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Analysis of Alternative Reservoir Development Plans to Improve Oil Recovery Based on Reservoir Simulation and Economic Evaluation

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Petroleum Engineering
Submission date: August 2017
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Case Study: Gullfaks Field-Gulltop Satellite

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ABSTRACT

This thesis work was done for the purpose of improving oil recovery in Gulltop field through analysis of alternative reservoir development plans based on reservoir simulation and economic evaluation. To accomplish this, a reservoir model "GULLTOP_JAN08" history-matched in 2003 was simulated by using Eclipse 100 reservoir simulator, to determine reservoir properties such as porosity, permeability, transmissibility and faults. These properties were applied as guidance in placement of both production and injection wells in the new plans.

Eleven new plans were simulated based on well placement optimization, water injection, gas injection and simultaneous water and gas injection (SWAG). Well placement optimization was done by introducing new wells, adding new perforations and side-track wells on the areas with good drainage properties and high oil saturation.

Sensitivity analysis was done by changing well locations, injection rates and production rates in order to come up with a proper combination of these parameters for optimum oil production.

Simulation results indicated that, highest oil recovery of about 68% could be achieved in gravity assisted simultaneous water and gas (GASWAG) injection, which is about 19.2% higher than the base case.

Economic analysis of the base case and the new plans was done by calculating their net present value. For ease of analysis, simple NPV was calculated based on oil price, well cost and discount rate. To take care of the fluctuations in oil price and well cost, eight oil prices (30, 40, 50, 60, 80, 100, 120 and 145 usd/bbl) with their respective well costs were analysed to see their effect on the projects' profitability.

From economic evaluation it was observed that gravity assisted simultaneous water and gas injection (GASWA G) had the highest NPV while down dip gas injection (Plan 7) had lowest NPV. Furthermore, relationship between NPV and number of wells indicated that economical number of wells in well placement optimization scenarios is four while in fluid injection cases is five.

ACKNOWLEDGEMENT

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ABBREVIATIONS

NPV	Net Present Value
SWAG	Simultaneous Water and Gas Injection
GASWAG	Gravity Assisted Simultaneous Water and Gas Injection
NGASWAG	Non-Gravity Assisted Simultaneous Water and Gas Injection
GPW1	Gulltop production well 1
GPW3	Gulltop production well 3
GPW4	Gulltop production well 4
WOC	Water-oil contact
GOC	Gas-oil contact
MM	Million

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1 INTRODUCTION

Reservoir development plans are developed by using reservoir simulation software such as Eclipse 100. The aim of reservoir development plan is to accelerate oil production with maximum recovery factors and at minimum cost possible. To achieve this objective, placement of additional infill wells and new perforations in the existing wells is inevitable (Keng , et al., 2011). However, oil production depending only on natural reservoir energy (primary oil recovery techniques) can recover about 30% to 50% of the original oil in place (Lyons, 1996). This is due to the fact that once reservoir pressure falls below the oil bubble point pressure, gas that was initially dissolved in the oil comes out of solution and flow preferentially towards production wells since it is less viscous than oil. Consequently oil production rate and oil recovery factor are lowered. To avoid this, water and/or gas injection is usually applied to maintain reservoir pressure above the bubble point for improved oil production (Muggeridge, et al., 2013)

Water injection is the most applied oil recovery technique due to its abundance and stability. Its viscosity and density makes it effective in improving oil recovery as it forms low mobility ration, a favourable condition for attaining high oil recovery factors. In most cases, this technique is applied in matured oil fields after reservoir pressure has dropped below bubble point pressure (Shehata, et al., 2012). However, to take care of the discontinuous water and aquifer columns, water flooding is applied from the beginning of oil production (Dake, 2001).

Another technique that can be applied to improve oil recovery through pressure maintenance is gas injection. This technique improves oil production since under gravity influence, the injected gas moves to the top where it creates a secondary gas cup which compresses oil column towards production wells. In addition to that, if the reservoir is under-saturated, the injected gas dissolves into the oil, reducing its density and making it move easily towards the production wells (Ranke, et al., 2016)

For inclined reservoir sweep efficiency is maximized by locating injector wells up dip or down dip depending on the injected fluid in order to take advantage of gravity on fluid movement (Thang, et al., 2010). The combined effect of water and gas injection in improving oil recovery results into higher oil recovery factors than single fluid injection. This is implemented through simultaneous water and gas (SWAG) injection as gravity assisted (GASWAG) or non-gravity assisted simultaneous water and gas NGASWAG) injection.

To come up with a most profitable reservoir development plan, economic evaluation of the simulated plans should be done by calculating net present value of each plan including the base case. Profitable plan should have positive net present value greater than that of base case.

1.1 Problem Statement

Gulltop field came into production since 2008 with recoverable oil reserve of about 8.7E6 Sm^3. It was produced for 8 years to 2015 when it was closed. The existing plan has recovered about 48% of the recoverable reserve equivalent to 3.6E6 Sm^3, leaving about 5.1E6 $Sm^3$of oil in the ground. Therefore, there is a need to simulate and analyse alternative reservoir development plans than can improve oil production at lowest cost possible.

1.2 Scope of Work

Since the existing reservoir development plan applied only one well to produce the field depending on natural reservoir energy alone, this study focuses on well placement optimization and pressure maintenance techniques to improve oil recovery.

In well placement optimization, addition of infill wells and new perforations are the main targets. Reservoir pressure maintenance techniques applied in this study are limited to water injection, gas injection and simultaneous water and gas injection only.

The study ends by calculating NPV of the base case and all the new simulated plans so as to determine the most profitable alternative plan to apply in Gulltop field.

1.3 Main Objective

The main objective of this study is to determine the best alternative reservoir development plans to improve oil production from Gulltop field with a higher NPV than the base case

1.4 Specific Objectives

i. To perform well placement optimization through infill well drilling and side-tracking.
ii. To add new perforations on the existing wells.
iii. To perform pressure maintenance through gas injection, water injection and simultaneous water and gas injection (SWAG)
iv. To determine the most profitable alternative reservoir development plan(s) based on improved oil recovery and incremental NPV

2 THE GULLTOP FIELD

2.1 Location

Gulltop field (marked with dark-blue colour in Figure 1 is one of the Gullfaks satellite fields located in the northern part of North Sea, Western part of Gullfaks field on block 34/10-47 ST2 in the Brent group, with water depth ranging between 130m – 220m (Kleppe, 2016). Hydrocarbon fluid present in Gulltop is essentially oil, with total recoverable reserve of about 8.7 million Sm3. Production from this field started in 2008 with start production rate of 2500Sm3/day, using a 10km horizontal reservoir section well A-32C-T4 (GTOPP1) tied in Gullfaks A platform to take oil from N7 segment as shown Figure 1 (Okorie, et al., 20011)

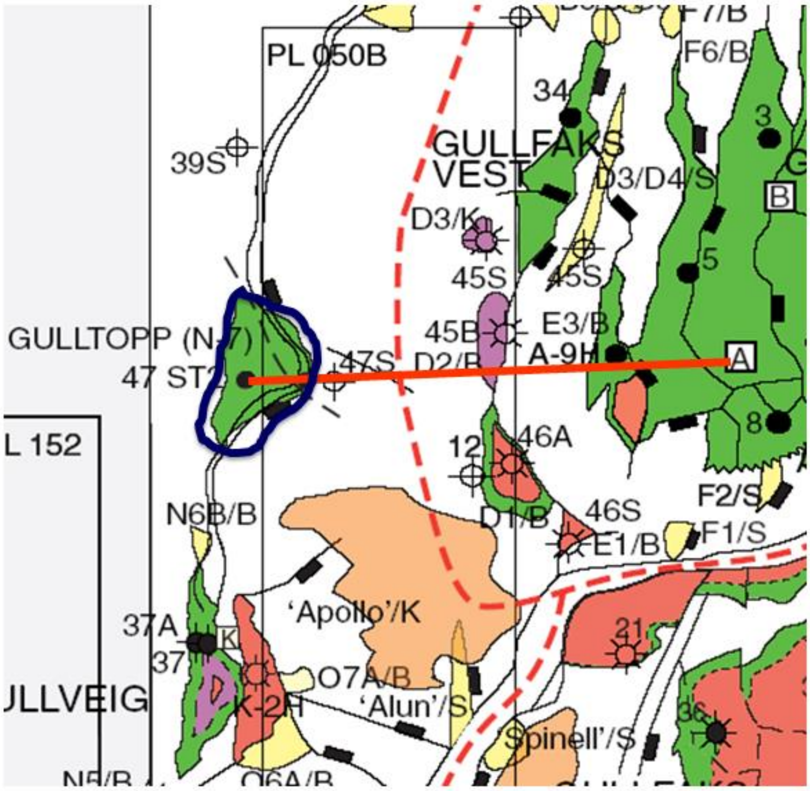


Figure 1: Location of Gulltpo satellite in Gullfaks field (Kleppe, 2016)

2.2 Geology of the Field

This field consists of four formations; Tarbert, Nesss, Etive and Ronnach, with 8 zones as presented in Figure 2 (Kleppe, 2016). These formations are deposits from different depositional environment in the North Sea during the Middle Jurassic (StatoilHydro, 2007).

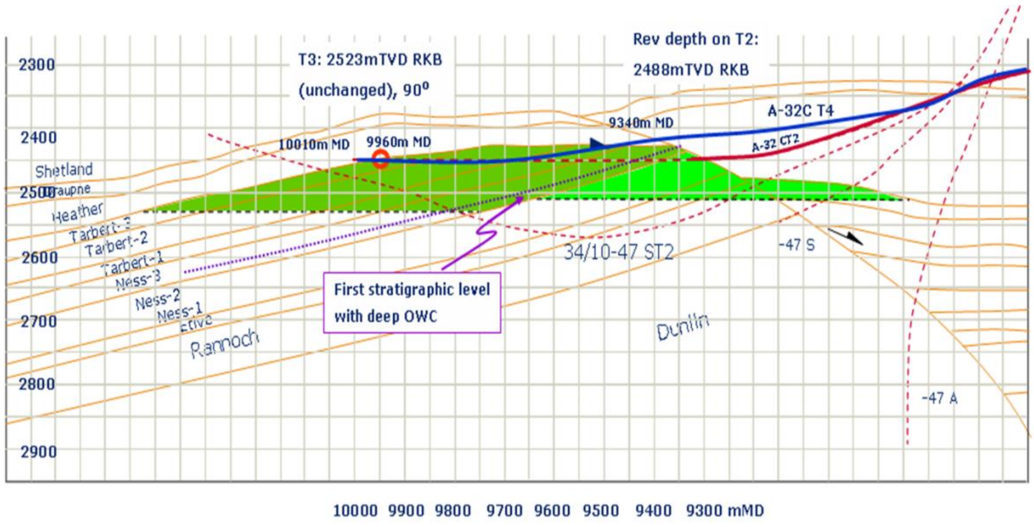


Figure 2: Gulltop field formations and layers. (Kleppe, 2016)

2.2.1 Tarbert Formation

This formation is characterised by massive, homogeneous and permeable reservoir sands separated by thin layers of shale, coal and carbonates (Okorie, et al., 20011). Based on variation in lithology and reservoir permeability, Tarbert formation is divided into three zones (Tarbert-1, Tarbert-2, and Tarbert-3) as presented in Figure 2 (Kleppe, 2016). From detailed reservoir characterisation, the first two zones are subdivided into sub-zones (Tarbert-1A, Tarbert-1B,Tarbert-1C,Tarbert-2A, Tarbert-2B1 and Tarbert-2B2), as shown in Figure 3 (StatoilHydro, 2007).

2.2.1.1 Drainage Mechanism and Communication

Vertical drainage is preferred in Tarbert -2/3 formation. However, saturation tables indicated presence of barriers caused by heavy minerals zones in Tarbert-3 and shale from Tarbert-2A to Tarbert-1A, as presented in Figure 3. As indicated by low permeability in Figure 3, Tarbert-1 is characterised by poorer drainage properties compared to Tarbert-2 and Tarbert-3. Further, Tarbert-1B is thicker and has relatively better drainage properties than Tarbert-1A. Generally, Gullfaks field has better communication between North and South compared to East and West in each segment. As a result, injection is always done in a North-to South direction. Therefore the reservoir in this formation can be produced by natural water drive combined with water injection. As a result of high permeability in Tarbert formation, water injection in this formation has a satisfactory performance and allows wide spacing between injector and producer wells. Another advantage is that due to the presence of non-sealing faults, this formation is in good communication with Ness formation and therefore over-injection in this formation provides pressure support in Ness formation as well. A balance between injected and produced volume is necessary in order to maintain positive pressure trend. The Mechanism to achieve this, for injector wells placed far from the production wells, is to inject water at high rates. Locating injectors far from producer wells ensures wide flow front and therefore improved volumetric sweep. If water injectors are located close to the production wells, water should be injected at relatively low rates to avoid early water breakthrough (StatoilHydro, 2007).

2.2.2 Ness Formation

This formation consists of alternating reservoir sand layers, shale and coal layers, resulting into pressure barriers. Reservoir sands in this formation are thin than the one in Tarbert formation, with significant permeability variation as shown in *Figure 3* (Okorie, et al., 20011).

2.2.2.1 Drainage Mechanism and Communication

In most Gullfaks satellites, Ness formation has been drained by using natural water influx and water and/or gas injection. During injection, there is a challenge of placing injector wells far enough so as to avoid early water or gas break though, and at the same time providing enough pressure support. Presence of faults in Ness formation give the injected fluid enough time and space to spread in the reservoir and give significant pressure support, that eventually results into improved oil recovery. However, past observations indicated that direct pressure support through fluid injection in this formation leads into early water or gas breakthrough, especially in the areas where production and injection wells are placed close to each other. As a result, oil production becomes automatically poor. To overcome this, drainage direction should be changed by changing well location points, alternating between injection fluids and use of pressure depletion. Pressure and flow communication pattern in Ness formation is more complex than in the other formations in Brent group (StatoilHydro, 2007).

2.2.3 Etive and Ronnach Formations

These formations are relatively homogeneous. Etive formation is about 10 to 20m thick, consisting of medium to fine grained clean sandstone, with good lateral continuity as presented in Figure 3. Ronnach formation consists of very fine to fine sands, with high mica content. As shown in ***Figure 3***, Ronnach formation is relatively thicker than Etive formation, and it is devided into three zones, Ronnach 1, Ronnach 2, and Ronnach 3. Ronnach 3 and

Ronnach 2 zones have high permeability than Ronnach 1 zone, which has alternating layers of shale (Okorie, et al., 20011).

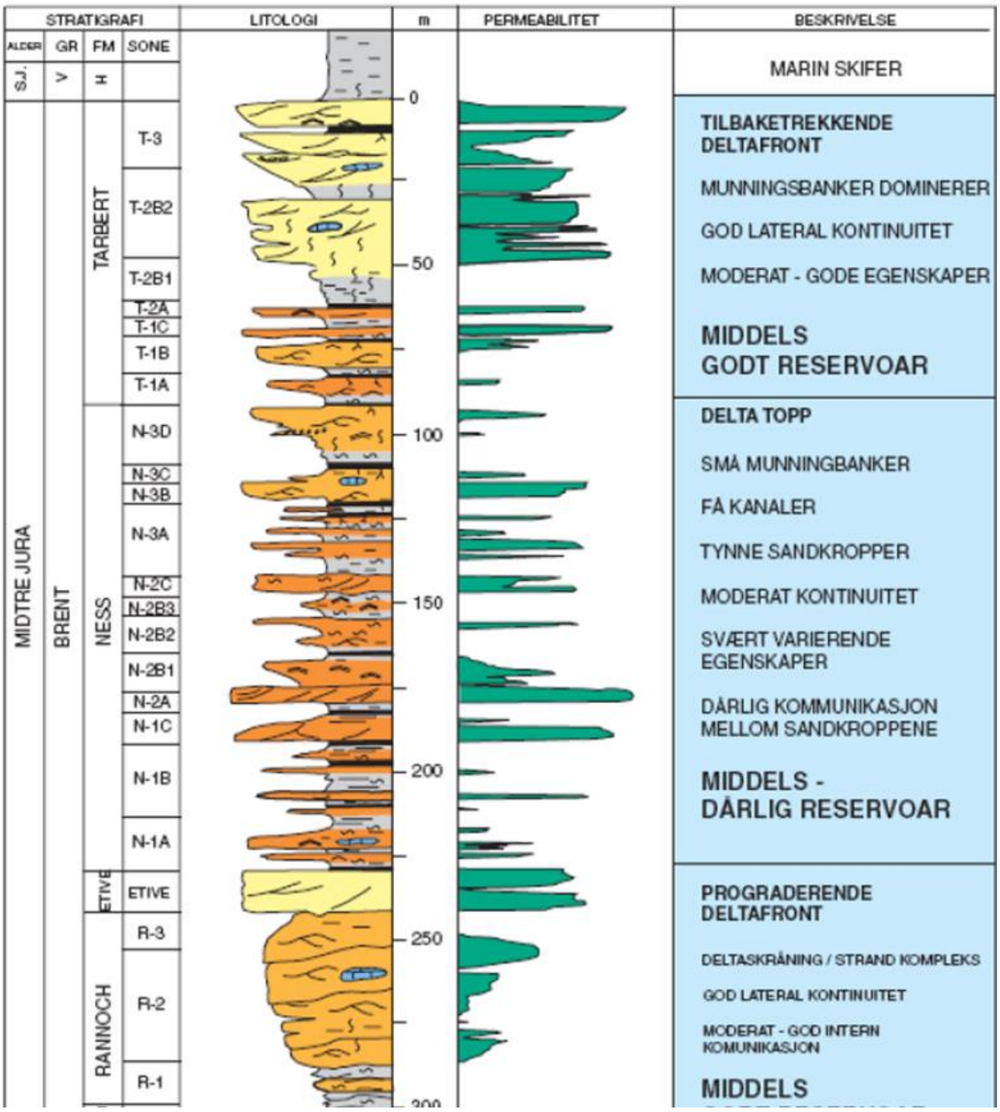


Figure 3: Brent group stratigraphic column showing permeability and Lithology variation in Tarbert, Ness, Etive and Ronnach formation *(StatoilHydro, 2007)*

2.3 Plan for Development and Operation

It was planned to produce oil from Gulltop field by using a single well A-32C-T4, drilled as a horizontal reservoir section well, 10 km long from Gullfaks A platform. Since Tarbert formation contains 80% of the oil in place in this field, the primary goal of drilling A-32C-T4 well was to drain oil from this formation. To recover the remaining percent of the initial oil volumes in Gulltop field, a side track from A-32C-T4 well to the Ness formation was planned. After 4 years of production when the water cut reaches 40%, it was planned to complete the well with gas lift. Further oil production from Gullveig, Tordis and Gullfaks

West fields is expected to cause pressure drop of about 70bar in Gulltop field. Therefore to provide pressure maintenance in Gulltop field, injection options has to be analysed for future production from the field. Due to different pressures and water-oil contacts in Tarbert and Ness formations, initially it was planned not to open Ness for production to avoid early water breakthrough (StatoilHydro, 2007).

2.4 Reservoir Model Description.

Reservoir simulation model for Golltop field was developed and history-matched in June 2003 using Eclipse 100 reservoir simulator. The model is a three phase, three dimensional black oil model with 44 layers and 8 zones (T3, T2, T1, N3, N2, N1, Etive and Ronnach).

It includes empirical data from exploration well 47ST2 since January 1987. Oil production was modelled to start in April 2008, using one horizontal reservoir section well A-32C-T4, named GTOPP1.

Aquifer size and aquifer properties from Gullveig Brent field data were incorporated in this model but were history –matched to reflex the actual one in Gulltop field. This history matching was done by using twelve simulated dummy wells and the data from exploration well 47ST2, shown in Figure 4. Since reservoir drive mechanism is supported by aquifer influx, the simulated dummy wells were located in the aquifer and connected to the reservoir as presented in Figure 4 (Kleppe, 2016).

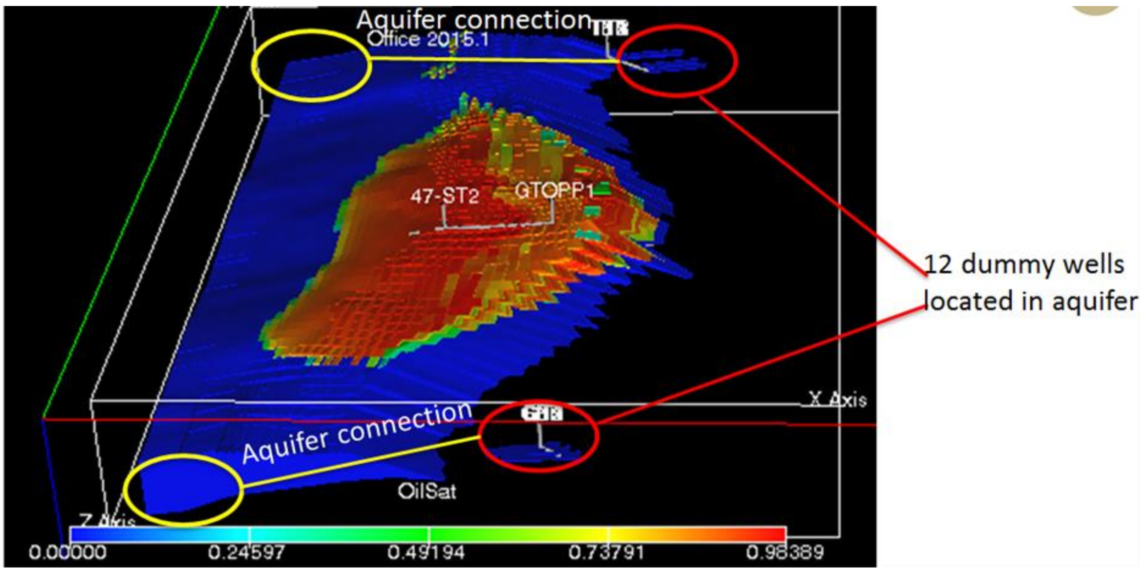


Figure 4: Gulltop field reservoir simulation model with 12 dummy wells located in the aquifer

2.5 Average Reservoir Pressure Variation with Oil Production

From the base case reservoir simulation model, reservoir pressure showed a declining trend from 1987 to 2008, even before starting production, as presented in Figure 5. In this period, pressure drop is about 74 bara. This pre-production pressure drop was a result of oil production from the nearby fields that are in communication with Gulltop field such as Gullveig field. As shown in Figure 5, during production, reservoir pressure dropped faster from 308 bar in 2008 to 252 bara in 2012.This resulted into cumulative oil production of about 3.4 million Sm^3. Effects of aquifer influx increased reservoir pressure to 268bara.

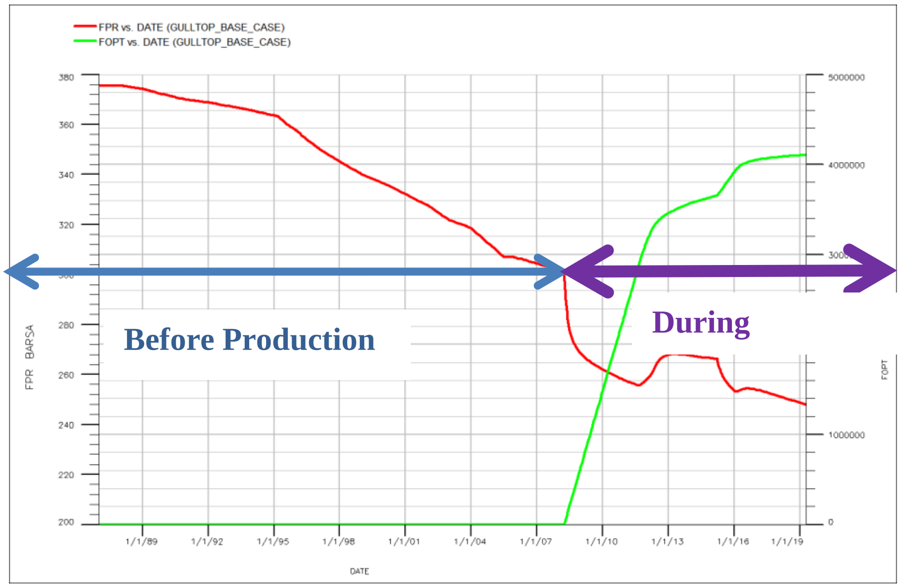


Figure 5: Variation of average reservoir pressure with oil production

3 LITERATURE REVIEW

3.1 Improving Oil Recovery by Infill Well Drilling

Infill well drilling is the technique of increasing oil recovery by increasing number of wells in an area to get access into the un-swept areas of a reservoir. In heterogeneous reservoirs, modification to well patterns and adding number of wells improves oil recovery significantly. However, infill wells can be more expensive than fluid injection processes (Alusta, et al., 2011). To determine the un-swept areas for the infill well locations, prediction simulation of the base case is run so as to identify the remaining oil saturated areas at the end of simulation period. Required number of infill wells is determined based on the identified oil saturation locations (Thang, et al., 2010).

