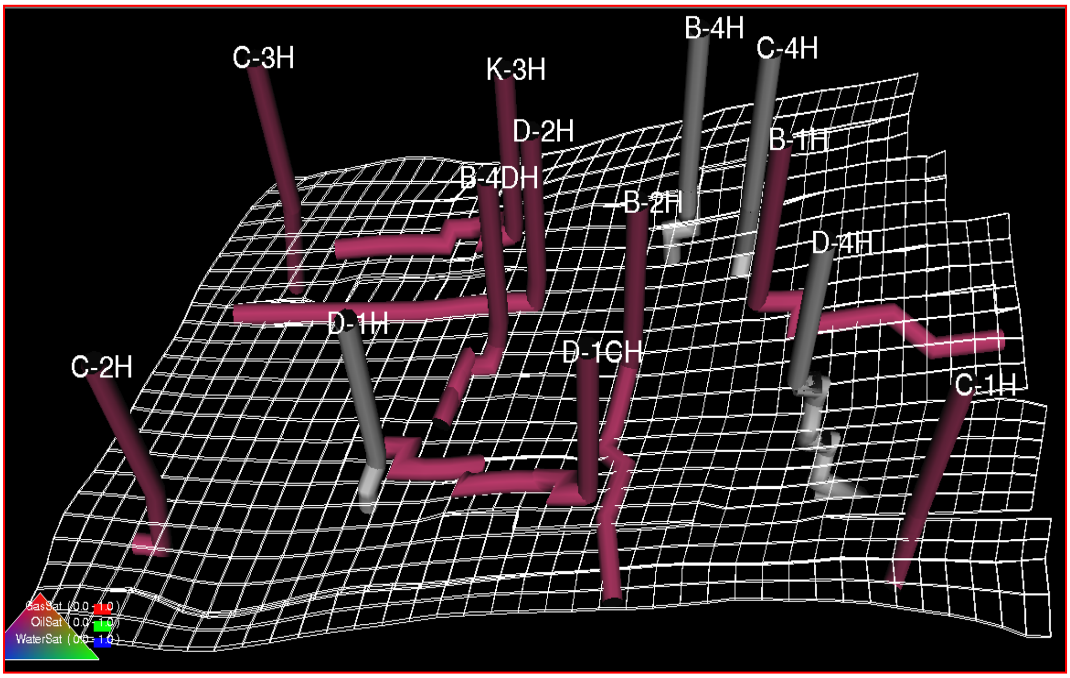


Figure13 - The wellbore location for Base case (Statoil case)

5.3.1. Wellbore location strategy

The well locations are based on the following principles: [26]

- Water injectors located at the flanks of the reservoir
- Gas injectors located at the structural heights of the reservoir
- Oil producers located between gas and water injectors for delaying gas and water breakthrough
- Oil producers are located at some distance from major faults to avoid gas inflow.

The principles presented above are used for all well locations as an initial location. The locations are thereafter optimized with regard to gas and water breakthrough. The wellbore location by Statoil case is shown in Figure 14.

5.3.2. Drainage Strategy

The drainage strategies/drive mechanisms on the field are pressure depletion, gas injection, water injection and combine gas and water injection. Based on the framework, water and gas injection is recommended as the base mechanism for the C-segment field.
The reservoir simulations show that two of the evaluated drive mechanisms, pressure depletion and gas injection, gives a significant lower ultimate recovery than water and combined water-and gas injection *[25].*

5.3.3. Drilling and placement order

Three wells B-2H, D-1H and D-2H was drilled from the start-up in the C-segment field for this case by Statoil. These give plateau production in 2000. Two (2) producers from shows good productivity and late gas break through. In the simulation, the next five were drilled continuously form the production start-up with a drilling time of 1-2 years until 2006. The four injectors are locations close to the edge of the simulation model rounding the in centre all the producers. The first injector well C-1H was drilled a year after the stat-up of the field 1997, and follow by the other four injectors all drilled in 1998. The water injection wells are planned completed the production wells, with a combination of 5.5" and 7" tubing. The injection pressures are dependent on the bottom hole pressure required to flow the water into the reservoir formation.

5.3.4. Completion of wells

The wells are completed in different formations depending on the drainage strategy. The water injectors will be perforated below the oil-water contact, and the two gas injectors are perforated in layer one top Garn formation. The vertical production wells are in generally perforated in the Ile 1, top of Tofte 3 and Tofte. The production wells are completed to delay gas and water breakthrough and to minimize the amount of well interventions required [25]. The well perforation is shown in Appendix B.

The general strategy for completing the wells is:

- Complete wells to give high production/injection rates
- Complete wells to maintain plateau length as length as long as possible
- Complete wells to give good sweep efficiency and a high ultimate recovery
- Complete wells to delay gas and water breakthrough and to minimize gas and water production
- Complete wells to minimize requirements for Workovers

In the reservoir simulator, Workovers are performed if an interval is either dominated by the water or gas production. For all vertical wells, workover is trigged for an interval if water-cut exceeds the maximum of 85% and gas oil ratio exceeds $1200 Sm^3/Sm^3$.

5.3.5. *Production and injection constraints*

Production and injection constraints used in the Statoil base case the simulation model includes;

Maximum oil production rate for each oil producer is 7008 Sm^3/day
Maximum gas injection rate for each water injector is 2600000 Sm^3/day.
Maximum water injection rate for each water injector is 3760 Sm^3/day
Maximum water-cut is 95%
Maximum gas oil-ratio is 15675 Sm^3/Sm^3
Maximum bottom-hole pressure is 376 bars

The main oil producing formations are Ile and Tofte in the C-segment. The production and injection profile from the simulated base case model will be discussed on the next chapter.

5.4. New wells placement

The objective was to place minimum number of wells to obtain same or higher recovery than the Statoil. A decision was made that 10 new wells will be placed taking well type, location and spacing in to consideration. In the base case the producing well and injection wells used a suffix name B, D, K and C respectively. For the new well placement, the suffix "P" will be is used for producers and "I" will be used for the injectors in both scenario cases. The flow in the reservoir from the base case shows good recovery on both vertical and horizontal wells but high recovery is achieved with horizontal wells then the vertical wells. Since few wells will be placed to achieve high recovery, slant vertical wells and horizontal will be placed to decrease the drilling and operational cost.

5.4.1. *Procedure*

The base case wells were all removed from the Schedule file and the field was left with no wells but information in the reservoir still remains the same. The flow pattern was studied along with oil/gas water saturation. Schedule files for Eclipse were performed and well were placed continuously each year starting with the P-1H to P-6H wells. First, by using keyword WELOPEN all existing injection wells were stopped and then opened only when observed pressure drop during production which are in both scenarios. Well properties in COMPDAT and WELSPECS keyword are almost defaulted except wellbore.

To achieve a successful placement both for Scenario 1 and 2, several numbers of simulation runs was carried out and 6 successful producers was placed on Scenerio1 case, while 4 producers was placed on Scenario 2. The remaining 2 producers were left in the same position as in Scenario 1. The producer placement and completion will be done where there is high oil saturation in the field after studying the direction of flow in the reservoir. The completions were targeted at the Ile and the Tofte formations which contain about 80% of the oil in Norne C-Segment.

The location of injection wells depends on the factor such as reservoir structure, injected fluid type, and displacement mechanism. Therefore, all injection wells in both scenario cases were left in the same location as in the base case. Injection wells are all vertical with perforation in the bottom for water injection and in the top for gas injection. Some of water injection wells are perforated throughout the reservoir.

To decrease simulation time restart file for first 9 years of production was made. Then for each case including the base case, additional 9 years of production were simulated in Eclipse. Results of simulation were extracted from RSM files and compared between each other. In this part of report cases are compared only by using value of recovery factor. For economic calculation following indexes were extracted with time step of one year: cumulative oil production, cumulative water and gas injected. Description of the scenario cases and recovery factor after additional 9 years of production is will be explain in the next chapter.

5.5. Scenario 1: Producer placement

5.5.1. Wells Trajectory:

The total number of wells in scenario1 is 10; 6 producers and 4 injectors. The well types are 5 verticals and 5 horizontal. The well trajectory can be seen in Figure 15

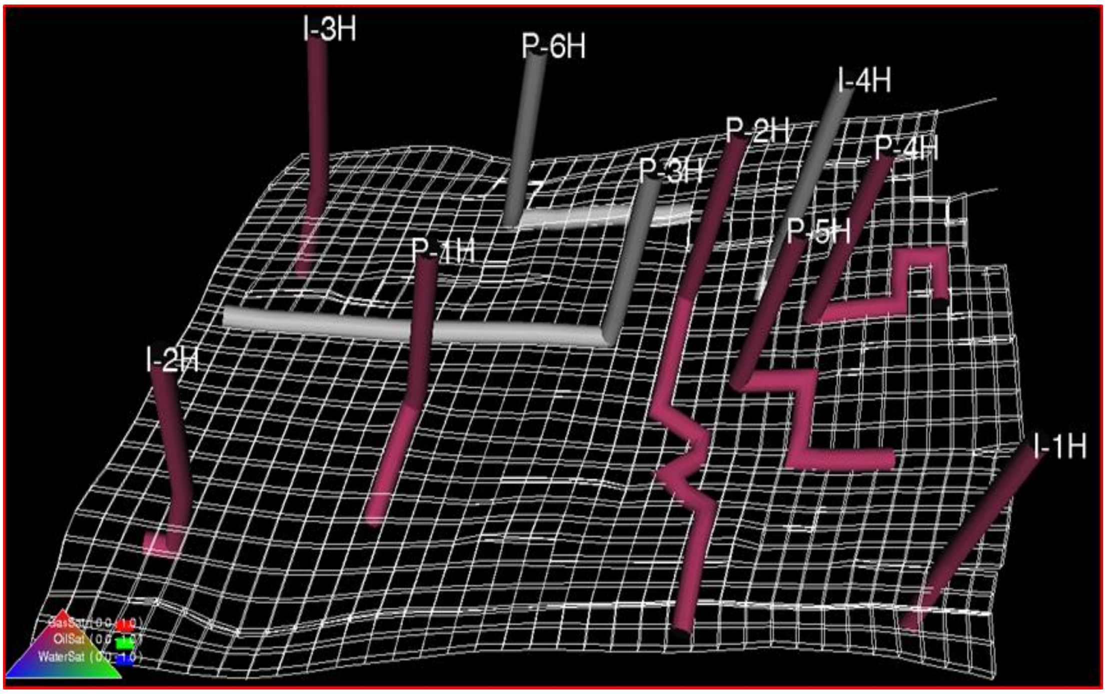


Figure14 - Well trajectory for new wells placement in scenario 1

- Well P-1H is the first well placement lying to the eastern part of C-segment. This is a vertical well with deviation to produce from Ile, Tofte, and Tilje formation. The purpose was to drain oil from the south-eastern part. Well P-1H started producing the 6th of November 1997.
- Well P-2H lies horizontal on the eastern part of C-segment to drainage oil from the lower Ile formation towards. This well started producing the 1st of January 1998.
- Well P-3H is the third well placement in the Scenario1case that lies horizontal towards the South-East part of C-segment to drainage oil from the Ile 1.3 formation. This well started producing the 31st of March 1998.
- Well P-4H well lays horizontally towards the northern-eastern part of C-segment to drainage. The well P-4H drains oil only from in Ile 1.2 formation. This well started producing the 8th of January 2001.

- Well P-5H was placed horizontal on north-east part of C-segment on Ile 3.1 through to Ile 1 formation to drainage oil from eastern part this well started producing the 3rd of January 2002.

- Lastly, Well P-6H is the fifth well placed in scenario1case that lies horizontal to the north. This well drains oil from this well from the Ile and Tofte formation. This well started producing the 2nd of January 2003.

The well completion coordinates for all the producers in Scenario 1 case wells are given in Appendix B and Figure 16 shows the well completion in the simulation model.

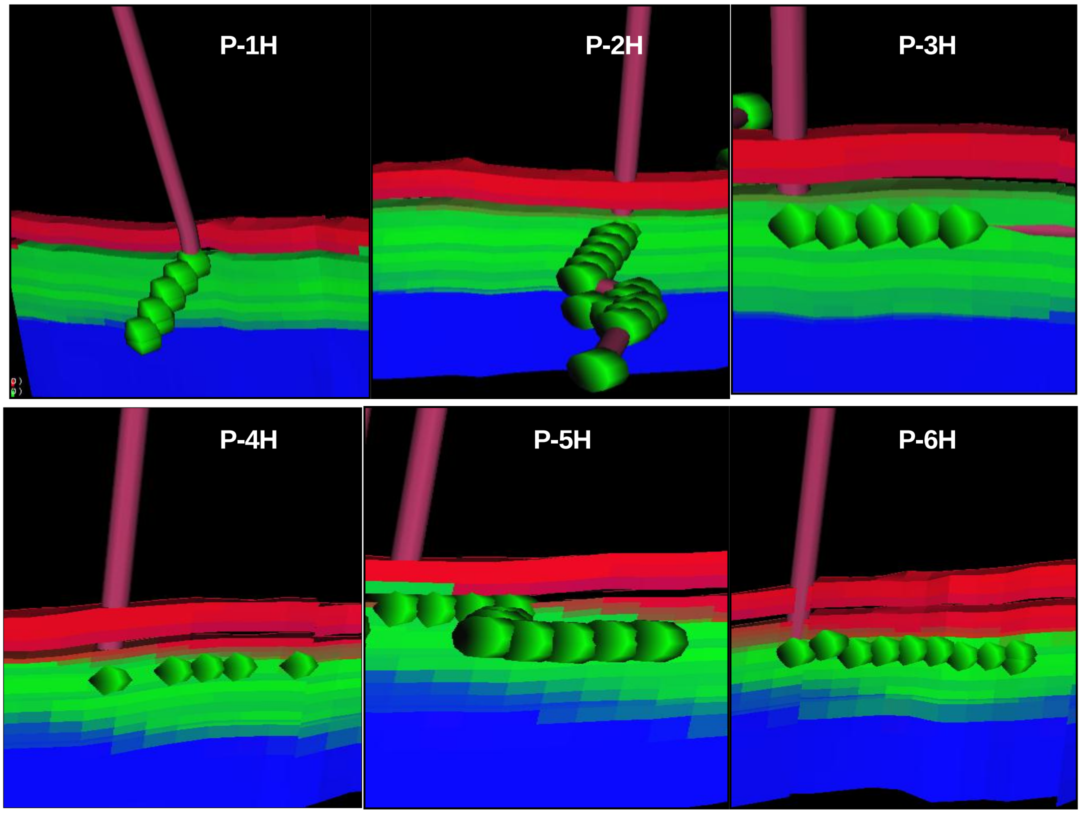


Figure15 - Well completion for producers in Scenario 1 case

5.5.2. Production and injection constraints

Production and injection constraints used in the Statoil base case the simulation model includes;

- Maximum oil production rate for each oil producer is 8009 Sm^3/day
- Maximum gas injection rate for each water injector is 1970000 Sm^3/day.
- Maximum water injection rate for each water injector is 4047Sm^3/day
- Maximum water-cut is 86 %
- Maximum gas oil-ratio is 748 Sm^3/Sm^3
- Maximum bottom-hole pressure is 370 bars

5.6. Scenario 2: Producer placement

5.6.1. Wells Trajectory:

The total number of wells in scenario two is 10; 6 producers and 4 injectors. The well types are 4 verticals and 6 horizontal.

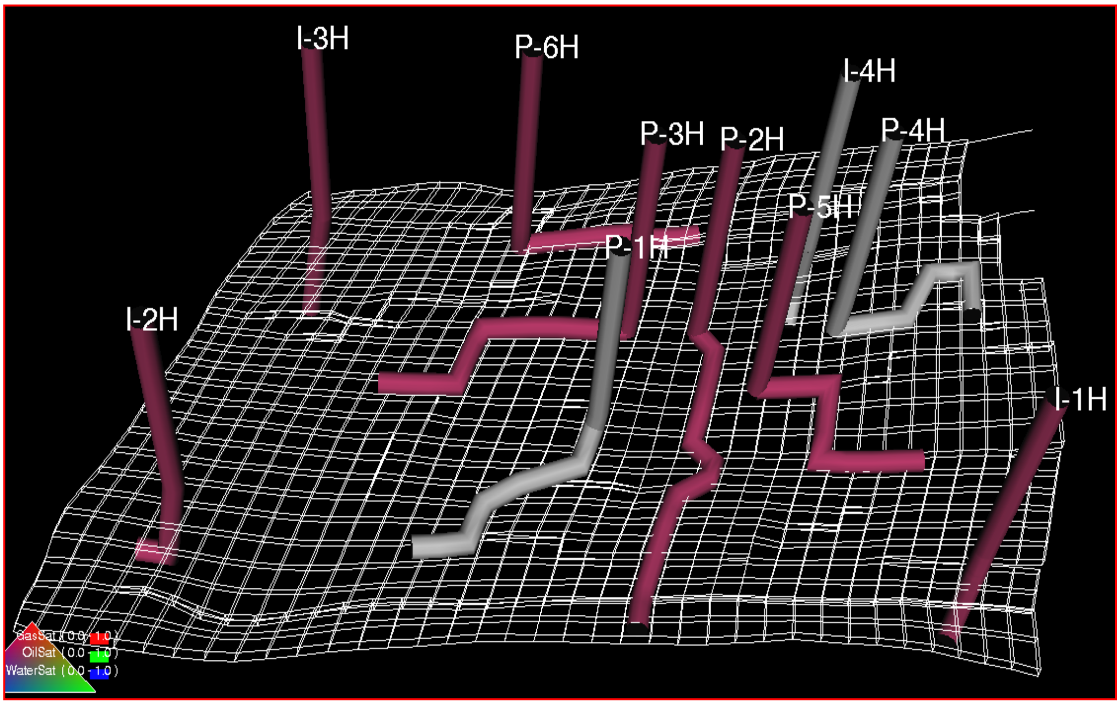


Figure16 - Well trajectory for new wells placement in scenario 2

- Well P-1H is the first production well placed in the scenario 2 case; the well lies horizontal to the western part of the field. Well P-1H was drilled horizontal because in the first scenario the first well was slant vertically to see the performance on oil production. Oil drainage from this well is from Ile 2.2 through to Ile 2.1.1. The well started producing the 6th of November 1997.

- Well P-2His the second well place in the field horizontally to the western part of the field to drain oil from Ile 2.1.1, Ile 1.3 and Ile 1.1 formation. Production started on 6th of January 1997.

- Well P-3H, This well was placed horizontal to the Southern part of the field to drain oil only from layer 9, the Ile 1.3 formations. This well was supported by injection I-2H and but gas injection from well I-3H had a great effect on the well. The well started producing the 2nd of January 1998.

- Well P-4H well lays horizontally towards the northern-eastern part of C-segment to drainage. The well P-4H drains oil only from in Ile 1.2 formation. This well started producing the 8th of January 2001.

- Well P-5H was placed horizontal on north-east part of C-segment on Ile 3.1 through to Ile 1 formation to drainage oil from eastern part this well started producing the 3rd of January 2002.

- Well P-6H is the last well place on this scenario case. The well lies horizontal to the eastern part of the field. The reason for this well was to drain the remaining oil from Ile 1.2 and Ile 1.1 formation. Production started from this well on 2nd of January 2003.

The well completion coordinates for all the producers in Scenario 2 case wells are given in Appendix B and Figure 17 shows the well completion in the simulation model.

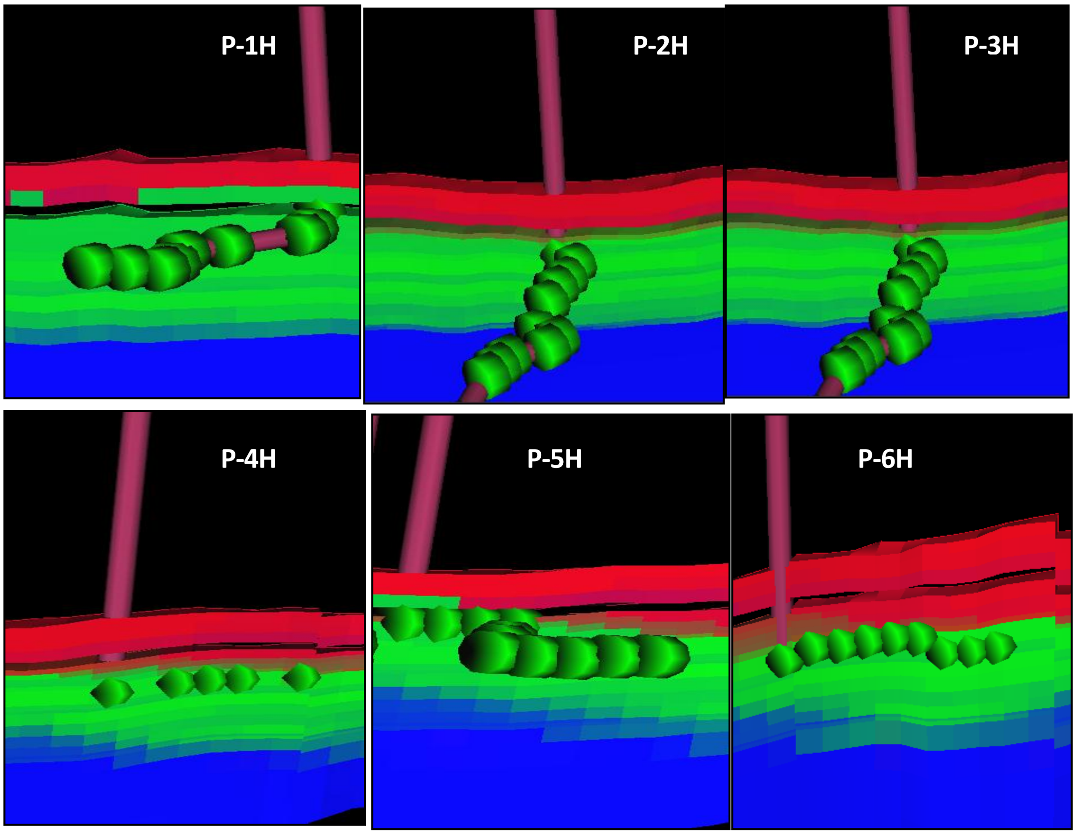


Figure17 - Well completion for producers in Scenario 2 case

5.6.2. Production and injection constraints

Production and injection constraints used in the Statoil base case the simulation model includes;

- Maximum oil production rate for each oil producer is 8003 Sm^3/day
- Maximum gas injection rate for each water injector is 1850000 Sm^3/day.
- Maximum water injection rate for each water injector is 4800Sm^3/day
- Maximum water-cut is 86 %
- Maximum gas oil-ratio is 788 Sm^3/Sm^3
- Maximum bottom-hole pressure is 416 bars

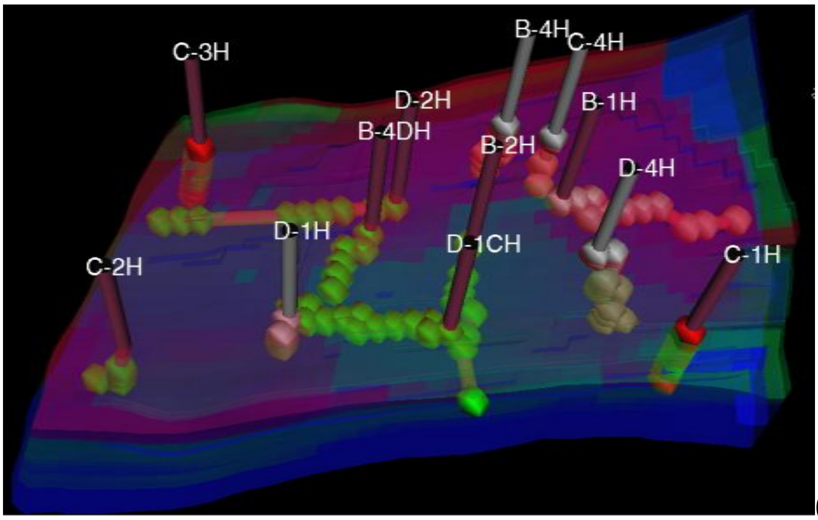
5.7. Injector placement for scenario 1 & 2

The location of injectors in the base case was studied, and a decision was made to use the same location and completion for new injectors in as the base case. The only difference in scenario cases from the base case is in the well names with slide different in injection rate, although from 1997 same rate of injection was used with until 2006. All the injectors are vertical wells, water was injected to the water leg to maintain the oil production and produced gas reinjection to gas cap for pressure in the reservoir to be maintained. The injectors used in scenario cases are I-1H, I-2H, I-3H and I-4H. Hence, gas injection stop in 2006 and well I-4H was shut in 18th November 2003.

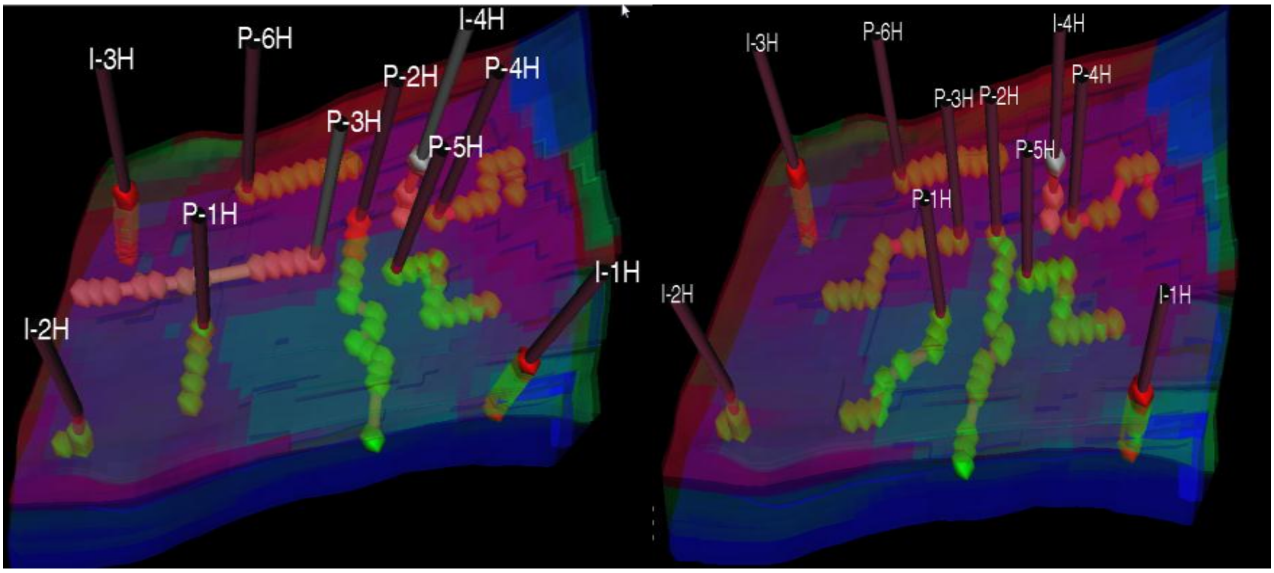
6. Results and Discussion

This chapter presents and analyses the results obtained from this research work. Here the production data generate from the existing wells in base case in other word is compared to the production data generate from the new well placement in all scenario cases from the simulation run. The simulation result combines the initial production profile state of the reservoir, which is from 1997 to 2006 and the production forecast of the reservoir is till 2015. A clear pofile figure from the simulaton results can be seen in Appendix D.