3.1.1 Estimation of Infill Well Performance

According to (Gao & McVay, 2004) infill well performance is estimated by using reservoir simulation model where forecast is made on the base case and then a new infill well is placed in the un-swept areas of the reservoir. Forecast of the new infill well is done and compared with the base case results to get the additional oil production from the new well.

3.1.2 Types of Wells and their Performance

Production or injection wells can be vertical, horizontal or deviated wells. Due to technological and economic constraints, vertical wells were preferred. Nevertheless, increase in drilling technology and the need to reduce cost of drilling many vertical wells to hit the reservoir, horizontal wells and deviated wells are now becoming popular in the petroleum industry (Wagenhofer & Hatzignatiou, 1996)

3.1.3 Well Placement Optimization

Since well performance depends on well location, well placement should be given special attention in analysing reservoir development plans. This is due to the fact that, wrong decision on well location results into wastage of money and recovery (Ermolaev & Kuvichko, 2013). Optimum well placement can be done by using simulators since they are capable of analysing complex interactions of parameters affecting reservoir development decisions like reservoir and fluid properties, well surface networks and economic factors (Badru & Kabir, 2003).

Optimal well placement determines the oil recovery factor for a given oil production technique. Economically, well spacing should be small to get access to the large area of the reservoir to attain highest recovery factors and net present value (NPV) (Abeeb & Carlos, 2014). However, for matured fields, well spacing should be managed to avoid collision with the existing wells. To avoid well collisions, an ‘Oriented Separation Factor’’ greater than 1.5 is required (Okafor & Moore, 2009).

Based on surface topography, wells can be spaced uniformly or non-uniform relative to each other. In fields where primary production has already taken place, some production wells can be converted into injectors and in other cases, new injection wells are required. Generally, injection well placement should be well-matched with the production wells taking advantage of known reservoir structures (Lyons, 1996).

3.2 Improving oil Recovery by Pressure Maintenance

Pressure maintenance is the oil recovery technique that takes place during the early life of a field when there is slight or no loss of natural reservoir energy. The reason for implementing this even before natural reservoir energy is depleted is to take care of the situations where aquifer and oil columns are not continuous (Torrey, 1951). Normally, if designed properly, this technique results into more oil recovery than the one obtained by primary oil recovery mechanisms. It is implemented by injection of water or gas into the reservoir to counter balance pressure drop caused by oil production (Lyons, 1996).

3.2.1 Water Injection

Water injection is the principal secondary oil recovery technique applied in petroleum industry due to its easy availability and more stable than gas injection. (Dake, 2001). Furthermore, due to its viscosity, density and wetting properties, water is more efficient in displacing oil from the reservoir rock. (Shehata, et al., 2012) .Water injection helps in maintaining reservoir pressure and displacing the oil toward production wells. This technique is mostly applied in matured oilfields where reservoir pressure has fallen below bobble point pressure. However, in offshore fields, water injection is applied from the beginning to avoid the risk that the oil and aquifer columns may not be continuous as shown in Figure ***6*** where the two are separated by a sealing fault. The occurrence of such segregation may not be detected during appraisal development since data at that period are collected under static conditions (Dake, 2001).

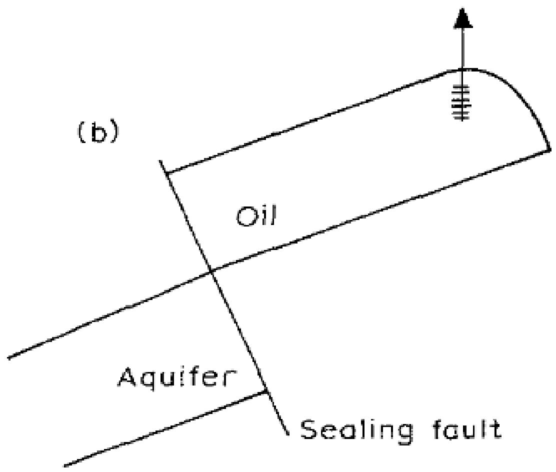


Figure 6: Aquifer-oil column separated by a sealing fault. (Lyons, 1996)

Mostly, water is injected into the underlying aquifer to avoid relative permeability problems caused by residual oil. However, in some cases, the reservoir requires that water should be injected into the oil zone. Mineralogical composition may cause problems whereby injected water may react with sensitive clays which swell and block reservoir pores. (Mitchell, 1982)

3.2.1.1 Factors to Consider in Water Injection

(Ahmed, 2006) stated that before water injection is done, the following reservoir properties should be well understood:

i. Reservoir geometry
ii. Fluid Properties
iii. Reservoir depth
iv. Lithology and rock properties

i. Reservoir Geometry

Aerial geometry of reservoir dictates the location of injection wells and for the case of offshore field, it determines the location and number of platforms to be used. It also determines the means to be used in producing a reservoir through water injection (Ahmed, 2006).

ii. Fluid Properties

Physical properties of reservoir fluids determine suitability and efficiency of water injection significantly. These properties are mainly fluid viscosity and density at reservoir conditions. Oil viscosity is very important in determining mobility ratio that controls the sweep efficiency. (Ahmed, 2006). Generally, fluid mobility is described as permeability of the formation to a fluid divided by fluid viscosity as shown in equation- 1. Therefore, a fluid with low viscosity has high mobility regardless of its low permeability, and vice versa. (Shehata, et al., 2012).

$$\boldsymbol{\lambda = \frac{k}{\mu}} \qquad - 1$$

Where

λ = mobility, md/cp

k = effective permeability of a reservoir rock to a given fluid, md

μ= fluid viscosity, cp

When more than one fluid is flowing through the reservoir, relative permeabilities are used together with viscosities of the fluids. In this case, the term mobility ratio is used to define sweeping efficiency of the injection process. Mobility ration is defined as the mobility of the displacing fluid (water) divided by the mobility of the displaced fluid (oil), as presented in equation - 2 (Lyons, 1996).

$$\boldsymbol{M = \frac{k_{rw}/\mu_w}{k_{ro}/\mu_o} = \frac{k_{rw}\mu_o}{k_{ro}\mu_w}} \qquad - 2$$

Where

M = mobility ratio

k_{rw} and k_{ro} = relative permeability of water and oil respectively, md

$\mu_w and\ \mu_o$= water and oil viscosity respectively, cp

The water-/oil mobility ratio is the crucial factor in determining the performance of a water injection displacement process, with the recovery factor increasing as the mobility ratio decreases. (Shehata, et al., 2012).

iii. Reservoir Depth

Reservoir depth affects technical and economic parts of water injection. This is due to the fact that maximum water injection pressure increases with depth and cost of taking oil from deeper wells limits the maximum water cut that can be accepted. As a result, it reduces ultimate recovery factor and increase project operating cost. Shallow reservoirs require low water injection pressure as it has to be less than fracture pressure to avoid pressure parting. (Ahmed, 2006).

iv. Lithology and Rock Properties

According to (Ahmed, 2006), lithology and rock properties that affect performance of the water injection process are porosity, permeability, clay content and net pay thickness. In heterogeneous reservoirs, reservoir rock permeability influences fluid flow process. The injected fluid flows through highly permeable areas leaving impermeable areas un-swept. (Jamshidnezhad, 2008)

3.2.1.2 Water Flooding Configurations

In principle, flood pattern should be chosen first when designing any water flooding project. This is due to the fact that, for a successful water flooding, proper flooding pattern is needed that provides the injected fluid with the maximum contact with the fluid to be displaced. This can be achieved by converting some production wells into injectors or drilling new wells for injection (Ahmed, 2006).

Generally, there are two main types of flooding configurations namely Peripheral or Central flooding and Pattern flooding. The first type refers to the well placement where injectors are grouped together while in the second case particular patterns are repeated throughout the field (Lyons, 1996).

i. Peripheral or Central Flooding

In peripheral flooding, injection wells are located at the edge to make the flood move towards the centre where production wells are located as presented in *Figure 7*. First raw of production wells are changed to injection wells after being flooded out (Lyons, 1996). For this method to work efficiently, sufficient permeability is required to make fluids move at adequate rates towards production wells. This flooding technique results into maximum oil production and minimum water production with delayed water production until the last row of producers are left. In addition to that, this flooding configuration is characterised by few number of injectors than producers, hence it takes long time for the injected water to fill the reservoir gas cap if it is present. (Ahmed, 2006). With central flooding, injection wells are located at the centre of the field and the flooding moves outwards to the production wells which are located at the edges (Lyons, 1996).

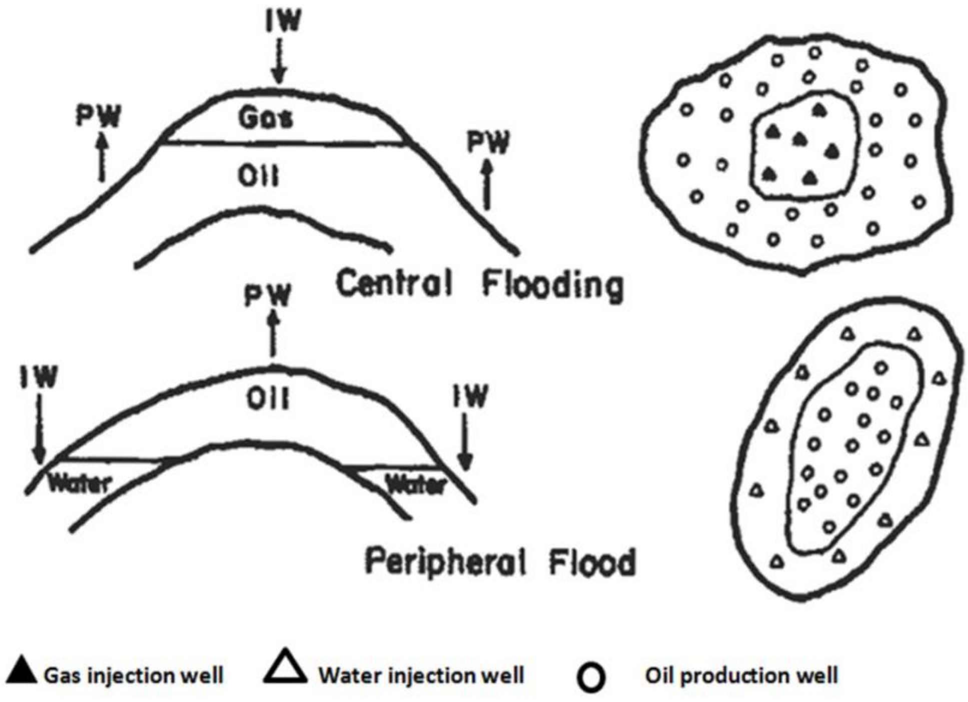


Figure 7: Peripheral and central water flooding (Lyons, 1996)

ii. Pattern Flooding

This flooding method is characterised by location of injection wells sandwiched between the producers in a repeating style as shown in *Figure **8***. Type of pattern to use depends on the field conditions (Lyons, 1996). When injected fluid is moves faster than the displaced fluid, a pattern with more production wells than injection wells should be chosen, and the opposite applies (Ahmed, 2006).

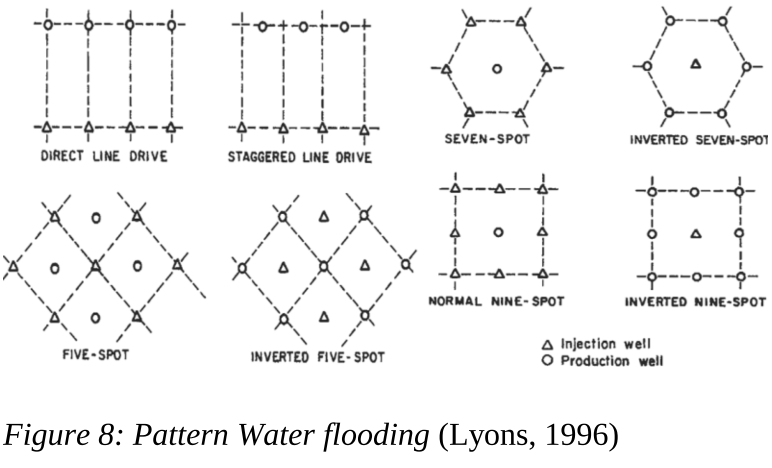


Figure 8: Pattern Water flooding (Lyons, 1996)

3.2.1.3 *Down-dip and Up-dip Water Injection*

In order to increase oil production, it is necessary to keep oil in contact with the production wells all the time. This can be achieved by balancing WOC and GOC movement through water injection down-dip closer to the WOC or up-dip closer to the GOC if the reservoir contain gas gap (Razak, et al., 2011).

Injection of water at the WOC helps to boost the bottom water aquifer to push the oil up towards production wells. However, excessive water injection down-dip after water break through into the production wells can push the oil up the gas cap or make it migrate into the nearby areas connected to the reservoir under production (Keng , et al., 2011).

Fluid movement in the up-dip water injection shows that under gravity influence, injected water is moving down and pushes oil at the lower part of the up-dip section indicated by letter B in ***Figure 9*** to the production well. As a result, at abandonment, most of the oil in region B will be produced as presented in the same figure (Thang, et al., 2010). However, excessive up-dip water injection results into joining the injected water with the bottom aquifer, bypassing some oil, leaving the area un-swept (Keng , et al., 2011).

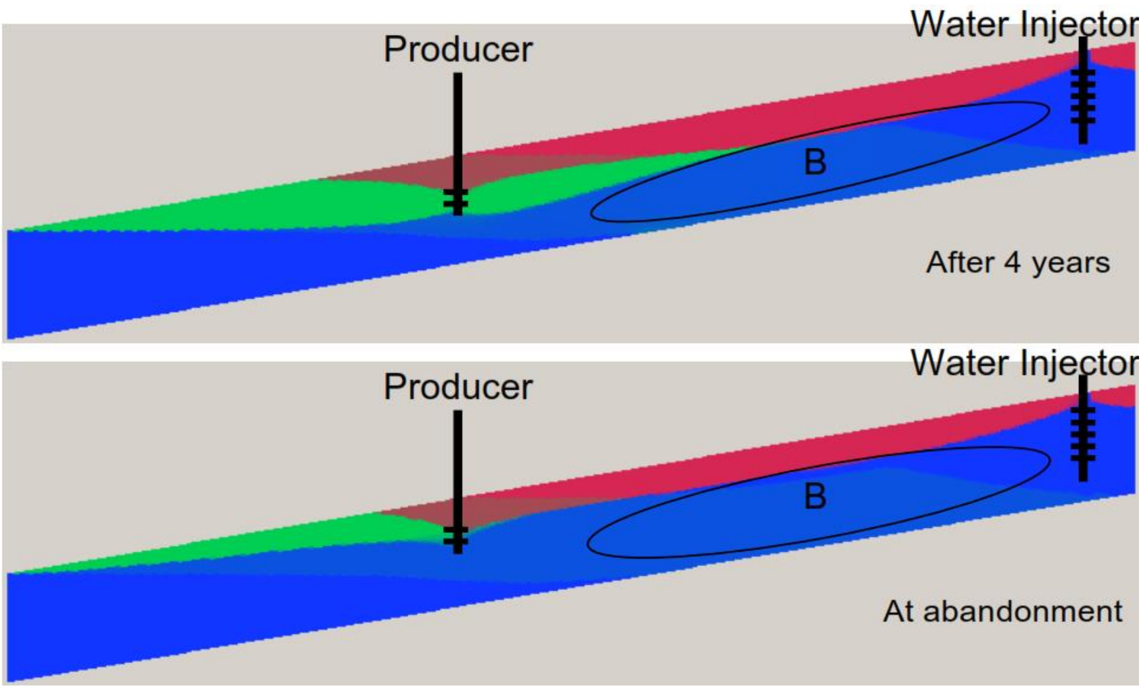


Figure 9: Fluid movement in up-dip water injection (Thang, et al., 2010)

Up-dip and down-dip water injection can be combined to get most of the oil produced. This is due to the fact that in down-dip water injection, production wells near injectors will get increased pressure support and efficient vertical sweep (Razak, et al., 2011). On the other hand, up-dip water injection prevents oil from moving upward into the gas cap, by 'building water fence' on top of oil making the oil progress towards to the production wells (Keng , et al., 2011).

3.2.1.4 Water Injection Oil Recovery Efficiency

Oil recovery efficiency is ''the ratio of average value of economically recoverable oil divided by the value of the original oil in place''. This factor is determined by location of injection and production wells, oil-water relative permeability, and nature of the reservoir rock, fluid viscosity, reservoir heterogeneity, pore size distribution, oil saturation and capillary pressure. Combination of these factors contributes to the overall oil recovery efficiency, denoted by E_R. These factors are combined by taking the product of displacement efficiency (E_D) and volumetric efficiency (E_V), as shown in equation- 3 (Lyons, 1996).

$$E_R = E_D * E_V = E_D * E_P * E_I \quad \text{- 3}$$

Where:

E_R = Overall oil recovery efficiency.

E_D = Displacement sweep efficiency: volume of hydrocarbons (gas or oil) displaced from individual pores

E_V = Volumetric seep efficiency sweep efficiency

E_P = Pattern sweep efficiency

E_I = Hydrocarbon pore space invaded by the injected fluid

3.2.2 Gas Injection

Gas injection is applied to increase oil recovery since it swells the oil and lowers its density to make it move easily towards the production wells. For a gas injection to be successful, mixing between the injected gas and the oil should be well established and maintained. Miscibility behaviour of the gas injection depends significantly on the composition of the crude oil in the reservoir. Crude oils composed mainly of heavy components are found to be immiscible while the one with high proportion of light components are form miscible gas injection. It is found that overall recovery factors form miscible gas injection processes are always above the one obtained from immiscibility processes (Ranke, et al., 2016).

In reservoirs with low permeability or swelling clays where gas injection rate is always high than water injection rates, gas injection is chosen over water injection. Also in reservoirs with good vertical permeability, gas injected downward migrates upward to form secondary gas cap that compresses the oil downwards to the production wells. Therefore, gas can be injected up-dip, down-dip or in combination of the two (Lyons, 1996).

3.2.2.1 Down dip and Up dip Gas Injection.

Down-dip gas injection is a potential gas injection technique that gives high oil recovery from attic traps. In highly under-saturated oil reservoirs, down-dip gas injection gives chance for solution gas to form before it goes up the crest. As a result, delayed gas breakthrough, reduced GOR and improved oil recovery is offered (Kasim, et al., 2011). Since gas is lighter than water and oil, the down-dip injected gas moves to the top, increasing sweep efficiency in the upper areas marked by letter ‘A’ in Figure 10 (Thang, et al., 2010).

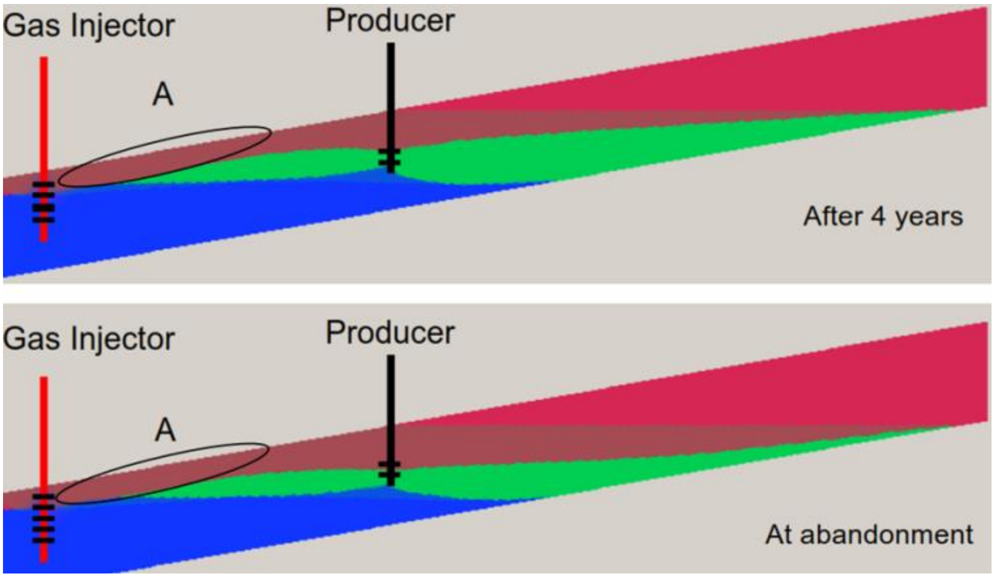


Figure 10: Fluid movement in down-dip gas injection (Thang, et al., 2010)

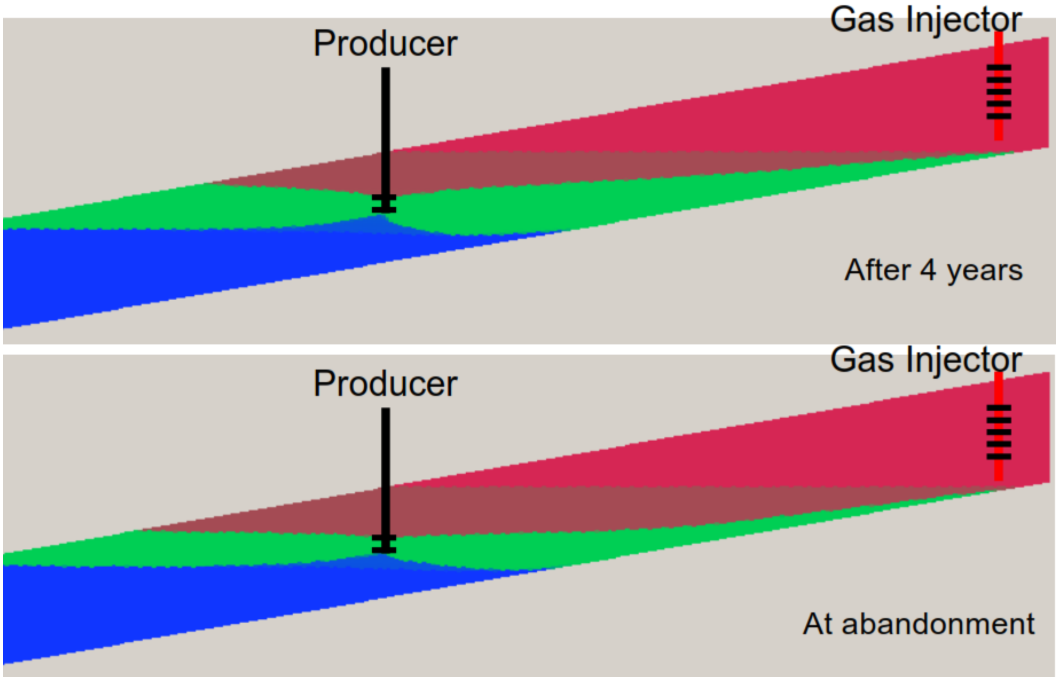


Figure 11: Fluid Movement in up-dip gas Injection (Thang, et al., 2010)

3.2.3 Simultaneous Water and Gas Injection (SWAG)

As described in sections 3.2.1 and 3.2.2, water and gas injection plays great role in increasing oil recovery. However, sweeping efficiency of gas is low due reservoir heterogeneity and low gas viscosity and density. As a result, gravity override occur which lowers gas sweep and oil recovery. To overcome this, water is injected simultaneously with gas so as to control gas mobility (Jamshidnezhad, 2008).

Performance of SWAG injection can be affected by several factors including position of injection wells and water and gas injection rates. Oil recovery factor obtained when gas and water injection rates are doubled or reduced, may be different from the one obtained before changing the injection rates. Likewise, SWAG performance with down-dip water injection and up-dip water injection may not be similar (Sohrabi, et al., 2005)

SWAG injection can be done in two ways; injecting water and gas together through a single well after mixing them at the surface or injecting without mixing via a single dual completion injection well (Morais, 2012). However, (Jamshidnezhad, 2008) pointed out that SWAG injection can be done by injecting water and gas simultaneously into the reservoir through two different wells.

In this case, water can be injected at the top (up-dip water injection) and gas at the bottom (down-dip gas injection) termed as gravity assisted simultaneous gas and water injection (GASWAG) as shown in Figure 12. This injection scheme improves oil recovery due to the fact that sweep efficiency is maximized by movement of water and gas under gravity as shown in regions A and B in Figure 13 (Thang, et al., 2010).

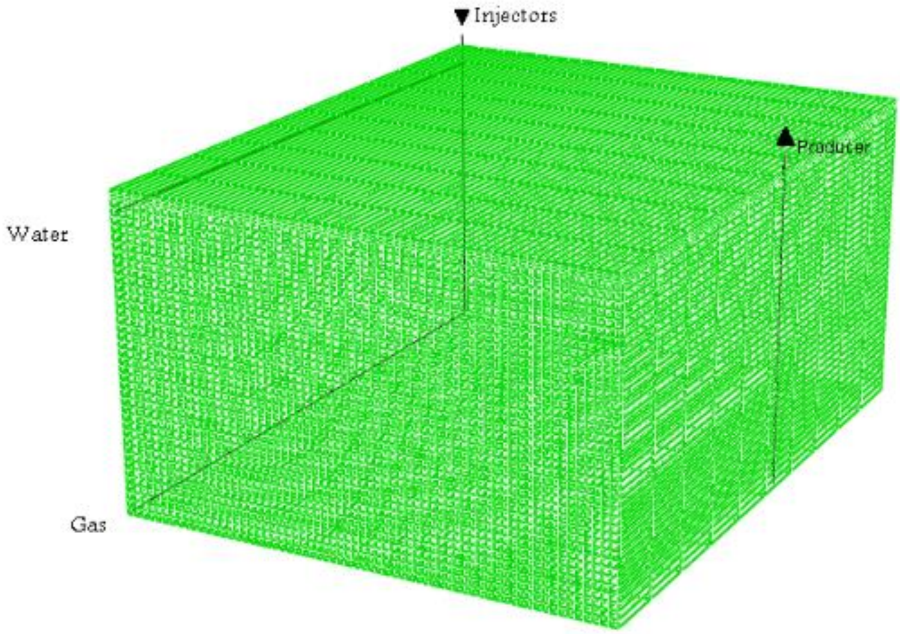


Figure 12: Simultaneous water and gas injection (Jamshidnezhad, 2008)

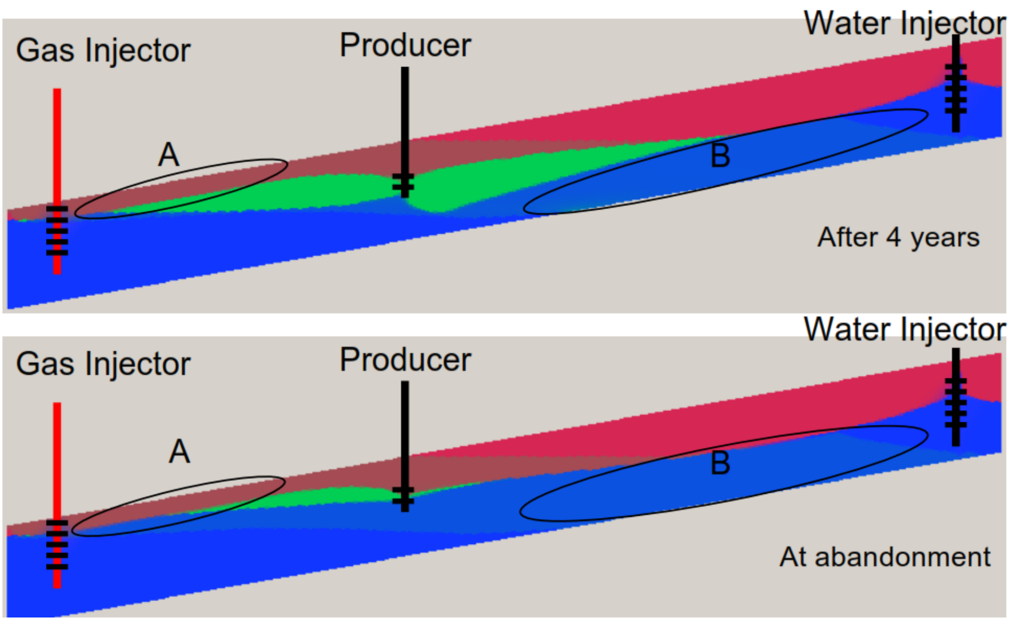


Figure 13: Fluid movement in up-dip water-down-dip gas injection. (Thang, et al., 2010)

3.5 Production and Injection Pressures and Rates

Production well bottom-hole pressure has to be a bit less than bobble point pressure for maximum oil recovery. This is due to the reason that, if bottom-hole pressure is much lower than the bobble point pressure, the dissolved gas will turn into free gas, leading into early gas breakthrough and less oil recovery (Morais, 2012).

3.6 Economic Evaluation

Economic viability of a project can be determined by using its net present value (NPV). Determination of NPV depends on oil price, well cost, tax, operating costs, royalties, interest rates, discount rates and capital expenditure. Oil price is always varying from time to time as displayed in Figure 14.

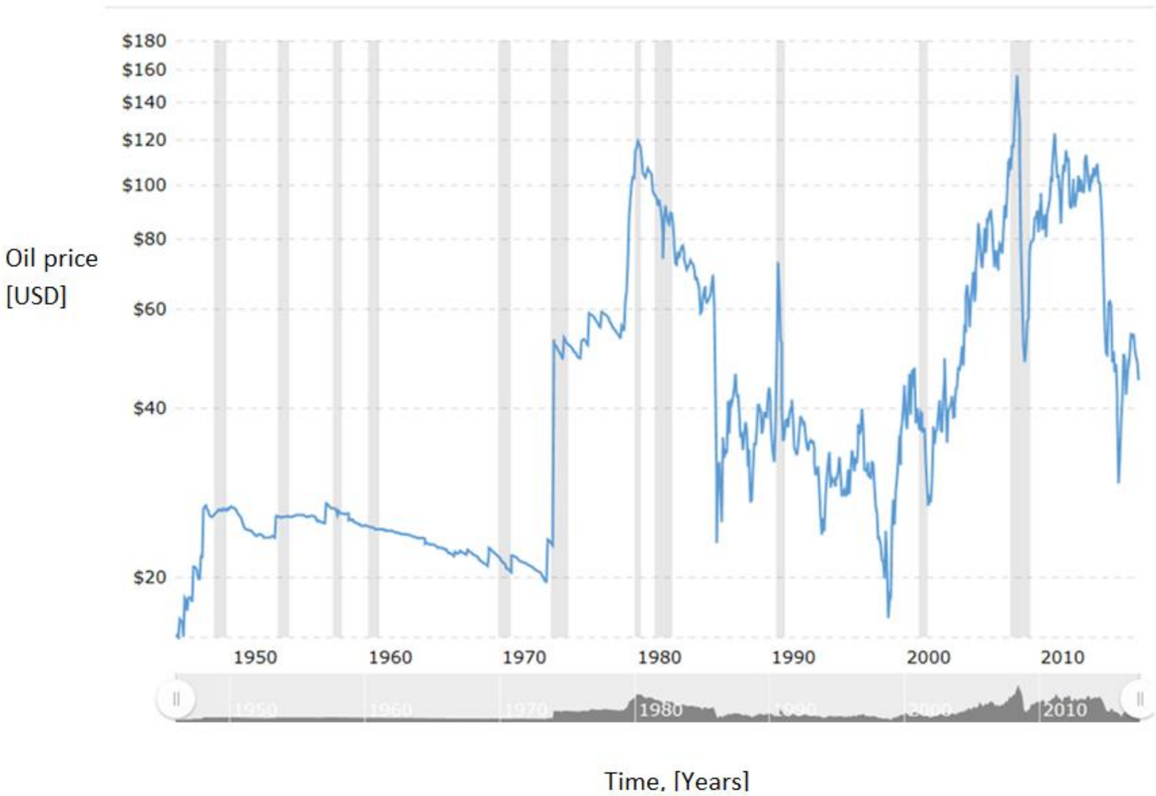


Figure 14: Variation in oil price from 1950 to 2015

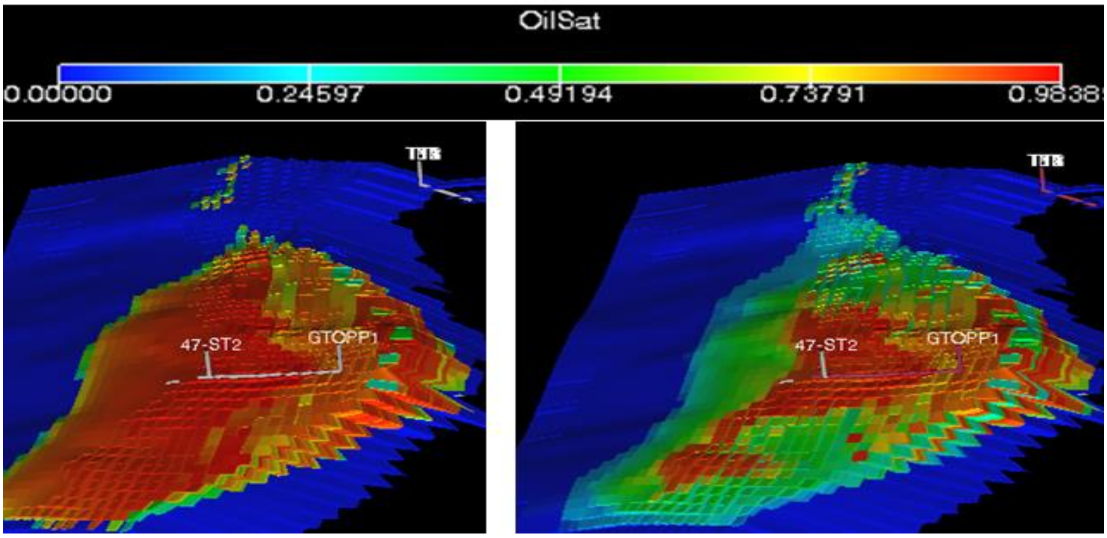
Oil price prediction studies have indicated that there is a 15% reduction on offshore well drilling cost in in 2015 from that of 2014, followed by an increase of 3% per annum from 2016 to 2020.

4 RESERVOIR SIMULATION WORK

To achieve objectives of this thesis, reservoir simulation was run to determine alternative reservoir development plan(s) that will result into optimum oil production. To come up with such a better performing plan, base case reservoir model history-matched in 2003 was simulated for 27 years from 2008 to 2035. Then eleven new plans were simulated based on infill well placement, addition of new perforations, addition of side-track wells, single-fluid injection schemes (water or gas injection) and simultaneous water and gas (SWAG) injection. Data file for gravity assisted simultaneous water and gas injection (GASWAG) is attached in Appendix 2 as an example.

4.1 Simulation of the Base Case

This was carried out in order to understand the model and determine oil saturation distribution at the beginning of production and at the end of simulation period as presented in Figure 15.



(a) April 2008 (b) April 2035

Figure 15: Oil saturation at the beginning of simulation and end of simulation

From this simulation, it was observed that the base case was able to produce only 48.8% of the original oil in place, equivalent to a cumulative field oil production of about 4.2E6Sm^3, (Figure 16). New reservoir development plans were simulated to recover more oil as described in the alternative plans 1 to 11.

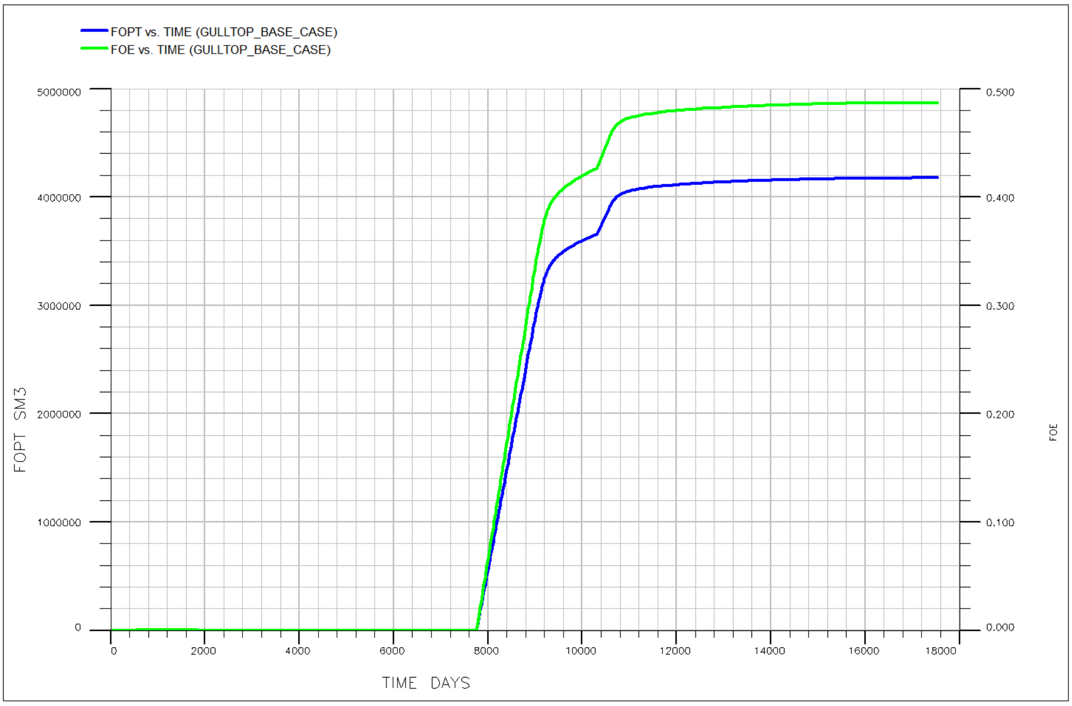


Figure 16: Cumulative field oil production and recovery factor for the base case.

For optimum well placement, it was necessary to understand reservoir drainage properties such as porosity, permeability and transmissibility. These properties were determined from the base case simulation as presented in Figure 17.

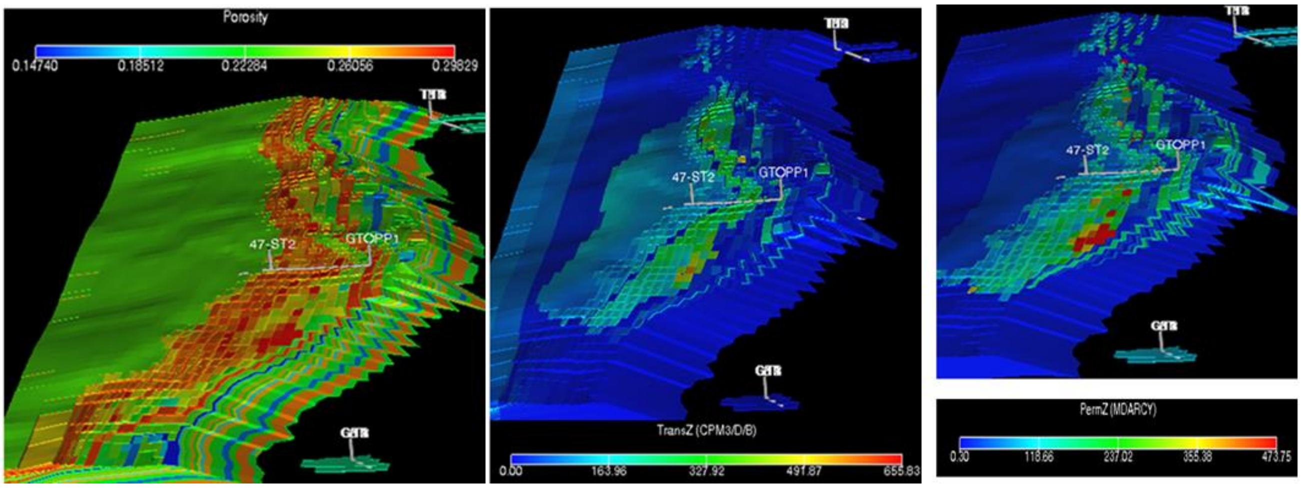


Figure 17: Porosity, transmissibility and Permeability for Gulltop Field.

Determination of these properties together with the oil saturation distribution were used as guidance in choosing proper well locations for improved oil recovery in each of the described new alternative reservoir development plans.

4.2 Plan 1-Three Production Wells with One Side-track

This started by removing the existing production well "GTTOP1" from the base case to get a reservoir model with no production well to restore the original initial oil in place. Then trial and error method was applied to get a better place to locate the wells based on oil saturation, reservoir permeability, porosity, transmissibility and faults. Well configuration presented in ***Figure 18*** with three production wells GPW1, GPW2 and GPW3 was used as the first alternative plan.

GPW1 is a horizontal well with one side-track. It is located almost at the middle of the reservoir model since this area is characterised by high oil saturation ranging between 0.953 and 0.998, high permeability (162 to 327), good porosity (0.22 to 0.29) and good transmissibility ranging between 120 and 237 CPM^3/D/B (***Figure 17).*** GPW1 was perforated in layers 1 to 22 (Tarbert formation) on the main stem and its side-track is perforated on layers 32, 33, 34, 35, 37, and 40 (Ness formation). The reason for perforating on these layers is high oil saturation, good porosity, permeability and transmissibility. Layer 36 was not perforated because from the base case model, this layer is crossed by a sealing shale barrier.

GPW2 and GPW3 wells are inclined wells located at the top and side respectively (***Figure 18***). The reason for this placement is again high oil saturation, good permeability and high porosity. In addition to that, GPW2 placed at the top was preferred due to the fact that in future, once this well is watered out, it can be converted into an injector well for the injected fluid to push oil towards the centre where production wells are located. Both wells were perforated on layers 1 and 2 on Tarbert formation due to its good drainage properties and high oil saturation.

Oil production rates for the three wells were maintained at 2500Sm^3/day each starting from 2008 to 2026 and then reduced to 1200Sm^3/day from 2026 to 2035. Reduction in oil production rate was done as a mechanism to reduce water cut. Bottom-hole and tubing head pressures for each well were set at 100 bar and 70 bar respectively, as was in the base case.

Results from plan 1 show that cumulative field oil production of about 4.5E6Sm^3 was achieved while that of base case was 4.2E6Sm^3 (***Figure 19***). On the other hand, ***Figure 20*** indicates that oil recovery factor in this plan is 53.2% which is 4.4% higher than that of base case.

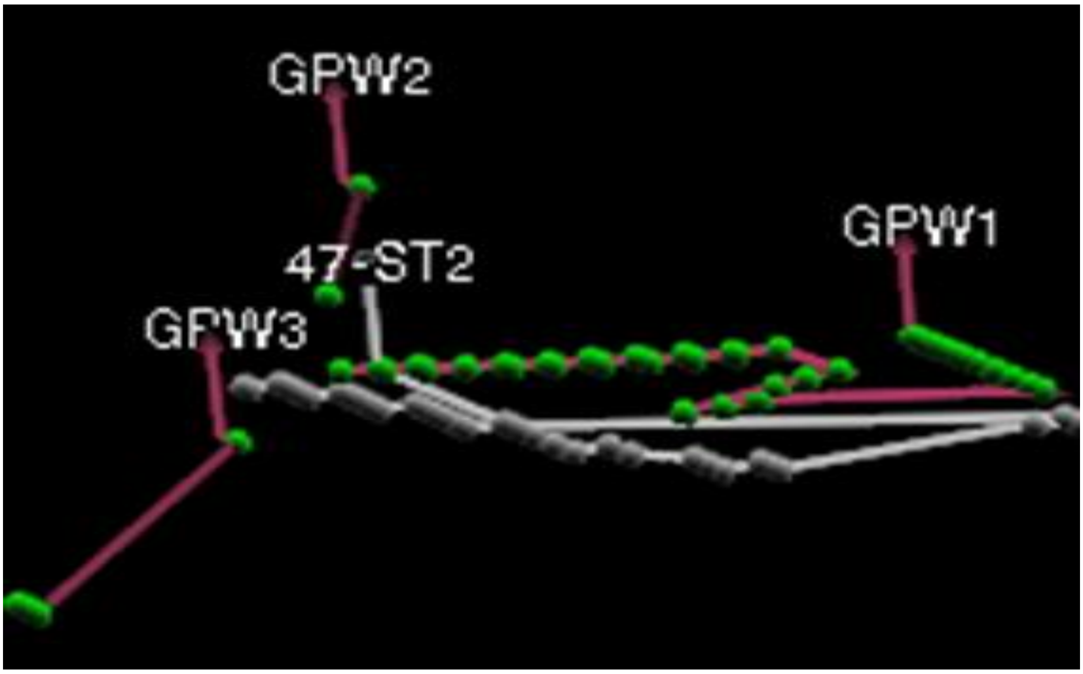


Figure 18: Well placement for alternative plan 1 (three production wells with one side-track)

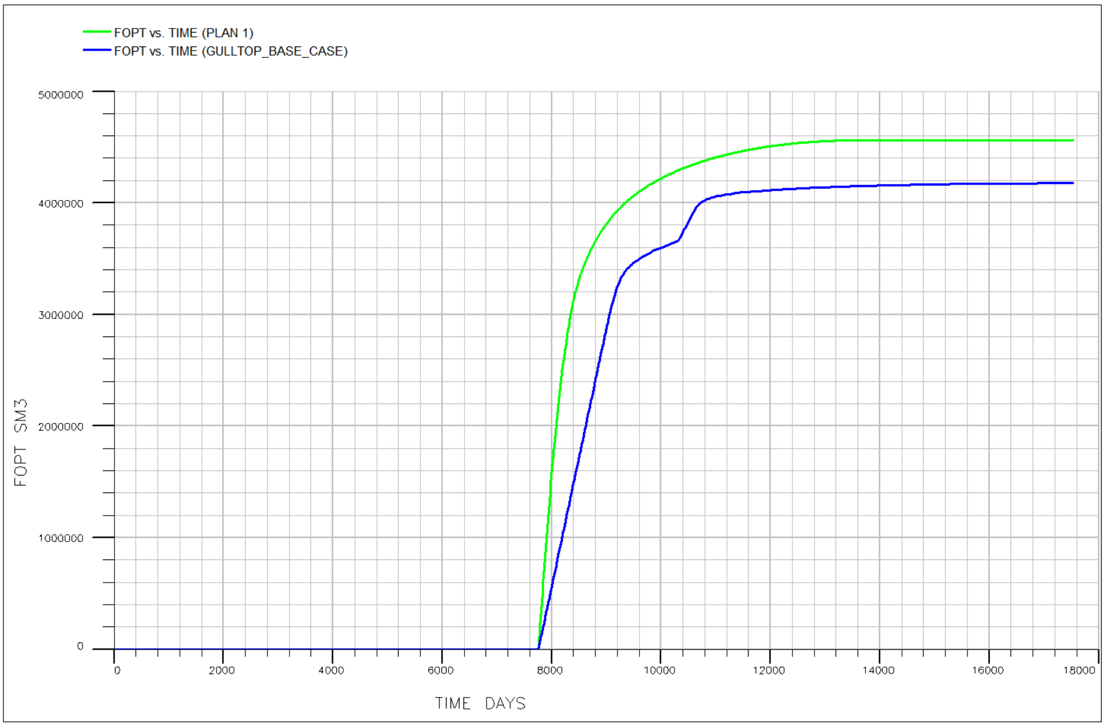


Figure 19: Comparison of cumulative field oil production between base case and alternative Plan 1

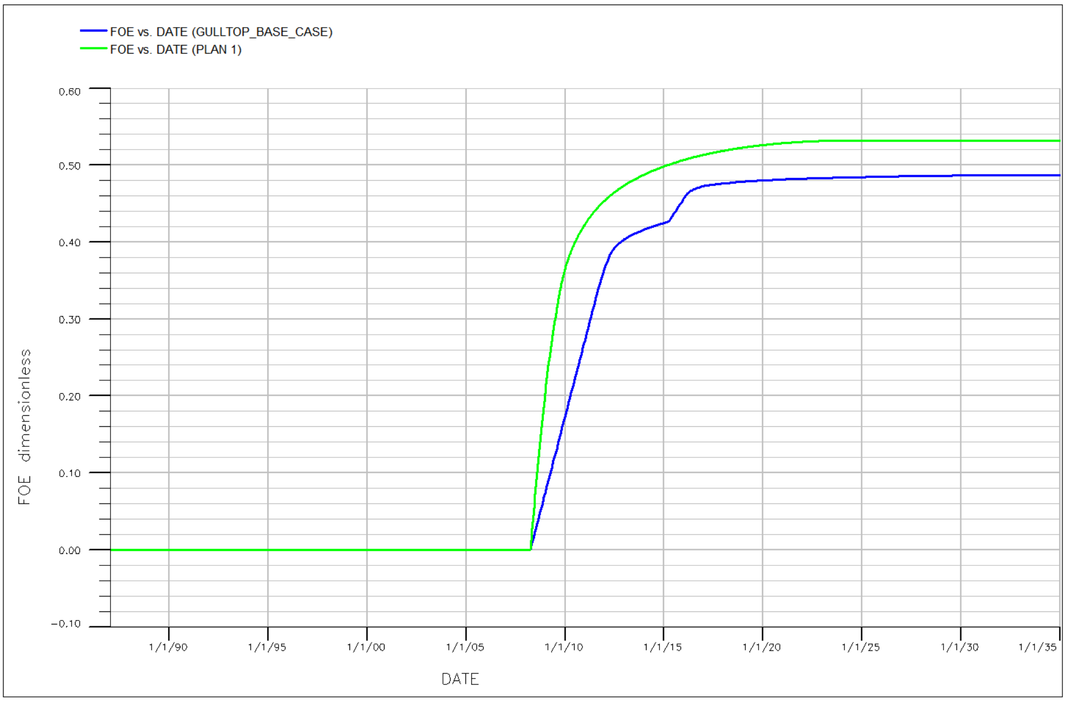


Figure 20: Oil recovery factors for base case and the new plan 1

Since plan 1 left about 46.7% of the original oil in place, it was necessary to formulate another plan that could recover more oil as described in section 4.3

4.3 Plan 2-Three Production Wells and 2 Side-tracks and Added Perforations

This plan is comprised of three production wells GPW1, GPW2 and GPW3 with two side tracks from GPW1 and added perforations on GPW2 and GPW3 wells as indicated in ***Figure 21***. Perforations were added on layers 3, 4, 5, 6 and 7 on each well GPW2 and GPW3. The second side-track on GPW1 was perforated on layers 3, 6, 8, 9, 10, 110 12, 13 and 14 on Tarbert formation. Oil production rates for all the three wells were maintained at 2500Sm^3/day from 2008 to 2035. Bottom hole and tubing head pressures maintained at 100 and 70 bar respectively as in the previous plan.