6.2. Visualization results of Base case wells and new well placement in scenario cases



(a)



(b) (c)

Figure18 - Shows (a) wells in the base case (b) New wells in the Scenerio1 and (c) New wells in scenario 2

The new well on scenario case shown in Figure 19 (a) and (b) has six producer which P-1H, P-2H, P-3H, P-4H, P-5H and P-6H. The injecting wells I-1H, 1-2H, I-3H, and I-4H.

6.3. Well Production Profile

6.3.1. Well production rate

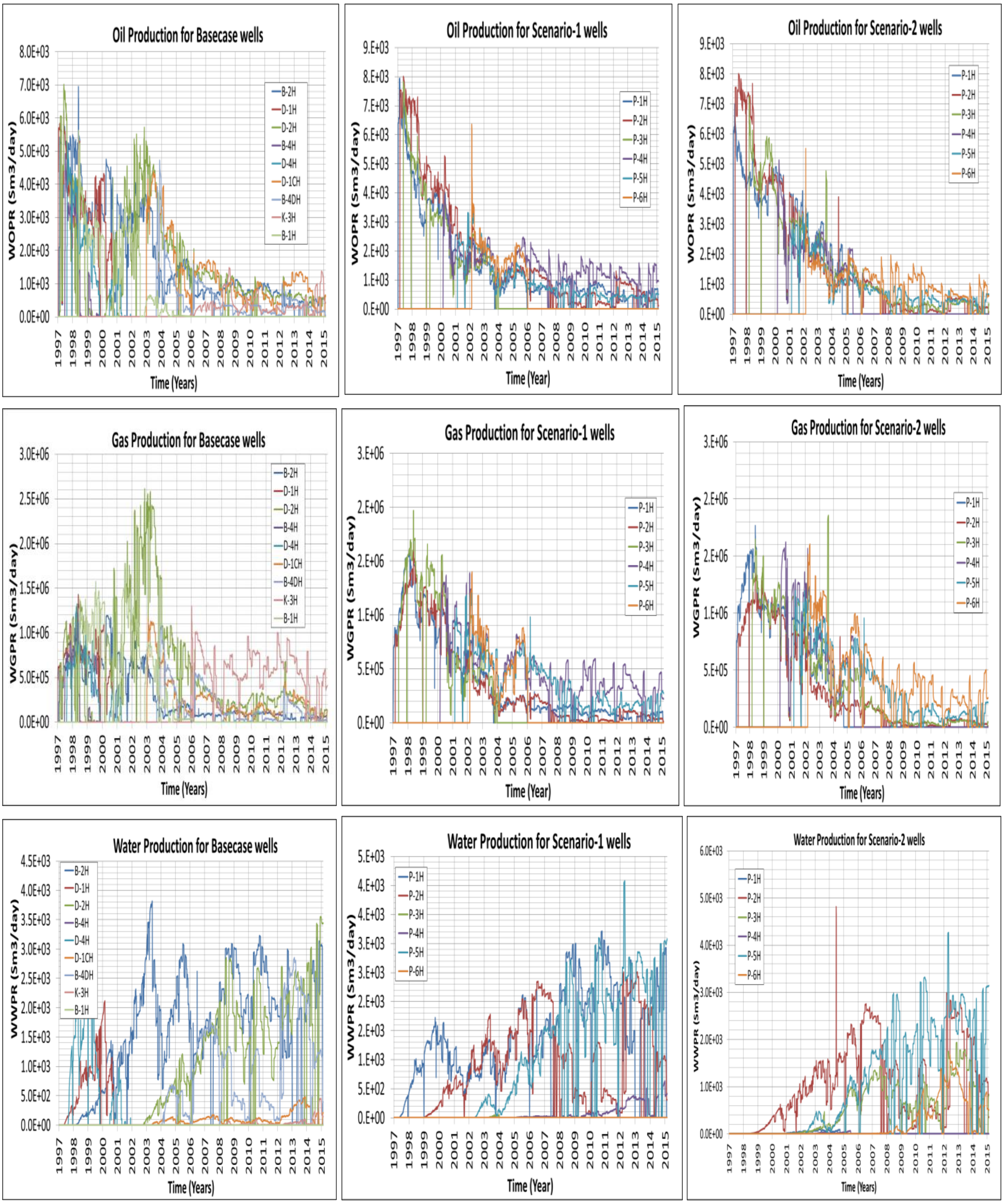


Figure19 - Top left-down shows (a) WOPR (b) WGPR (c) WWPR for Base case wells, (d) WOPR (e) WGPR (f) WWPR for Scenarios 1 well and (g) WOPR (h) WGPR (i) WWPR for Scenarios 2 wells.

6.3.2. *Well production total*

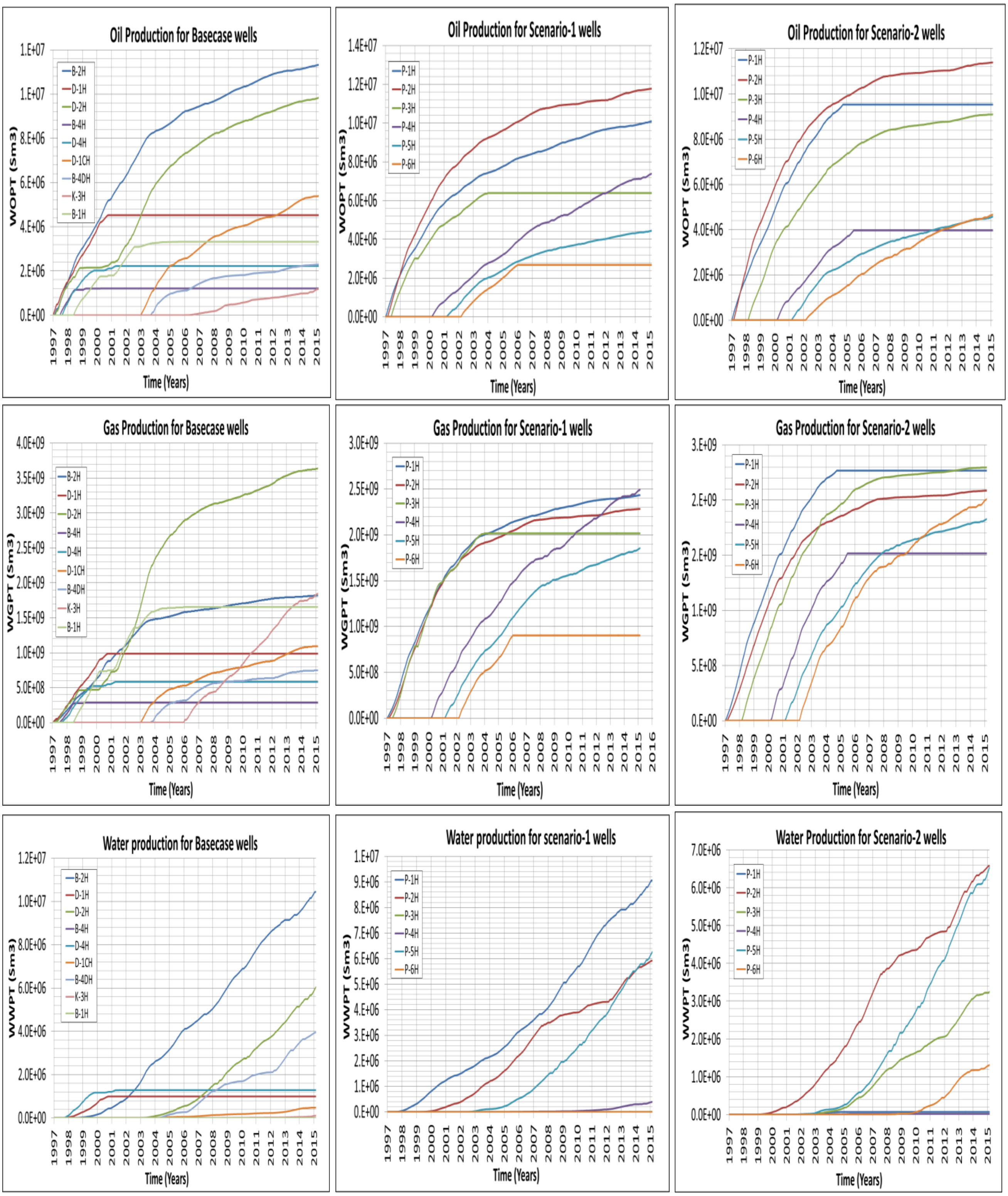


Figure20 - Top left-down shows (a) WOPT (b) WGPT (c) WWPT for Base case wells, (d) WOPT (e) WGPT (f) WWPT for Scenarios 1 well and (g) WOPT (h) WGPT (i) WWPT for Scenarios 2 wells.

6.3.3. Well Water-cut and Well Gas Oil-Ratio

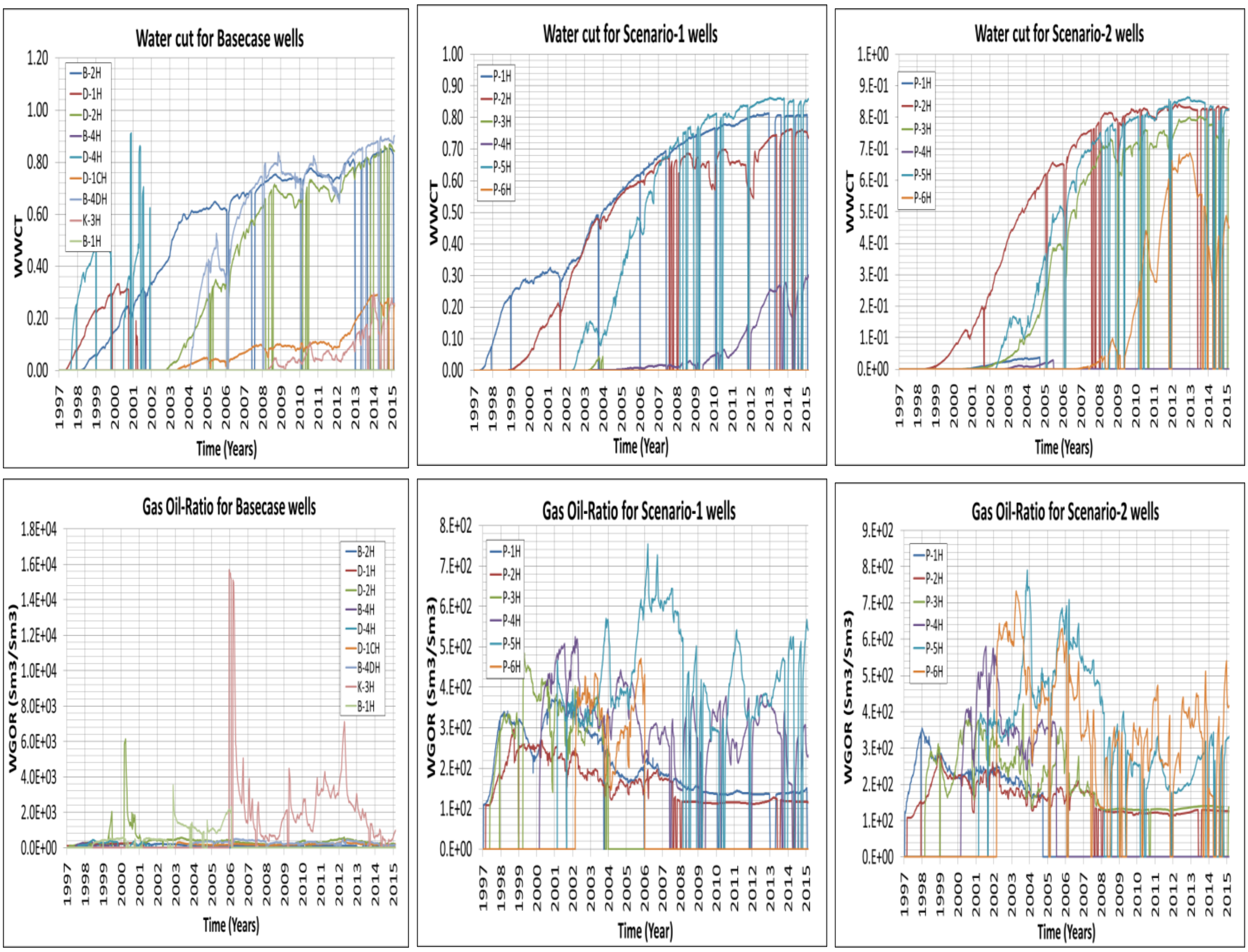


Figure21 - Top left-down shows (a) WWCT (b) WGOR for Base case wells (c) WWCT (d) WGOR for Scenarios 1 well (e) WWCT (f) WGOR for Scenarios 2 wells.

6.3.4. Well Bottom Hole Pressure

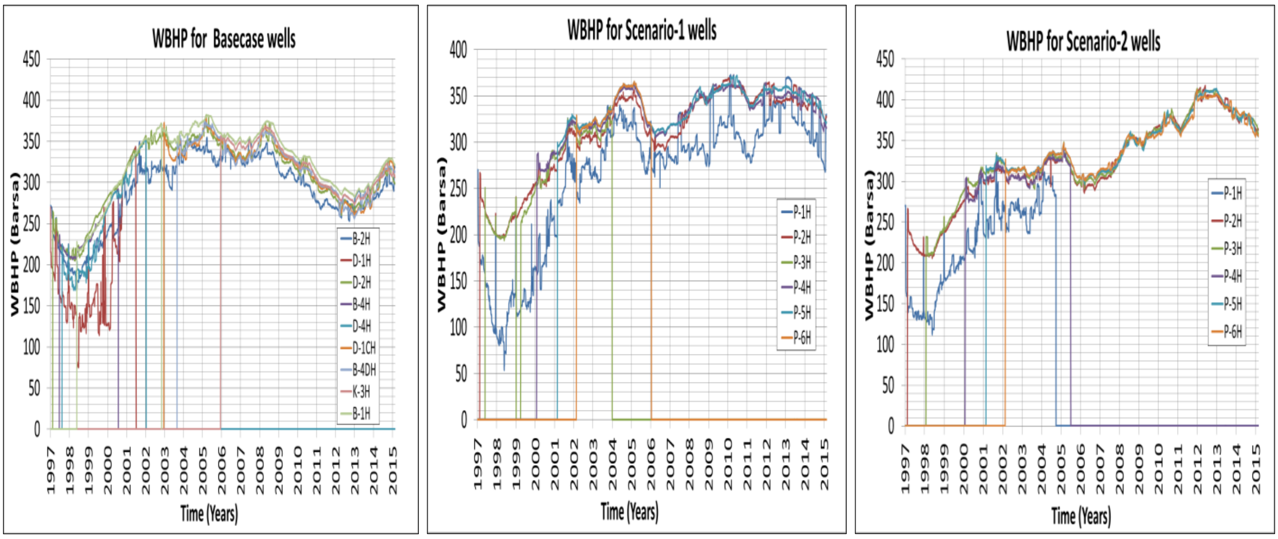


Figure22 - Shows results on (a) WBHP for Base case wells, (b) WBHP for Scenarios 1 new wells and (c) WBHP for Scenarios 2 new wells.

6.4. Field Rate Profile

6.4.1. Field Production Rate

Comparison of field oil production rate for base case and new wells scenarios

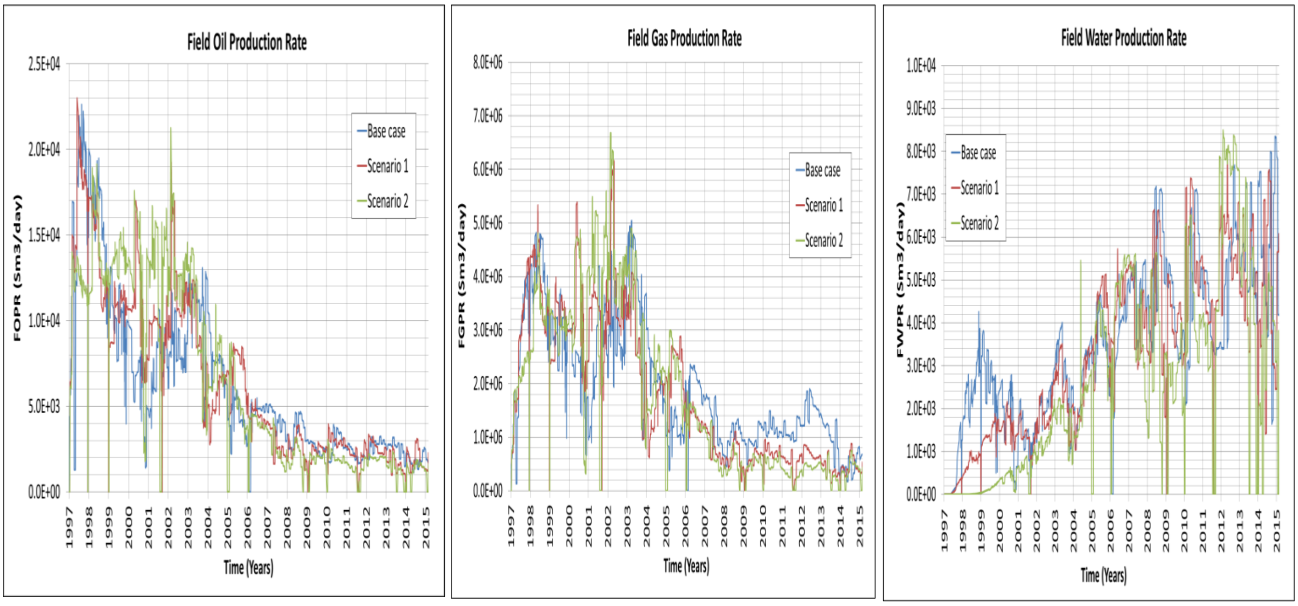


Figure23 - Left-right shows production profile for (a) Field Oil Production Total (FOPT), (b) Field Gas production Total (FGPT) and (c) Field Water Production Total (FWPT) for field reservoir in Base case, Scenario 1& 2 case.

6.4.2. Field Injection Rate

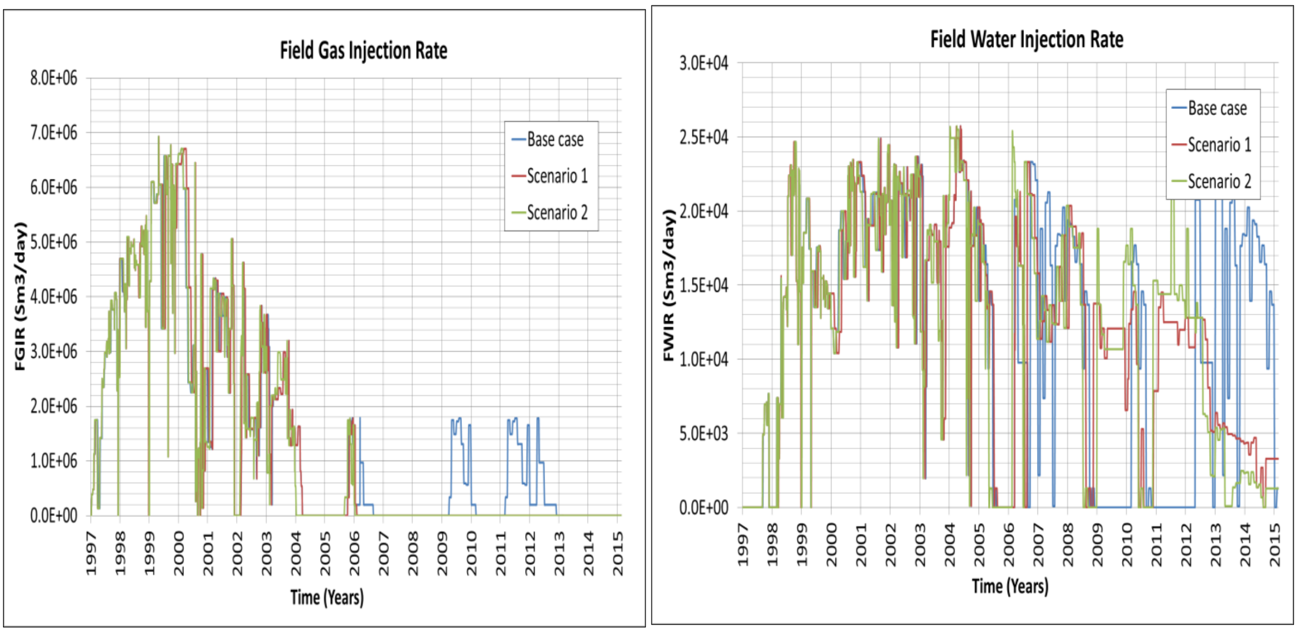


Figure24 - Shows injection profile (a) Field Gas Injection Rate (FGIP) and (b) Field Water Injection Rate (FWIR) for field reservoir in Base case, Scenario 1& 2 case.

6.5. Field Water-cut and Gas-Oil Ratio

Comparison of field Water Production Rate for existed wells and new wells scenarios

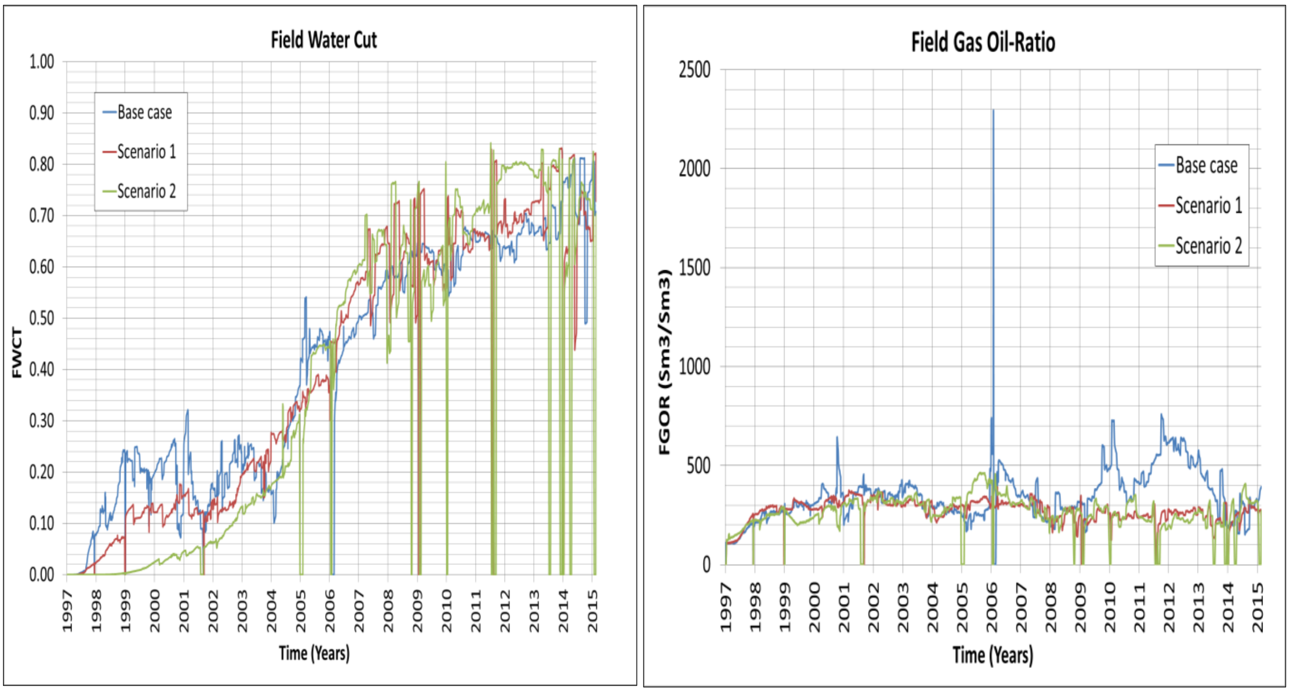


Figure25 - Shows (a) Field Water Cut (FWCT) and (b) Field Gas Oil Ratio (FGOR) profile for reservoir in Base case, Scenario 1& 2 case.

6.5.1. Field Reservoir Pressure

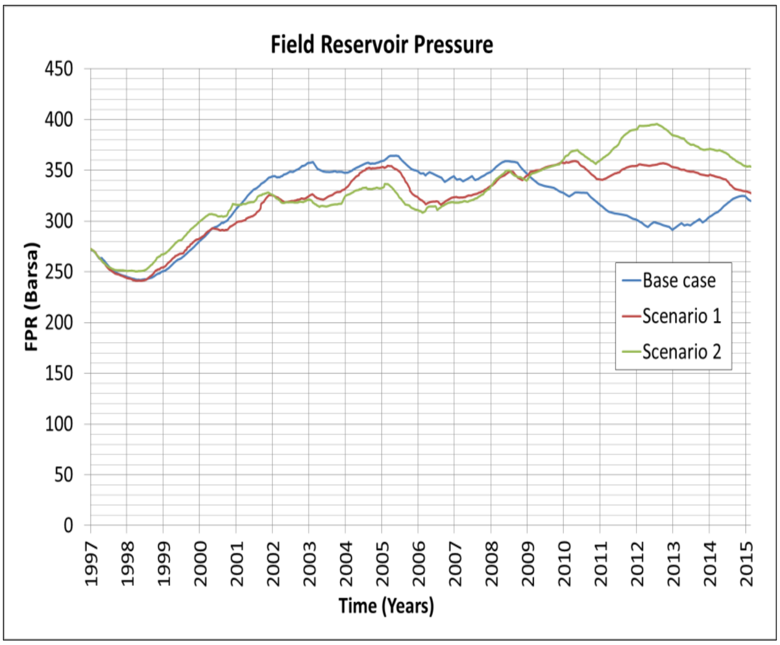


Figure26 - Shows Field Reservoir Pressure (FRP) profile for the reservoir in Base case, Scenario 1case and Scenario 2 case.