This plan recovered about 54.5% of the original oil in place as displayed in ***Figure 22*** and a cumulative field oil production of about 4.7E6Sm3 as can be seen in ***Figure 23***. This means that the added perforations and one side-track recovered extra 1.5% of the original oil in place compared to plan 1 and 5.7% more compared to the base case as shown in ***Figure 22***

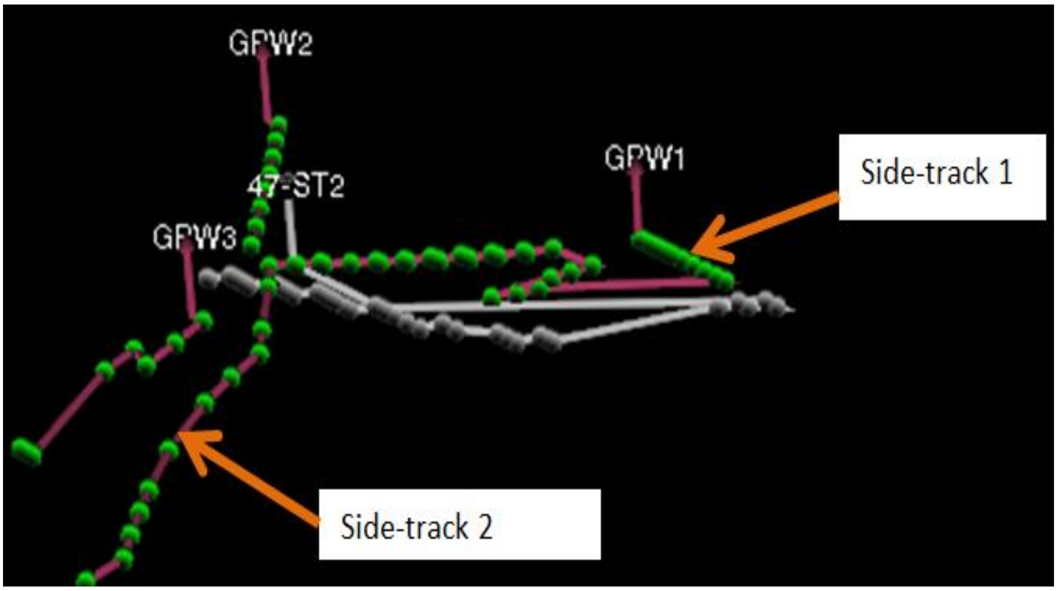


Figure 21: Well placement for alternative plan 2 (three production wells with 2 side-tracks)

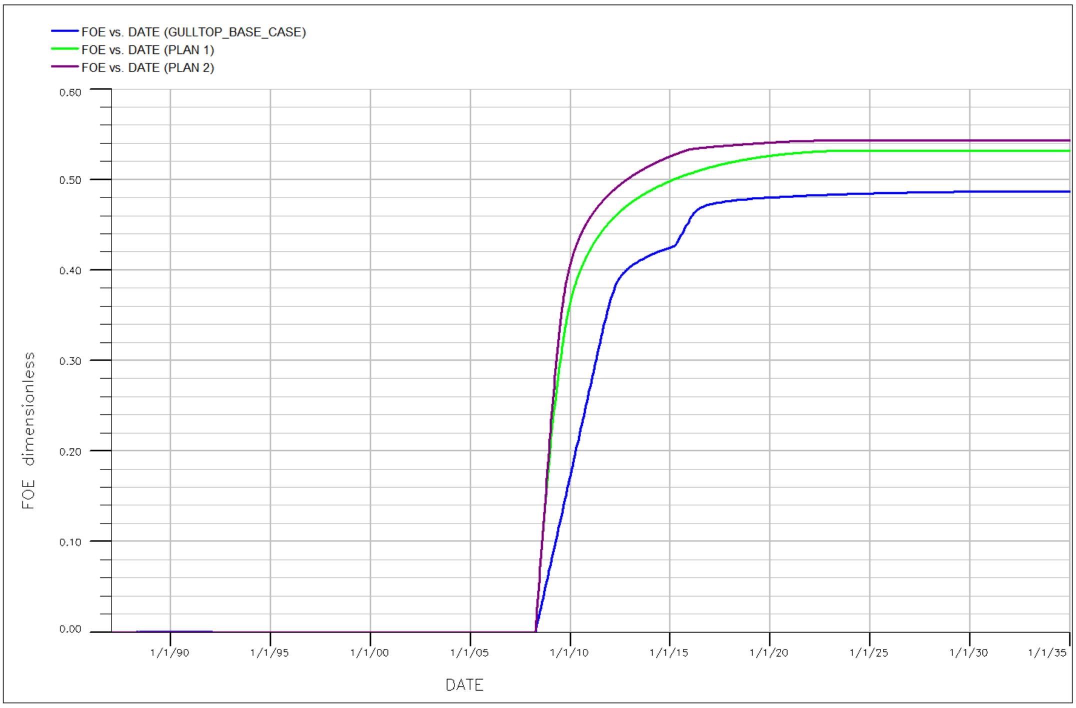


Figure 22: Field oil recovery factors for base case, plan 1 and plan 2

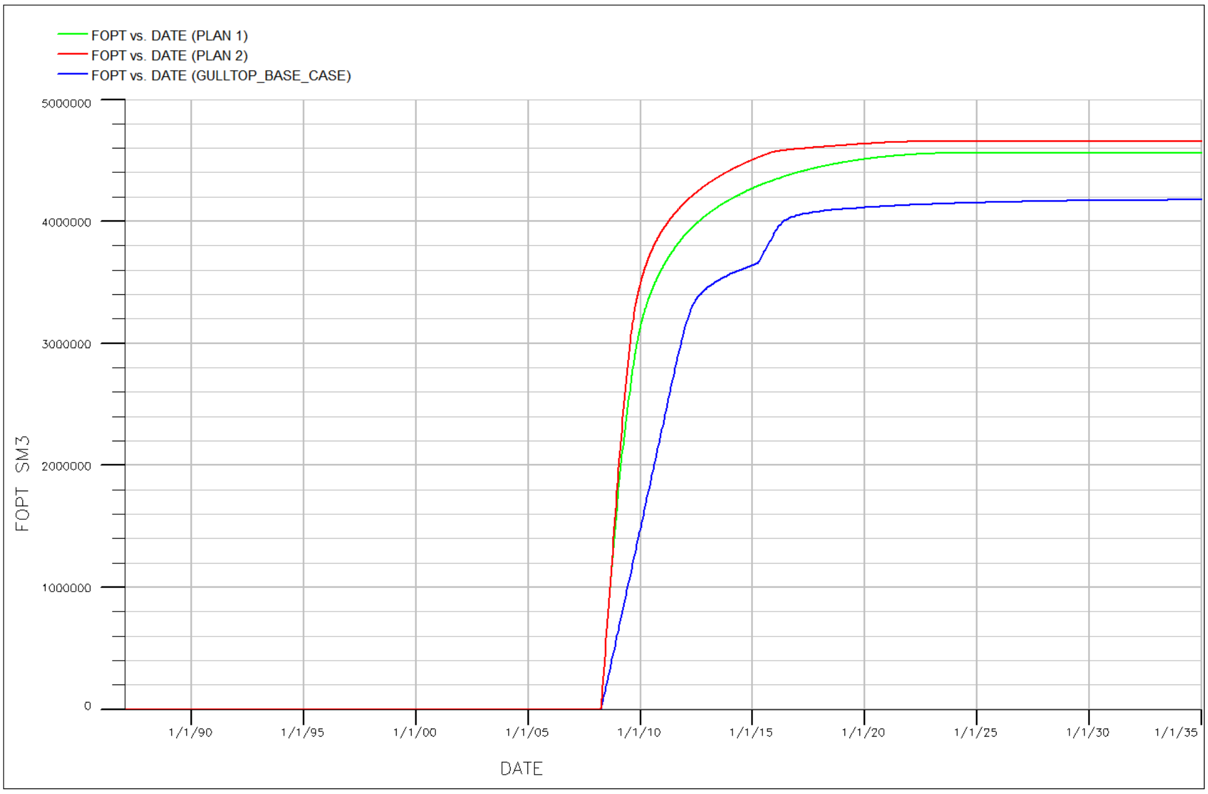


Figure 23: Comparison of oil production for the case cane and the new plans 1 and 2.

Significant amount of oil was left at the middle in the marked area in ***Figure 24*** after producing the reservoir by using plan 2. It was then decided to simulate another plan 3 as elaborated in section 4.4 to recover this oil.

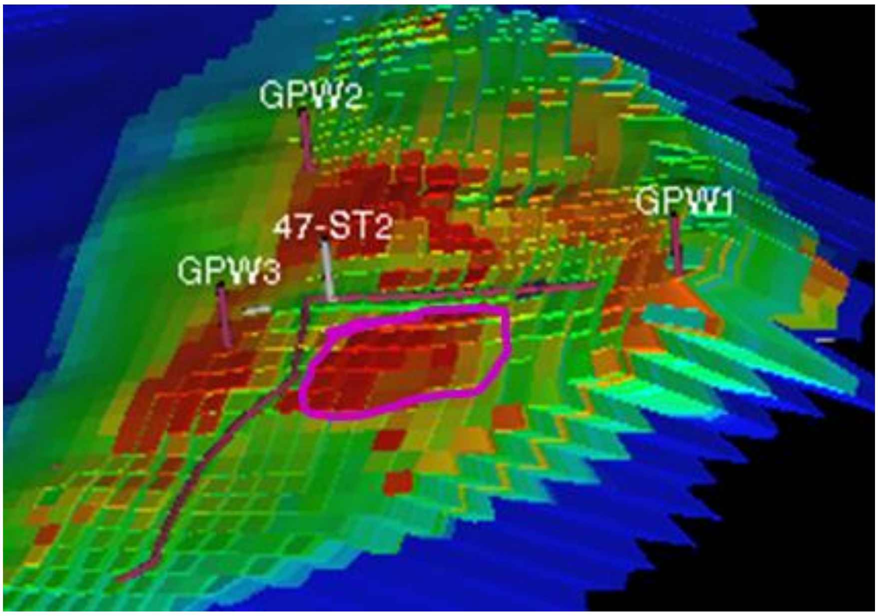


Figure 24: Oil left at the middle after producing the reservoir by plan 2

4.4 Plan 3-Four Production Wells with One Side-track

In plan 3 the field was produced by using four production wells GPW1, GPW2, GPW3 and GPW4, placed as presented in

Figure ***25***. The first three wells with the same features as described in plan 2 were used. To avoid well interference between the added well GPW4 and the second side track from GPW1 well, this side track was removed. Then a horizontal well GPW4 was placed in such a way that it can take oil that was recovered by the removed side-track and that was left in the marked area in in Figure 24. This was achieved by perforating GPW4 well on layers 6,7,8,9,10,11,12,13,14,19,21,22 and 24 on Tarbert formation since these layers were characterised by high oil saturation and good drainage properties.

GPW4 well started production in 2026 to join the other three wells which were in production since 2008. Oil production rates were reduced to 700MSm^3/day for each well from 2026 to 2035. The same bottom hole and tubing head pressures as set in the previous plans were applied in this case.

Simulation results presented in Figure 26 indicate that plan 3 recovered more oil compared to the base case and the previous plans 1 and 2. It recovered 56% of the original oil in place, which is 1.5% higher than plan 2 and exceeded plan 1 and the base case by 3.0% and 7.2% respectively.

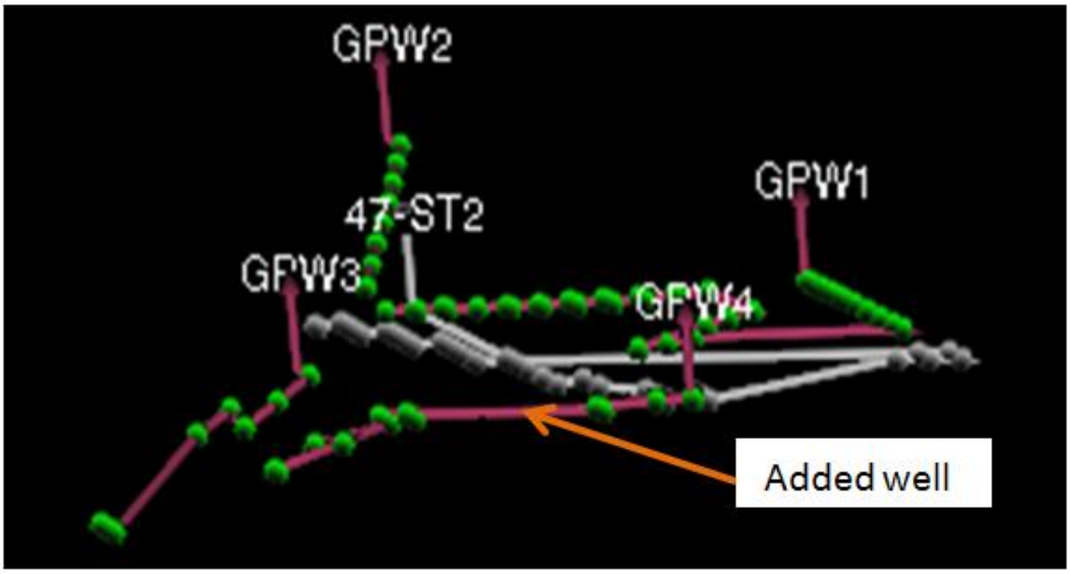


Figure 25: Well placement for alternative plan 3 (four production wells with one side-track)

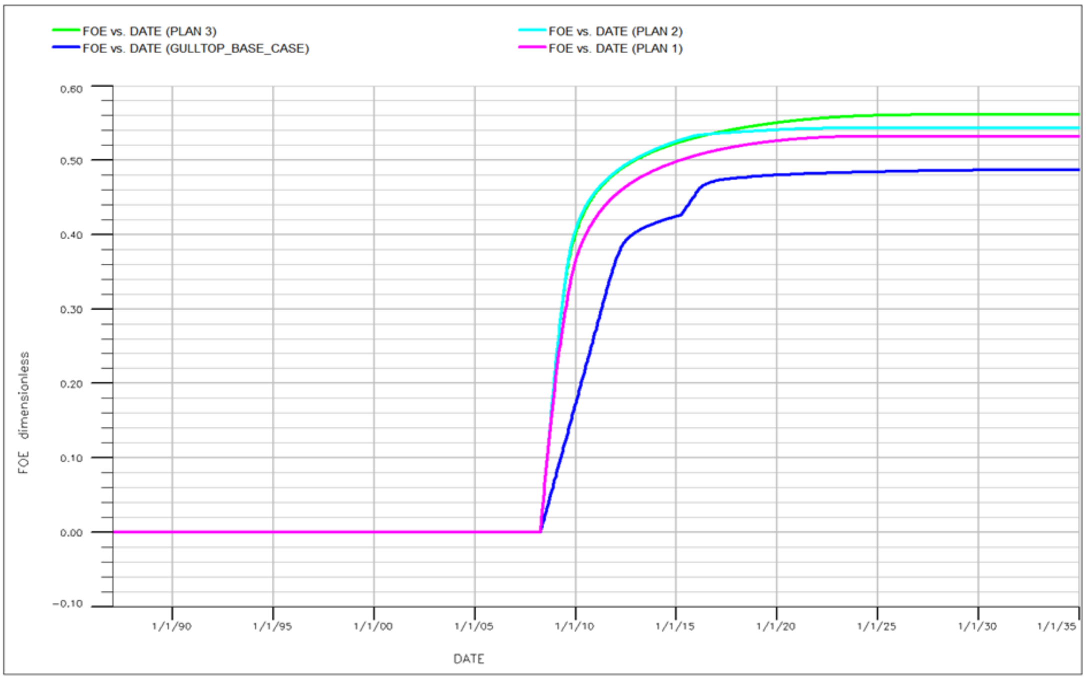


Figure 26: Field oil recovery factors for the base case and the new plans plan 1 to 3.

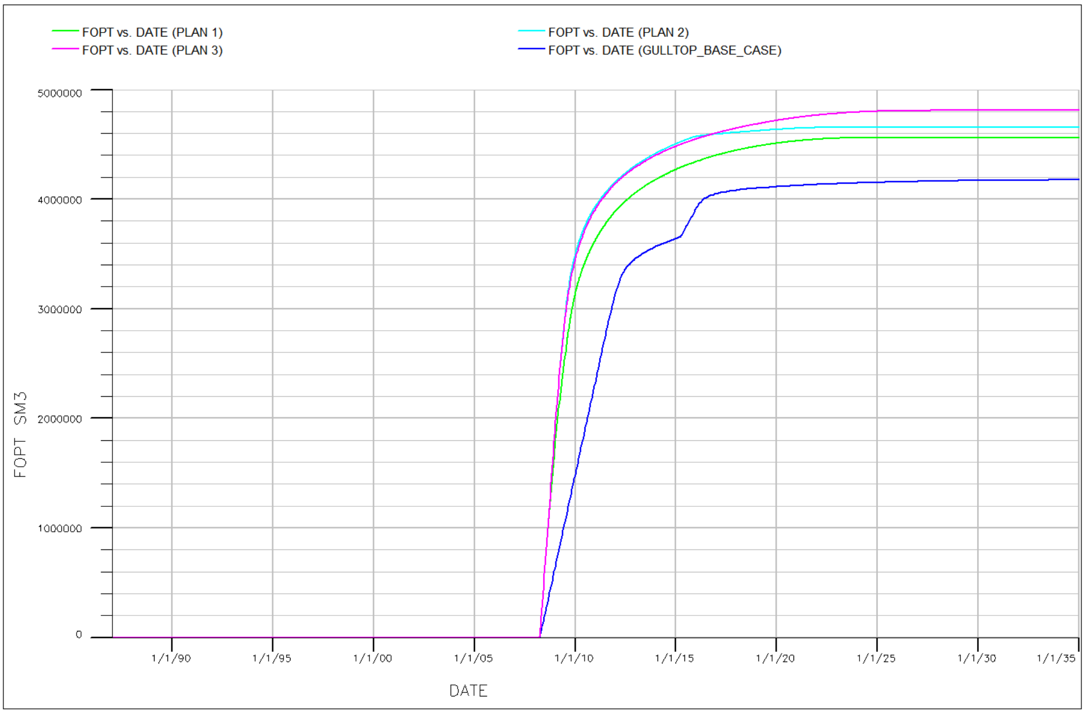


Figure 27: Comparison of oil production for the base case and the new plans 1, to 3.

Due to the continuous decline in oil production rate and reservoir pressure as presented ***Figure 28***, there was a need to develop another plans which will applied pressure maintenance techniques through water and gas injection to improve oil recovery. Since Gulltop field is characterised by sloping reservoir, the injection wells were located up dip and down dip so as to utilize the effect of gravity on fluid movement to maximize sweep efficiency.

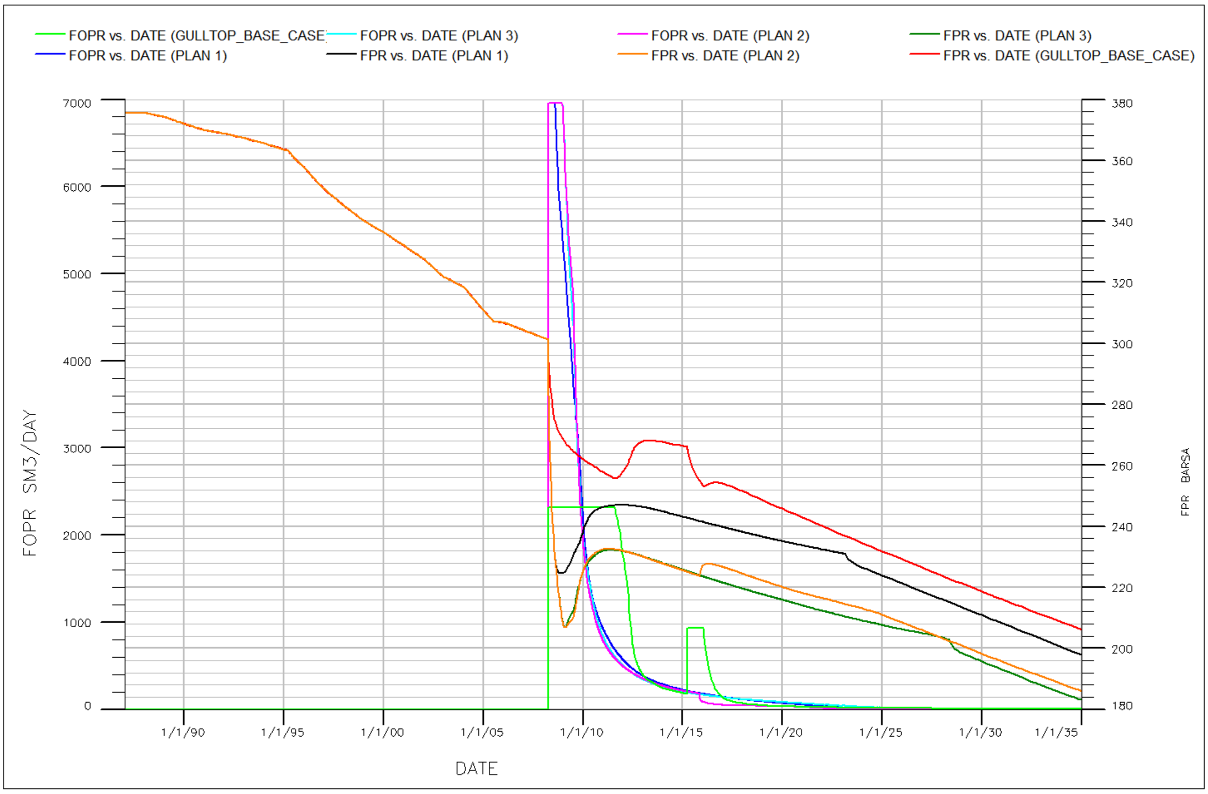


Figure 28: Continuous decline in oil production rate and reservoir pressure

4.5 Plan 4-Up dip Water Injection

This plan involved three production wells (GPW1, GPW3 and GPW4) with one *up-dip* water injector as presented Figure 29. GPW2 that was used as a producer in the previous plans was converted into water injector. This is due to the fact that location of GPW2 at the top favoured peripheral water flooding that pushed oil towards the centre where production wells GPW1, GPW3 and GPW4 are located.

This water injection scheme was applied as a mechanism to improve oil production due to the fact that under gravity influence, up-dip injected water moves down and pushed more oil at the lower part of the up-dip section towards production wells.

Perforation layers for all the four wells were kept as in plan 3. Production rates for all the three wells were set at 2600Sm^3/day each well and water injection rate at 4.5E6 Sm^3/day from 2008 to 2025. As a technique to reduce water cut, oil production rate was reduced to 1500Sm^3/day for each well from 2026 to 2035. Since fluids move from high pressure region to low pressure region, bottom-hole pressures were set at 300bar and 160bar for injector and producer wells respectively. The reason for increasing bottom-hole pressures for production wells from 100bar used in the previous plans to 160bar is to make it a closer to bobble point pressure (177.4bar) to prevent dissolved gas from turning into free gas.

As a result, plan 4 increased oil recovery factor to 58% which is 9.2% higher than the base case and 2% higher than the previous plan 3, as displayed in ***Figure 30***. This increase in oil recovery factor resulted into cumulative field oil production of about 4.96E6Sm3 as shown in ***Figure 31***.

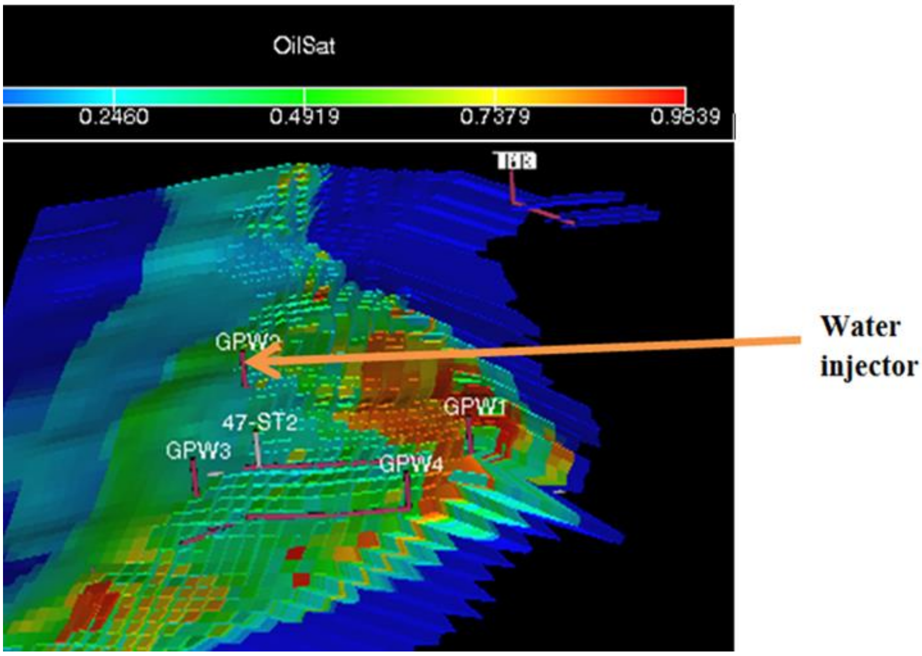


Figure 29: Well placement for alternative plan 4 (3 production wells with 1 up-dip water injector-2035)

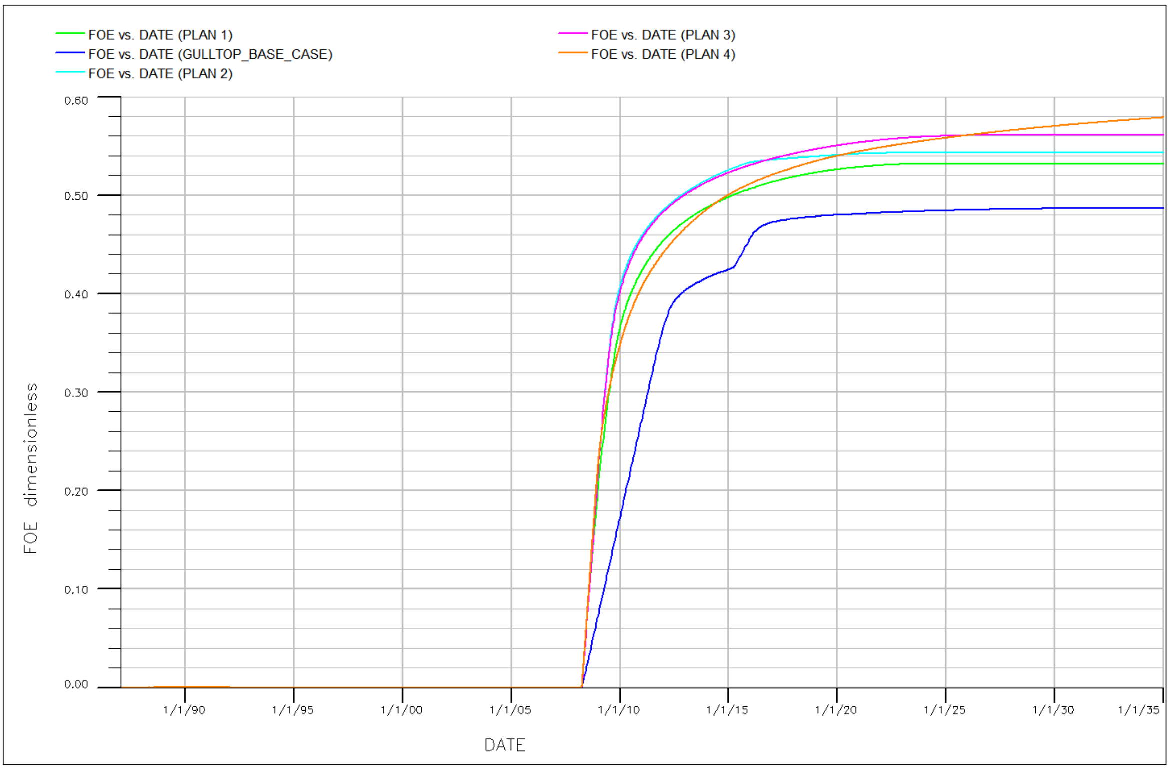


Figure 30: Field oil recovery factors for the base case and plans 1, to 4

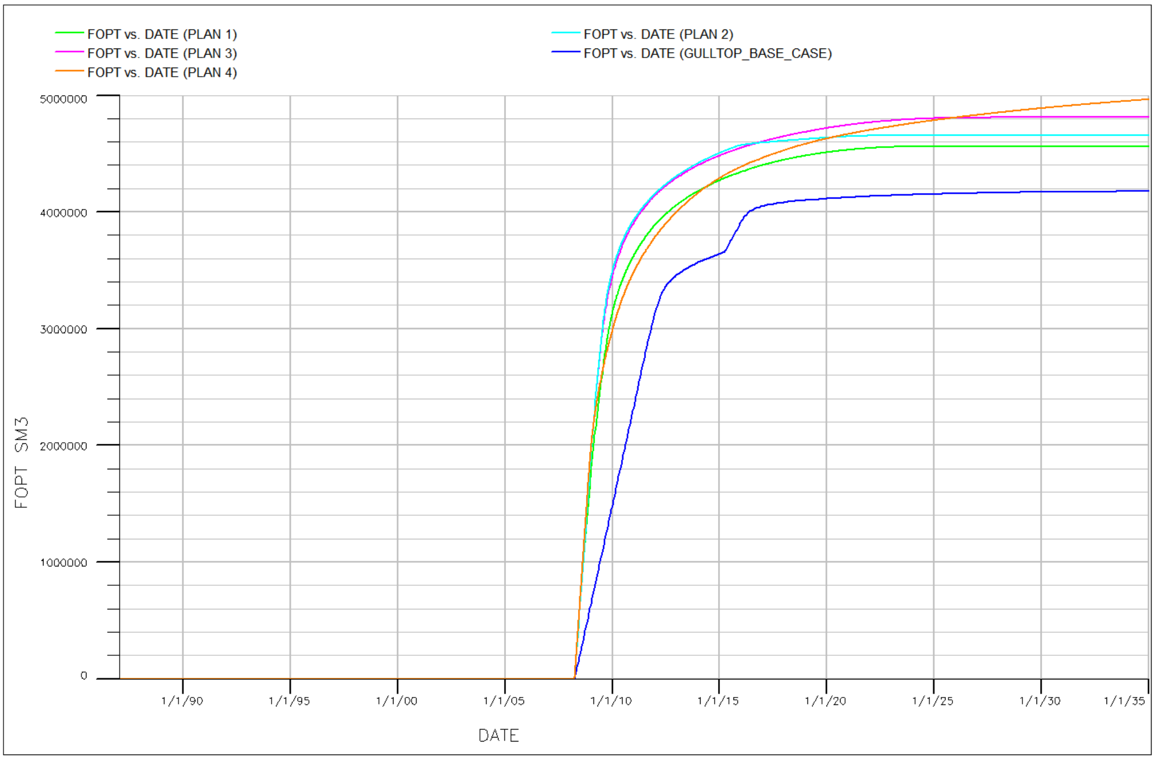


Figure 31: Comparison of oil production for the base case and the new plans 1, to 4

As shown in ***Figure 31***, plan 4 recovered less oil at the beginning of production compared to plans 2 and 3. This called for a need to simulate another plan that will produce more oil from the beginning, so as to recover the invested capital as soon as possible.

4.6 Plan 5-Down dip Water Injection

This plan consists of two cases. Case (a) was simulated for the purpose of optimizing drainage direction and case (b) to optimize drainage points. In case (a), drainage direction was optimised by altering location of water injection well from *up-dip* water injection applied in plan 4, to *down-dip* water injection. To come up with unbiased results, 3 production wells (GPW1, GPW3, GPW4) with one injector well (GTV3) were used as in plan 4 and its configuration is presented in Figure 32.

In case (b) oil production was optimized by changing drainage points (production well location) while maintaining injector well location and number of wells as in case (a). Likewise, oil production and water injection rates were kept as in the previous case. Then, GPW4 well was removed and GPW2 used as a producer with the other two production wells (GPW1 and GPW3) as shown in Figure 33. In both cases (a) and (b), injector well was perforated close and at the WOC on layers 22, 23, 29, 30, 31, 32 and 33 for the injected water to boost the bottom water aquifer to push oil up towards production wells.

*Figure **34*** shows that changing drainage direction (plan 5-a) increased oil recovery factor to 58.5 % compared to plan 4 which recovered 58%. In addition to that, altering production well location (plan 5-b) increased oil recovery to 59.2 % as can be seen in the same figure. Improved oil production corresponding to the mentioned increased recovery factors are as shown in *Figure **35***.

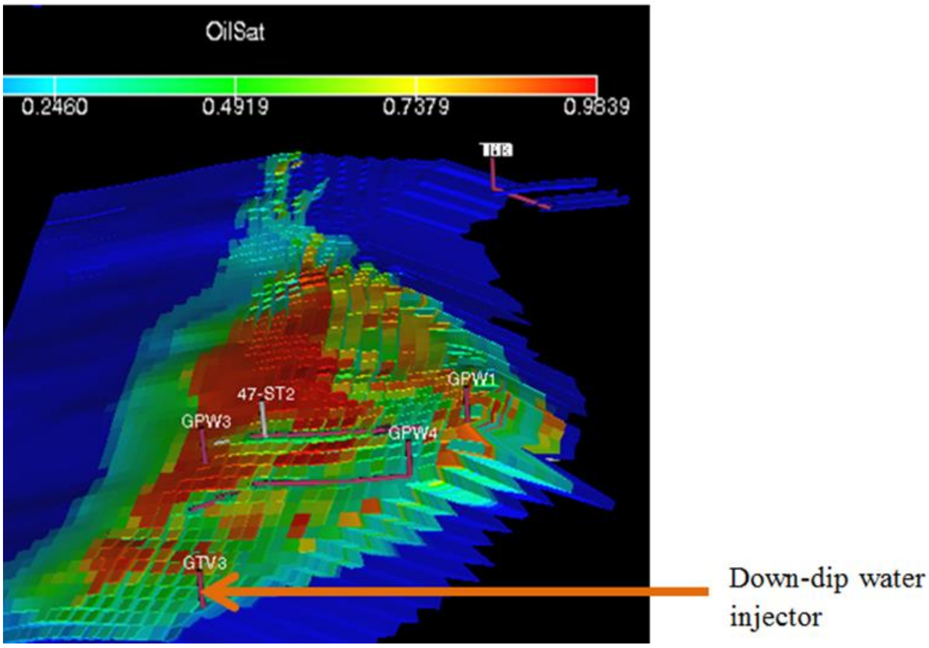


Figure 32: Alternative plan 5 (Case (a): 3- production wells with 1 down-dip water injector-2035)

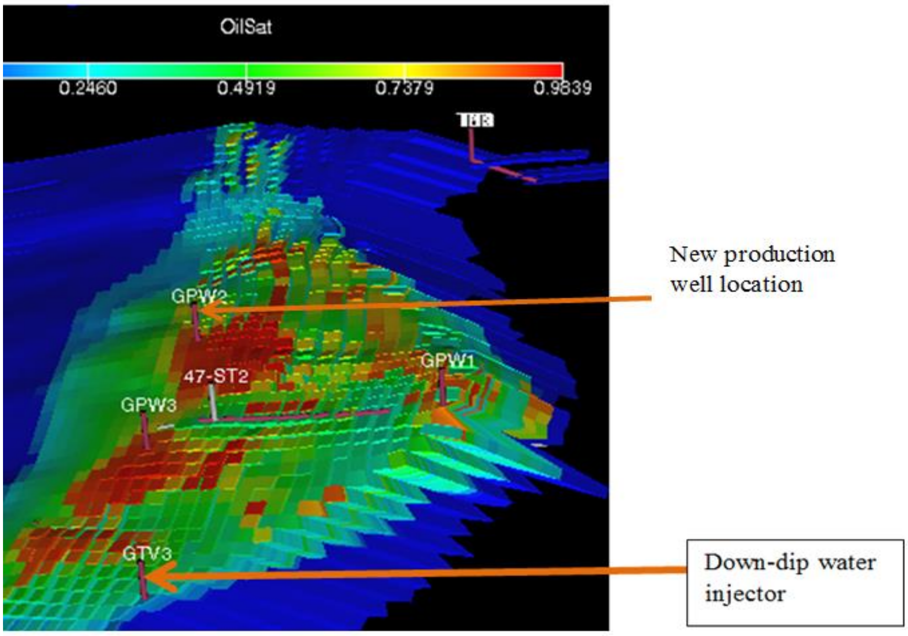


Figure 33: Alternative plan 5 (Case (b): 3- production wells with 1 down-dip water injector-changed location of producer)

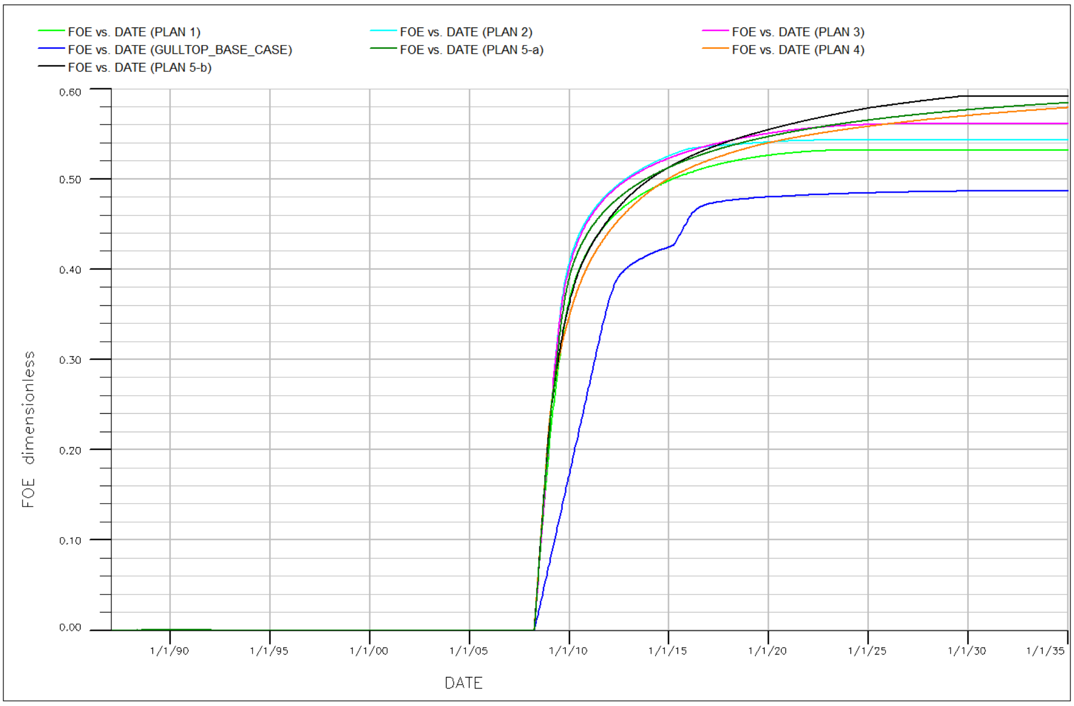


Figure 34: Field oil recovery factors for the base case and plans 1 to 5

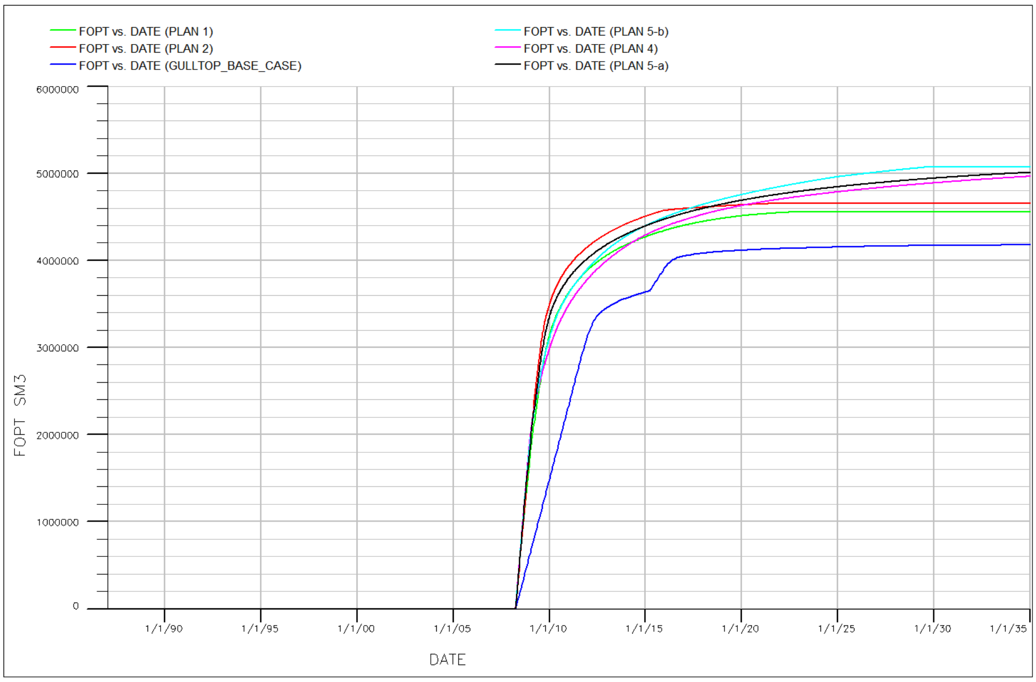


Figure 35: Comparison of oil production for the base case and the new plans 1 to 5

4.7 Plan 6-Up dip Gas Injection

In this plan, oil production was optimized by changing injection fluid from water injection implemented in plans 4 and 5 to gas injection while maintaining other operating conditions as in the previous plans. This was achieved by injecting gas into the reservoir up-dip using GPW2 as indicated in Figure 36. The reason for injecting gas up-dip was to form a secondary gas cap that compressed oil down towards production wells. Another factor for injecting gas was that since the reservoir is under saturated, the injected gas would dissolve into the oil, lowering its density and viscosity making it lighter and move faster towards production wells, and hence improve oil recovery. Gas injection rate was 2.5E6Sm^3/day. Gas was injected at lower rate than water since it can move faster compared to water because it is lighter than water.

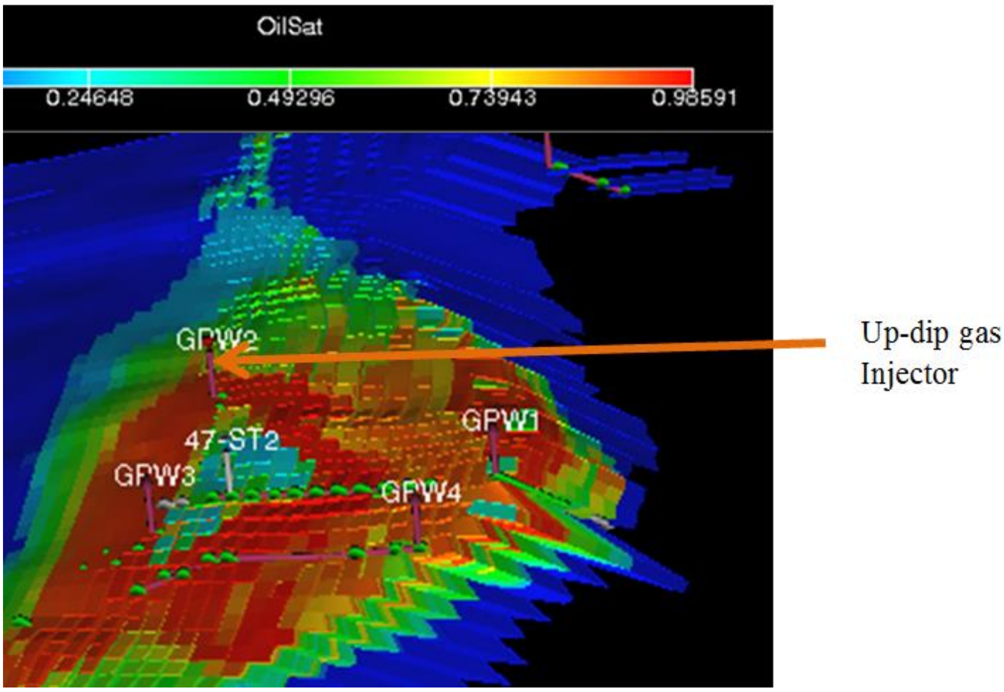


Figure 36: Alternative plan 6 (3- production wells with 1 up-dip-gas injector-2010)

Figure 37 shows that changing injection fluid from water to gas improved oil recovery to 60.2 % .This is equivalent to 11.4% higher than oil recovered by the base case.

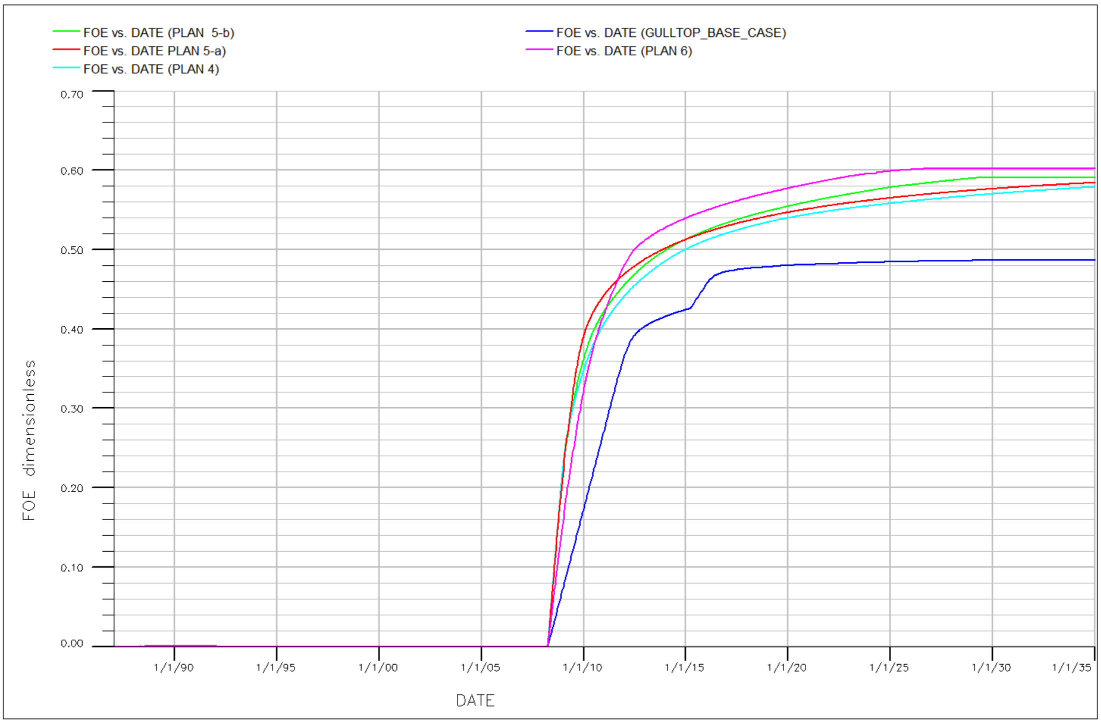


Figure 37: Field oil recovery factors for the base case and the new plan 4 to 6

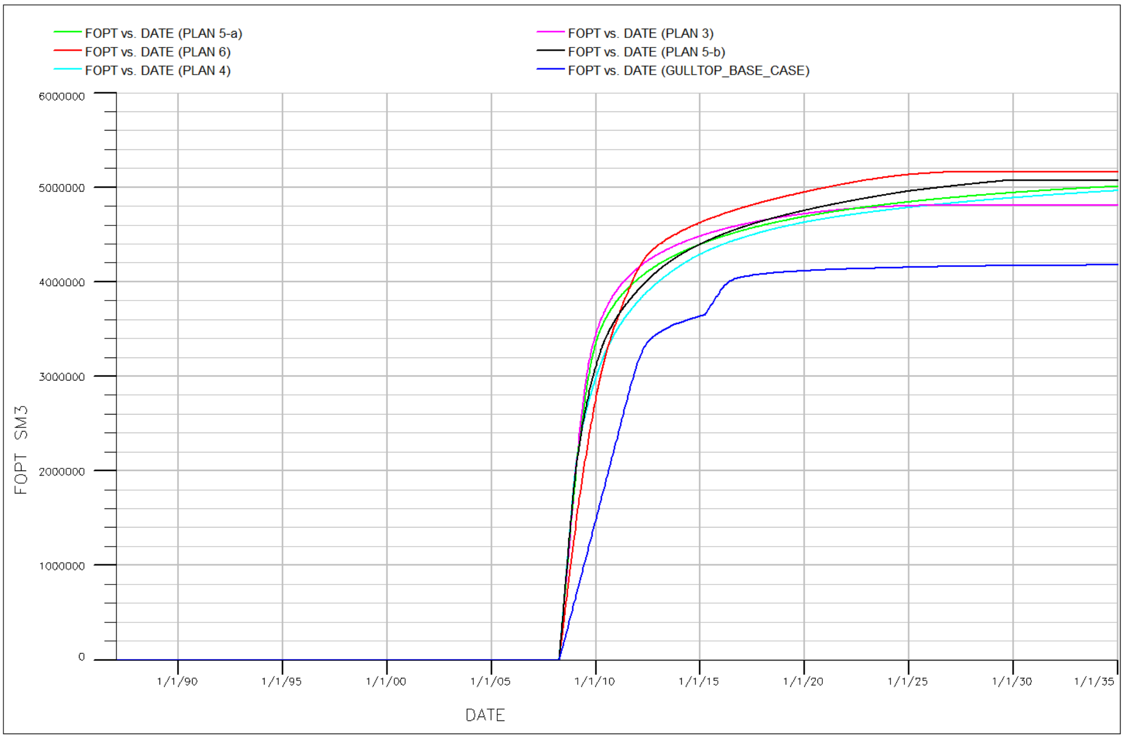


Figure 38: Comparison of oil production for the base case and the new plans 3 to5

4.8 Plan 7-Downdip Gas Injection

This plan was simulated in order to study the effect of changing gas injection direction on oil recovery. Gas was injected down dip as presented in Figure 39. The same number of wells as in plan 5 and 6 were used in this plan.