6.6. Field Total and Recovery

Comparison of field oil production rate for base case and new wells scenarios

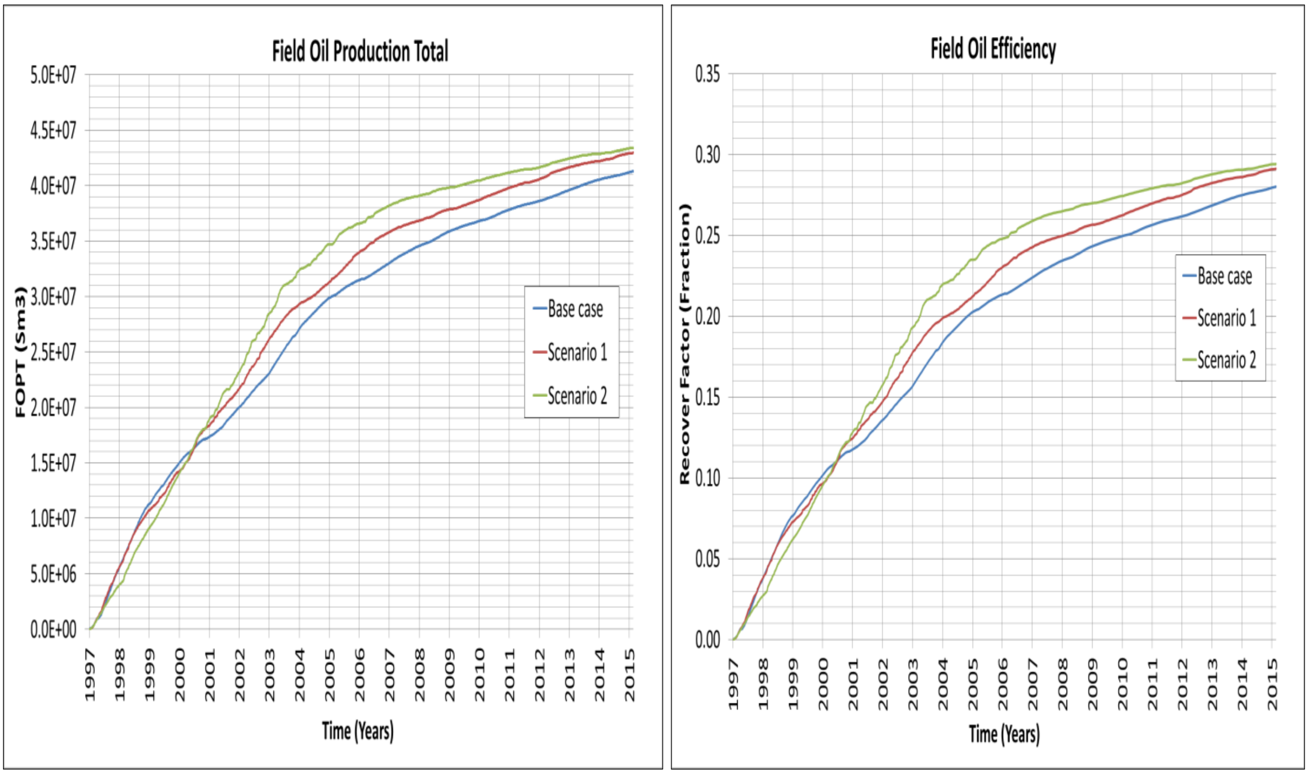


Figure27 - Shows (a) Field Oil Production Total (FOPT) and (b) Field Oil Efficiency (FOE) profile for field reservoir in Base case, Scenario 1& 2 cases.

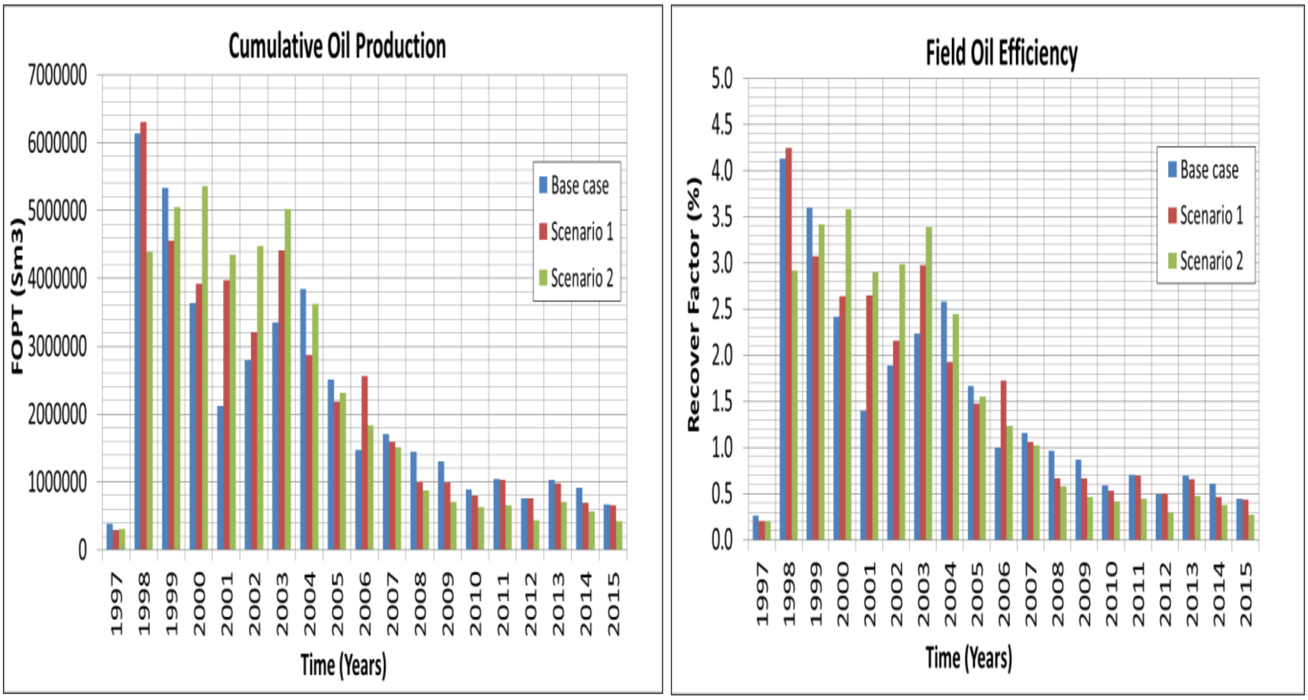


Figure28 - Shows (a) Cumulative oil Production and (b) Field Oil Efficiency (FOE) profile for reservoir in Base case, Scenario 1& 2 cases.

The cumulative oil production and oil recovery values for the field for each year given in Appendix C.

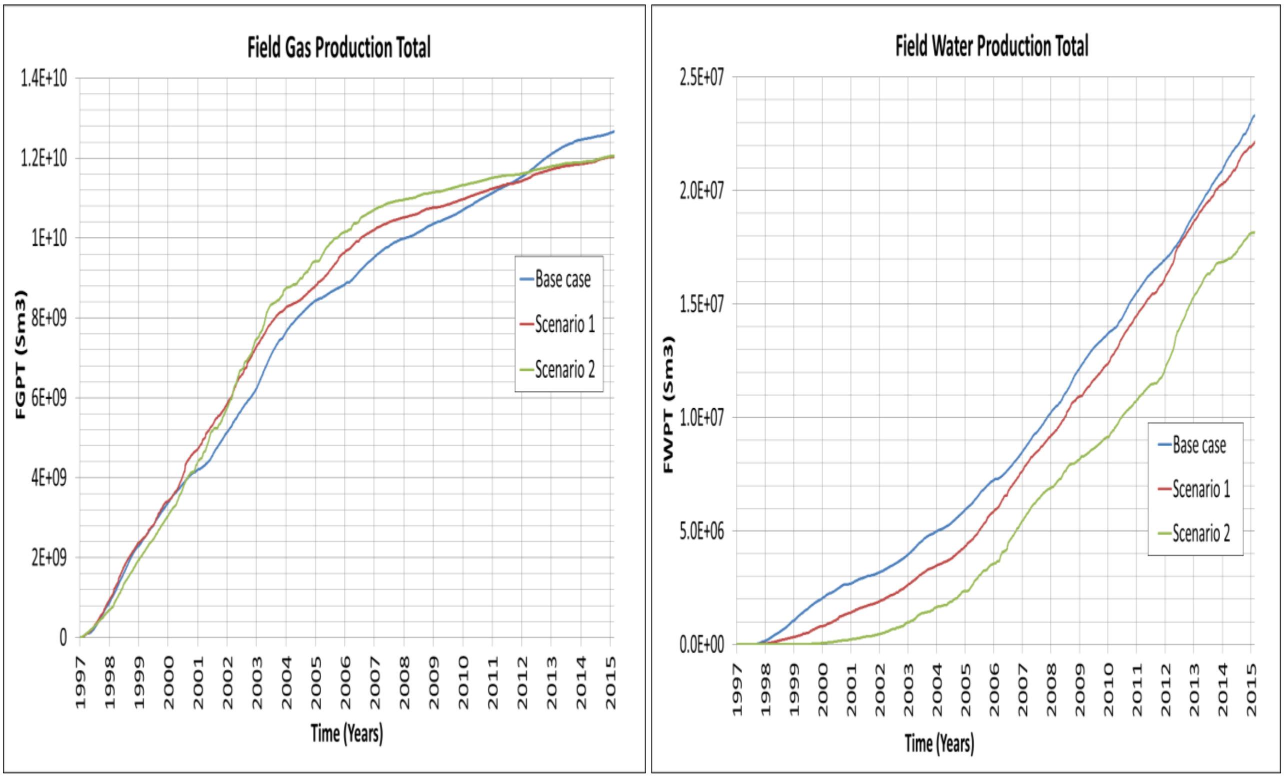


Figure29 - Shows (a) Field Gas Production Total (FGPT) and (b) Field Water Production Total (FWPT) profile for reservoir in Base case, Scenario 1&2 cases.

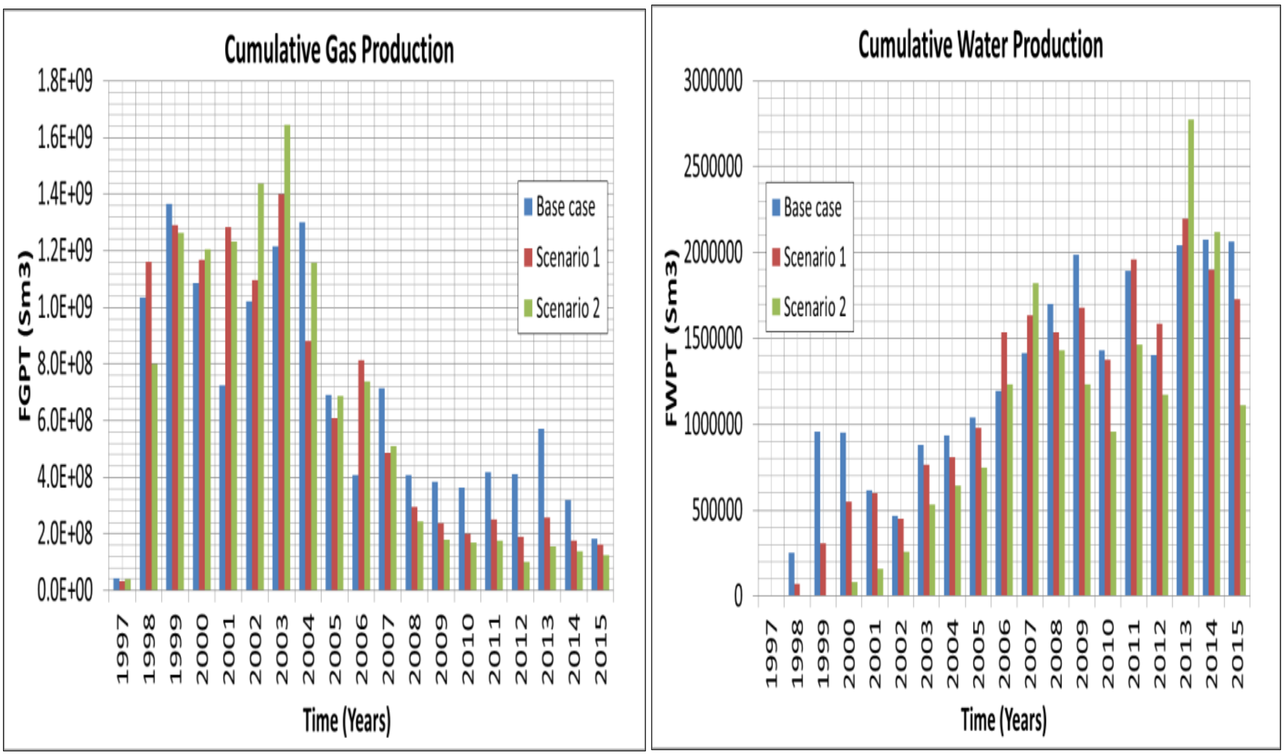


Figure30 - Shows Cumulative (a) Gas Production and (b) Water Production profile for reservoir in Base case, Scenario 1&2 cases.

Producers in Base case	Year started to produce	Total produced (Sm^3)	Total produced (bbl)	Deviation
B-2H	12.1997	11315690	71175690	Horizontal
D-1H	11.1997	4526007	28468584	vertical
D-2H	12.1997	9830420	61833342	Horizontal
B-4H	4.1998	1208418	7600949	vertical
D-4H	6.1998	2224143	13989859	vertical
B-1H	4.1999	5393659	33926115	Horizontal
D-1CH	11.2003	2295369	14437871	Horizontal
B-4DH	7.2004	1188925	7478338	Horizontal
K-3H	10.2006	3324006	20907998	vertical
	Total oil produced	**41306637**	**259818747**	

Table10 - Present the production start years and the total oil produced for each wells in base case.

Producers in Scenario 1	Year started to produce	Total produced (Sm^3)	Total produced (bbl)	Deviation
P-1H	11.1997	10085510	63437858	Vertical
P-2H	1.1998	11775710	74069216	Horizontal
P-3H	3.1998	6391716	40203894	Horizontal
P-4H	1.2001	7390042	46483364	Horizontal
P-5H	1.2002	4447052	27971957	Horizontal
P-6H	1.2003	2683210	16877391	Horizontal
	Total oil produced	**42773240**	**269043680**	

Table11 - Present the production start years and the total oil produced for each wells in scenario 1.

Producers in Scenario 2	Year started to produce	Total produced (Sm^3)	Total produced (bbl)	Deviation
P-1H	11.1997	9531810	59955085	Horizontal
P-2H	1.1998	11390290	71644924	Horizontal
P-3H	1.1999	9096941	57219759	Horizontal
P-4H	1.2001	3967219	24953808	Horizontal
P-5H	1.2002	4577033	28789538	Horizontal
P-6H	1.2003	4668236	29363204	Horizontal
	Total oil produced	**43231529**	**271926317**	

Table12 - Presents the production start years and the total oil produced for each wells in scenario 2.

6.7. Injection rate and total injection

6.7.1. Field Injection Total (FIT)

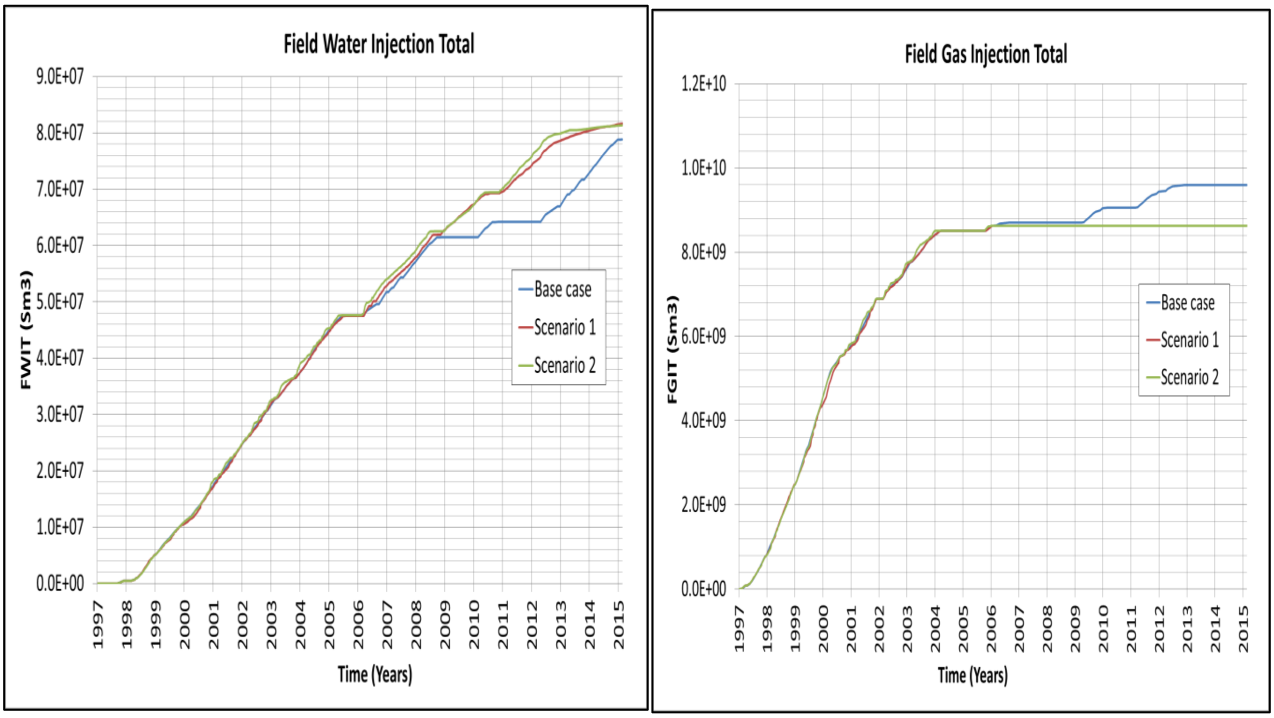


Figure31 - Shows (a) Field Gas Injection Total (FGIT) and (b) Field Water Injection Total (FWIT) profile for field reservoir in Base case, Scenario 1& 2 cases.

Table13 - Present the total gas and water injected into the reservoir from the base case and Scenario case wells

Injectors	Year started of injection	Deviation	Total Gas injected (Sm^3)	Total Water injected (Sm^3)
Base case				
C-1H	6.1998	Vertical	**9597153000**	**78838410**
C-2H	1.1999	Vertical		
C-3H	5.1999	Vertical		
C-4H	5.1999	Vertical		
Scenario 1				
I-1H	6.1998	Vertical	**8628871000**	**81665320**
I-2H	1.1999	Vertical		
I-3H	5.1999	Vertical		
I-4H	5.1999	Vertical		
Scenario 2				
I-1H	6.1998	Vertical	**8628871000**	**81351090**
I-2H	1.1999	Vertical		
I-3H	5.1999	Vertical		
I-4H	5.1999	Vertical		

6.8. Discussion on production and injection profile

6.8.1. Well production

In simulation results from the base case, the maximum production for each well is found to 11.3 million Sm^3per day with a maximum oil production rate of 7008 Sm^3/day. A maximum water and gas production rate of 3760 and 2.6 million Sm^3/day respectively. Maximum water-cut and gas-oil ratio was 95% and 15670 Sm3/Sm3 respectively.

For the purpose of this study, in order to obtain the same or production as the base case, the production rates were increase for each well in scenario 1. The maximum of 11.8 million Sm^3 per day with maximum oil production rate of 8009 Sm^3/day. A maximum water production rate of 4000 Sm^3/day and 1.97 million Sm3/day of gas production rate. Maximum water-cut and gas-oil ratio was 86% and 748 Sm^3/Sm^3. In scenario 2, the maximum oil production of 11.4 million Sm^3 per day with a maximum oil production rate of 8003 Sm^3/day. A maximum water and gas production rate of 4800 and 1.85 million Sm^3/day. Maximum water-cut and gas-oil ratio was 86% and 788 Sm^3/Sm^3 respectively.

6.8.2. Oil production

Oil production from 1997 to 2006

The current oil production in the base case from the year 1997 to 2006 is approximately 31.6 million Sm^3 with plateau production in 1998.With same plateau year in Scenario 1 case, oil production from the scenario 1 case is 34.3 million Sm^3 and Scenario 2 is 36.7 million Sm^3. Plateau production was in the year 1998 in both the base case and Scenario 1, while in scenario 2. The plateau production was seen in the year 2000.

Forecasts for oil production

Expected oil production in 2006 to 2015

Forecast oil production in the base case from 2006 to 2015 is estimated to be 9.7 million Sm^3. Total of 8.5 million Sm^3 of oil are expected to be produced in this nine-year period in scenario 1 and 6.5 million Sm^3 in scenario 2.

Oil production in 1997 to 2015

The expected oil production from in 1997 to 2015 can be seen in Appendix C. The total oil production can be seen in Figure 28(a). The cumulative oil production rises from the base case to 41.3 million Sm^3. The production for scenario case rises to 42.8 and 43.2 million Sm^3 in scenario 1 & 2 cases.

6.8.3. Gas Production

The total volume of gas produced from the base case from 1997 to 2006 is 8.9 billion Sm^3. Thus it reaches a plateau in 1999. However, Scenario 1 field produced gas of about 9.7 billion Sm^3 and scenario 2 at 10.2 billion Sm^3, both scenarios reaches plateau at the year 2000.

Expected gas production in 2006 to 2015

However, the gas production in the base case from 2006 to 2015 is estimated at 8.5 billion Sm^3. Production in scenario 1 is estimated at 2.3 billion Sm^3 and 1.8 billion Sm^3 in scenario 2 case.

Gas production in 1997 to 2015

The cumulative Gas production from 1997 to 2015 is therefore, estimated in the base case to 12.7 billion Sm^3 and 12.0 billion Sm3 in both Scenario 1 and 2 cases the total gas production can be seen in Figure 30(a).

6.8.4. Water production

The total water produced from the base case is at 7.3 million Sm^3. An approximately 6.1 million Sm^3 is produced in scenario 1 and 3.7 million Sm^3 in scenario 2 case.

Expected water production in 2006 to 2015

Water production forecast for base case in 2006 to 2015 is estimated to be 16.0 million Sm^3. Total of 15.5 million Sm^3 of oil are expected to be produced in this nine-year period in scenario 1 and 14.1 million Sm^3 in scenario 2.

Water production in 1997 to 2015

The total water production can be seen in Figure 30(b). The cumulative water production rises from the base case to 23.3 million Sm^3. In scenario 1 case its rises to 21.6 million Sm^3 and 17.8 million Sm3 in scenario 2 case.

6.8.5. Gas injection and water injection

To improve the recovery of oil in the C-segment reservoir, the total volume of 8.63 billion Sm^3 gas was injected in the base case and the same volume was also injected in the scenario cases from 1997 to 2006. Water injection in the base case was 7.3 million Sm^3, Scenario 1 case; 6.1 million Sm^3, and scenario 2 case 3.7 million Sm^3.

Expected gas and water in 2006 to 2015

From 2006 to 2015, gas injection is estimated to cease in scenario cases but in other to maintain pressure in base case the injection is estimated at 10 million Sm^3 volume of gas and 31million Sm^3 volume of water. Water injection in scenario 1 is estimated at 34million Sm^3 and 33million Sm^3 in scenario 2 case to improve oil recovery.

Gas and water injected in 1997 to 2015

A total of 9.6 billion Sm^3 volume of injected gas is estimated, with 79 million Sm^3 of injected water for the base case. Injected water estimated in scenario 1 & 2 from 1997 to 2015 is 81.2 million Sm^3 in both cases the total gas injected can be seen in Figure 32.

6.8.6. Oil Recovery

The recovery factor varies from reservoir field case, and significant differences exist between sandstone and chalk reservoirs. From Figure 28, Oil recovery factor from the base case was 21.4%, Scenario 1 is 23.2% and Scenario 2 is 24.9%. From 1997 to 2015, the expected average recovery factor for oil rose in the base case to 28.0% and 29.0% in scenario1 and 29.3% in scenario 2 case. This is mainly because the each reservoir field seems to reach a techno-economic limit for a further increase in their reserves.

6.9. Reserve Estimation

6.9.1. Volumetric oil-in-place

The volumetric calculation entails determining the physical size of the reservoir, the pore volume within the rock matrix, and the fluid content within the void space. This provides an estimate of the hydrocarbons-in-place, from which recovery can be estimated by using an appropriate recovery factor. Each of the factors used in the calculation have inherent uncertainties that, when combined, cause significant uncertainties in the reserves estimate [33].

Volumetric estimation is also known as the "geologist's method" as it is based on cores, analysis of wireline logs, and geological maps. Knowledge of the depositional environment, the structural complexities, the trapping mechanism, and any fluid interaction is required to: [33]

Estimate the volume of subsurface rock that contains hydrocarbons. The volume is calculated from the thickness of the rock containing oil or gas and the areal extent of the accumulation.
Determine a weighted average effective
Obtain a reasonable water resistivity value and calculate water saturation.

With these reservoir rock properties and utilizing the hydrocarbon fluid properties, original oil-in-place or original gas-in-place volumes can be calculated.

The volumetric method for calculating the amount of oil in place (N) is given by the following equation: [35]

$$N = \frac{7758A}{B_{oi}} \sum_{i=1}^{n} h_i \emptyset_i (1 - s_{wi}) \qquad (1.3)$$

where, N= oil in place, stb

A= drainage area, acres

B_{oi} = initial oil formation volume factor, rb/stb

h_i = individual zone thickness, ft

$\emptyset$= porosity, fraction

s_{wi} = water saturation, fraction

Reserves here are defined by: $R = N * (RF)$ *(1.4)*

RF = recovery factor

To calculate recoverable oil volumes the original oil in place (OOIP) must be multiplied by the Recovery Factor (fraction). The recovery factor is one of the most important, yet the most difficult variable to estimate. Fluid properties such as formation volume factor, viscosity, density, and solution gas/oil ratio all influence the recovery factor. In addition, it is also a function of the reservoir drive mechanism and the interaction between reservoir rock and the fluids in the reservoir [35].

6.9.2. Volumetric gas-in-place

The volumetric method for calculating the amount of gas in place (G) is given by the following equation:[34]

$$G = \frac{43560A}{B_{gi}} \sum_{i=1}^{n} h_i \emptyset_i (1 - s_{wi}) \qquad (1.5)$$

where, G= gas in place, scf

A= drainage area, acres

B_{gi} = initial gas formation volume factor, Rm^3/Scf

h_i = individual zone thickness, ft

$\emptyset$= porosity, fraction

s_{wi} = water saturation, fraction

Reserves here are defined by: $R = G * (RF)$ *(1.6)*

RF = recovery factor

The reservoir area *A*, and the recovery factor *RF*, are often subject to large errors. They are usually determined from analogy or correlations. This calculation was implemented in the Norne field during calculations of oil and gas reserves. Some of the reservoir parameters are listed in Table 7.

To calculate recoverable gas volumes, the OGIP is multiplied by a recovery factor. Volumetric depletion of a gas reservoir with reasonable permeability at conventional depths in a conventional area will usually recover 70 to 90% of the gas-in-place. However, a reservoir's recovery factor can be significantly reduced by factors such as: low permeability, low production rate, overpressure, soft sediment compaction, fines migration, excessive formation depth, water influx, water coning and/or behind pipe cross flow, and the position and number of producing wells. As an example, a 60% recovery factor might be appropriate for a gas accumulation overlying a strong aquifer with near perfect pressure support [35].