Gas injection rate was 4500, 000Sm3/day. This rate was set high than the one used in plan 6 (2500000Sm^3/day) due to the fact that in this case gas was injected at the bottom, so it has to travel long distance to the top to form a secondary gas cap while the up-dip injected gas (plan 6) had no such a distance to cover.

Due to difference in densities between water, gas and oil, down-dip injected gas moved to the top and created a secondary gas cap that was expected to provide pressure support and improve oil production. However, this gas injection scheme produced less oil compared to the up dip gas injection as shown in Figure 40. The reason for this could be due to increased gas injection rate or location of the production wells. To cleat this out, another plan 8 was simulated by changing production well location as described in section 4.9

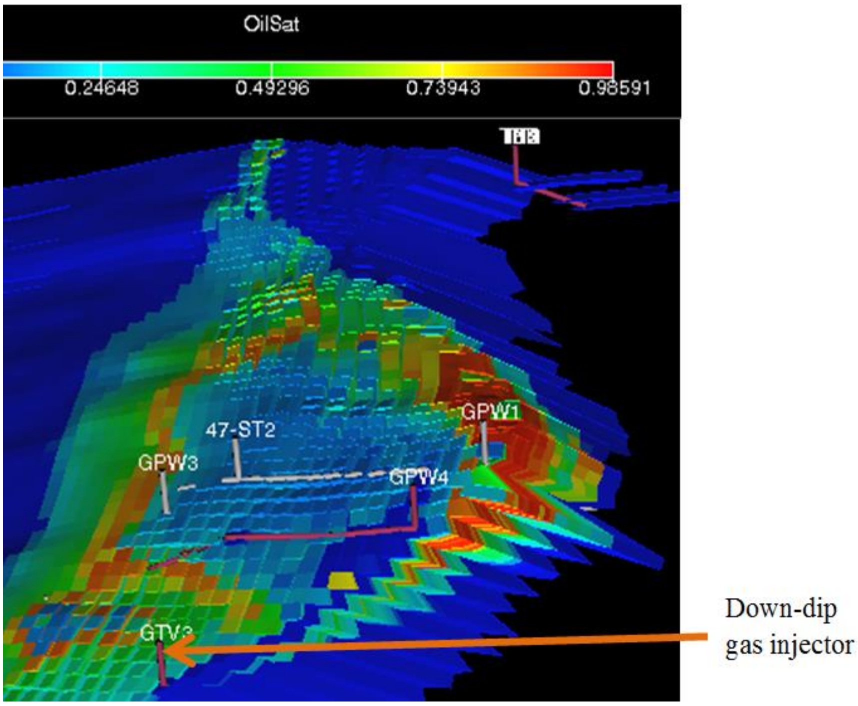


Figure 39: Alternative plan 7 (down-dip gas injection)

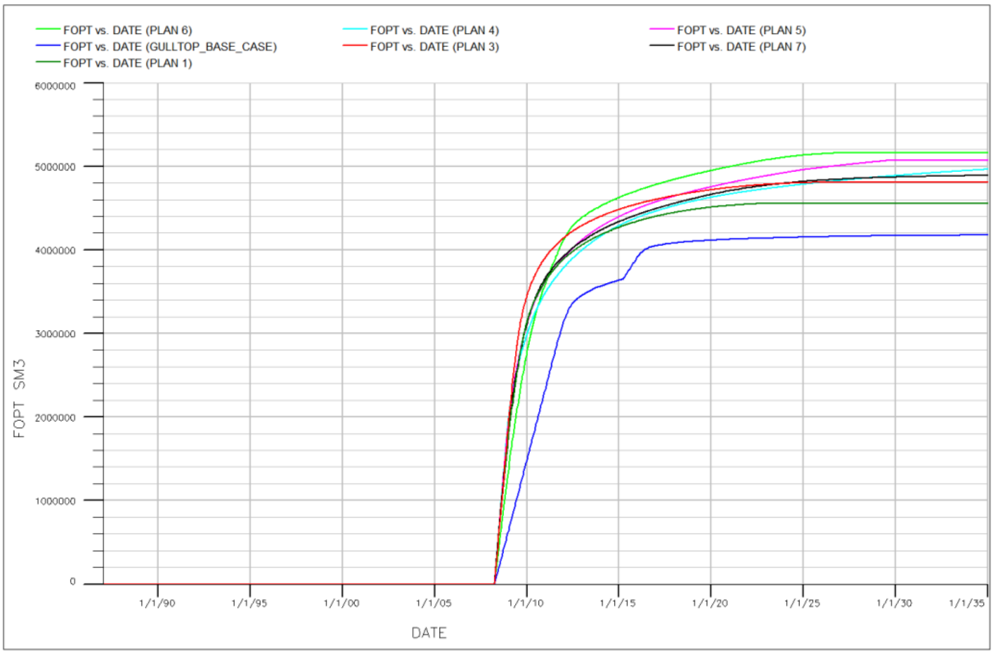


Figure 40: Comparison of oil production for the base case and the new plans 1 to7

4.9 Plan 8-Down dip Gas Injection with Changed Production Well Location and Reduced Gas Injection Rate

To optimize oil production in down dip gas injection, production well location was changed. GPW2 was used together with the other two production wells as shown in ***Figure 41*** instead of using GPW4 and the other two production wells, implemented in plan 7. Oil production and gas injection rates were maintained at 2600 Sm^3/day and 2500000 Sm^3/day respectively. Other operation conditions like bottom hole and tubing head pressures were not changed.

As presented in Figure 42 and Figure 43, changing production well location and reducing gas injection rate to 2.5E6Sm3/day under down dip gas injection scheme produced 5.4E6 Sm^3 of oil equivalent to 63% compared to the previous plan 7 which recovered only 57% of oil, and the base case which recovered only 48.8%.

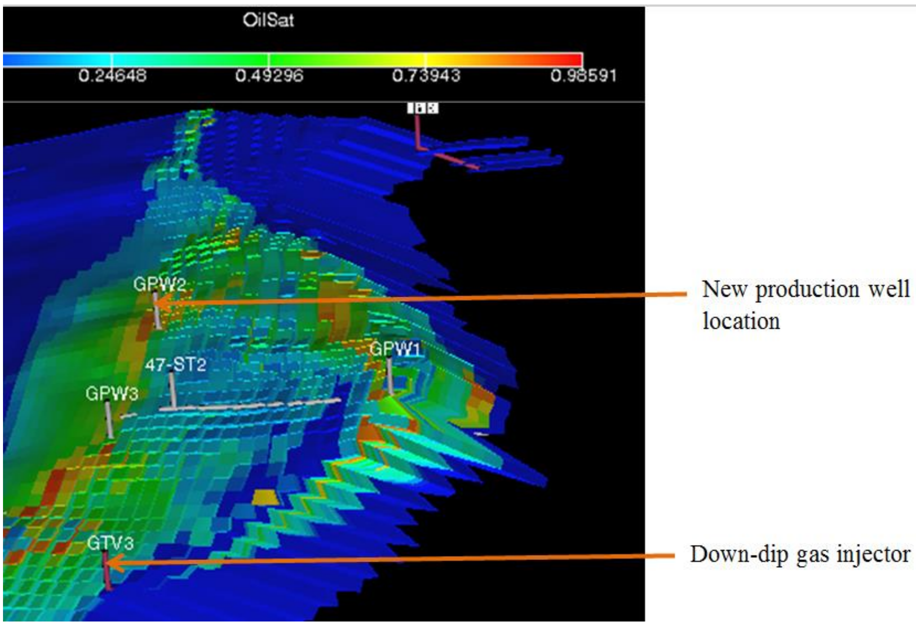


Figure 41: Alternative plan 8 (down-dip gas injection with changed production well location)

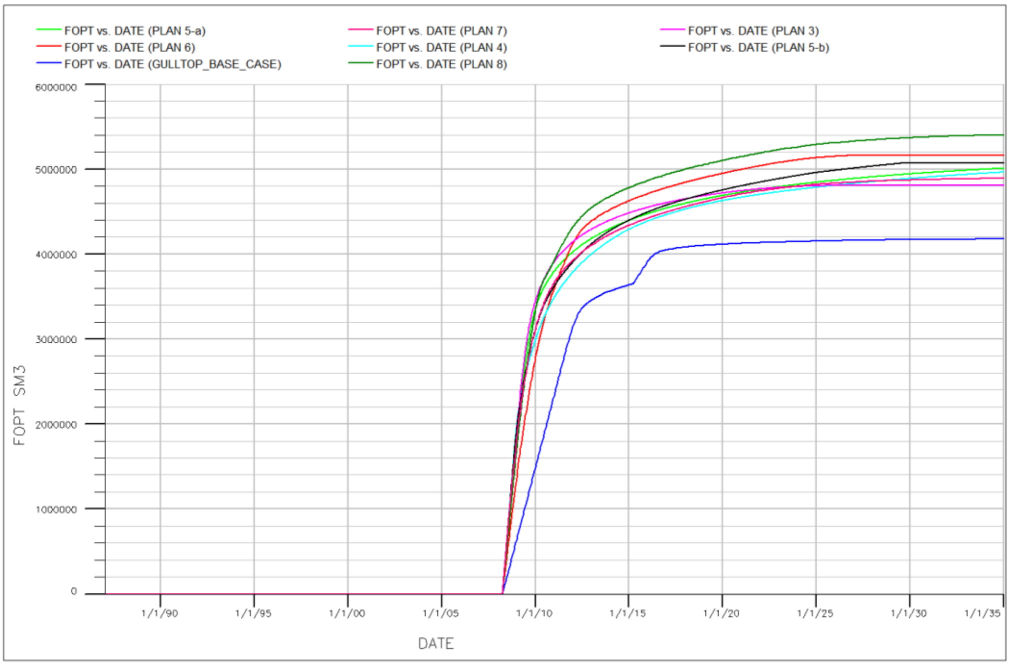


Figure 42: Comparison of oil production for the base case and the new plans 3 to 8

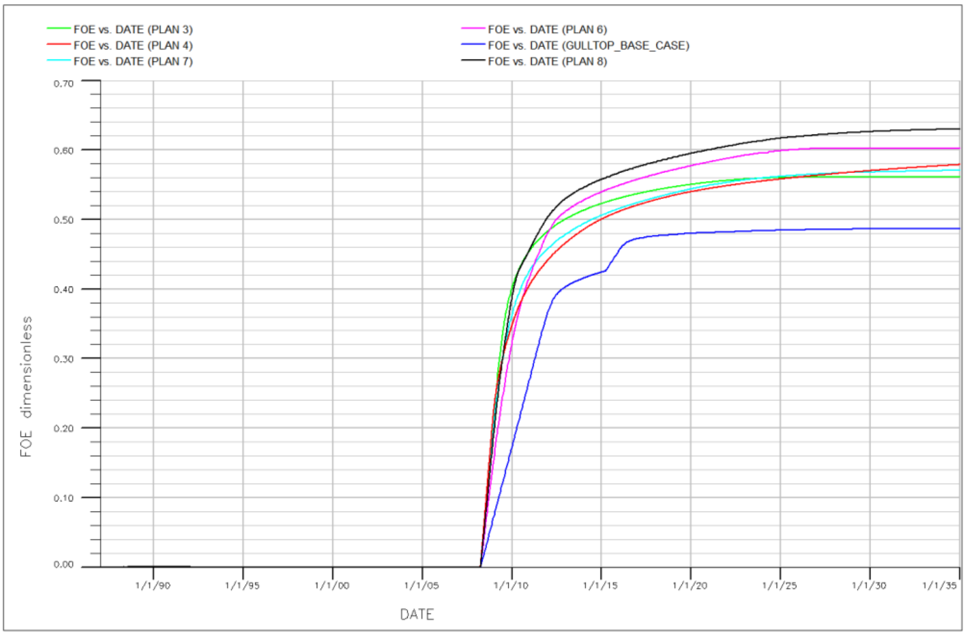


Figure 43: Comparison of oil recovery factors for the base case and the new plans 3 to 8

As described in the previous sections, up-dip and down-dip water and gas injection (plan 4, 5, 6, 7 and 8) indicated significant increase in oil recovery compared to the no-injection (only infill well optimization) plans 1, 2 and 3.The combined effect of injecting gas and water simultaneously (SWAG) at different wells was simulated to see how this affects oil recovery. SWAG performance was optimized by changing gas and water injection rates and changing injector well location as described in sections 4.10, 4.11and 4.12

4.10 Plan 9- Non Gravity Assisted Simultaneous Water and Gas Injection

Three production wells as in the previous plans were used with GTV3 well as a down-dip water injector and GPW2 as an up-dip gas injector (non-gravity assisted simultaneous water and gas injection NGASWAG) as shown in ***Figure 44***. Oil production rate, gas and water injection rates, tubing head and bottom-hole pressures were kept as in plans 6 and 8.

*Figure **45*** and ***Figure 46*** show that simultaneous up-dip gas and down-dip water injection recovered 66% of the initial oil in place which is equal to 5.7E6sm^3.

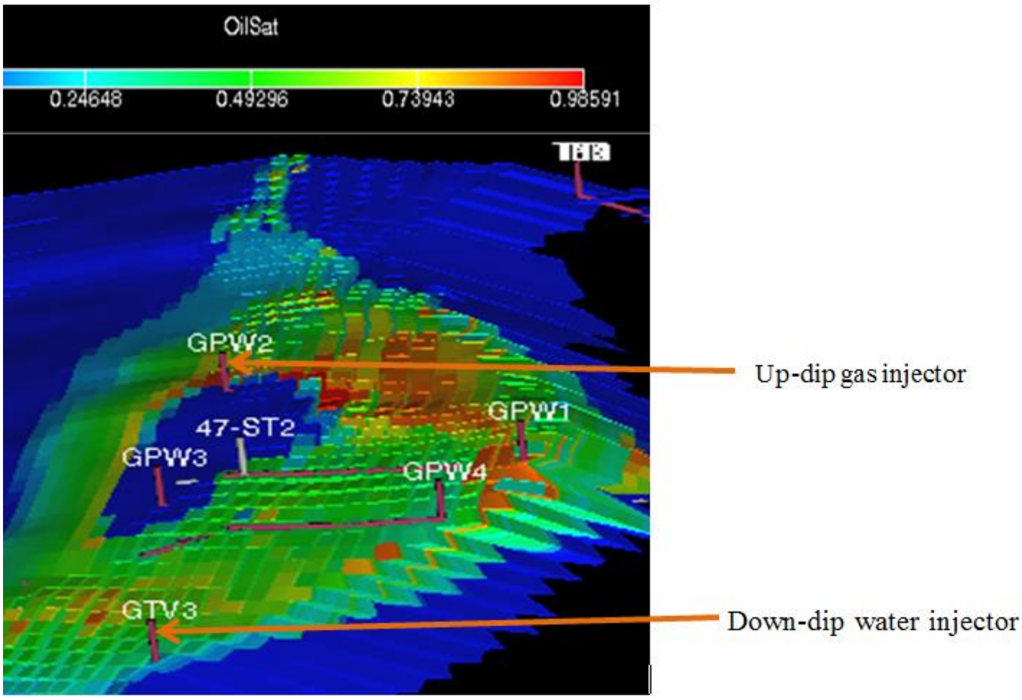


Figure 44: Alternative plan 9 (Simultaneous up-dip gas and down-dip water injection with 3 production wells)

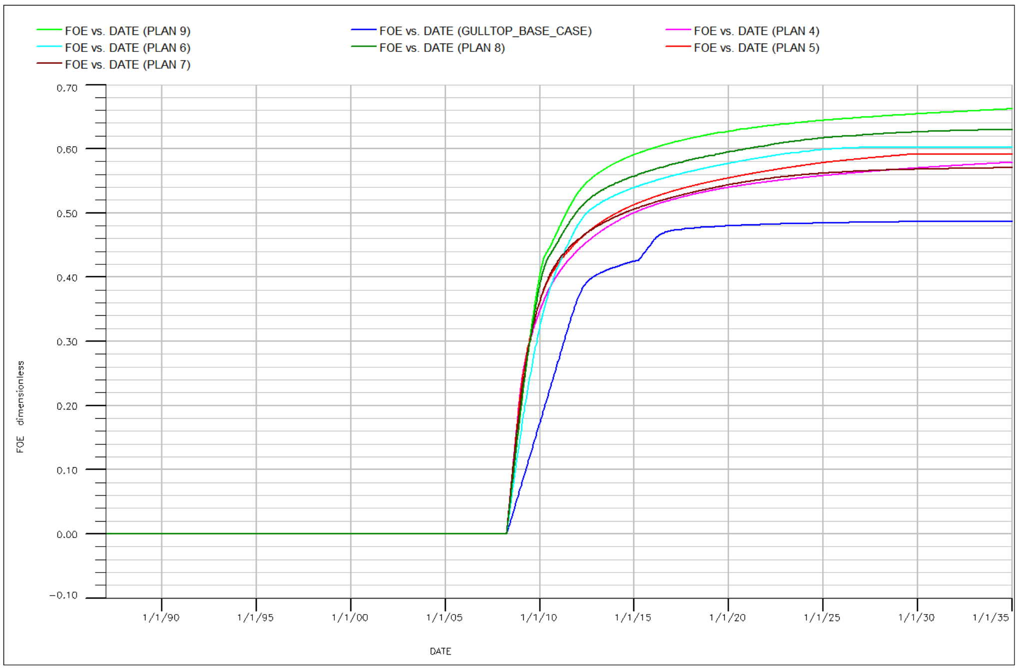


Figure 45: Comparison of oil production for the base case and the new plans 4 to 9

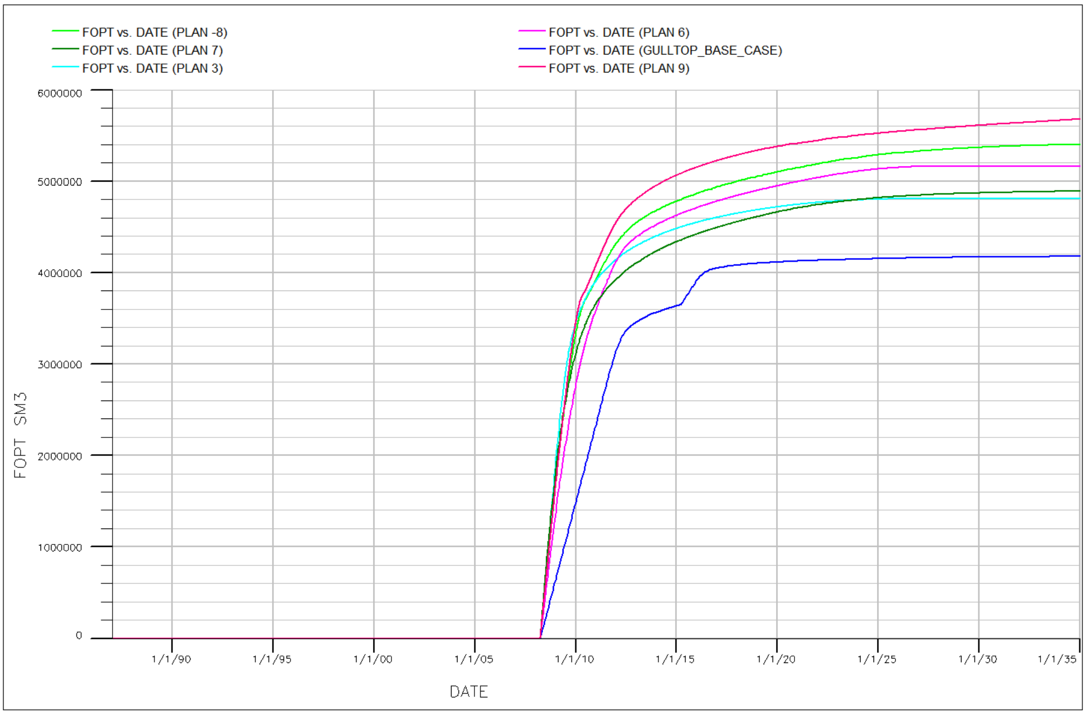


Figure 46: Comparison of oil production for the base case and the new plans 6 to 9

4.11 Plan 10-NGASWAG Injection with Reduced Injection Rates

This plan was developed to analyse the effect of water and gas injection rates on SWAG performance. It comprised of simultaneous Up-dip gas and down-dip water injection (Non gravity assisted simultaneous water and gas-NGASWAG injection) as in plan 9, but with water and gas injection rates reduced by 40% to 2500000Sm3/day and 1500000Sm3/day respectively. Well location, tubing head pressures, oil production rates and bottom-hole pressures were maintained as in plan 9.

Reducing injection rates by 40% affected NGASWAG performance by lowering its recovery factor and oil production to 63% and 5.5E6Sm3 respectively. It recovered 3% less than plan 9 which recovered 66% of oil when injection rates were maintained as in the single-fluid injection cases.

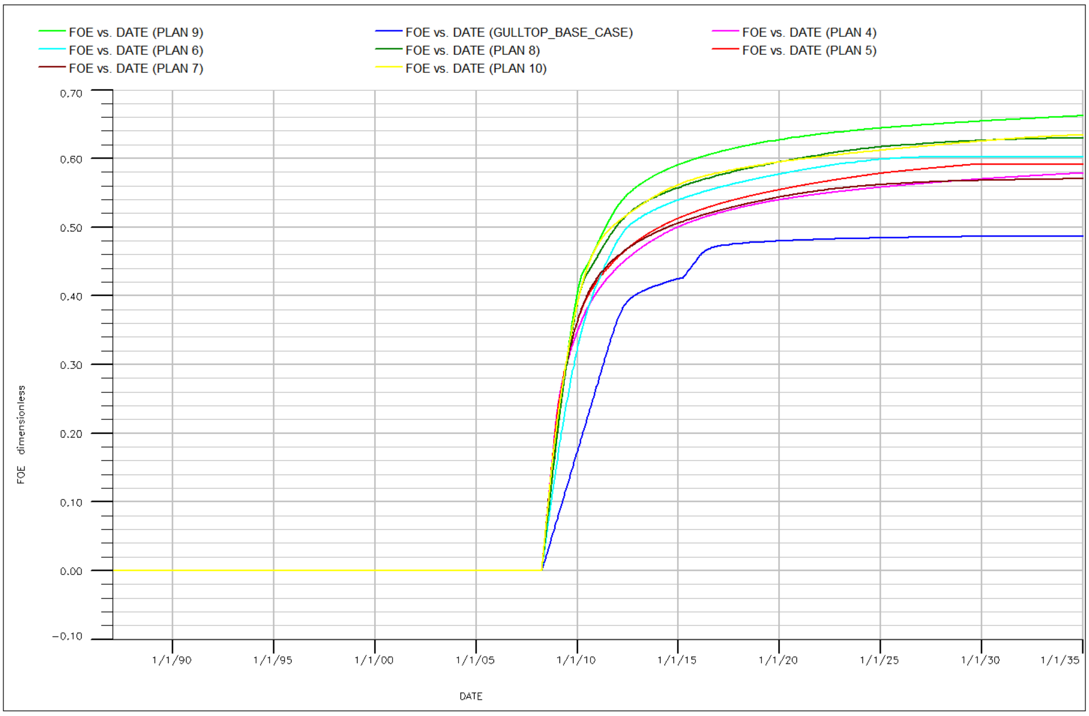


Figure 47: Comparison of oil recovery factors for the base case and the new plans 3 to 10

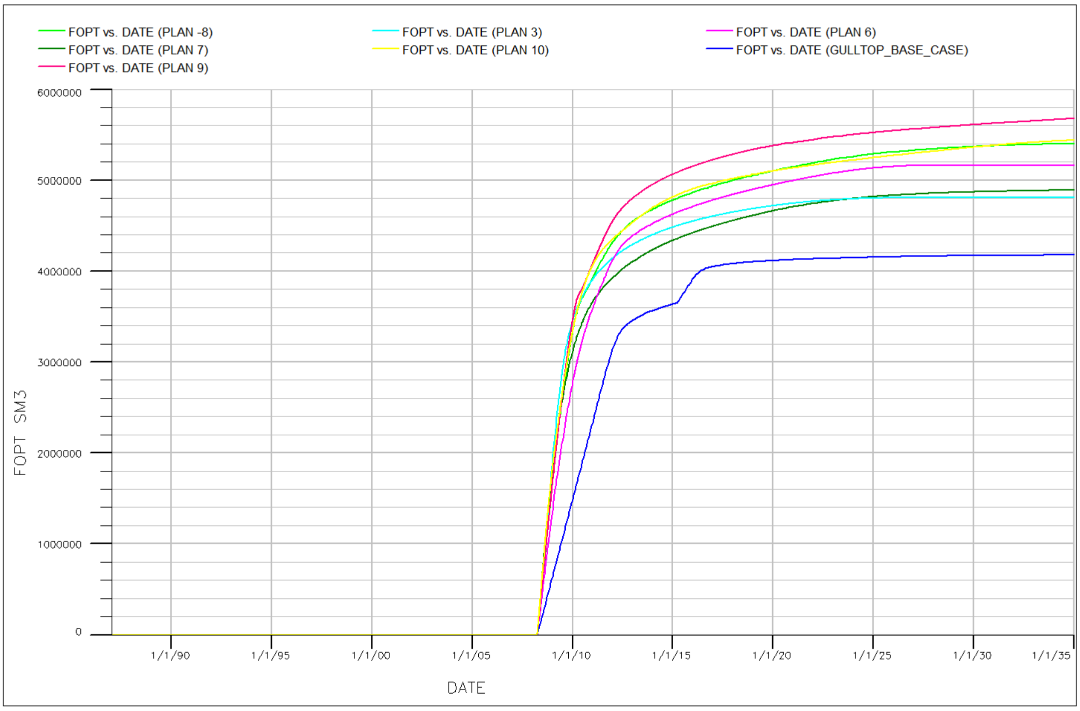


Figure 48: Comparison of oil production for the base case and the new plans 3 to 10

After analysing the effect of reducing fluid injection rates on NGASWAG performance, it was necessary to study the effect of injection well location (direction of injection fluid) on SWAG performance. This was simulated so as to come up with a good combination of fluids injection rates and injection well locations that will result into a better performing SWAG injection scheme for optimum oil production, as described in section 4.12.

4.12 Plan 11- Gravity Assisted Simultaneous Water and Gas Injection

To analyse the effect of gravity on SWAG performance, location of water and gas injectors were interchanged by injecting water up-dig and gas down-dip to make gravity assisted simultaneous water and gas injection (GASWAG) scheme as presented in *Figure **49***. This is opposite to what was done in plan 10. Other operating conditions were kept as in the previous plan.

As shown in Figure 50 and Figure 51, gravity assisted simultaneous water and gas injection (GASWAG-Plan 11) recovered more oil (68% equivalent to 5.86E6 Sm^3) compared to the non-gravity assisted simultaneous water and gas injection (NGASWAG-Plan 9 and Plan 10).

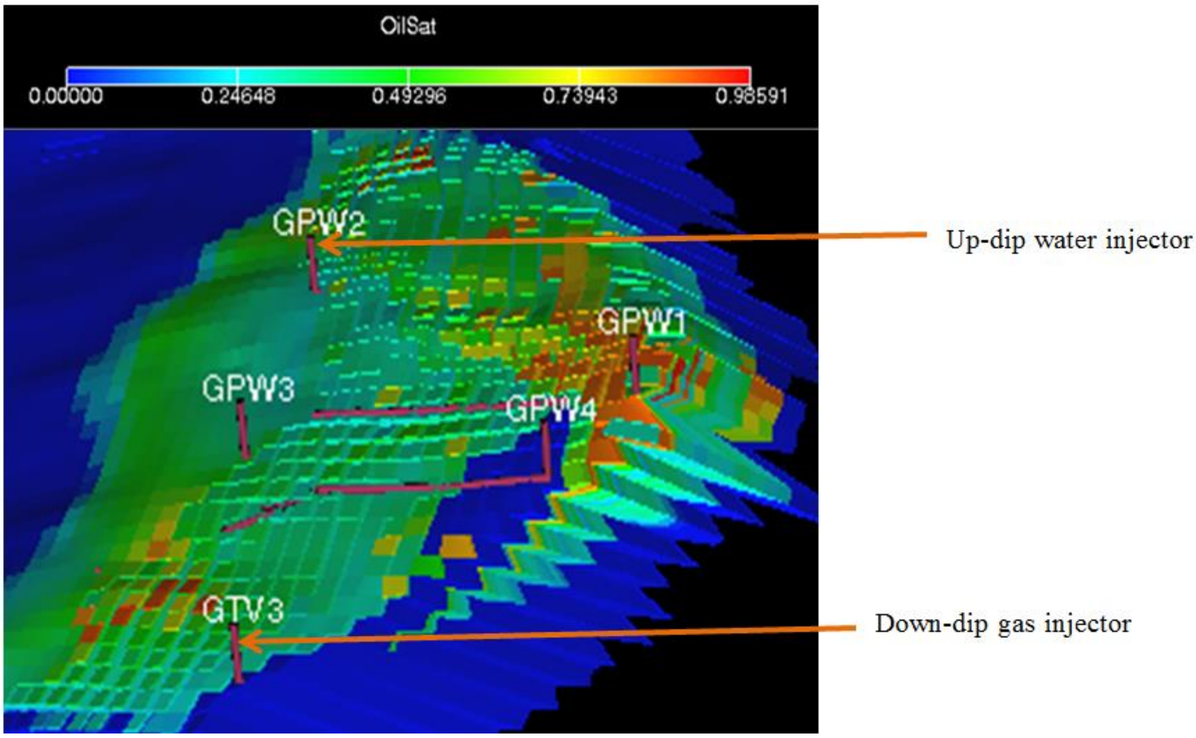


Figure 49: Alternative plan 11 (Simultaneous up-dip water and down dip gas injection with three production wells)

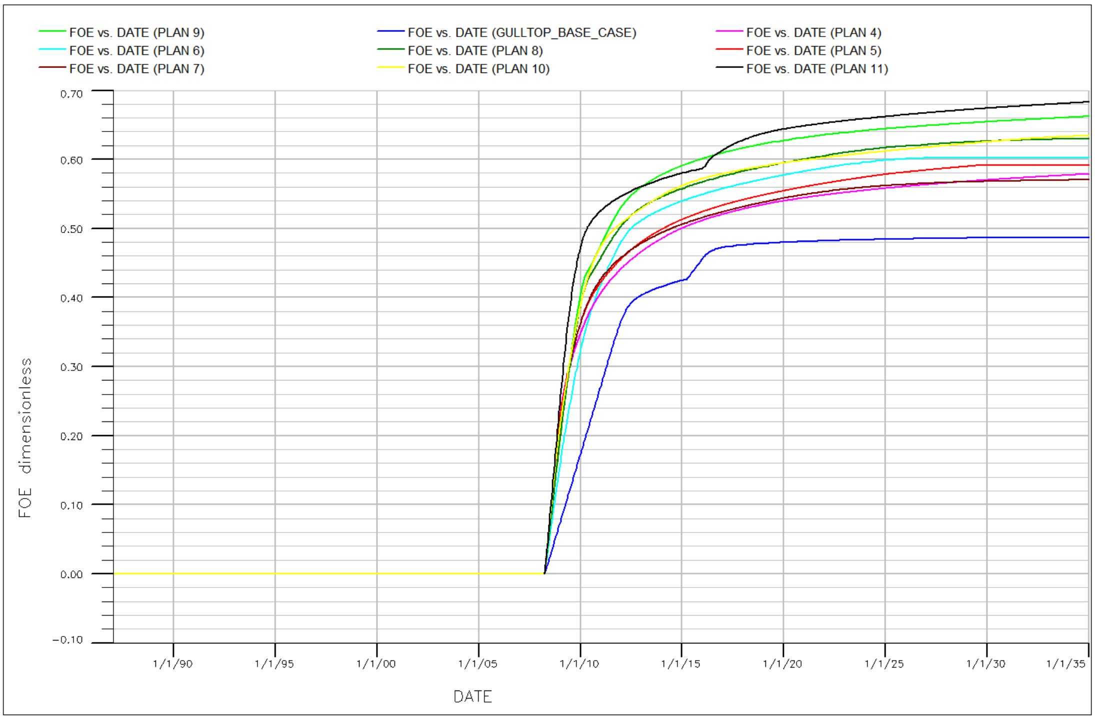


Figure 50: Comparison of oil recovery factors for the base case and the new plans 3 to 11

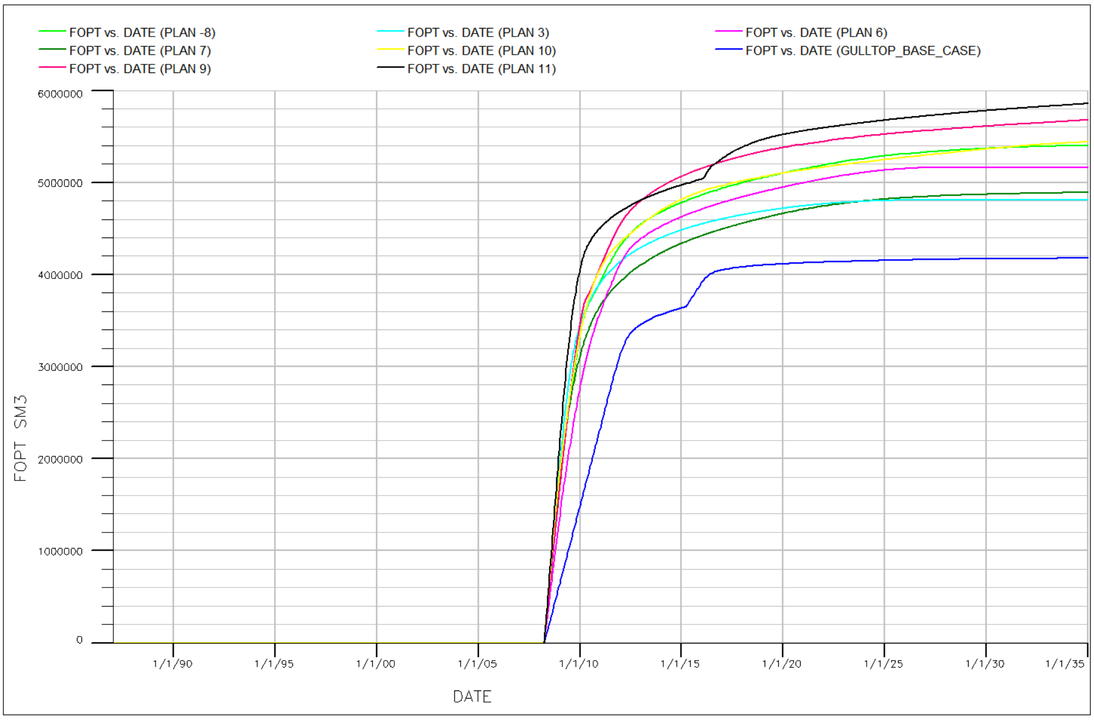


Figure 51: Comparison of oil production for the base case and the new plans 3 to 11

Both single-fluid injection and SWAG injection schemes recovered more oil compared to the no-fluid injection schemes as described in the previous sections. The reason for this is pressure support induced by the injected fluids as presented in Figure 52. As can be seen in this figure, plan 11 maintained reservoir pressure almost to the initial pressure that is why in this plan more oil was recovered compared to the other plans.

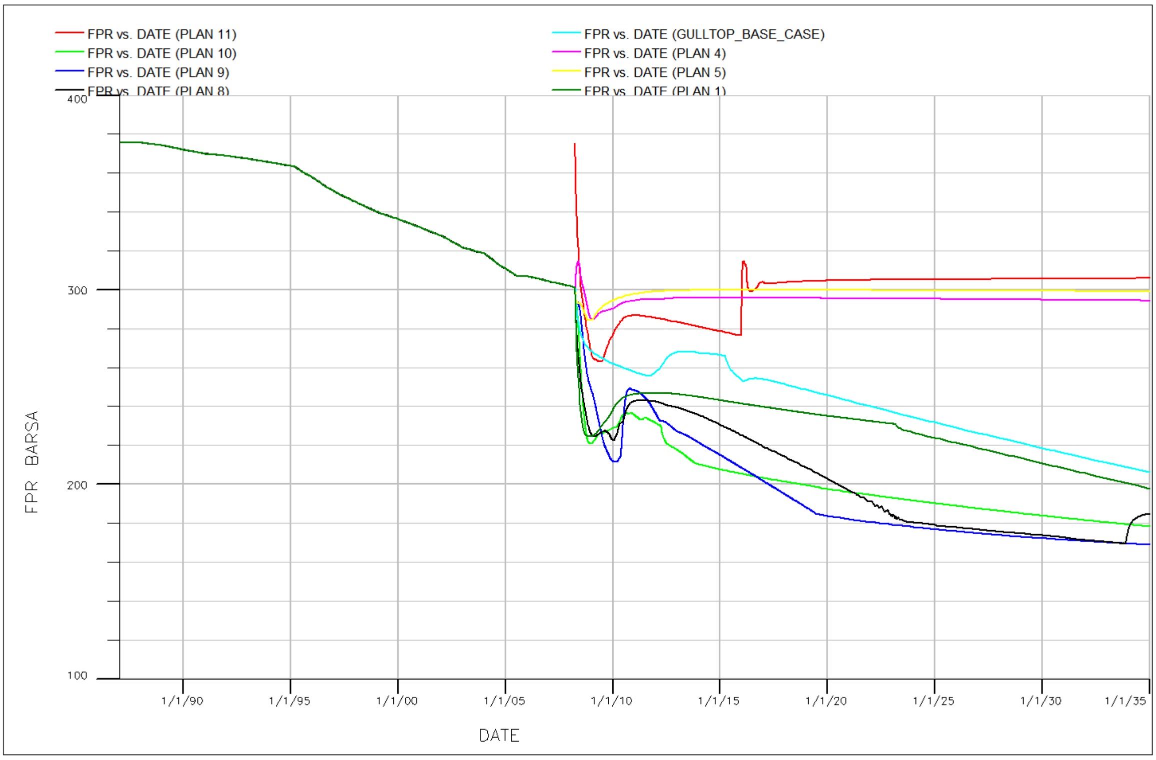


Figure 52: Average reservoir pressure for the base case and the new plans

5 ECONOMIC EVALUATION

Base case and the new plans were economic evaluated by calculating their net present value (NPV) using equation 4. NPV calculations were done by using Excel Microsoft computer programme for 28 years from 2008 to 2035 Results from NPV calculations were used to accept or reject the simulated new plan. For a new plan to be accepted, its NPV should be positive and greater than that of the base case.

$$\boldsymbol{NPV = \sum_{t=0}^{t-n} \frac{C_t}{(1+i)^t}} \qquad - 4$$

Where:

t= time for cash flow (year)

C_t=cash flow at time t (UDS)

i=Discount rate. (%)

Assumptions made

1. Since the developed alternative plans were taken as separate projects, income from these plans is base on incremental oil production as addition to the base case.
2. Only oil price, well cost (drilling, completion and facilities cost) and discount rate were considered in NPV calculation.
3. No operating costs, tax, royalties, fluid injection system maintenance costs or gas price were considered in this analysis.
4. Gas price is not included in NPV calculations due to the fact that produced dissolved gas will be re-injected into the reservoir for pressure support (no gas will be transported or bought for injection purpose)
5. Water treatment and storage costs were not considered in this analysis.
6. To take care of the fluctuation in oil price and well cost occurred during the project evaluation period from 2008 to 2017 and the prediction period to 2035, oil prices and well costs used in NPV calculation were varied as given in Table 1.
7. Discount rate was assumed to be 8% per year throughout the projects evaluation period.

8. Both water and gas injection started at the beginning of oil production in 2008 to avoid the risk that the oil and aquifer columns may not be continuous.

Table 1: Oil price and well cost used in NPV calculation

Oil Price (USD/bbl)	145	120	100	80	60	50	40	30
Well cost (MMUSD/well)	85	82	78	75	70	65	60	55

5.1 Economic Evaluation Results

Economic evaluation of the base case and the simulated new plans was done by calculating their net present values based on the assumptions stated in section 5 as presented in Appendix 3. Figure 53, Figure 54, Figure 55 and Figure 56 show yearly incremental NPV at oil price of 145usd/bbl, 100usd/bbl, 50usd/bbl and 30usd/bbl respectively from 2008 to 2035. Cumulative NPV for the base case and all the new plans evaluated at different oil prices and well costs are presented in Figure 57. From these plots it was observed that all the new plans have positive NPV, greater than that of the base case. Producing the field by simultaneous down dip gas –up dip water injection (GASWAG) resulted into highest NPV, while gas injection at the bottom alone (Plan 7) has lower NPV than other plans.

In addition to that, relationship between NPV and number of wells was analysed based on reservoir production energy. Figure 58 shows that when the reservoir was produced by using its natural energy (no injection, only well placement optimization) NPV increased with the number of wells but it reached a point where NPV decreased with the increase in number of wells. On the other hand, when fluid injection was applied, number of wells and NPV were directly proportional related as show in Figure 59.

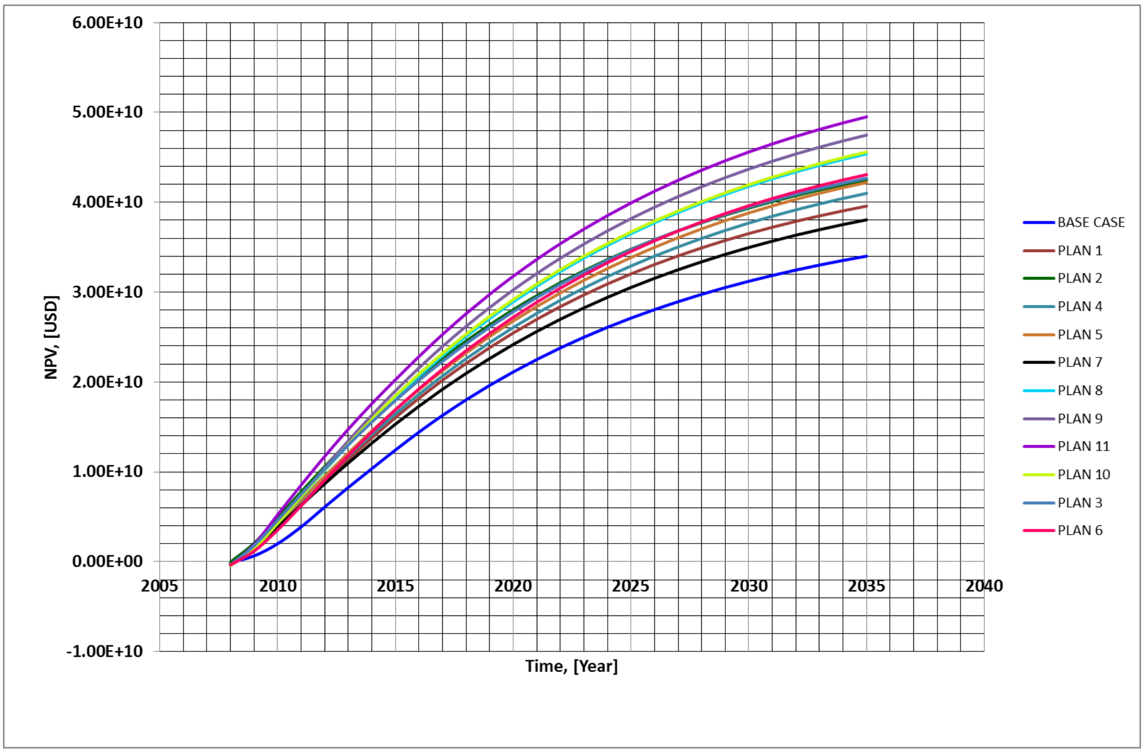


Figure 53: NPV comparison between base case and the new plans at oil price of 145USD/bbl and well cost of 85E6 USD/well

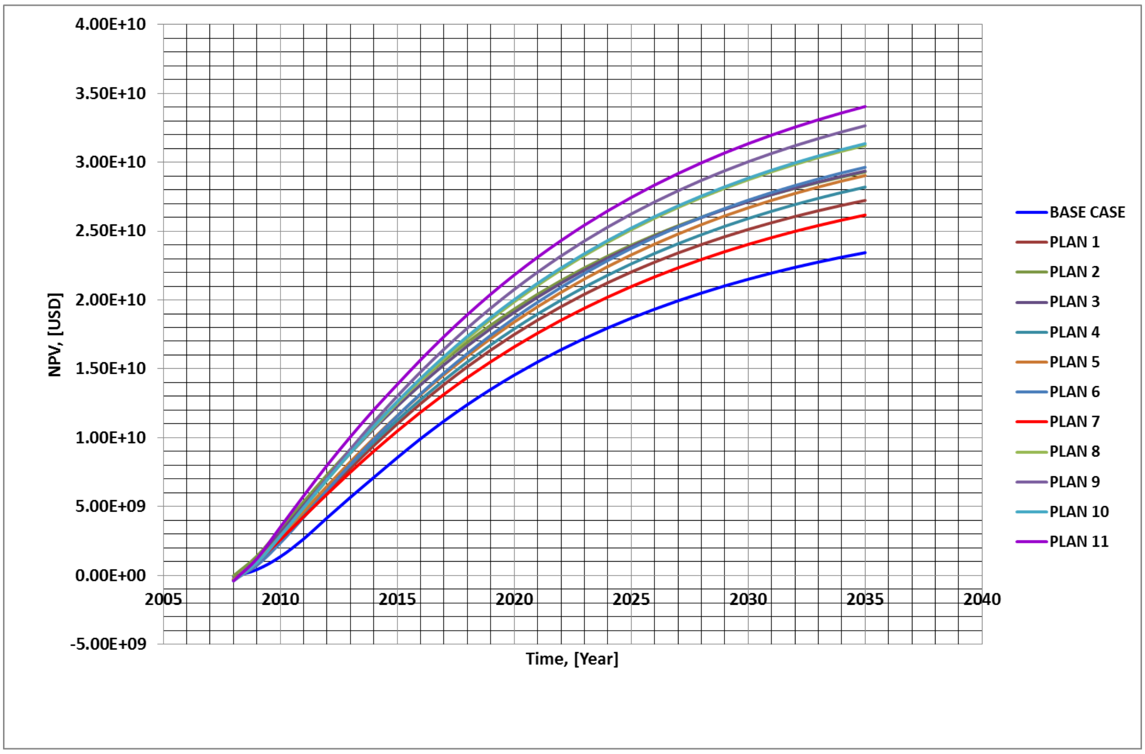


Figure 54: NPV Comparison between base case and the new plans at oil price of 100SD/bbl and well cost of 78E6 USD/well

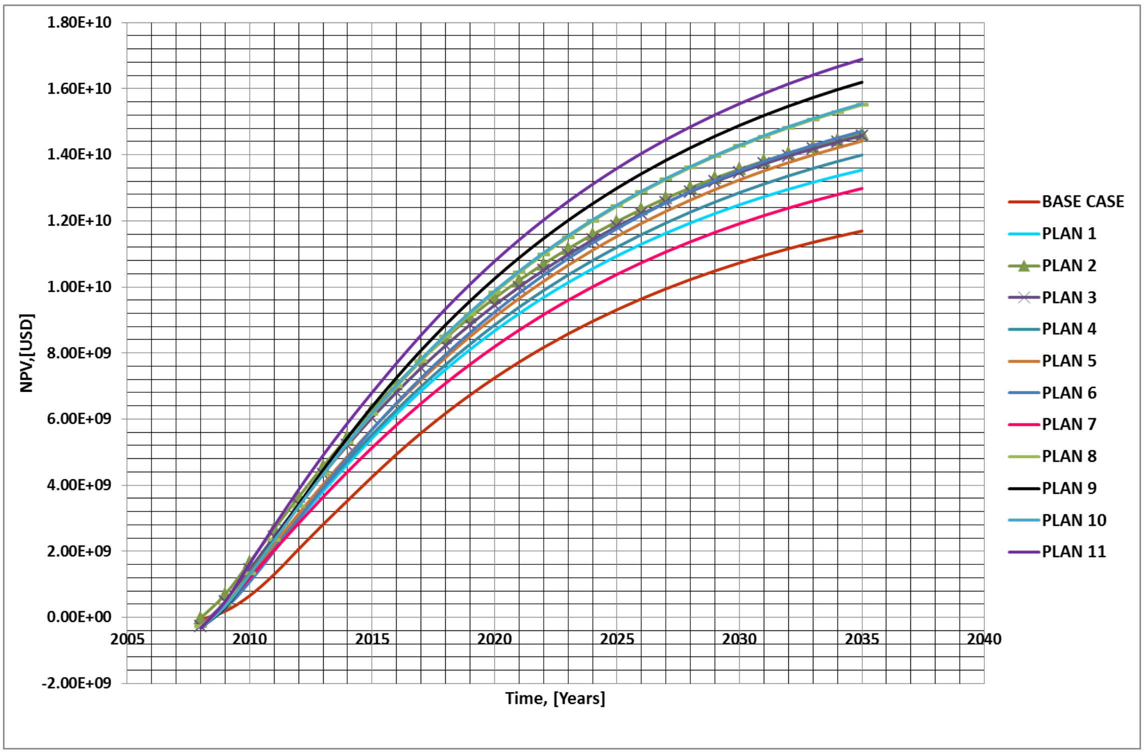


Figure 55: NPV comparison between base case and the new 11 plans at oil price of 50USD/bbl and well cost of 65E6 USD/well