6.9.3. Reserves from the simulation study

The initial oil in place (IOIP) and gas in place (IGIP) discovered from the simulation study from the field generally applied to all the study cases in the field.

Recoverable reserved

Volumetric estimation is the only means available to assess hydrocarbons in place prior to acquiring sufficient pressure and production information to apply material balance techniques. Recoverable hydrocarbons are estimated from the in place estimates and a recovery factor that is estimated from analogue pool performance and/or simulation studies. Figure 33 & 34 show recoverable oil and gas reserved from the in the study case field from 1997 to 2006.

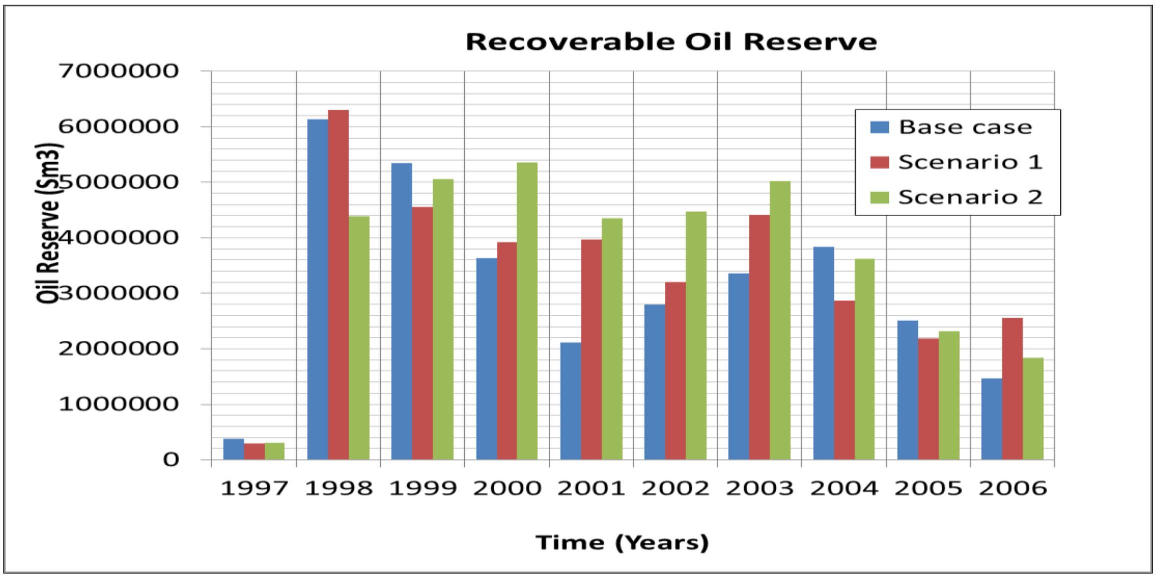


Figure32 - Show recoverable oil in the C-Segment Field in 2006

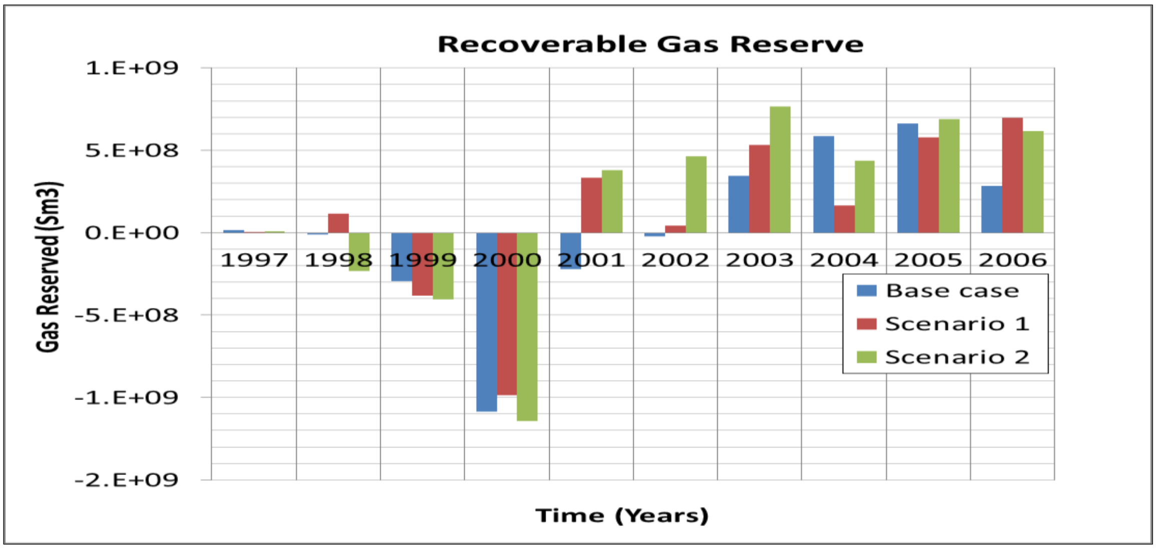


Figure33 - Show recoverable Gas in the C-Segment Field in 2006

Recoverable and unrecoverable reserves of oil and gas from the start year production until 2006, the current production year is presented in Table 14.

Table14 - Recoverable and unrecoverable reserves of oil and gas in the C-segment Field in 2006

Description	Units (Sm^3)	Base case	Scenario 1	Scenario 2
Oil in Place, STOIIP	X 10^6	147.6	147.6	147.6
Gas in Place (free & Solution)	X 10^9	229.9	229.9	229.9
Recoverable oil Reserves	X 10^6	31.6	34.3	36.7
Recoverable gas reserves	X 10^6	284.7	696.3	618.4
Unrecoverable oil reserved	X 10^6	116.0	113.3	111.0

Originally from the simulations model, oil in-place was estimated at 147 million Sm3 and gas in place at 230 billion Sm3 in 1997. In the base case from 1997 to 2006, 21% oil was recovered from the STIOIP, 23 % for scenario 1 and 25% for scenario 2 cases. Hence, gas recoverable (IGIP) from base case from 1997to 2006 was at230 billion Sm3for the base case, while 696 billion $Sm^3$and 618.4billion Sm^3 is recovered in scenario 1 and scenario 2 case respectively. The remaining or unrecoverable oil reserved at the end of 2006 is estimated at 116million Sm3 for the base case, 113million Sm^3 for scenario 1 case and 111 million Sm^3 for scenario 2 case. The recoverable and unrecoverable oil reserve can be seen in Table 14. The Table also present the recoverable gas reserved for each reservoir case. Lastly, Figure 33 & 34 shows the recoverable oil and gas for each year in the field in each reservoir case.

Forecasts: Production period from 1997 to 2015

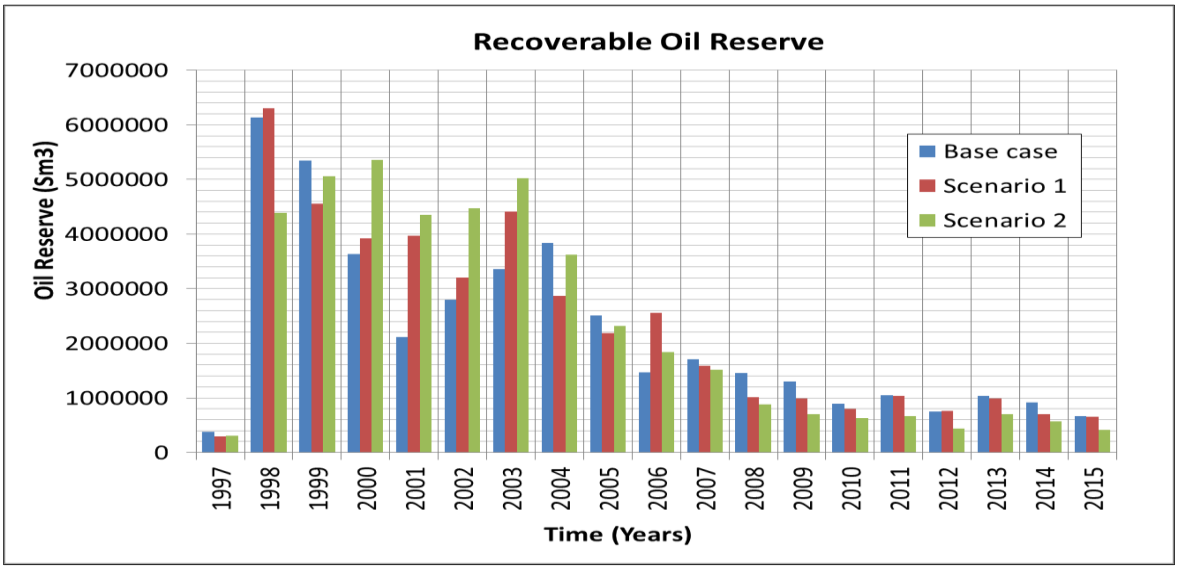


Figure34 - Show recoverable oil in the C-Segment Field in 2015

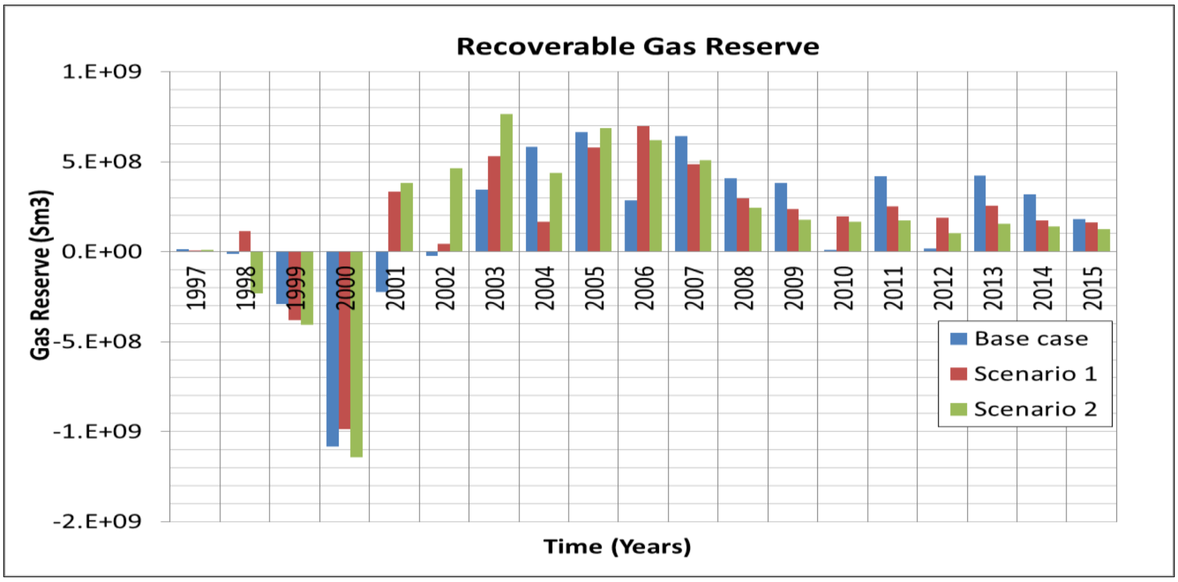


Figure35 - Show recoverable Gas in the C-Segment Field in 2015

Recoverable and unrecoverable reserves of oil and gas from the start year production until 2015, the forecast production year is presented in Table 15.

Table15 - Recoverable and unrecoverable reserves of oil and gas in the C-segment Field in 2015

Description	Units (Sm^3)	Base case	Scenario 1	Scenario 2
Oil in Place, STOIIP	X 10^6	147.6	147.6	147.6
Gas in Place (free & Solution)	X 10^9	229.9	229.9	229.9
Recoverable oil Reserves	X 10^6	41.4	43.0	43.4
Recoverable gas Reserves	X 10^9	3.06	3.35	3.37
Unrecoverable oil reserved	X 10^6	106.2	104.6	104.2

At the end of the year in 2006, 21% oil was recovered from the IOIP, 23 % for scenario 1 and 25% for scenario 2 cases. Hence in forecast result, recoverable OIP from 2006 to 2015 increase by the ratio of 7:4:3 to 28% for the base case, 29% for both scenario 1 & 2.The remaining or unrecoverable oil reserved at the end of 2015 is estimated at 106 million Sm3 for the base case, and 104 million Sm^3 also for both scenario 1 and scenario 2 case. Recoverable and unrecoverable oil reserve can be seen in Table 15, also recoverable gas reserved for each reservoir case. Figure 35 & 36 shows the recoverable oil and gas for each year in the field in each reservoir case.

6.10. Economics

The objective is to calculate the net present value over the life of the reservoir and this is achieved after optimum well placement. Net present value of the field project is the one of the main objective of this work. Parameter definitions prior to NPV are available in the formulation of this work. Calculation of NPV is possible after extracting results to a user friendly Excel Spread sheet program from the simulation output file. Annual oil production represents a single value, the total oil volume by the end of simulation; NPV takes more consideration of the economics of the project period, starting with the first year of production 1997-2006 until the forecast production period 2015.

6.11. Net Present Value (NPV)

Present value of money compares the value of a certain amount of money today to the value of that same amount in the future and vice versa, taking into consideration inflation and returns. Net present value (NPV) is the difference between the present value of cash inflows and the present value of cash outflows. Given an investment opportunity, NPV is used by an organization to analyze the profitability of the project or investment and to make decisions with regards to capital budgeting. It is sensitive to the future cash inflows that an investment or project will yield [36].

The base case will be compared with other Scenario case. The NPV formula used is from Cape presentation 4 in 2010 in his economic class [37].

Formula:

$$NPV = \sum_{t=0}^{n} \left(\frac{CF_t}{(1+d\,)^t}\right) \qquad (1.7)$$

Where: CF_t = Cash Flow of a period "t"

dt = Discount rate for period "t"

n = Last period of economic horizon

Cash flow, CF_t

Cash flow is cash inflow minus cash outflow. The main elements required for a cash flow analysis are:

- Revenue
  - Production
  - Price
- Expenditure estimates,
  - Capital expenditure (CAPEX)
  - Operational expenditure (OPEX).

Usually,
Revenue, R= Production x Price,
Expenditure, E = Operating expenditure + capital expenditure.

In a simple form, Net present value is the difference between the present value of revenue R and the present value of expenses $[38], thus,

$$\boldsymbol{NPV} = R - E \qquad (1.8)$$

If we define $\Delta E\ (k)$ (as the expenses incurred during a time period k, then E may be written as

$$E = \sum_{k=0}^{N*Q} \Delta E\ (k) / \left(1 + \frac{i'}{Q}\right)^k \qquad (1.9)$$

Where i' is the annual inflation rate, N is the number of years of the expenditure schedule, and QQ is the number of times interest is compounded each year. A similar expression is written for revenue R:

$$R = \sum_{k=0}^{N*Q} \Delta R\ (k) / \left(1 + \frac{i}{Q}\right)^k \qquad (1.10)$$

Where $\Delta R\ (k)$ is revenue obtained during time period k, and i is the annual interest or discount rate. Equations (1.8) and (1.9) include the assumptions that i and i' are constants over the life of the project, but i and i' are not necessarily equal. These assumptions let us compute the present value of money expended relative to a given inflation rate i' and compare the result to the present value of revenue associated with a specified interest or discount rate i.

The investment Decision is:
If NPV > 0 Project accepted or
If NPV < 0 Project rejected

This means the project with the highest NPV is favorable.

6.12. Application to the Norne field C-segment Project

In carrying out this analysis, a number of assumptions are made. The economic parameters assume can be seen in Table 16 below.

Table16 - Economic assumptions for NPV calculation

Economic Parameter	Cost (USD)
Vertical well	
Cost of drilling a vertical well	17000000
Capital expenditure (CapEx) per vertical well	1700000
Operating Expenditure (OpEx) per vertical well	800000
Horizontal wells	
Cost of drilling a horizontal well	20000000
Capital expenditure (CapEx) per horizontal well	2000000
Operating Expenditure (OpEx) per horizontal well	1000000
Fixed parameters	
Fixed Capital expenditure	200000000
Fixed Operating expenditure per year	5000000
Other operational costs were not taken into consideration:	
Cost of gas injection Per MScf	12
Cost of water injection Per Mbbl	8
Discount rate	8%
Inflation rate	8%
Oil price	25

Oil price:

In any petroleum project, the price of crude oil is very important to encourage project sanctioning. Oil prices changing with respect to time. Therefore in the forecasting of oil price, inflation needs to be factored into the estimates. Hence, inflation is used to calculate current price value of 1997 to 2015. The assume oil prices based on 1997 are $25 as low price, $35 as the medium price and $45 for high price.

Inflation was defined by cape from his presentation 2 in 2010, as a sustained increase in prices. The rate of inflation is stated as a percentage. This represents the rate of changes of prices between the current and previous year. Thus, Inflation;

$$I = P_o(1 + R)^n \qquad (1.11)$$

Where, I is an inflation index

P_o, Current oil Price (based on 1997)

R, inflation rate per annum

n , the number of years

Using the above equation to calculate, the result for the forecast oil price is presented in Table 17 and Figure 38.

Table17 - Forecast oil price for NPV calculation (assume oil price for 1997)

Year	Number Year	Oil Price at 25 USD/ barrel	Oil Price at 35 USD/ barrel	Oil Price at 45 USD/ barrel
1997	0	25.0	35.0	45.0
1998	1	27.0	37.8	48.6
1999	2	29.2	40.8	52.5
2000	3	31.5	44.1	56.7
2001	4	34.0	47.6	61.2
2002	5	36.7	51.4	66.1
2003	6	39.7	55.5	71.4
2004	7	42.8	60.0	77.1
2005	8	46.3	64.8	83.3
2006	9	50.0	70.0	90.0
2007	10	54.0	75.6	97.2
2008	11	58.3	81.6	104.9
2009	12	63.0	88.1	113.3
2010	13	68.0	95.2	122.4
2011	14	73.4	102.8	132.2
2012	15	79.3	111.0	142.7
2013	16	85.6	119.9	154.2
2014	17	92.5	129.5	166.5
2015	18	99.9	139.9	179.8

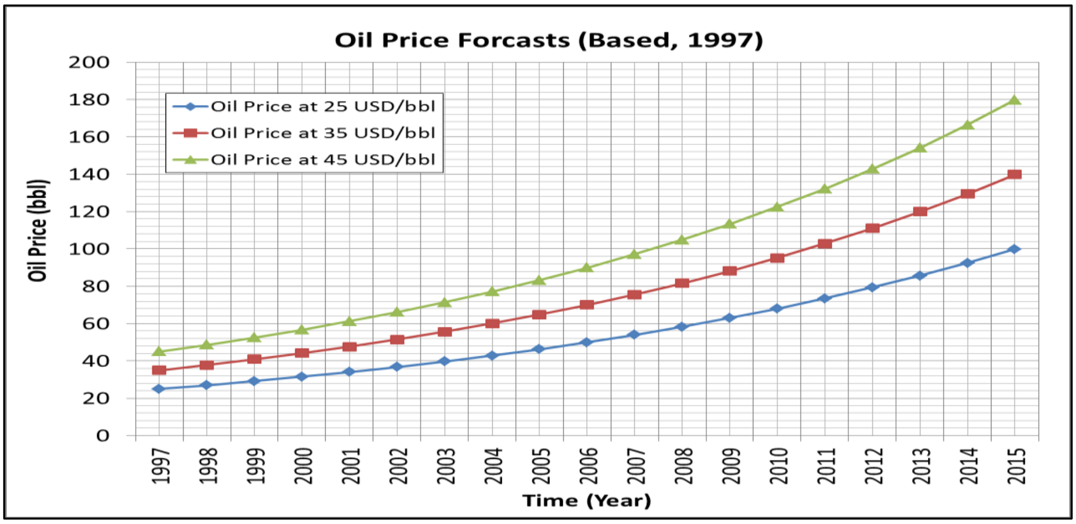


Figure36 - Forecast oil price for NPV calculation (assume oil price for 1997)

Oil production:

Cumulative oil production is used, from the production start year of production to the end of production in the field (i.e. 1997 to 2015). From the simulation result, total oil production each field case is generate in standard cubic meter per day of production for the base case and the New well placement scenario 1 & scenario 2. By adding all the total oil produced for each year gives the Cumulative oil production. For economic calculation, the oil production is converted from standard cubic feet (Sm^3) to barrel (bbl). The Table 18 below give simulation result for cumulative oil production for the all the cases. The conversion unit is given in Appendix A.

Table18 - Cumulative oil production for Base case and Scenario Cases (in Sm^3)

Year	Oil production (Sm^3)	Oil production (Sm^3)	Oil production (Sm^3)
	Base case	**Scenario 1**	**Scenario 2**
1997	384337	293356	306413
1998	6139044	6308123	4387918
1999	5329219	4553771	5052367
2000	3635180	3916340	5358832
2001	2114810	3966190	4352620
2002	2795720	3204060	4477600
2003	3356280	4413450	5021370
2004	3837120	2867970	3623370
2005	2507320	2188040	2310810
2006	1465200	2557960	1838920
2007	1700750	1583690	1505740
2008	1449620	1009530	877030
2009	1299620	988210	703930
2010	894290	793770	627940
2011	1046370	1033440	660850
2012	754400	759330	439670
2013	1024350	984500	702160
2014	908990	697280	568860
2015	664020	654230	415130

Operating expenditure:

Operating expenditure is costs which arise on routine basis and are incurred to carry out day to day operations. The costs of running everyday operations are production costs (costs incurred to operate, support and maintain wells and related equipment and facilities, includes the cost of work-overs), Transportation costs, General and administrative Costs (such as salaries, training, office stationary, information technology and office rental), maintenance and insurance cost *[39].*

Capital expenditure:

Capital expenditure is not costs incurred on a day to day basis, but costs incurred in carrying out, exploration, appraisal, and development and abandonment activities. Hence, exploration expenditures costs are incurred to identify areas that may warrant examination and examine specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells. Appraisal costs are incurred to carry out stratigraphic tests. To drill appraisal wells carried out to determine the physical extent, reserves and likely production rate of a field. Development costs are incurred to drill and equip development wells. Acquire, construct and install production facilities. Finally, Abandonment Expenditure also called decommissioning costs are incurred to Plug and abandon wells, dismantle wellhead, production and transport facilities, remediate and restore producing areas. Capital expenditure can be classified as tangible and intangible expenditures *[39].*

NPV results

A detailed economic analysis is carried out in excel sheet (attached at the Appendix C), **(EconsAnalysis.xlsx)**. From the Appendix C, the cost of gas and water injection, well cost and total expenditure for base case wells and the new well case scenario 1 & 2 are presented. NPV calculation for all reservoir field case is given, lastly NPV results is summarised for reservoir field case at different oil price value. Therefore, the results plots are presented below.

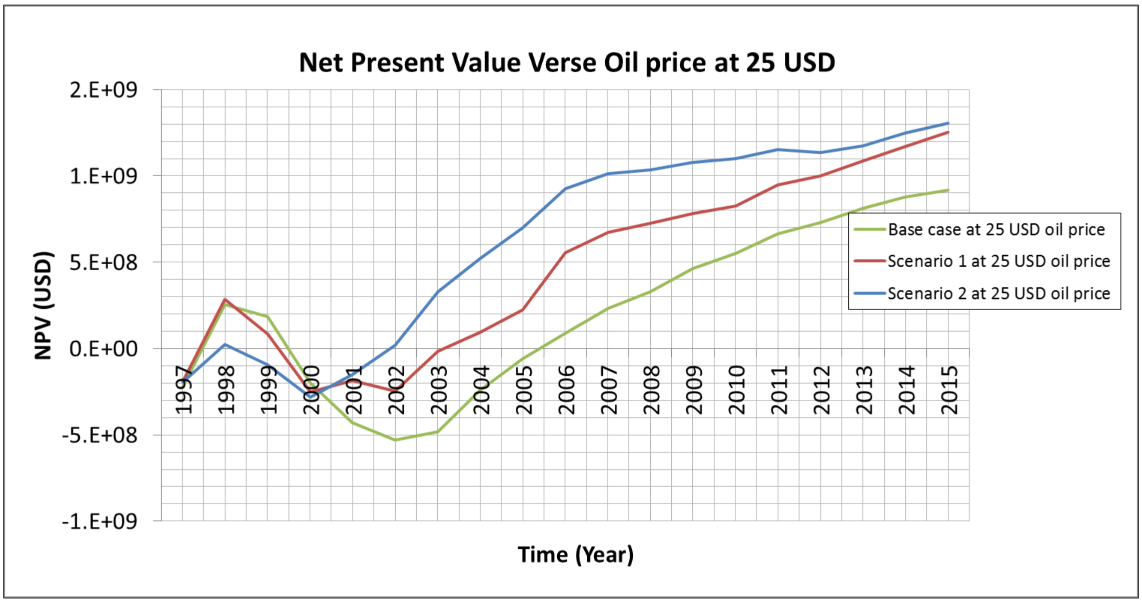


Figure37 - Comparison of NPV for base case and scenario case at oil price at 25 USD

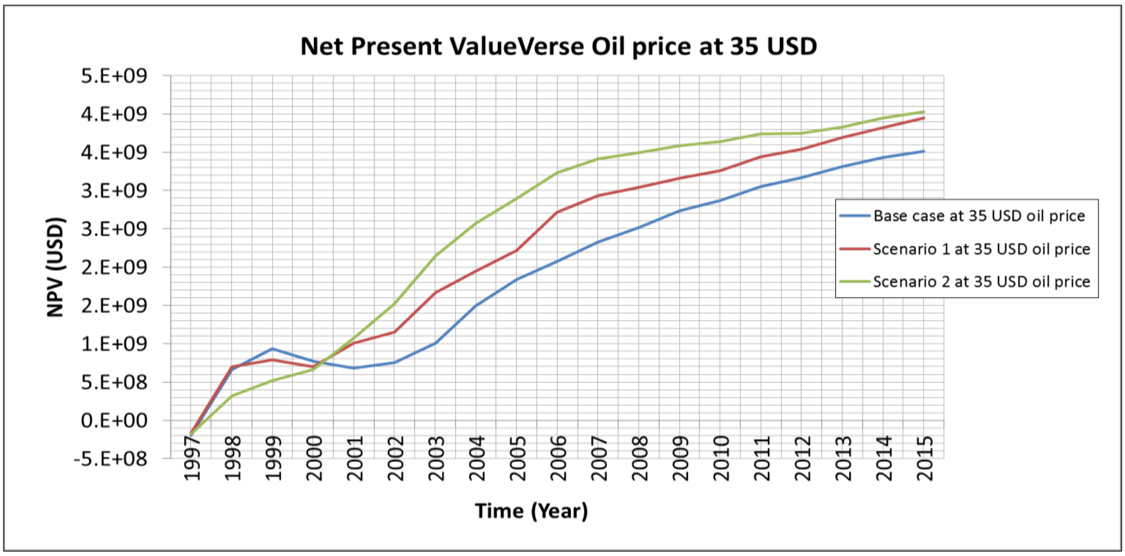


Figure38 - Comparison of NPV for base case and scenario case at oil price at 35 USD

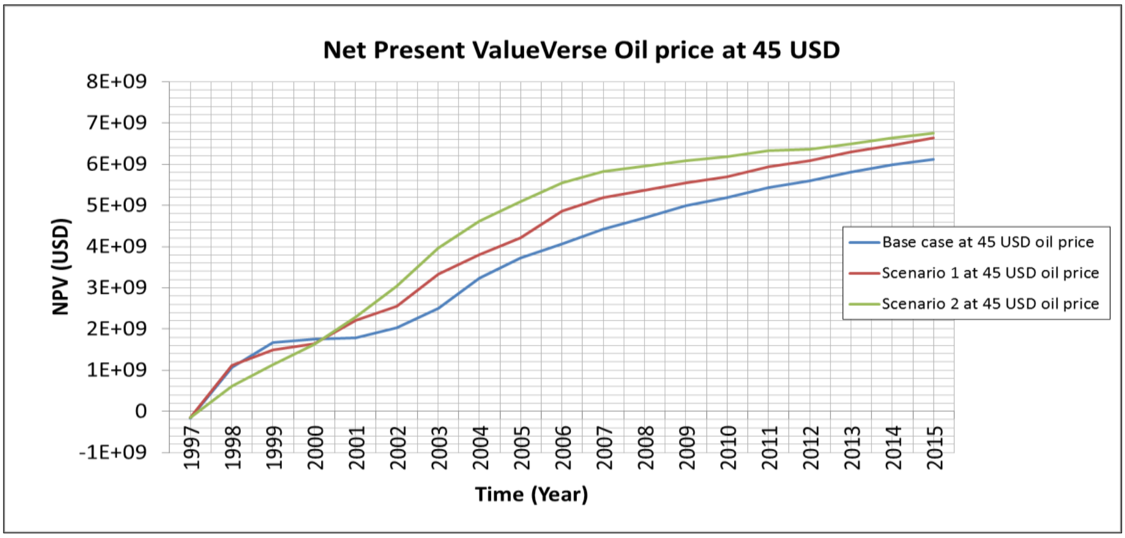


Figure39 - Comparison of NPV for base case and scenario case at oil price at 45 USD

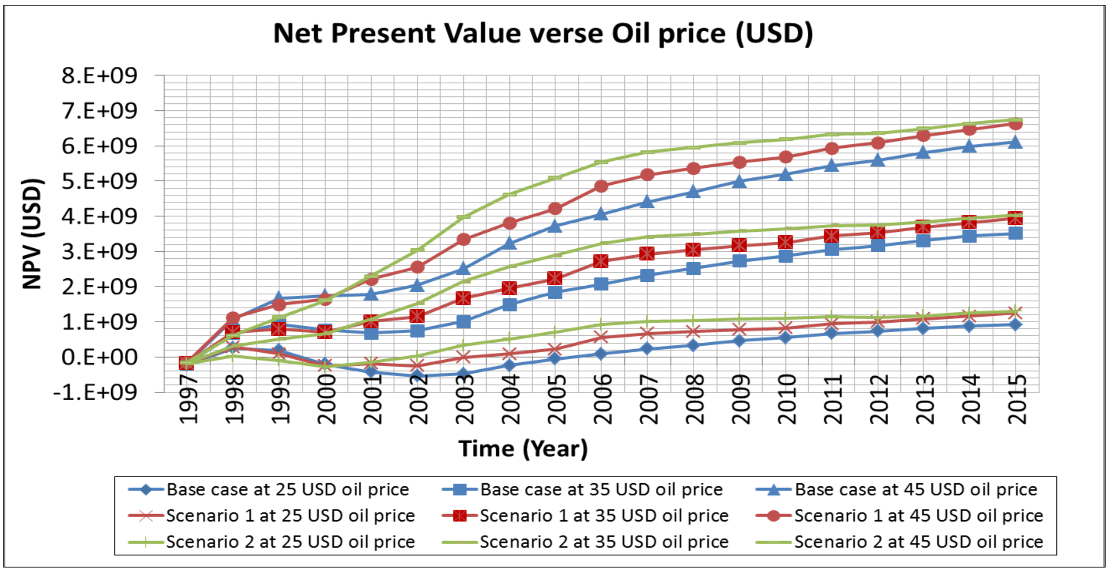


Figure40 - Summary of NPV comparison for base case and scenario case at various oil price values

The Net present value for the three project for the base case, scenario 1 & 2 at low oil price; $25, medium oil price; $35 and high oil price; $45 is presented below in Table 19.

Table19 - Economic decision on the best NPV project

Present Value (PV)	Oil price at 25 USD (mill)	Oil price at 35 USD (mill)	Oil price at 45 USD (mill)
Base case	918	3,516	6,115
Scenario 1	1,254	3,945	6,635
Scenario 2	1,307	4,026	6,745

The NPV show values in relative to the oil prices, the higher the oil price, the higher the NPV. Base on economic decision, all field case are considered since there is no negative NPV. However, the NPV for the base case from the Table 19 is less than the scenario cases, making scenario 1 & 2 the best option depending on production status.

6.13. Discussion

Figure 19-22, give the well production profile from the simulation result for the base case and scenario cases. In Figure 19, it is seen that the rate of production used for each scenario cases was higher than the base case. The reason for the increase was to achieve same or maximum oil production, since few wells were used. In Figure 20, the increase in production rate gives a better improvement to the scenario case on total oil production and reduces water production, but more gas were produced in the scenario cases than base case.

The total oil production from each well in each case is given in Table 10-12, where the base case wells produced the total of $41.3x10^6$ Sm^3 (26 million barrel) oil from the reservoir. The total of produced from the scenario1 wells is $43.0x10^6$ Sm^3 (269 million barrel) of oil and a total of $43.3x10^6$ Sm^3 (272 million barrel) of oil is produced from the Scenario 2 wells. Other effect can be seen in well water-cut and well gas oil ratio in Figure 21. The Maximum water cut was 95% and gas oil-ratio 748 Sm^3/Sm^3. Pressure depletion was observed as the wells, but water and gas injection was used to maintain the bottom-hole pressure to the maximum of 416 bar shown in Figure 22.

Figure 23-30, shows the field production profile from the simulation result for the base case and scenario cases. Each profile presents a clear results and effects from the well rate increase for oil, water and gas production in the field.

Figure 27 & 28(a), Oil production and oil recovery in scenario cases in are lower than the base case at the start year of production until the year 2000. The reason is only 3 wells were in production within the first 4 years from the scenario cases comparesdto the base case, were 6 wellswas used to acheive maxmium production. Thus, the cumulative production and recovery factor is higher in the scenario cases than the base case. The peak from oilproduction was discovered in 1998 for both base case and scenario 1 case, and 2002 for scenario 2 case. The cumulative oil production from the field in each case stands the same as in the total oil produced from all the wells in each reservoir field case. These can seen in Appendix C.

From figure 27& 28 (b), same profile sequence as oil production is seen for field recovery profile. The base case has 28% RF. From the figure, it can be seen that the recovery factor for the scenario case 1 is 29%, and 29.3 % higher in scenario 2 than the base case, therefore one of the objective of this work is achieved.

Oil production and injection rate was controlled in a systematic manner in order to maintain reservoir pressure above the bubble point (395 bars) and to have the maximum period of plateau. From Figure 31, The total gas injected in base case is $9{,}597x10^6$ Sm^3 and $78.8x10^6$ Sm^3 of water. In scenario1& 2, the total volumes of $8{,}629x10^6$ Sm^3 gas were injected. The total volume of $82.0x10^6$ Sm^3 and $81.4x10^6$ Sm^3 water were injected in scenario 1 & 2 respectively.

The NPV takes into account; theeconominic parameters, oil price and cumulative oil production for all reservoir field case in Table 16-18, gives the NPV results presented in Table 19 (in Million USD). As stated eailer, all the reservoir field cases are considered valuable since there is no nagative Net Present value.

7. Conclusion and Recommendation

7.2. Conclusion

In conclusion from the economic analysis above based on an oil price of $35/bbl and NPV the following conclusions were reached:

- ✓ The Net Present value comparison shows that the scenario 2 is the best option with respect to the total number of wells, field production from the reservoir as well as the total water and gas injection.
- ✓ Base case has 13 wells; 9 producers and 4 injectors. The field has 8 horizontal and 5 vertical wells.
- ✓ The IOIP was estimated at 147.6million Sm^3 and IGIP at 229.9 million Sm^3. After 9 years of prodcution, the base case oil recoverable reserves stands at 41.4 million Sm3 and gas at 3.06 billion Sm3. Unrecoveable oil at 106.2 millilon Sm^3.
- ✓ Cumulative oil production is of 41.3 million Sm^3 with 28.0% RF. Cumulative gas and water production at 12.7 million Sm^3 and 23.3 million Sm^3 respectively.
- ✓ The total gas injected is 9.6 million Sm^3 and total water injected is 79 million Sm^3 from the start year production to 2015.
- ✓ The Scenario 2 field has ten (10) new wells i.e. 4 vertical injectors, 'I' and 6 horizontal producers, 'P'.
- ✓ From the initial reserves in places that was estimated, the scenario 2 case oil recoverable reserves stands at 43.4 million Sm^3 and gas at 3.37 billion Sm^3. Unrecoveable oil at 104.2 millilon Sm^3
- ✓ Cumulative oil production is of 43.2 million Sm^3 with 29.3% RF. Cumulative gas production is 3.7 million Sm^3 and water production is 17.8 million Sm^3.
- ✓ Total gas injected is 8.6 million Sm^3 and total water injected is 81.3 million Sm^3 from the start year production to 2015.

7.3. Recommendation

It is recommended that more research should be done as a follow up with the current information by extending the production year to from 2015-2020. Or a comparative study should be done with the available results using any of the literature well placement optimizaton methods.

It is recommended that more research should be done as a follow up with the current information on this work to the year 2020 and compare the results with any optimizaton methods.

Norne field comprises of five different segment, annual information on C-segment or any given reservoir segment should made available to instituational research center for students. This imformation should includes reservoir field data, reservoir management plan and field development plan for easlier work, less economic assumptions and accurate search results.

To appreciate more the functionalities of Eclipse on research, students need a more extensive training on Eclipse or more access to their industry supervisors.

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Nomenclature

Bo	Oil Formation volume factor
Bg	Gas Formation volume factor
CapEx	Capital Expenditure
EIA	Energy Information Administration
FGPT	Field Gas Production Total
FOPT	Field Oil Production Total
FWPT	Field Water Production Total
FOIP	Field Oil in Place
FGIP	Field Gas in Place
FGPR	Field Gas Production Rate
FOPR	Field Oil Production Rate
FPR	Field Reservoir Pressure
GOC	Gas-Oil Contact
GIIP	Gas initially in place
IGIP, G	Initial gas in place
S	Saturation
STOIIP, N	Stock Tank Oil initially in Place
Sw	Water Saturation
Poro,Φ	Porosity
Perm, k	permeability
OpEx	Operating Expenditure
OWC	Oil-Water Contact
WBHP	Well Bottom Hole Pressure
WCT	Water Cut
WOPR	Well Oil Production Rate
WGOR	Well Gas-Oil Ratio
NTG	Net to Gross
3D	Three Dimensions
NPV	Net Present Value
Np	Cumulative oil produced

Subscript

o	Original
i	Initial
g	Gas
w	Water

Units

rcf	Reservoir cubic feet
res.bbl	Reservoir barrel
rm3	Reservoir cubic metres
scf	Standard cubic feet
sm3	Standard cubic metres
Mscf	1000 scf
MMscf	1000000 scf
stb	Stock tank barrel
$ *(USD)*	Dollars
bbl	Barrel
bcf	Billion Cubic Feet
d	Day

Appendix A - Conversion factor

Oil equivalents (abbreviated o.e.) are term s used to sum up volumes of oil, gas, NGL and condensate. Such a total can be arrived at by applying a common property, such as energy, mass, volume or sales value. The Norwegian Petroleum Directorate uses a volumetric conversion of NGL to liquid and an energy conversion factor for gas, based on typical properties (*) on the Norwegian continental shelf. Oil, condensate and gas volumes are stated in standard cubic metres (Sm^3) and NGL volumes in tonnes. A measure of total resources can be obtained by adding up the energy content in the various types of petroleum. The total is calculated in standard cubic metre (Sm^3) oil equivalents Sm^3o.e.

Conversion Factor *[19]*

Conversion factors			
1 Sm^3 oil	=	1.0	Sm^3o.e.
1000Sm^3 gas	=	1.0	Sm^3o.e.
1 Sm^3condensate	=	1.0	Sm^3o.e.
1 tonne NGL	=	1.9	Sm^3o.e.
1 Sm^3 crude oil	=	6.29	barrels
1 Sm^3 crude oil	=	0.84	tonnes crude oil
1 Sm^3 gas	=	35.314	Scf

Appendix B - Wells Information

Exploration wellbores *[27]*

Name	UTM coordinates	Entry Date	Completion Date	Purpose
6608/10-2	7321933.62N - 457994.68E	28.10.1991	29.01.1992	**WILDCAT**
6608/10-3	7324321.37N - 458426.47E	07.01.1993	11.03.1993	**APPRASIAL**
6608/10-3R	7324321.37N - 458426.47E	08.08.1995	17.08.1995	**APPRASIAL**
6608/10-4	7324847.23N - 462006.74E	15.12.1993	06.03.1994	**WILDCAT**
Name	**Status**	**Contents**	**TVD (m)**	**HC Formation**
6608/10-2	Plugged & Abandoned	Oil & Gas	3677	**Fangst and Båt**
6608/10-3	Susp. Rentered later	Oil & Gas	2920	**Fangst and Båt**
6608/10-3R	Plugged & Abandoned	Oil & Gas	2920	**Fangst and Båt**
6608/10-4	Plugged & Abandoned	Oil & Gas	2800	**Melke and Garn**

Well Completions

Well Completion for base case producers

B-2H	I	J	K1	K2
Top	15	13	1	1
Perforation	17	31	9	9
	19	31	9	9
	20	31	10	10
	21	31	10	10
	22	32	10	10
	24	32	10	10
	25	32	10	10
	29	33	10	10

D-1H	I	J	K1	K2
Top	22	22	1	1
Perforation	22	22	5	5
	23	22	6	6
	23	22	7	7
	23	22	9	9
	23	22	10	10
	23	22	11	11
	23	22	12	12
	23	22	13	13

D-2H	I	J	K1	K2
Top	14	28	1	1
Perforation	14	26	9	9
	14	25	9	9
	14	23	9	9
	14	22	9	9
	14	21	9	9
	14	20	9	9
	14	15	9	9
	14	14	9	9
	14	13	9	9

B-4DH	I	J	K1	K2
Top	10	29	1	1
Perforation	16	25	8	8
	16	25	9	9
	17	25	9	9
	17	24	9	9
	17	24	8	8
	18	24	8	8
	18	24	7	7
	19	24	7	7
	19	24	6	6
	19	24	5	5
	20	24	5	5

D-1CH	I	J	K1	K2
Top	25	37	1	1
Perforation	24	31	5	5
	24	30	5	5
	23	30	7	7
	23	29	7	7
	23	29	8	8
	23	28	8	8
	23	27	8	8
	23	26	8	8
	22	26	8	8
	22	26	7	7
	22	25	7	7
	22	24	7	7
	22	23	7	7
	21	23	7	7
	21	22	7	7

B-4H	I	J	K1	K2
Top	10	32	1	1
Perforation	10	32	2	2
	10	32	3	3
	10	32	5	5
	10	32	6	6
	10	32	7	7
	10	32	8	8
	10	32	9	9
	10	32	10	10
	9	32	13	13
	9	32	14	14
	9	32	15	15
	9	32	16	16
	9	32	17	17
	9	32	18	18
	9	32	19	19
	9	32	20	20
	9	31	20	20
	9	31	21	21
	9	31	22	22

B-1H	I	J	K1	K2
Top	14	34	1	1
Perforation	15	38	9	9
	16	38	10	10
	16	39	10	10
	16	40	10	10
	16	41	10	10
	16	42	10	10
	17	44	15	15
	17	45	15	15
	17	47	15	15

Well Completion for Scenario 1 producers

D-4H	I	J	K1	K2
Top	19	38	1	1
Perforation	19	38	2	2
	19	39	2	2
	19	39	3	3
	19	39	5	5
	19	39	6	6
	19	39	7	7
	19	39	8	8
	19	39	9	9
	19	39	10	10
	20	39	10	10
	20	39	11	11
	20	39	12	12
	20	39	13	13
	20	39	14	14
	20	39	15	15
	20	40	15	15
	20	40	16	16
	20	40	17	17
	20	40	18	18
	20	40	19	19
	20	40	20	20
	21	40	20	20
	21	40	21	21
	21	40	22	22
	21	41	22	22

K-3H	I	J	K1	K2
Top	11	28	1	1
Perforation	11	24	5	5
	11	23	5	5
	10	23	5	5
	10	22	5	5
	10	21	5	5
	11	21	5	5
	11	20	5	5
	11	19	5	5
	11	18	5	5
	11	16	5	5

P-1H	I	J	K1	K2
Top	19	21	1	1
Perforation	19	21	5	5
	20	21	6	6
	20	21	7	7
	21	21	8	8
	21	21	9	9
	22	21	10	10
	22	21	11	11
	23	21	12	12
	23	21	13	13

P-2H	I	J	K1	K2
Top	13	31	1	1
Perforation	13	31	9	9
	14	31	9	9
	15	31	9	9
	16	31	9	9
	17	31	9	9
	18	31	9	9
	19	33	10	10
	20	33	10	10
	21	32	10	10
	22	33	10	10
	23	34	9	9
	24	34	9	9
	25	34	9	9
	29	34	9	9

P-3H	I	J	K1	K2
Top	14	28	1	1
Perforation	15	28	9	9
	15	27	9	9
	15	26	9	9
	15	25	9	9
	15	24	9	9
	15	20	9	9
	15	19	9	9
	15	17	9	9
	15	16	9	9
	15	14	9	9
	15	13	9	9
	15	12	9	9

P-4H	I	J	K1	K2
Top	14	37	1	1
Perforation	14	37	10	10
	14	37	10	10
	14	39	10	10
	14	40	10	10
	14	41	10	10
	13	41	10	10
	12	41	10	10
	12	42	10	10
	12	43	10	10
	13	43	10	10
	14	43	10	10

P-5H	I	J	K1	K2
Top	17	34	1	1
Perforation	17	34	6	6
	17	35	6	6
	17	36	6	6
	17	37	6	6
	18	37	8	8
	18	37	8	8
	19	37	8	8
	20	37	9	9
	20	38	9	9
	20	39	9	9
	20	40	9	9
	20	41	9	9

P-6H	I	J	K1	K2
Top	9	22	1	1
Perforation	9	22	10	10
	9	22	10	10
	9	23	10	10
	9	24	11	11
	9	25	11	11
	9	26	11	11
	9	27	11	11
	9	28	12	12
	9	29	12	12
	9	30	12	12
	9	30	13	13
	9	30	13	13
	9	30	13	13

Well Completion for Scenario 2 producers

P-1H	I	J	K1	K2
Top	19	28	1	1
Perforation	19	28	5	5
	20	28	6	6
	21	28	6	6
	22	26	7	7
	23	25	7	7
	4	25	8	8
	25	25	8	8
	25	24	8	8
	25	23	8	8

P-2H	I	J	K1	K2
Top	14	31	1	1
Perforation	14	31	9	9
	15	32	9	9
	16	32	9	9
	17	32	8	8
	18	32	8	8
	19	32	10	10
	20	33	10	10
	21	33	10	10
	22	32	10	10
	23	32	10	10
	24	32	10	10
	27	32	10	10
	28	32	10	10
	29	32	10	10

P-3H	I	J	K1	K2
Top	14	28	1	1
Perforation	14	28	9	9
	14	27	9	9
	14	25	9	9
	14	24	9	9
	14	22	9	9
	15	22	9	9
	16	22	9	9
	17	22	9	9
	17	21	9	9
	17	20	9	9
	17	19	9	9

P-6H	I	J	K1	K2
Top	9	22	1	1
Perforation	9	22	10	10
	9	22	10	10
	9	23	10	10
	9	24	10	10
	9	25	10	10
	9	26	10	10
	9	27	10	10
	9	28	11	11
	9	29	11	11
	9	30	11	11
	9	30	11	11
	9	30	11	11
	9	30	11	11

Well Completion for injectors in all case

C-1H I-1H	I	J	K1	K2
Top	26	44	1	1
Perforation	26	44	2	2
	26	44	3	3
	26	44	5	5
	26	44	6	6
	26	44	7	7
	26	44	8	8
	26	44	9	9
	26	44	10	10
	26	44	11	11
	26	44	12	12
	26	44	13	13
	26	44	14	14
	26	44	15	15
	26	44	16	16
	26	44	18	18
	26	44	19	19
	26	44	20	20
	26	44	21	21
	26	44	22	22
	27	44	22	22

C-2H I-2H	I	J	K1	K2
Top	24	14	1	1
Perforation	24	14	19	19
	24	14	20	20
	24	13	20	20

C-4H I-4H	I	J	K1	K2
Top	11	35	1	1
Perforation	11	35	2	2

C-3H I-3H	I	J	K1	K2
Top	9	13	1	1
Perforation	9	13	2	2
	9	13	3	3
	9	13	5	5
	9	13	6	6
	9	13	7	7
	9	13	8	8
	9	13	9	9
	9	13	10	10
	9	13	11	11
	9	13	12	12
	9	13	13	13
	9	13	14	14
	9	13	15	15
	9	13	16	16
	9	13	17	17
	9	13	18	18
	9	13	19	19
	9	13	20	20
	9	13	21	21
	9	13	22	22

Appendix C - Tables of Simulation Results

Cumulative oil production for Base case and Scenario Cases

	Cum. oil production (Sm^3)	Cum. oil production (Sm^3)	Cum. oil production (Sm^3)	Cum. oil production (bbl)	Cum.oil production (bbl)	Cum. oil production (bbl)
Year	**Base case**	**Scenario 1**	**Scenario 2**	**Base case**	**Scenario 1**	**Scenario 2**
1997	384337	293356	306413	2417481	1845209	1927340
1998	6139044	6308123	4387918	38614586	39678094	27600002
1999	5329219	4553771	5052367	33520788	28643220	31779388
2000	3635180	3916340	5358832	22865282	24633779	33707053
2001	2114810	3966190	4352620	13302155	24947335	27377980
2002	2795720	3204060	4477600	17585079	20153537	28164104
2003	3356280	4413450	5021370	21111001	27760601	31584417
2004	3837120	2867970	3623370	24135485	18039531	22790997
2005	2507320	2188040	2310810	15771043	13762772	14534995
2006	1465200	2557960	1838920	9216108	16089568	11566807
2007	1700750	1583690	1505740	10697718	9961410	9471105
2008	1449620	1009530	877030	9118110	6349944	5516519
2009	1299620	988210	703930	8174610	6215841	4427720
2010	894290	793770	627940	5625084	4992813	3949743
2011	1046370	1033440	660850	6581667	6500338	4156747
2012	754400	759330	439670	4745176	4776186	2765524
2013	1024350	984500	702160	6443162	6192505	4416586
2014	908990	697280	568860	5717547	4385891	3578129
2015	664020	654230	415130	4176686	4115107	2611168
	41306640	**42773240**	**43231530**	**259818766**	**269043680**	**271926324**

Recovery factor in each year

Recovery Factor RF (Fraction)			
Year	**Base case**	**Scenario-1**	**Scenario-2**
1997	0.003	0.002	0.003
1998	0.044	0.044	0.031
1999	0.080	0.075	0.066
2000	0.105	0.099	0.100
2001	0.119	0.128	0.131
2002	0.138	0.150	0.162
2003	0.161	0.181	0.197
2004	0.187	0.200	0.221
2005	0.204	0.215	0.236
2006	0.214	0.232	0.249
2007	0.226	0.244	0.260
2008	0.235	0.251	0.266
2009	0.244	0.257	0.270
2010	0.250	0.264	0.275
2011	0.257	0.271	0.280
2012	0.262	0.276	0.283
2013	0.270	0.283	0.288
2014	0.276	0.287	0.291
2015	0.280	0.291	0.294

Cost of gas injection (in Sm^3 and Scf)

Year	Total gas injected (Sm^3)	Total gas injected (Sm^3)	Total gas injected (Sm^3)	Costs of gas injection (USD/Scf)	Costs of gas injection (USD /Scf)	Costs of gas injection (USD /Scf)
	Base case	**Scenario 1**	**Scenario 2**	**Base case**	**Scenario 1**	**Scenario 2**
1997	27068270	25636610	31295750	955888887	905331246	1105178116
1998	1047243730	1048675390	1035985250	36982365081	37032922722	36584783119
1999	1657076000	1670657000	1667069000	58517981864	58997581298	58870874666
2000	2170290000	2154696000	2349805000	76641621060	76090934544	82981013770
2001	948453000	950466000	853363000	33493669242	33564756324	30135660982
2002	1043499000	1050320000	974221000	36850123686	37091000480	34403640394
2003	873764000	866945000	879802000	30856101896	30615295730	31069327828
2004	716852000	715147000	718664000	25314911528	25254701158	25378900496
2005	25959000	27662000	0	916716126	976855868	0
2006	123771000	118666000	118666000	4370849094	4190571124	4190571124
2007	70404000	0	0	2486246856	0	0
2008	0	0	0	0	0	0
2009	0	0	0	0	0	0
2010	353277000	0	0	12475623978	0	0
2011	1120000	0	0	39551680	0	0
2012	391197000	0	0	13814730858	0	0
2013	147179000	0	0	5197479206	0	0
2014	0	0	0	0	0	0
2015	0	0	0	0	0	0
	9597153000	**8628871000**	**8628871000**	**60366092370**	**54275598590**	**54275598590**

Cost of water injection (in Sm3 and bbl)

Year	Total Water injected (Sm^3)	Total Water injected (Sm^3)	Total Water injected (Sm^3)	Costs of Water injection ($/bbl)	Costs of Water injection ($/bbl)	Costs of Water injection ($/bbl)
	Base case	**Scenario 1**	**Scenario 2**	**Base case**	**Scenario 1**	**Scenario 2**
1997	0	0	0	0	0	0
1998	465521	465521	465521	2928125	2928125	2928125
1999	5434252	5475522	5443252	34181448	34441036	34238058
2000	5611987	5567587	5948987	35299398	35020122	37419128
2001	7059300	7062430	7098850	44402997	44422685	44651767
2002	6964340	7095900	6801140	43805699	44633211	42779171
2003	7200530	7069010	7180550	45291334	44464073	45165660
2004	5658350	5638240	6676880	35591022	35464530	41997575
2005	7411840	7431910	6687070	46620474	46746714	42061670
2006	1810130	1713130	1501380	11385718	10775588	9443680
2007	4607690	5533470	6328420	28982370	34805526	39805762
2008	5881330	4980280	5208850	36993566	31325961	32763667
2009	3385690	4678230	3205540	21295990	29426067	20162847
2010	0	4371820	4214260	0	27498748	26507695
2011	2701040	2204000	2700120	16989542	13863160	16983755
2012	0	4260820	5545750	0	26800558	34882768
2013	4032220	4394590	4532530	25362664	27641971	28509614
2014	5640200	2068220	1045800	35476858	13009104	6578082
2015	4973990	1207780	590300	31286397	7596936	3712987
	78838410	**81218460**	**81175200**	**495893599**	**510864113**	**510592008**

Well cost and total expenditure for base case wells

Numbers of wells and Expenditures in Base case								
Year of well Placement	**Nos. of Vertical well**	**Nos. of Horizontal well**	**CapEx. for vertical wells + Cost of drilling vertical well**	**CapEx. for horizontal wells + Cost of drilling horizontal well**	**CapEx. + drilling costs for both Vertical and Horizontal**	**Nos. of vertical well X OpEx. per vertical wells (USD)**	**No. of horizontal well X OpEx. Per horizontal wells (USD)**	**OpEx. + Drilling costs for both Vertical and Horizontal**
1997	1	2	18700000	42000000	**60700000**	800000	2000000	**2800000**
1998	3	0	52700000	2000000	**54700000**	2400000	0	**2400000**
1999	3	1	52700000	22000000	**74700000**	2400000	1000000	**3400000**
2003	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
2004	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
2006	1	0	18700000	2000000	**20700000**	800000	0	**800000**
Total	**8**	**5**	**146200000**	**112000000**	**258200000**			**11400000**

Well cost and total expenditures for new wells in Scenario 1 case

Numbers of wells and Expenditures in Scenario-1 wells								
Year of well Placement	**Nos of Vertical well**	**Nos of Horizontal well**	**CapEx. for vertical wells + Cost of drilling vertical well**	**CapEx. for horizontal wells + Cost of drilling horizontal well**	**CapEx. + drilling costs for both Vertical and Horizontal**	**Nos. of vertical well X OpEx. per vertical wells (USD)**	**No. of horizontal well X OpEx. Per horizontal wells (USD)**	**OpEx. + Drilling costs for both Vertical and Horizontal**
1997	1	0	18700000	2000000	**20700000**	800000	0	**800000**
1998	1	3	18700000	62000000	**80700000**	800000	3000000	**3800000**
1999	3	1	52700000	22000000	**74700000**	2400000	1000000	**3400000**
2003	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
Total	**5**	**5**	**91800000**	**86000000**	**177800000**			**9000000**

Well cost and total expenditures for new wells in Scenario 2 case

Numbers of wells and Expenditures in Scenario-2 wells								
Year of well Placement	**Nos of Vertical well**	**Nos of Horizontal well**	**CapEx. for vertical wells + Cost of drilling vertical well**	**CapEx. for horizontal wells + Cost of drilling horizontal well**	**CapEx. + drilling costs for both Vertical and Horizontal**	**Nos. of vertical well X OpEx. per vertical wells (USD)**	**No. of horizontal well X OpEx. Per horizontal wells (USD)**	**OpEx. + Drilling costs for both Vertical and Horizontal**
1997	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
1998	1	1	18700000	22000000	**40700000**	800000	1000000	**1800000**
1999	3	1	52700000	22000000	**74700000**	2400000	1000000	**3400000**
2001	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
2002	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
2003	0	1	1700000	22000000	**23700000**	0	1000000	**1000000**
Total	**4**	**6**	**78200000**	**132000000**	**210200000**			**9200000**

Net Present Value Calculation for base case reservoir field

NPV for Base case with Oil Price at 25 USD											
Year	Year	Cum. oil production (bbl)	Oil Price at 25 (USD/bbl)	Revenue (USD)	Capital Expenditure (CapEx) = Fixed CapEx + CapEx per well + Well cost (USD)	Operating Expenditure (OpEx)		Total Expenditure (CapEx + OpEx) (USD)	Cash Flow (USD)	Present Value (PV) (USD)	Net Present Value (USD)
						Fixed OpEx. + OpEx per well (USD)	Total Cost of Gas +Water injection (USD)				
1997	**0**	2417481	25.0	60437025	**260700000**	**7800000**	**11470667**	279970667	-219533642	-219533642	-219533642
1998	**1**	38614586	27.0	1042593809	**54700000**	**7400000**	**467213378**	529313378	513280431	475259658	255726016
1999	**2**	33520788	29.2	977466164	**74700000**	**8400000**	**975667363**	1058767363	-81301199	-69702674	186023342
2000	**3**	22865282	31.5	720091759	0	5000000	1202094639	1207094639	-487002879	-386598587	-200575245
2001	**4**	13302155	34.0	452435872	0	5000000	757148007	762148007	-309712135	-227647665	-428222910
2002	**5**	17585079	36.7	645956250	0	5000000	792647073	797647073	-151690823	-103238225	-531461135
2003	**6**	21111001	39.7	837512643	**23700000**	**6000000**	**732603892**	762303892	75208751	47394271	-484066864
2004	**7**	24135485	42.8	1034099490	**23700000**	**6000000**	**588507110**	618207110	415892379	242669209	-241397655
2005	**8**	15771043	46.3	729777489	0	5000000	383964382	388964382	340813107	184130717	-57266938
2006	**9**	9216108	50.0	460576063	**20700000**	**5800000**	**143535931**	170035931	290540133	145342401	88075463
2007	**10**	10697718	54.0	577389243	0	5000000	261693923	266693923	310695320	143912049	231987512
2008	**11**	9118110	58.3	531503510	0	5000000	295948526	300948526	230554984	98881081	330868593
2009	**12**	8174610	63.0	514626453	0	5000000	170367921	175367921	339258532	134724231	465592824
2010	**13**	5625084	68.0	382452805	0	5000000	149707488	154707488	227745317	83741480	549334304
2011	**14**	6581667	73.4	483290781	0	5000000	136390953	141390953	341899828	116403571	665737875
2012	**15**	4745176	79.3	376312519	0	5000000	165776770	170776770	205535748	64793440	730531315
2013	**16**	6443162	85.6	551847544	0	5000000	265271061	270271061	281576483	82189491	812720806
2014	**17**	5717547	92.5	528875687	0	5000000	283814864	288814864	240060823	64880987	877601793
2015	**18**	4176686	99.9	417252947	0	5000000	250291177	255291177	161961771	40530776	**918132569**
Total									**2725782929**	**918132569**	

Net Present Value Calculation for base case reservoir field

NPV for Scenario 1 with Oil Price at 25 USD											
Year	**Year**	**Cum. oil production (bbl)**	**Oil Price at 25 (USD/bbl)**	**Revenue (USD)**	**Capital Expenditure (CapEx) = Fixed CapEx + CapEx per well + Well cost (USD)**	**Operating Expenditure (OpEx)**		**Total Expenditure (CapEx + OpEx) (USD)**	**Cash Flow (USD)**	**Present Value (PV) (USD)**	**Net Present Value (USD)**
						Fixed OpEx. + OpEx per well (USD)	**Total Cost of Gas +Water injection (USD)**				
1997	**0**	1845209	25.0	46130215	**220700000**	**5800000**	**10863975**	237363975	-191233760	-191233760	-191233760
1998	**1**	39678094	27.0	1071308546	**80700000**	**8800000**	**467820069**	557320069	513988477	475915256	284681497
1999	**2**	28643220	29.2	835236283	**74700000**	**8400000**	**983499263**	1066599263	-231362979	-198356464	86325033
2000	**3**	24633779	31.5	775786663	0	5000000	1193252192	1198252192	-422465530	-335366758	-249041725
2001	**4**	24947335	34.0	848514350	0	5000000	758158553	763158553	85355796	62739058	-186302667
2002	**5**	20153537	36.7	740303959	**23700000**	**6000000**	**802157694**	831857694	-91553735	-62309934	-248612601
2003	**6**	27760601	39.7	1101314603	0	5000000	723096132	728096132	373218471	235190945	-13421656
2004	**7**	18039531	42.8	772914663	0	5000000	586772651	591772651	181142013	105694625	92272968
2005	**8**	13762772	46.3	636848243	0	5000000	385695982	390695982	246152262	132988408	225261376
2006	**9**	16089568	50.0	804078042	0	5000000	136491555	141491555	662586487	331458206	556719582
2007	**10**	9961410	54.0	537648432	0	5000000	278444210	283444210	254204221	117745740	674465322
2008	**11**	6349944	58.3	370144409	0	5000000	250607690	255607690	114536719	49122836	723588158
2009	**12**	6215841	63.0	391313620	0	5000000	235408534	240408534	150905087	59926486	783514644
2010	**13**	4992813	68.0	339464338	0	5000000	219989982	224989982	114474355	42091983	825606627
2011	**14**	6500338	73.4	477318754	0	5000000	110905280	115905280	361413474	123047208	948653834
2012	**15**	4776186	79.3	378771719	0	5000000	214404462	219404462	159367257	50239206	998893040
2013	**16**	6192505	85.6	530379174	0	5000000	221135769	226135769	304243405	88805750	1087698790
2014	**17**	4385891	92.5	405696916	0	5000000	104072830	109072830	296624085	80168280	1167867070
2015	**18**	4115107	99.9	411101165	0	5000000	60775490	65775490	345325676	86417415	**1254284485**
Total									**3226921781**	**1254284485**	

Net Present Value Calculation for Scenario 2 reservoir field

NPV for Scenario 2 with Oil Price at 25 USD											
Year	Year	Cum. oil production (bbl)	Oil Price at 25 (USD/bbl)	Revenue (USD)	Capital Expenditure (CapEx) = Fixed CapEx + CapEx per well + Well cost (USD)	Operating Expenditure (OpEx)		Total Expenditure (CapEx + OpEx) (USD)	Cash Flow (USD)	Present Value (PV) (USD)	Net Present Value (USD)
						Fixed OpEx. + OpEx per well (USD)	Total Cost of Gas +Water injection (USD)				
1997	**0**	1927340	25.0	48183491	**223700000**	**6000000**	**13262137**	242962137	-194778646	-194778646	-194778646
1998	**1**	27600002	27.0	745200063	**40700000**	**6800000**	**462442394**	509942394	235257669	217831175	23052529
1999	**2**	31779388	29.2	926686967	**74700000**	**8400000**	**980354957**	1063454957	-136767990	-117256507	-94203978
2000	**3**	33707053	31.5	106152949	0	5000000	1295125191	1300125191	-238595704	-189404962	-283608940
2001	**4**	27377980	34.0	931185982	**23700000**	**6000000**	**718842064**	748542064	182643918	134248732	-149360208
2002	**5**	28164104	36.7	1034557719	**23700000**	**6000000**	**755077050**	784777050	249780670	169996527	20636318
2003	**6**	31584417	39.7	1253012520	**23700000**	**6000000**	**734157210**	763857210	489155311	308250820	328887138
2004	**7**	22790997	42.8	976494107	0	5000000	640527408	645527408	330966700	193115890	522003028
2005	**8**	14534995	46.3	672581529	0	5000000	336493362	341493362	331088167	178876635	700879663
2006	**9**	11566807	50.0	578052508	0	5000000	125836295	130836295	447216213	223719449	924599111
2007	**10**	9471105	54.0	511185112	0	5000000	318446094	323446094	187739017	86959490	1011558602
2008	**11**	5516519	58.3	321563253	0	5000000	262109332	267109332	54453921	23354353	1034912955
2009	**12**	4427720	63.0	278743786	0	5000000	161302773	166302773	112441013	44651873	1079564828
2010	**13**	3949743	68.0	268545342	0	5000000	212061563	217061563	51483779	18930479	1098495307
2011	**14**	4156747	73.4	305229233	0	5000000	135870038	140870038	164359195	55957903	1154453210
2012	**15**	2765524	79.3	219317769	0	5000000	279062140	284062140	-64744371	-20410126	1134043084
2013	**16**	4416586	85.6	378274292	0	5000000	228076910	233076910	145197383	42381732	1176424816
2014	**17**	3578129	92.5	330978585	0	5000000	52624656	57624656	273353929	73879080	1250303895
2015	**18**	2611168	99.9	260856926	0	5000000	29703896	34703896	226153030	56594576	**1306898471**
Total									**2846403202**	**1306898471**	

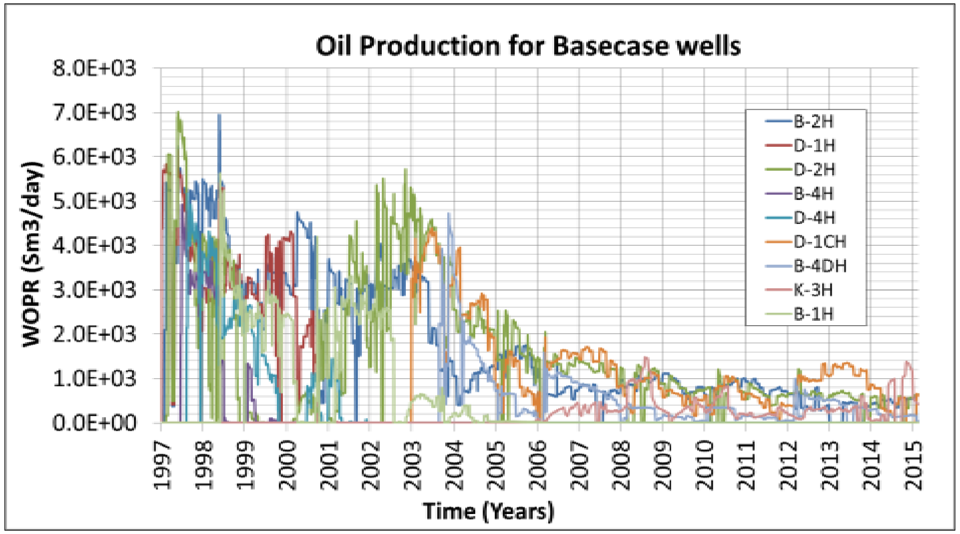
Net Present Value Result for base case reservoir field

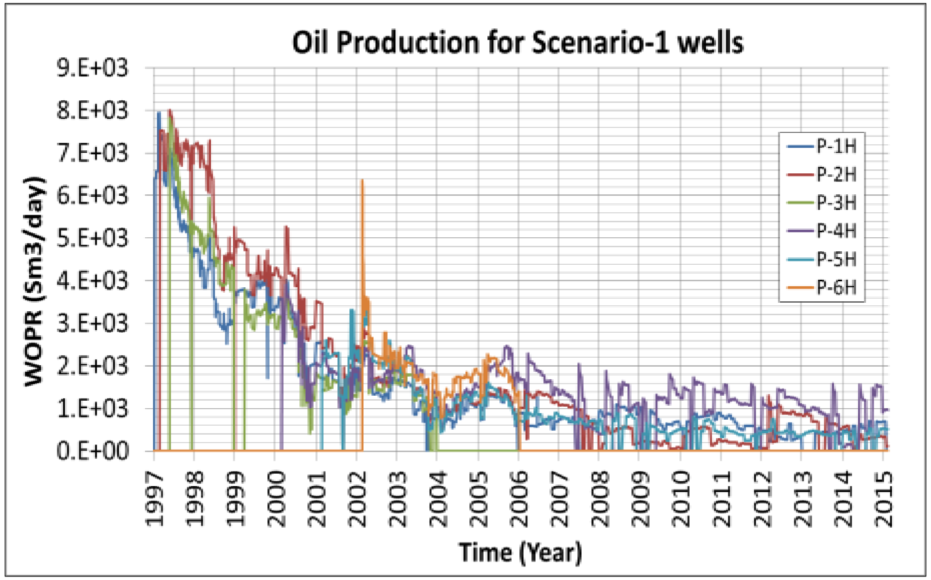
Year	Cumulative oil production (bbl)	Net Present Value (USD) for Base case		
		Base case at 25 USD oil price	Base case at 35 USD oil price	Base case at 45 USD oil price
1997	2417481	-219533642	-195358832	-171184022
1998	38614586	255726016	666046681	1076367346
1999	33520788	186023342	931551882	1677080422
2000	22865282	-200575245	773606117	1747787479
2001	13302155	-428222910	678980001	1786182912
2002	17585079	-531461135	751592564	2034646263
2003	21111001	-484066864	1010096847	2504260558
2004	24135485	-241397655	1494120904	3229639463
2005	15771043	-57266938	1835962049	3729191036
2006	9216108	88075463	2073465530	4058855597
2007	10697718	231987512	2324354754	4416721996
2008	9118110	330868593	2514416933	4697965273
2009	8174610	465592824	2730887262	4996181700
2010	5625084	549334304	2870879583	5192424862
2011	6581667	665737875	3053099827	5440461779
2012	4745176	730531315	3165345027	5600158739
2013	6443162	812720806	3311966133	5811211460
2014	5717547	877601793	3434022591	5990443389
2015	4176686	918132569	3516320225	6114507881

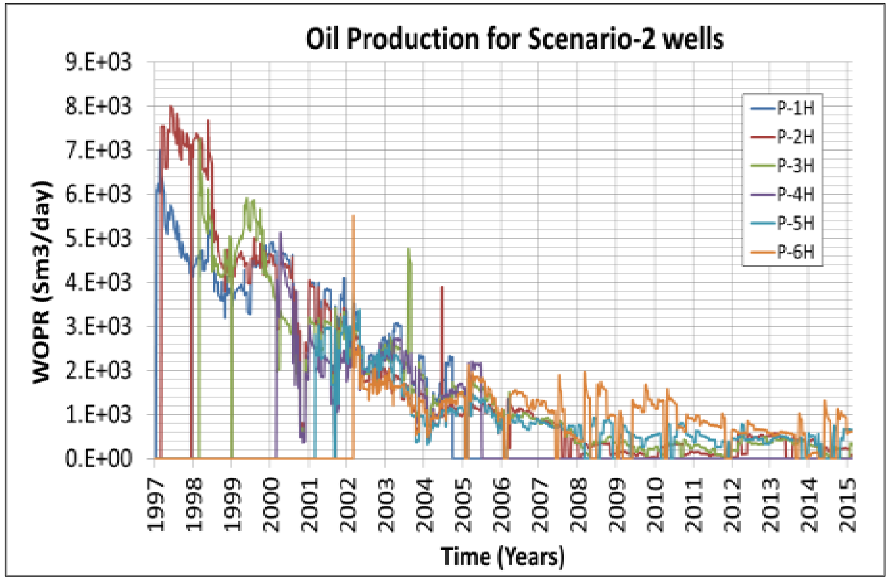
Net Present Value Result for Scenario 1 and Scenario 2 reservoir field

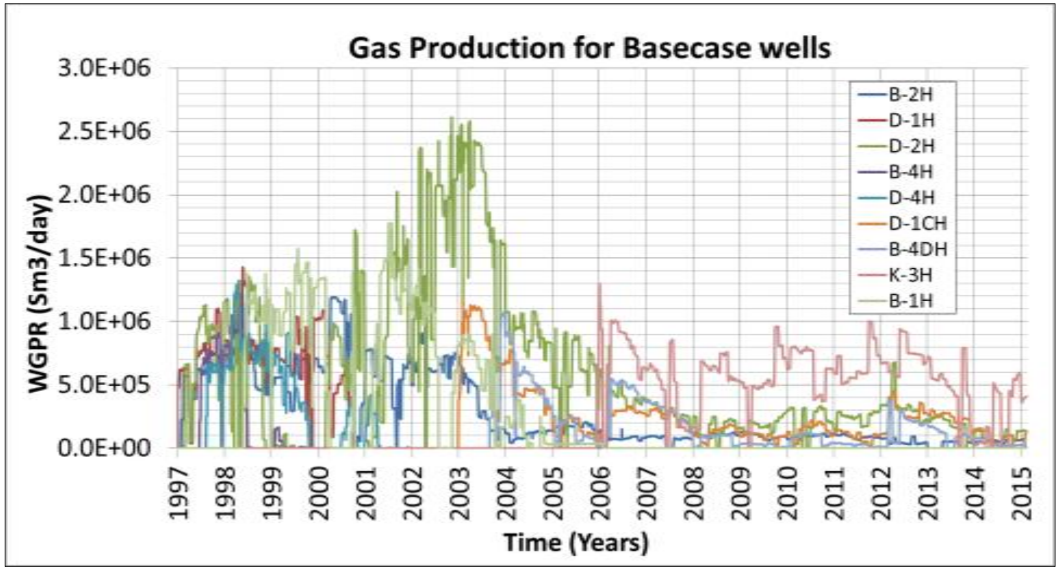
Year	Cum.oil production (bbl)	Net Present Value (USD) for Scenario 1			Cum. oil production (bbl)	Net Present Value (USD) for Scenario 2		
		Scenario 1 at 25 USD oil price	Scenario 1 at 35 USD oil price	Scenario 1 at 45 USD oil price		Scenario 2 at 25 USD oil price	Scenario 2 at 35 USD oil price	Scenario 2 at 45 USD oil price
1997	**1845209**	-191233760	-172781674	-154329587	**1927340**	-194778646	-175505249	-156231853
1998	**39678094**	284681497	699914526	1115147555	**27600002**	23052529	318325949	613599369
1999	**28643220**	86325033	787990258	1489655483	**31779388**	-94203978	518863326	1131930630
2000	**24633779**	-249041725	698961286	1646964297	**33707053**	-283608940	666528897	1616666734
2001	**24947335**	-186302667	1011173695	2208650057	**27377980**	-149360208	1074557427	2298475062
2002	**20153537**	-248612601	1150399135	2549410871	**28164104**	20636318	1526194993	3031753668
2003	**27760601**	-13421656	1663196085	3339813826	**31584417**	328887138	2150289986	3971692834
2004	**18039531**	92272968	1949286022	3806299076	**22790997**	522003028	2571315849	4620628670
2005	**13762772**	225261376	2219902146	4214542916	**14534995**	700879663	2895542433	5090205203
2006	**16089568**	556719582	2712256036	4867792490	**11566807**	924599111	3234929949	5545260787
2007	**9961410**	674465322	2929615877	5184766432	**9471105**	1011558602	3416600486	5821642370
2008	**6349944**	723588158	3042238150	5360888142	**5516519**	1034912955	3495120026	5955327097
2009	**6215841**	783514644	3164323045	5545131446	**4427720**	1079564828	3584049096	6088533364
2010	**4992813**	825606627	3256343161	5687079695	**3949743**	1098495307	3642477001	6186458695
2011	**6500338**	948653834	3444393744	5940133654	**4156747**	1154453210	3740002369	6325551528
2012	**4776186**	998893040	3542394807	6085896574	**2765524**	1134043084	3747247486	6360451888
2013	**6192505**	1087698790	3693125607	6298552424	**4416586**	1176424816	3833795082	6491165348
2014	**4385891**	1167867070	3817152799	6466438528	**3578129**	1250303895	3943455455	6636607015
2015	**4115107**	1254284485	3944721281	6635158077	**2611168**	1306898471	4026161708	6745424945

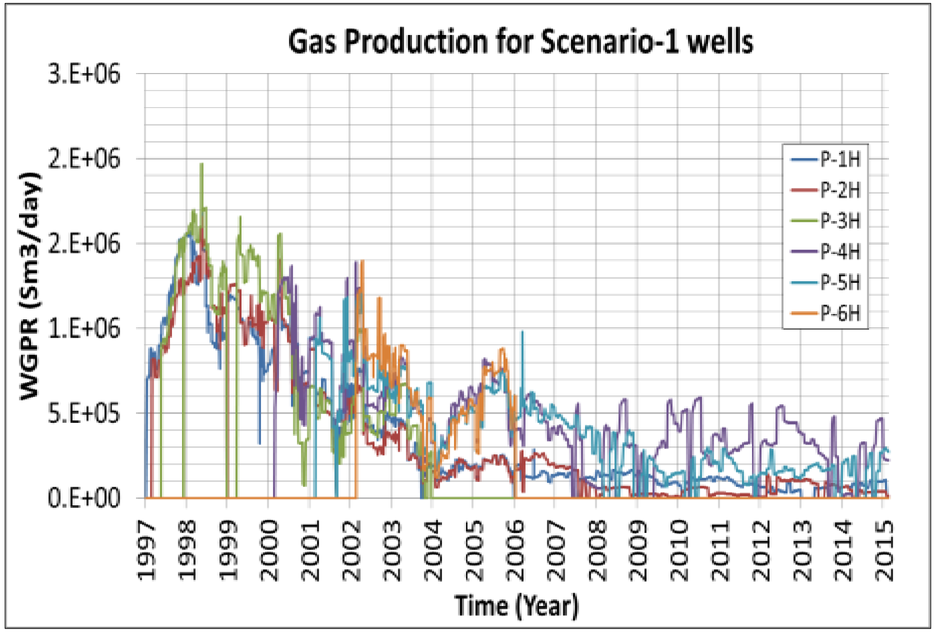
Well Production Profile: Well production rate

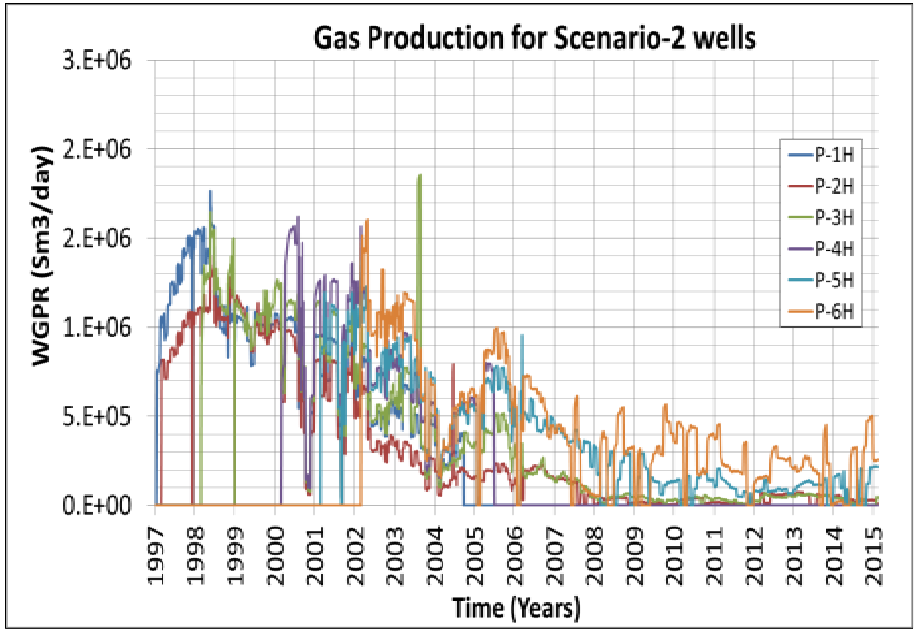


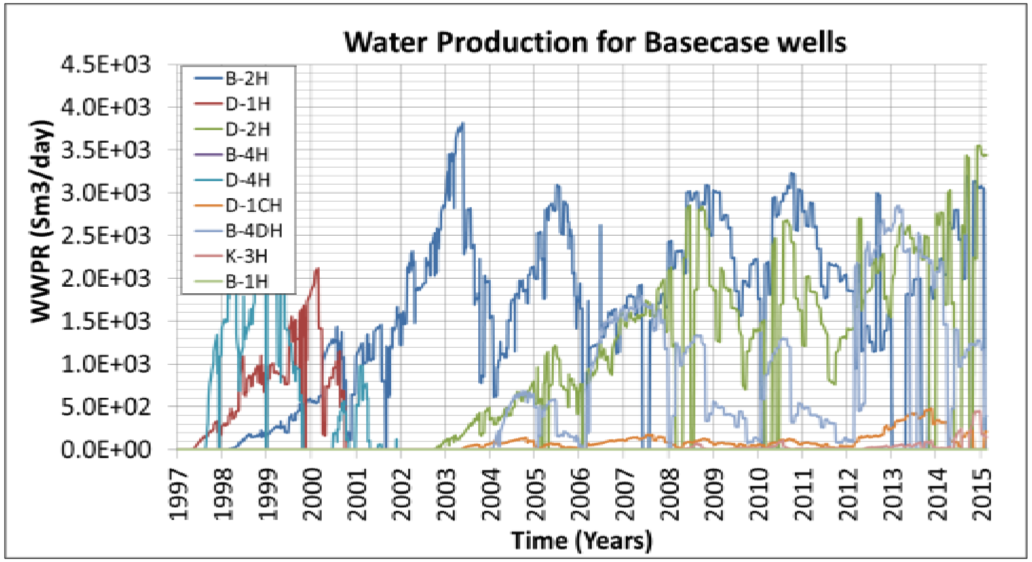


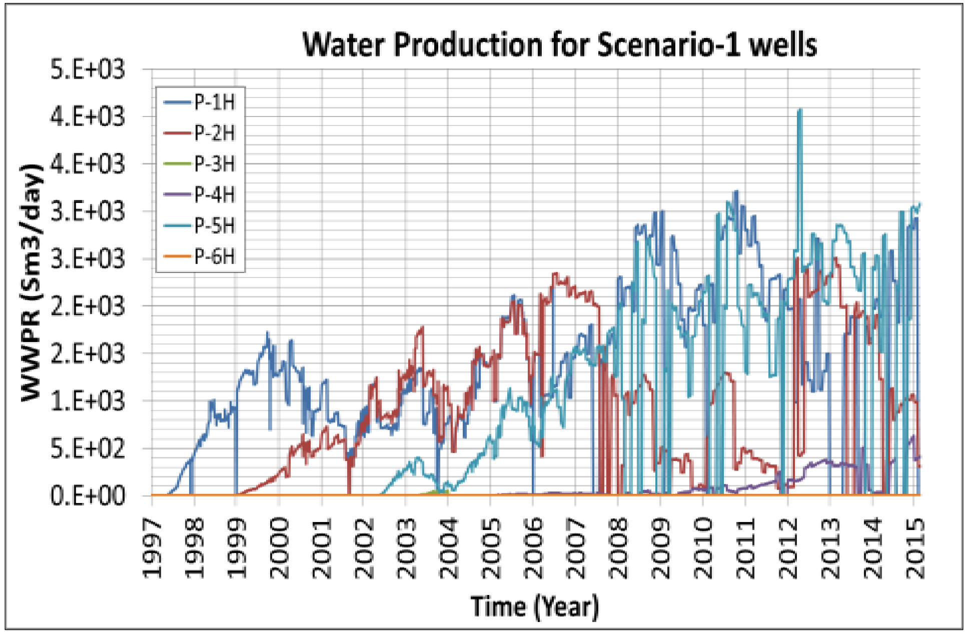



Gas Production for Basecase wells
WGPR (Sm3/day)
Time (Years)
B-2H
D-1H
D-2H
B-4H
D-4H
D-1CH
B-4DH
K-3H
B-1H


Gas Production for Scenario-1 wells
WGPR (Sm3/day)
Time (Year)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H


Gas Production for Scenario-2 wells
WGPR (Sm3/day)
Time (Years)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H


Water Production for Basecase wells
WWPR (Sm3/day)
Time (Years)
B-2H
D-1H
D-2H
B-4H
D-4H
D-1CH
B-4DH
K-3H
B-1H


Water Production for Scenario-1 wells
WWPR (Sm3/day)
Time (Year)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H

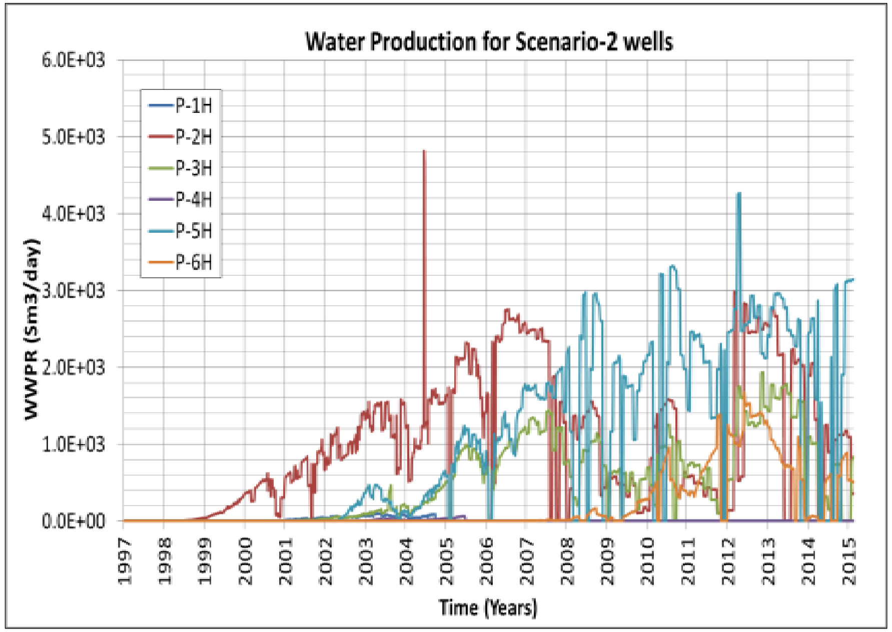
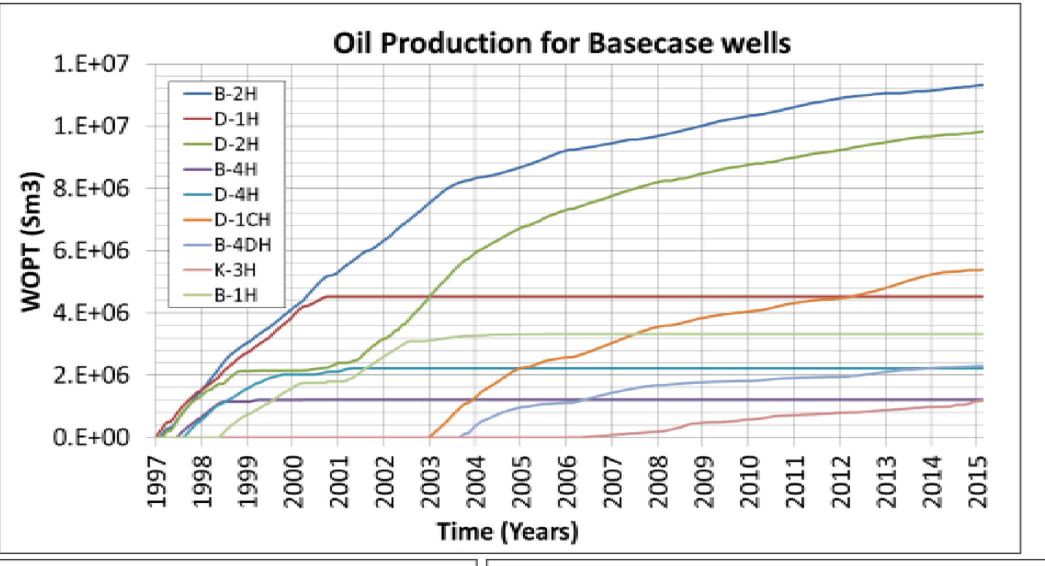
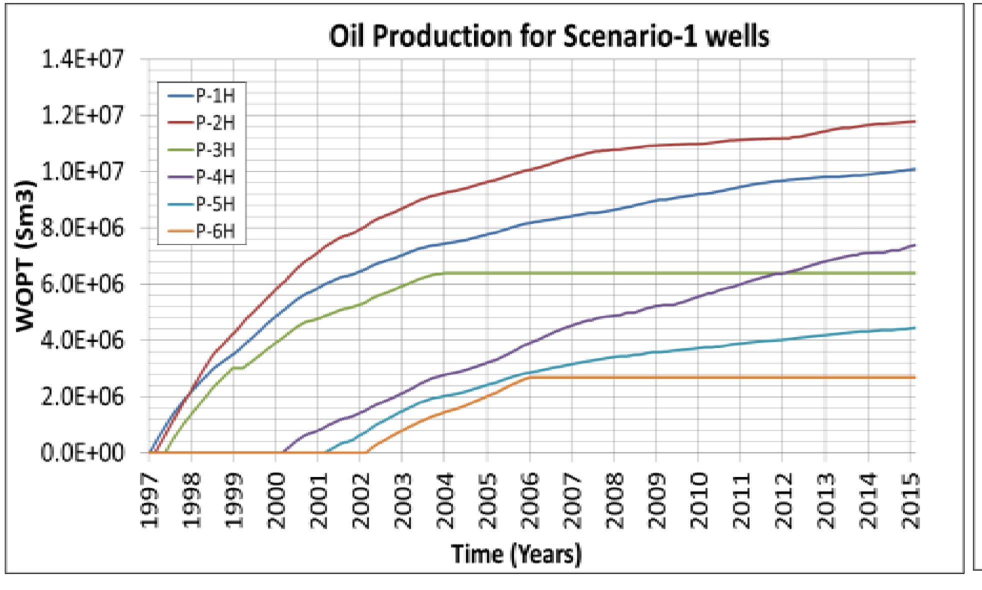
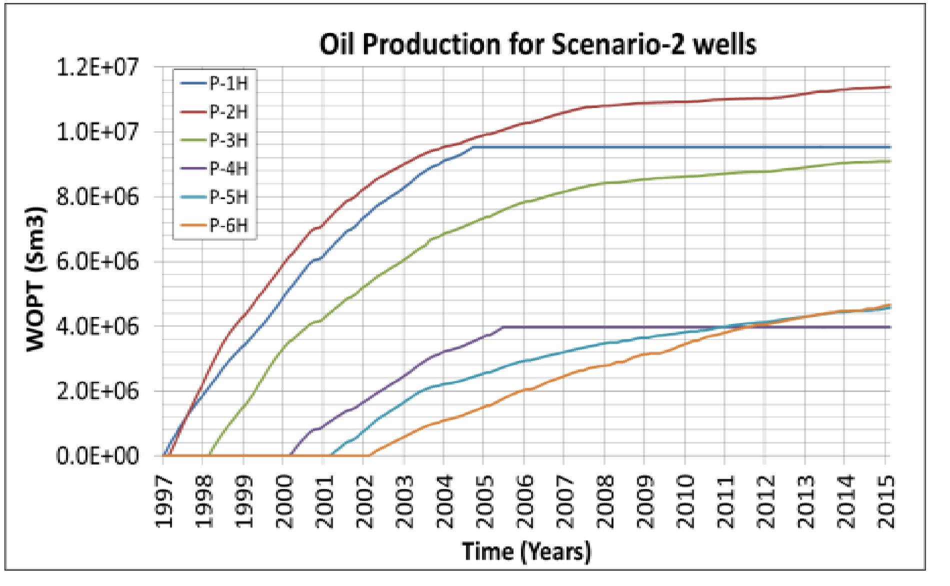

Water Production for Scenario-2 wells
WWPR (Sm3/day)
Time (Years)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H

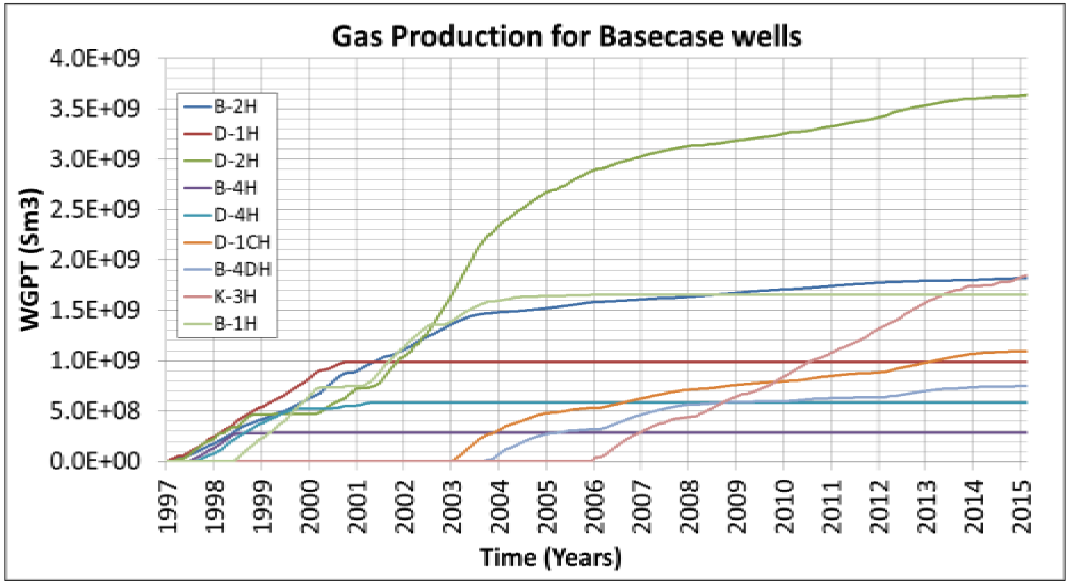
Figure41 - Top left-down shows (a) WOPR (b) WGPR (c) WWPR for Base case wells, (d) WOPR (e) WGPR (f) WWPR for Scenarios 1 well and (g) WOPR (h) WGPR (i) WWPR for Scenarios 2 wells

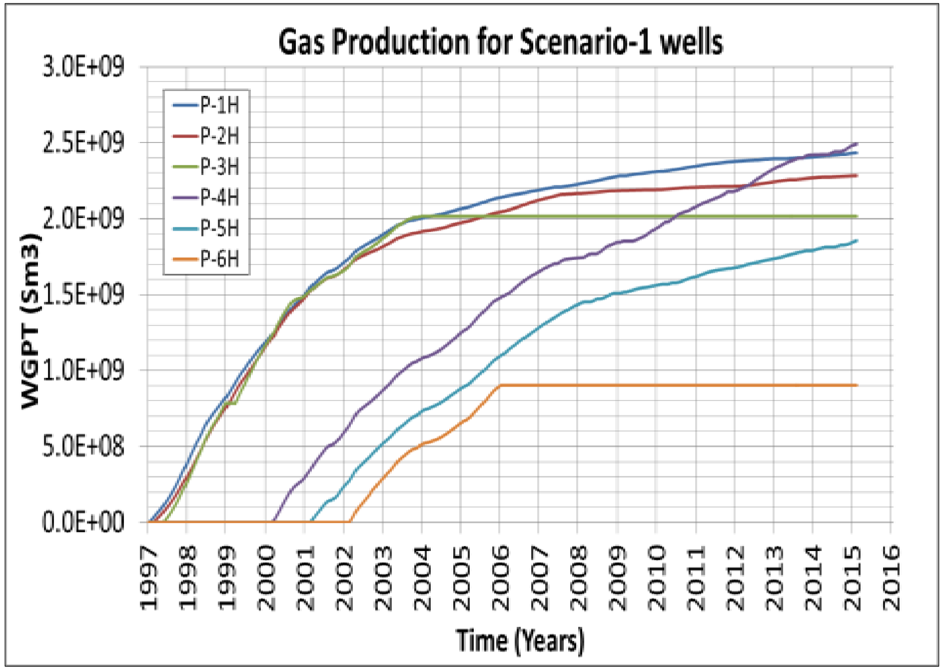
Well production total

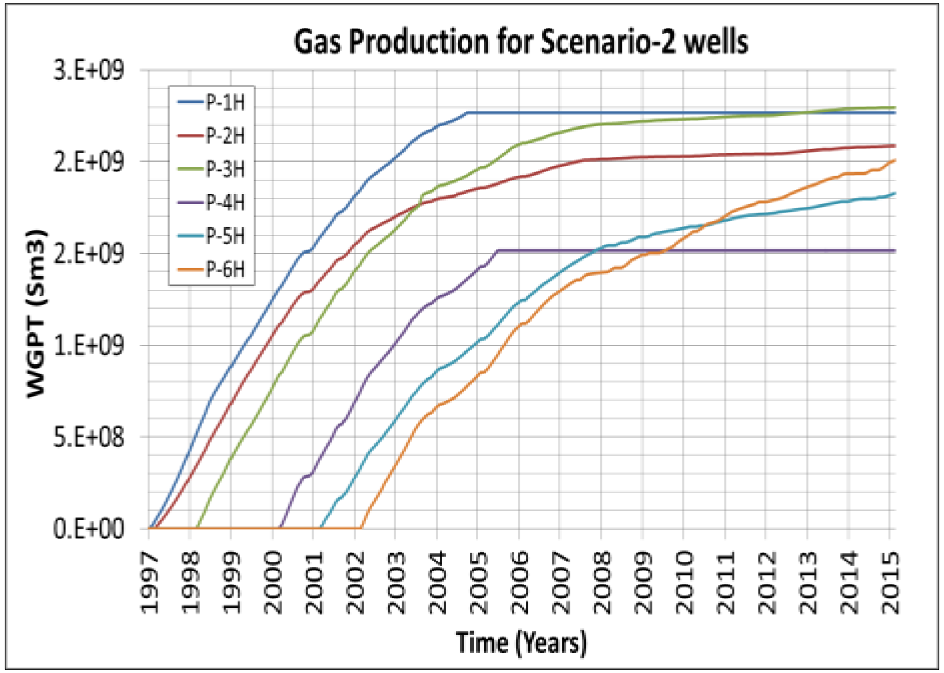


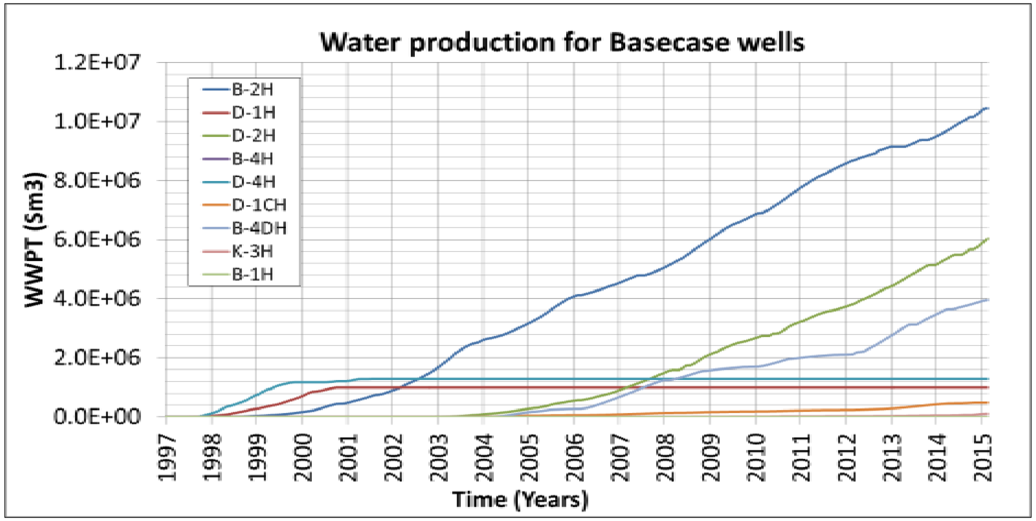


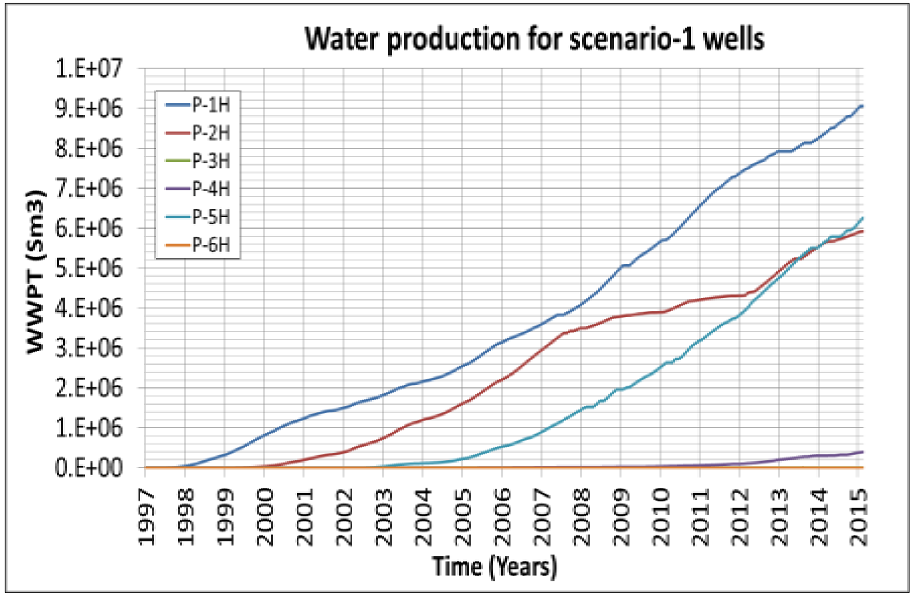



Gas Production for Basecase wells
WGPT (Sm3)
Time (Years)
B-2H
D-1H
D-2H
B-4H
D-4H
D-1CH
B-4DH
K-3H
B-1H


Gas Production for Scenario-1 wells
WGPT (Sm3)
Time (Years)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H


Gas Production for Scenario-2 wells
WGPT (Sm3)
Time (Years)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H





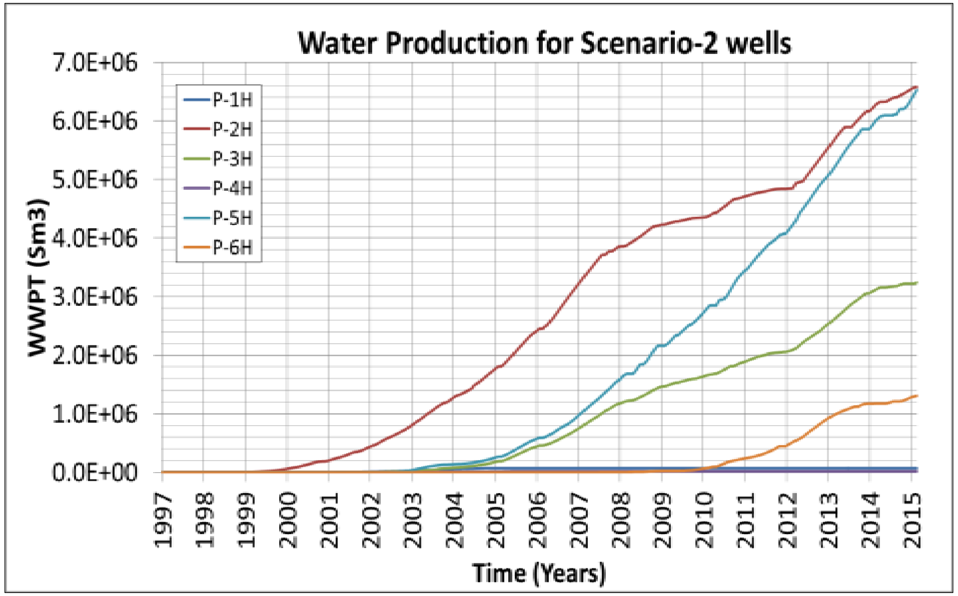
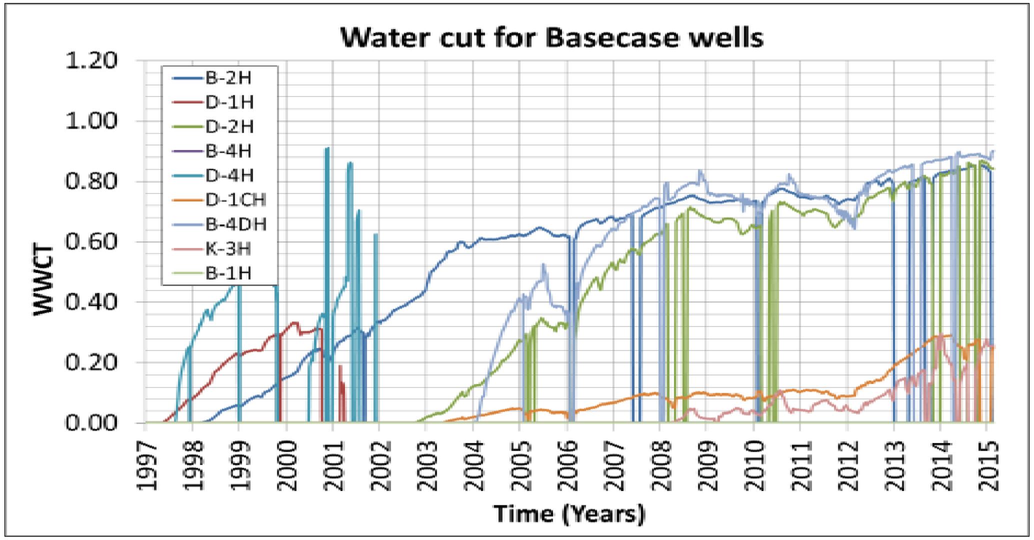
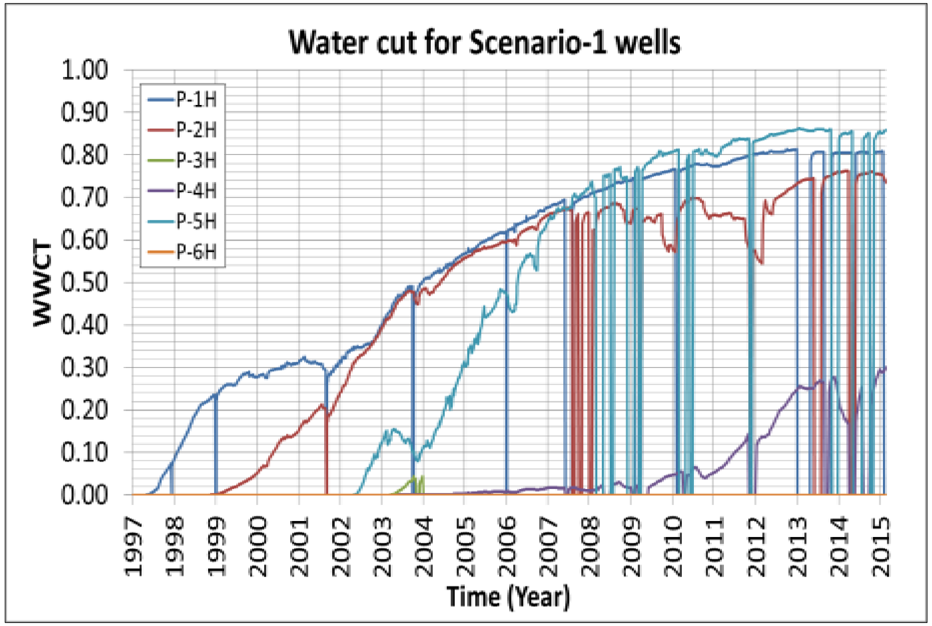
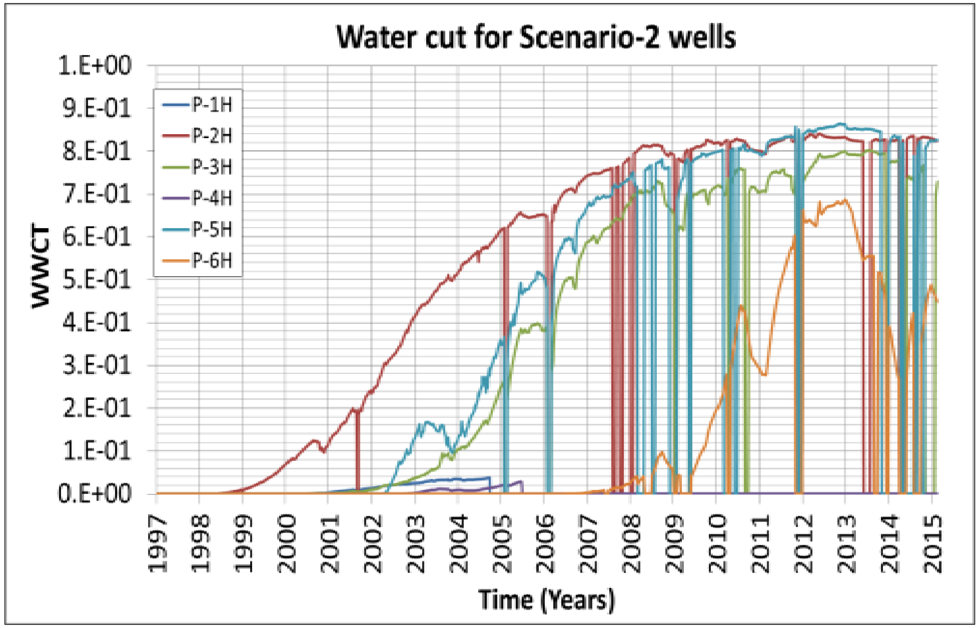


Figure42 - Top left-down shows (a) WOPT (b) WGPT (c) WWPT for Base case wells, (d) WOPT (e) WGPT (f) WWPT for Scenarios 1 well and (g) WOPT (h) WGPT (i) WWPT for Scenarios 2 wells.

Well Water-cut and Well Gas Oil-Ratio


Water cut for Basecase wells
WWCT
Time (Years)
B-2H
D-1H
D-2H
B-4H
D-4H
D-1CH
B-4DH
K-3H
B-1H


Water cut for Scenario-1 wells
WWCT
Time (Year)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H


Water cut for Scenario-2 wells
WWCT
Time (Years)
P-1H
P-2H
P-3H
P-4H
P-5H
P-6H

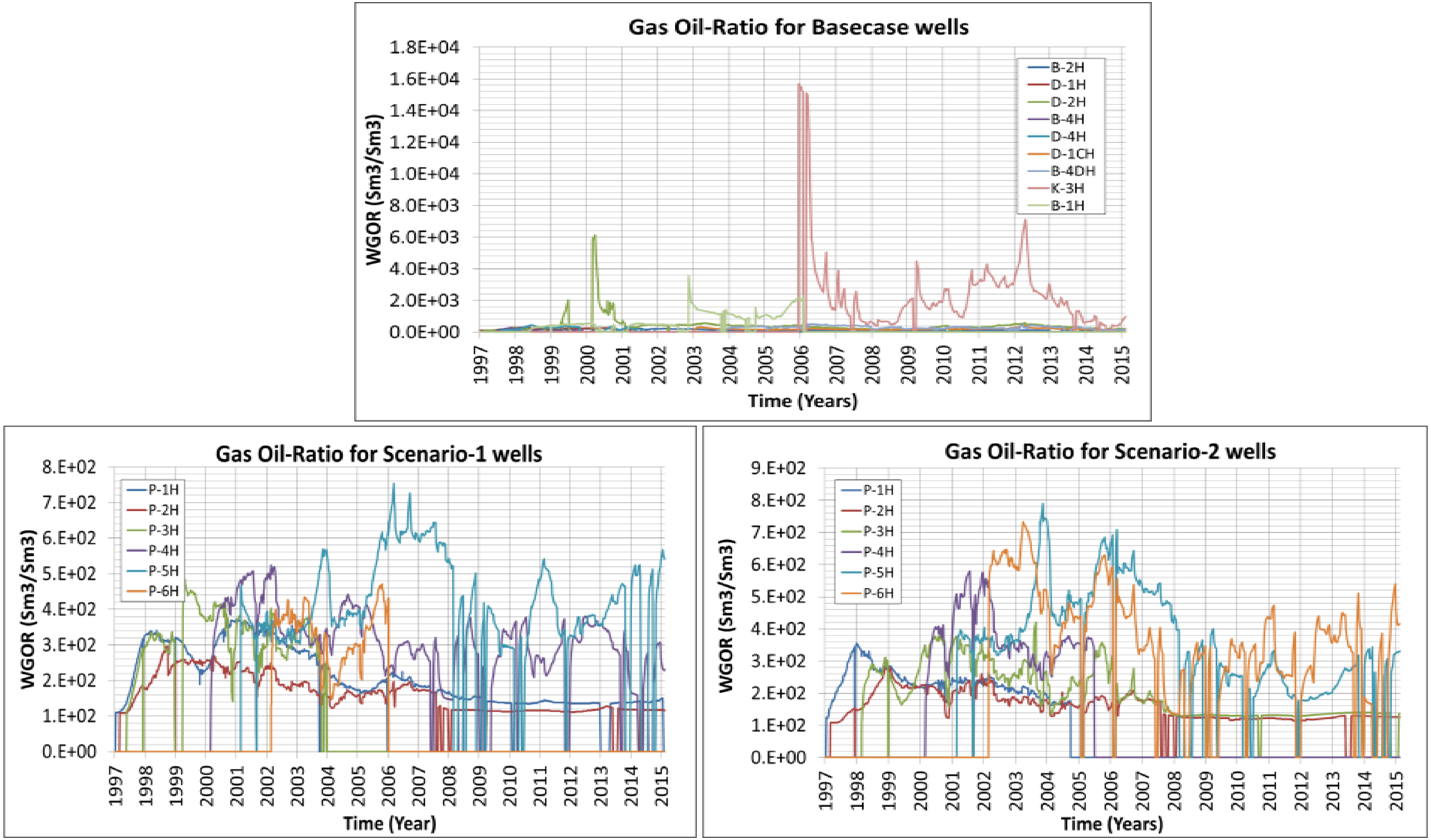


Figure43 - Top left-down shows (a) WWCT (b) WGOR for Base case wells (c) WWCT (d) WGOR for Scenarios 1 well (e) WWCT (f) WGOR for Scenarios 2 wells

Well Bottom Hole Pressure

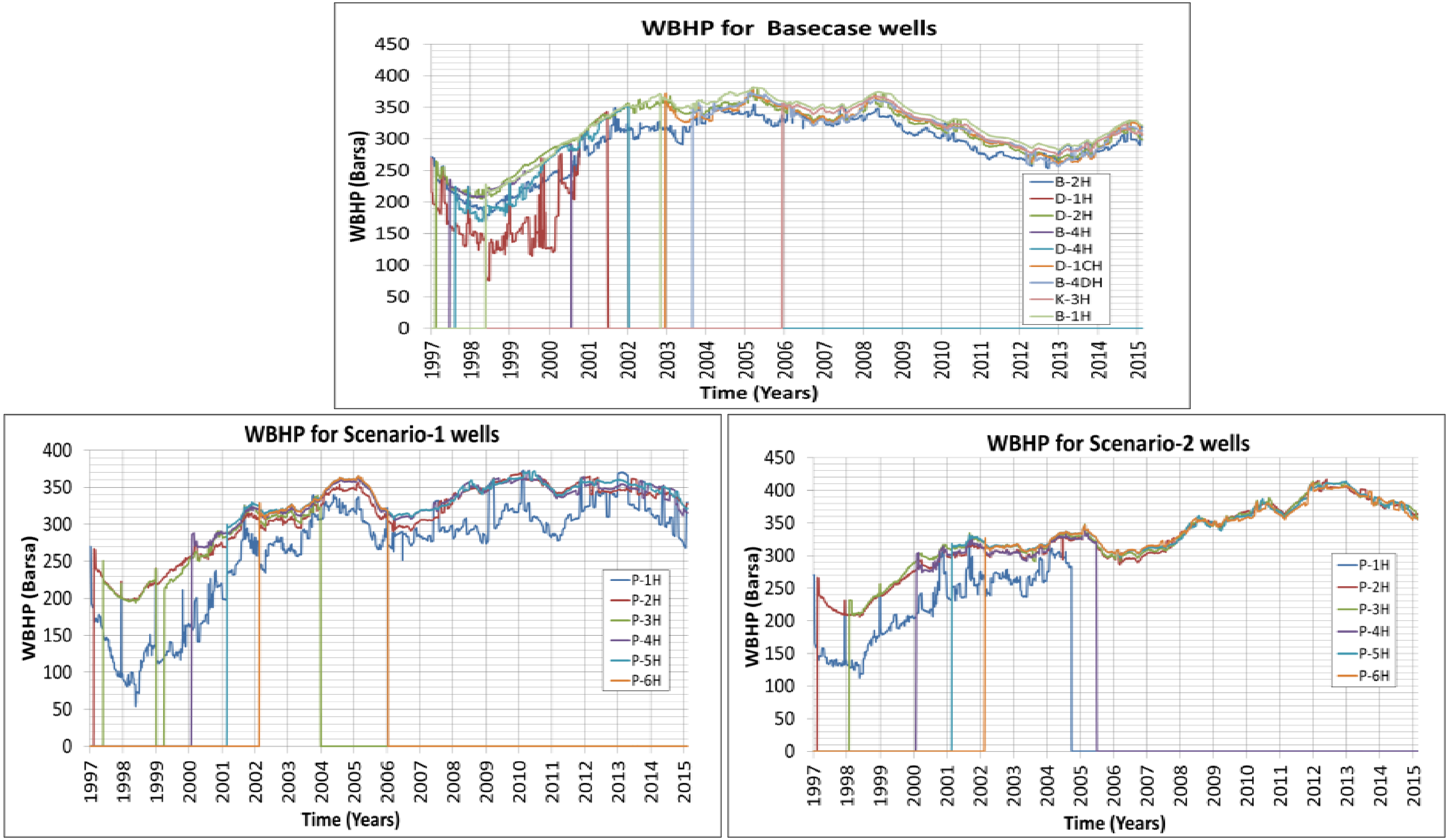


Figure44 - Shows results on (a) WBHP for Base case wells, (b) WBHP for Scenarios 1 new wells and (c) WBHP for Scenarios 2 new wells.

Field Rate Profile: Field Production Rate

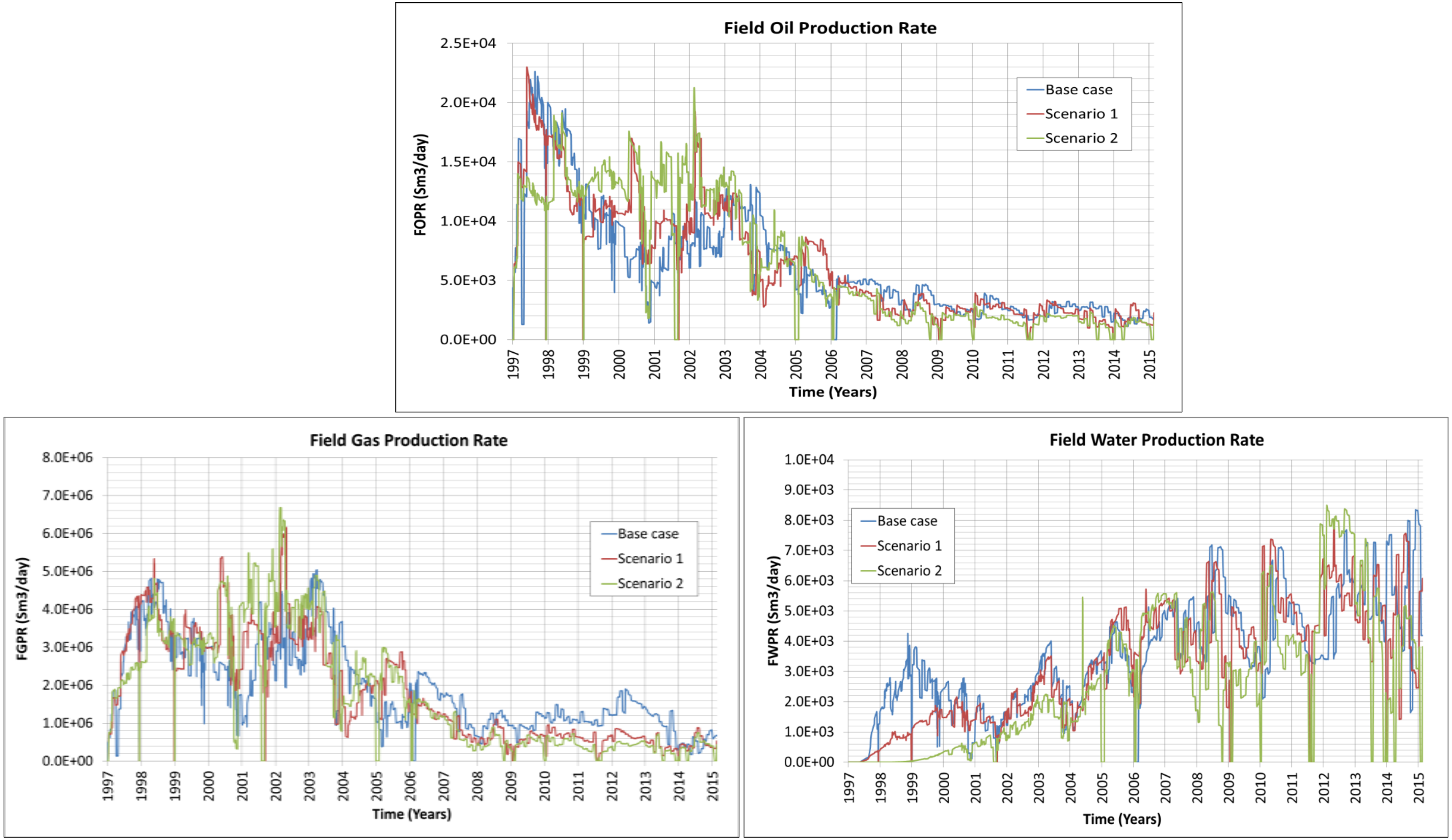


Figure45 - Left-right shows production profile for (a) Field Oil Production Total (FOPT), (b) Field Gas production Total (FGPT) and (c) Field Water Production Total (FWPT) for field reservoir in Base case, Scenario 1& 2 case.

Field Production Total and Recovery

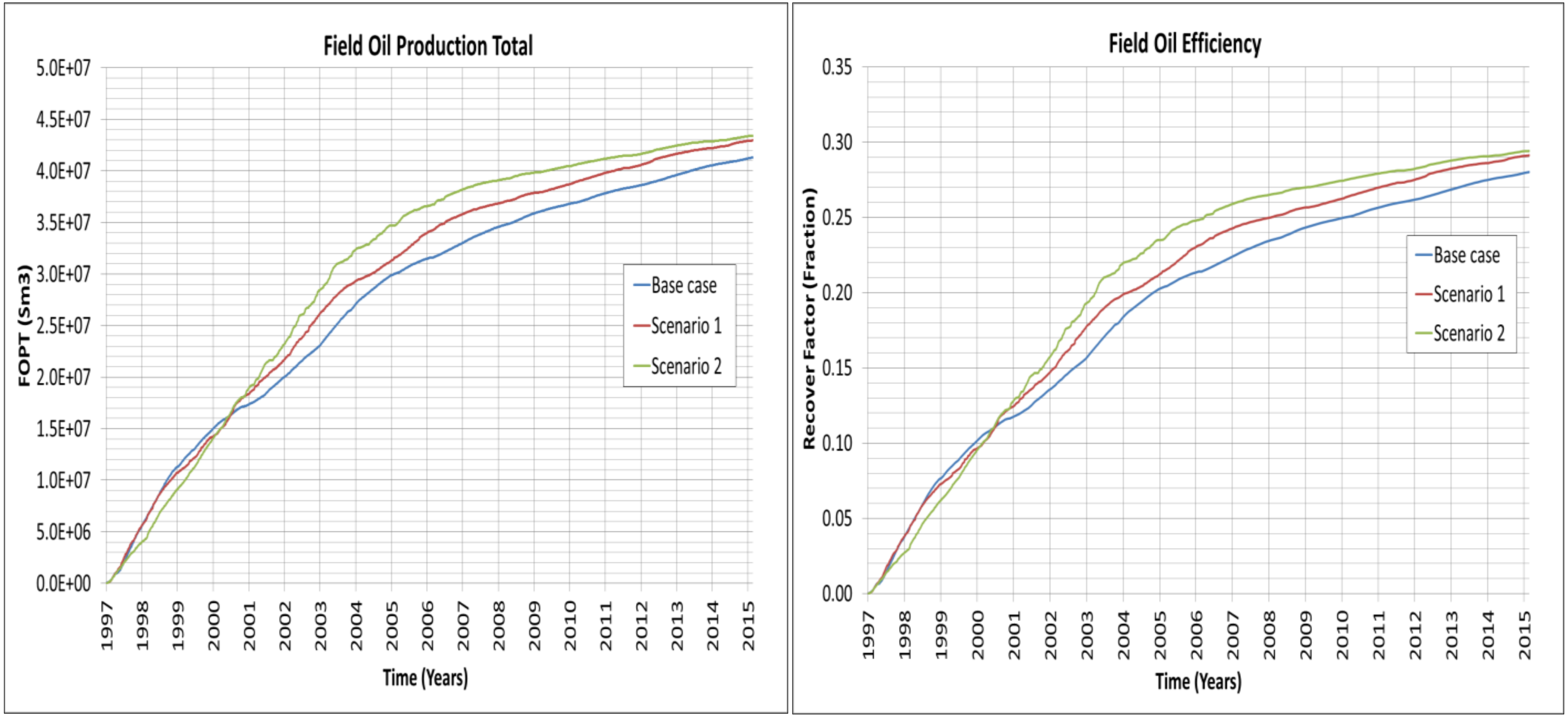


Figure 28 - Shows results on (a) Field Oil Production Total (FOPT) and (b) Field Oil Efficiency (FOE) for field reservoir in Base case, Scenario 1case and Scenario 2 case.

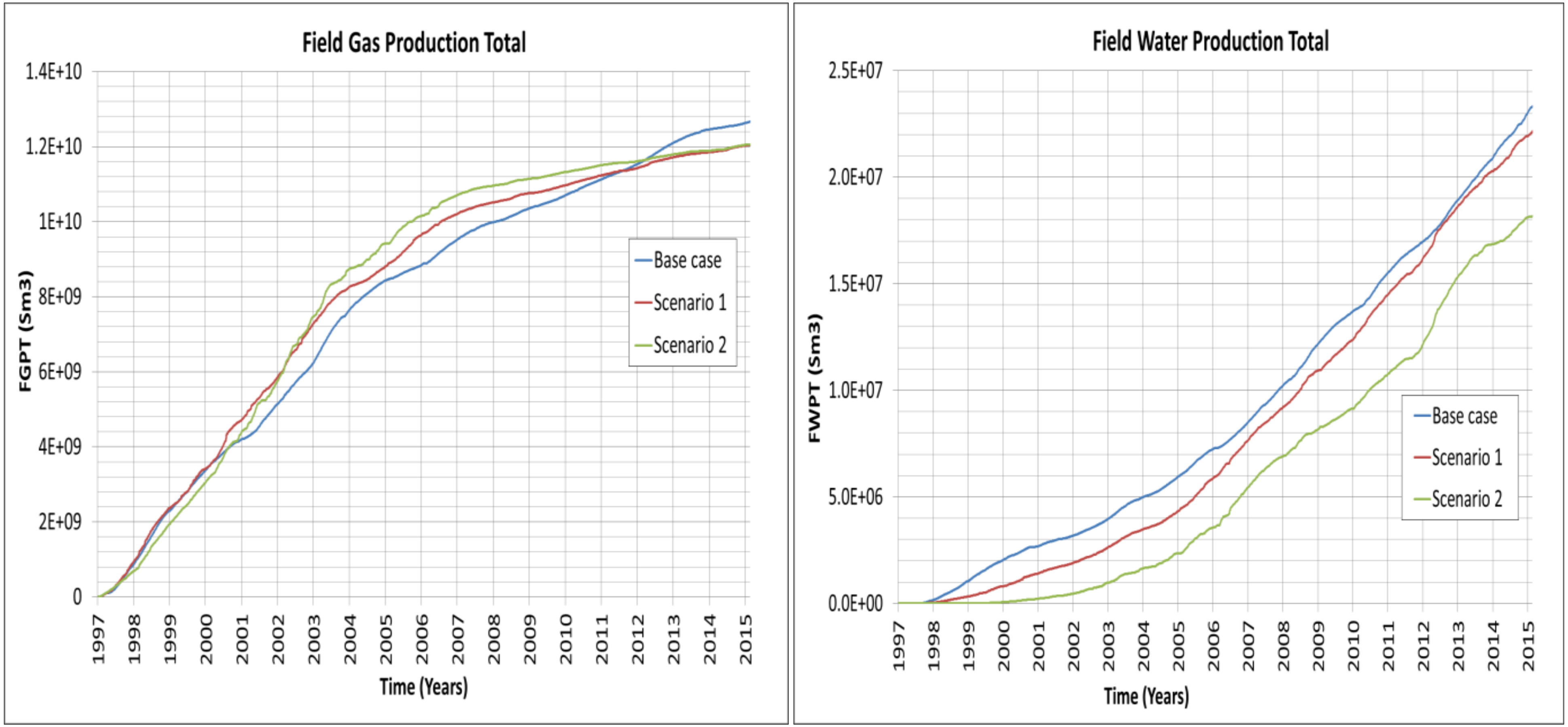


Figure 30 - Shows results on (a) Field Gas Production Total (FGPT) and (b) Field Water Production Total (FWPT) for reservoir in Base case, Scenario 1case and Scenario 2 case

Field Injection Total (FIT)

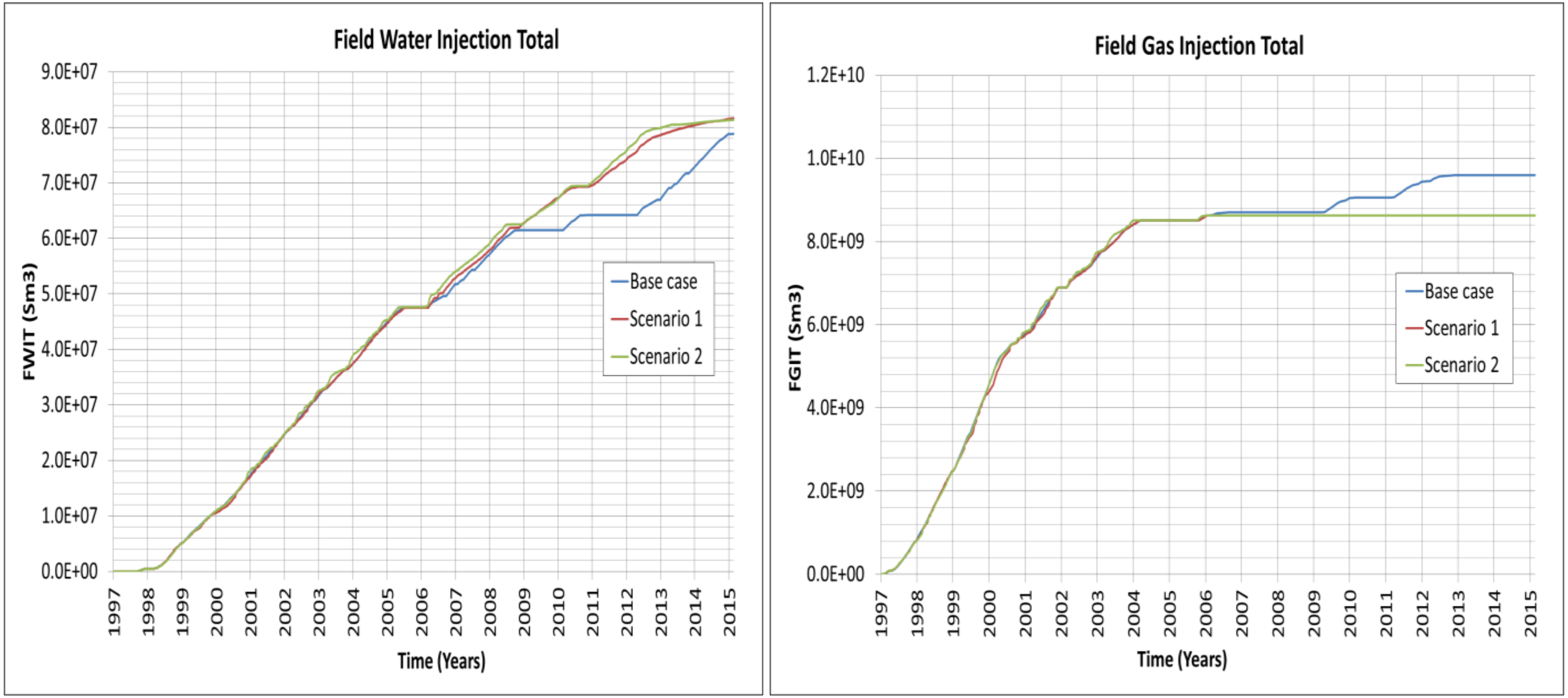


Figure 32 - shows results on (a) Field Gas Injection Total (FGIT) and (b) Field Water Injection Total (FWIT) for field reservoir in Base case, Scenario 1case and Scenario 2 case.