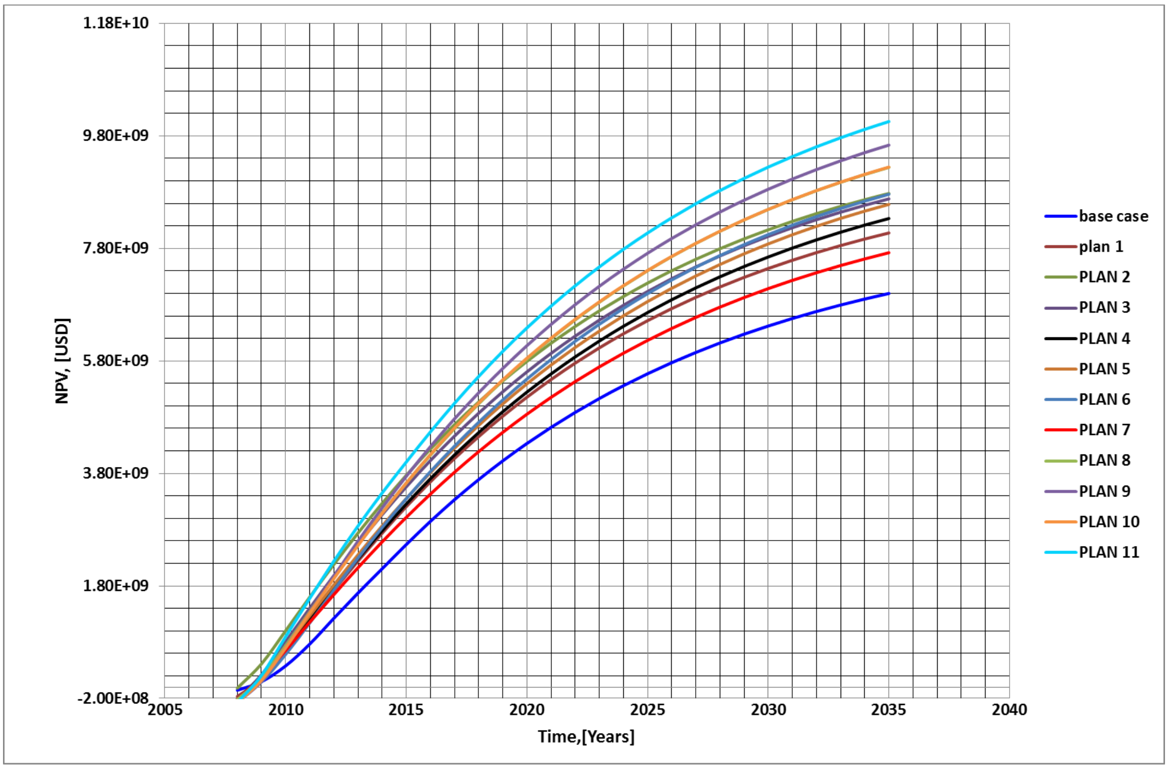


Figure 56: NPV comparison between base case and the new plans at oil price = 30USD/BBL and well cost = 55E6 USD/well

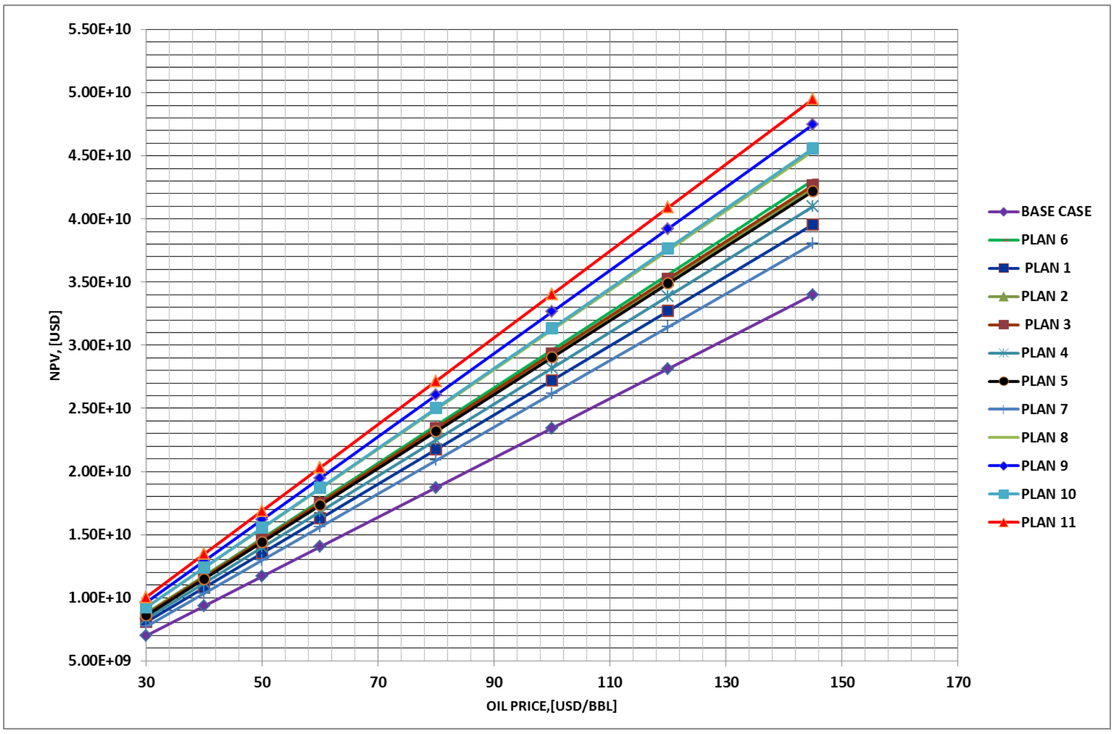


Figure 57: Cumulative NPV for the base case and the new plans at different oil prices

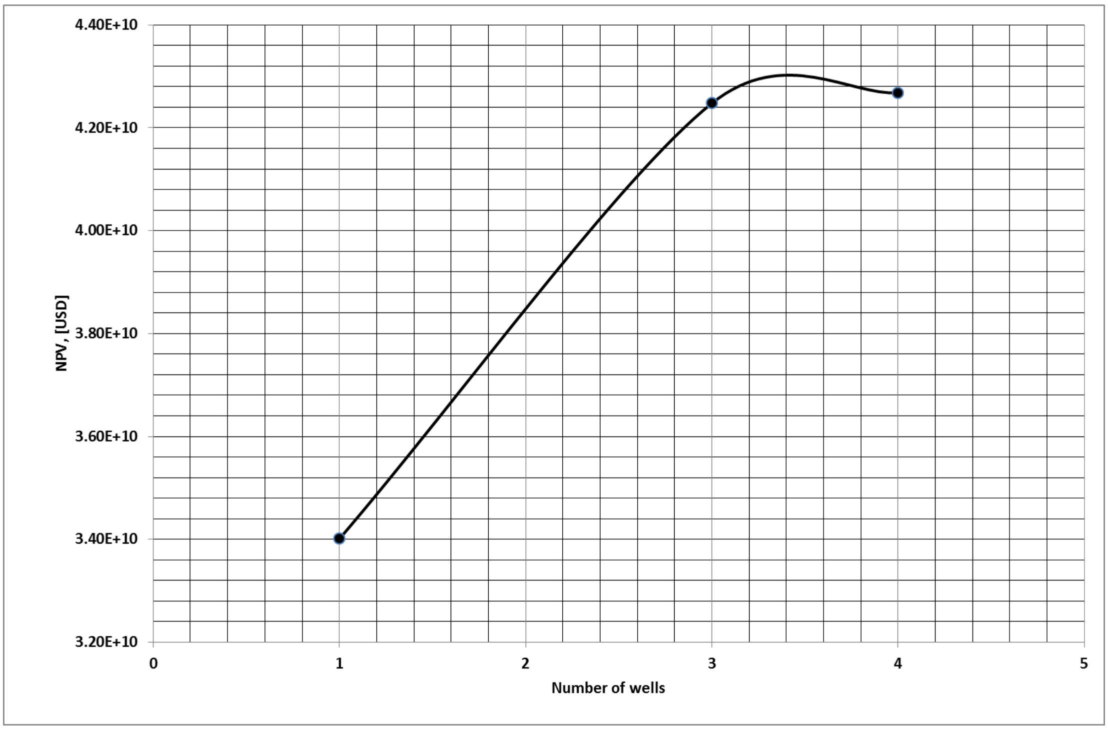


Figure 58: Relationship between number of wells and NPV when the reservoir is produced under pressure depletion (well placement)

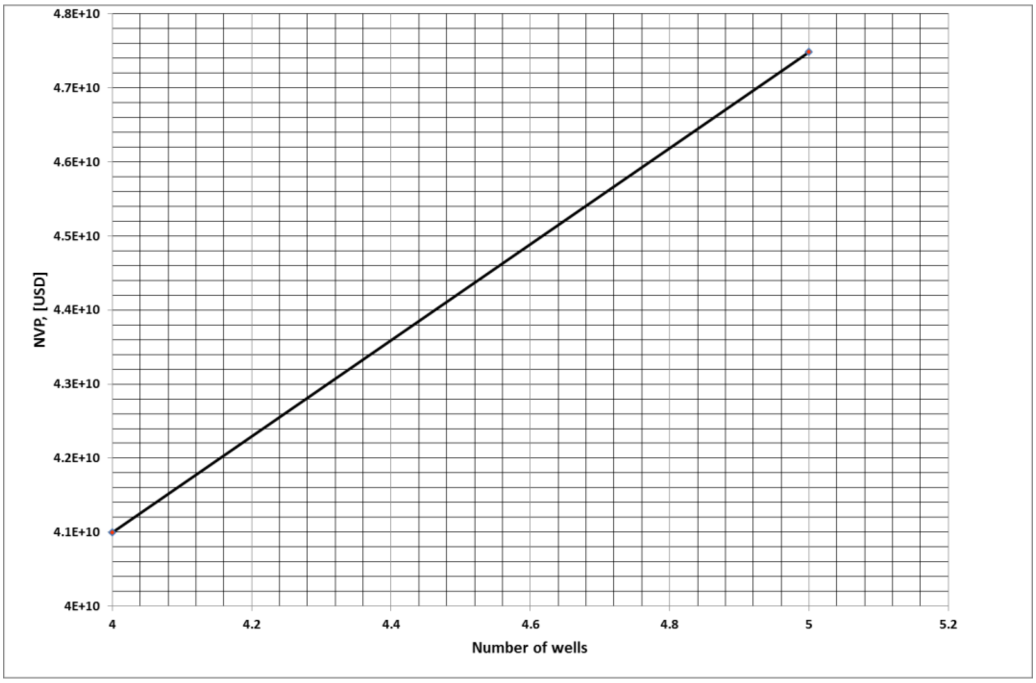


Figure 59: Relationship between number of wells and NPV when the reservoir is produced by pressure maintenance (fluid injection)

6 DISCUSSION AND SUMMARY

In this thesis report, eleven reservoir development plans were simulated based on infill well placement optimization, gas injection, water injection and simultaneous water and gas injection (SWAG).

In well placement optimization, three plans were simulated; Plan 1, Plan 2 and plan 3. The first plan used three production wells with one side-track, the second plan used three production wells with two side tracks and added perforations while the third plan used four production wells and one side-track. Simulation results from these plans showed significant increase in oil recovery compared to the base case. Plan 1 recovered 53% plan 2 54% and plan 3 recovered 56%, while base case recovered only 48.8% of the initial oil in place. Therefore well placement optimization recovered additional 7.2% of oil compared to the base case.

The reason for this increase in oil recovery is optimum well placement and perforation strategies by focusing on areas with high oil saturation and good drainage properties. This was achieved by locating wells on the Tarbert formation which contain about 80% of oil in Gullfaks field.

Continuous decline in oil production rates and reservoir pressure as presented in Figure 28 paved the way to simulate other plans which applied pressure maintenance techniques through gas and water injection to improve oil production. These plans based on water injection alone, gas injection alone and simultaneous water and gas injection (SWAG).

In water injection, two water injection schemes were analysed by changing injector well location. In the first scheme water was injected up-dip (plan 4). Three production wells were used as in plan 1 and plan 2. This plan recovered about 58% of oil as shown in Figure 30, which is 2% higher than the best performed well placement plan 3 and 9.2% above the base case. This improved oil production is a result of pressure maintenance induced by the injected water as shown in Figure 52. In addition to that, since water is viscous than oil, this resulted into low mobility ration which is favourable for improved sweep efficiency.

To optimize injector well location, sensitivity analysis was done by injecting water at the bottom (plan 5), to avoid relative permeability problems caused by residual oil. This resulted into oil recovery of about 59.2%, which is 10.4% higher than the bas case.

Injection fluid was changed by injecting gas up-dip instead of water (Plan 6). Since the reservoir was under saturated, the injected gas dissolve into the oil, lowered its density and viscosity. This made the oil lighter and moved faster towards production wells. This mechanism improved oil recovery factor to 60.2% as shown in Figure 37.

In gas injection, sensitivity analysis was performed by changing gas injector well location. This was achieved by locating gas injector down dip (plan 7) instead of up dip. Results from this simulation as presented in Figure 40 showed that injecting gas down dip recovered less oil than injecting up dip (plan 6).

To improve oil production in down dip gas injection, production well location was changed as presented in Figure 41 (plan 8). This improved oil recovery to 63%, which is 14.2% more than the base case.

After analysing the all single-fluid injection cases, simultaneous water and gas injection schemes were analysed based on gravity influence in fluid movement. Non-gravity assisted simultaneous water and gas (NGASWAG) injection was simulated by simultaneous up dip gas and down dip water injection (plan 9). As shown in Figure 42 and Figure 43, this plan recovered oil up to 66% which is 17.2% above the base case. This implies that combined effect of water and gas injection recovered extra 3% and 6% above gas injection alone and water injection alone respectively.

To study the effect of injection rate on NGASWAG injection performance, water and gas injection rates were reduced by 40% (plan 10). As displayed in Figure 47, reducing injection rates lowered oil recovery to 63% similar to what was recovered by down dip gas injection in plan 8.

Gravity assisted simultaneous water and gas injection (GASWAG) was simulated by injecting gas down dip and water up dip (plan 11). In this case, sweep efficiency was maximized due to the fact that the injected water controlled gas mobility and prevented gravity override that could happen if gas was injected alone. This plan resulted into oil recovery factor of about 68%, as shown in Figure 50 which is 19.2% higher than the base case.

Economic evaluation of the base case and the eleven new plans by using NPV revealed that, for a given set of oil price and well cost, all the new plans have positive NPV greater than that of base case as shown in Figure 53 to Figure 57.

For the case of well placement optimization, plan 2 and plan 3 have equal NPV values although simulation results indicated that plan 3 recovered more oil than plan 2. The reason for this is that plan 3 used four wells while plan 2 used three wells. The additional oil recovered in plan 3 was enough to cover the cost of drilling the added well.

Figure 57 shows that, at oil prices less than 50USD/bbl, producing the field by using 3 or 4 production wells without injection (plan 2 and plan 3) gave NPV value equal to that of up dip gas injection (plan 6) although plan 6 recovered extra 4.2% of oil above plan 3. At higher oil prices greater than 50USD/bbl, the trend changed whereby NPV from plan 6 became relatively greater than that of plan 3 and plan 2.

Among all the eleven new plans, down dip gas injection (plan 7) resulted into the lowest NPV while gravity assisted simultaneous water and gas injection (GASWAG plan 11) had the highest NPV as presented in Figure 57.

Furthermore, relationship between NPV and number of wells was analysed in natural pressure depletion and pressure maintenance reservoir development aspects. Results showed that, when the reservoir was produced by natural pressure depletion (no fluid injection), NPV increased with the increase in number of wells until a maximum number of wells (4 wells in this case) was reached where increasing number of wells resulted into decreased NPV as shown in Figure 58. This is because the added wells beyond the maximum limit could not produce enough oil to cover the cost of drilling them. On the other hand, when fluid injection was applied, maximum number of wells was increased to 5 as presented in Figure 59.

A summary of all the parameters applied in each plan and their performances in terms of oil recovery and incremental NPV is presented in *Table **2***.

Table 2: Summary of all the parameters applied in each plan and their performances in terms of oil production and incremental NPV.

	Parameters									
Plans	**Number of producers**	**Number of injectors**	**Production rate/ well [Sm^3/day]**	**Water Injection rate [Sm^3/day]**	**Gas Injection rate [Sm^3/day]**	**Cum Oil Produced [Million Sm^3]**	**Recovery factor [%]**	**Additional recovery factor over base case [%]**	**NPV @ OIL PRICE = 120 UDS/BBL,[Billion USD]**	**Additional NPV over base case, [Billion USD]**
Base case	1	N/A	2500	N/A	N/A	4.2	48.8		28	
Plan 1: well placement	3	N/A	2500	N/A	N/A	4.5	53.2	4.4	33	5
Plan 2: well placement	3	N/A	2500 and 700	N/A	N/A	4.7	54.5	5.7	35	7
Plan 3: well placement	4	N/A	2500	N/A	N/A	4.8	56	7.2	35	7
Plan 4: Up dip water injection	3	1	2600 and 1500	4500000	N/A	5.0	58	9.2	34	6
Plan 5: Down dip water injection	3	1	2600 and 1500	4500000	N/A	5.1	59.2	10.4	35	7
Plan 6: Up dip water injection	3	1	2600 and 1500	N/A	2500000	5.2	60.2	11.4	36	8
Plan 7: Down dip gas injection	3	1	2600 and 1500	N/A	4500000	4.9	57	8.2	31	3
Plan 8: Down dip gas injection changed producer well location	3	1	2600 and 1500	N/A	2500000	5.4	63	14.2	38	10
Plan 9: NGASWAGI	3	2	2600 and 1500	4500000	2500000	5.7	66	17.2	39	11
Plan 10 : NGASWAGI reduced injection rate	3	2	2600 and 1500	2500000	1500000	5.4	63	14.2	38	10
Plan 11: GASWAGI	3	2	2600 and 1500	4500000	2500000	5.9	68	19.2	41	13

7 CONCLUSION AND RECOMMENDATION

7.1 Conclusion

Based on the reservoir simulation and economic analysis results obtained from this study, the following conclusion can be given about alternative reservoir development plans to be applied in Gulltop field:

For the case of well placement optimization, it is profitable to use plan 2 (with 3 wells) as the alternative plan to develop Gulltop field than plan 3 which used four wells and both plans resulted into the same additional NPV in all the analysed oil prices and well costs.

In single-fluid injection cases, down dip gas injection (plan 8) should be chosen over the other single fluid injection plans since it performed better in terms of oil recovery and incremental NPV than the other single-fluid injection plans. It recovered 14.2% additional oil higher than the base case.

Economical number of wells for well placement optimization is four while in fluid injection cases it increased to five wells.

Gravity assisted simultaneous water and gas injection (GASWAG-plan 11) is the best alternative plan for developing Gulltop reservoir since it had higher oil recovery factor (68%) with greater incremental NPV than all the other plans in all the oil prices and well costs analysed in this study.

7.2 Recommendations

From the results of this study, it is recommended that gravity assisted simultaneous water and gas injection (GASWAG) is the best alternative reservoir development plan for Gulltop field. This is due to the fact that this plan has the highest oil recovery and incremental NPV compared to other plans analysed in this work.

It is also recommended that, further studied on Enhanced Oil Recovery (EOR) methods such as polymer flooding, surfactant injection and alkaline injection should done to recover the remaining oil that could not be drained by the oil recovery techniques applied in this work.

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9 APPENDICES

Appendix 1-Eclipse100 Reservoir Simulator

Table 3: Eclipse 100 data file sections **(Schlumberger, 2015)**

Section Name	**Required/Optional**	**Description**
RUNSPEC	Required	This section is consisting of title, dimensions, switches, present phases and components.
GRID	Required	It gives specification of grid geometry and rock properties in each grid block.
EDIT	Optional	All the modifications on calculated pore volumes, grid block centre depths and transmissibility are defined in this section
PROPS	Required	Consists of all the tables of properties for reservoir rock and fluids as functions of fluid saturations, compositions and pressures
REGIONS	Optional	This section divides computational grids into regions for calculation of PVT properties, saturation properties, initial conditions and fluids in place .
SOLUTIONS	Required	This section is composed of specification reservoir initial conditions
SUMMARY	Optional	In this section, data to be written to the Summary file after each time-step are specified.
SCHEDULE	Required	States operations to be simulated including production and injection controls and constraints and the times at which output reports are required

Appendix 2- Data File for Plan 11- GASWAG Injection

```
WELSPECS
--NEW PRODUCTION WELL 1
 'GPW1'  'TEMPLATE'   35   26  1*      'OIL'  7* /
--UP DIP WATER INJECTOR
 'GPW2'   'TEMPLATE'   20   35  1*      'WAT'  7* /
 --NEW PRODUCTION WELL 2
 'GPW3'   'TEMPLATE'   19   24  1*      'OIL'  7* /
 --NEW PRODUCTION WELL 3
 'GPW4'   'TEMPLATE'   32   23  1*      'OIL'  7* /
 --DOWN DIP GAS INJECTOR
'GTV3'    'TEMPLATE'   21   19  1*      'GAS'  7* /
/
COMPDAT
      --NEW PRODUCTION WELL 1
  'GPW1'   32   26   22   22     'OPEN'  1*     46.706     0.216   3065.626  2*        'X'
3.636 /
  'GPW1'   31   26   20   20     'OPEN'  1*      3.049     0.216    200.830  2*        'X'     3.680
/
  'GPW1'   31   26   19   19     'OPEN'  1*     33.844     0.216   2275.645  2*        'X'
3.962 /
  'GPW1'   30   26   18   18     'OPEN'  1*      4.107     0.216    276.232  2*        'X'     3.968
/
  'GPW1'   30   26   17   17     'OPEN'  1*    105.684     0.216   7085.591  2*        'X'
3.921 /
  'GPW1'   30   26   16   16     'OPEN'  1*    249.932     0.216  16633.107  2*        'X'
3.819 /
  'GPW1'   29   26   16   16     'OPEN'  1*     74.739     0.216   4835.051  2*        'X'
3.457 /
  'GPW1'   29   26   15   15     'OPEN'  1*     78.656     0.216   5301.021  2*        'X'
3.996 /
  'GPW1'   29   26   14   14     'OPEN'  1*    127.894     0.216   8750.649  2*        'X'
4.221 /
  'GPW1'   29   26   13   13     'OPEN'  1*    133.252     0.216   9160.928  2*        'X'
4.296 /
  'GPW1'   28   26   13   13     'OPEN'  1*     13.318     0.216    903.322  2*        'X'     4.089
/
  'GPW1'   28   26   12   12     'OPEN'  1*     72.954     0.216   5012.785  2*        'X'
4.288 /
  'GPW1'   28   26   11   11     'OPEN'  1*    140.643     0.216   9697.563  2*        'X'
4.343 /
  'GPW1'   28   26   10   10     'OPEN'  1*     67.909     0.216   4712.327  2*        'X'
4.447 /
  'GPW1'   27   26    9    9    'OPEN'  1*     70.116     0.216   4801.709  2*        'X'     4.235
/
```

```
  'GPW1'   27   26    8    8     'OPEN'  1*    117.310     0.216   8064.661  2*        'X'     4.296
/
  'GPW1'   26   26    7    7     'OPEN'  1*     47.147     0.216   3193.053  2*       'X'     4.067
/
  'GPW1'   26   26    6    6     'OPEN'  1*     65.240     0.216   4399.398  2*       'X'     4.004
/
  'GPW1'   25   26    5    5     'OPEN'  1*     80.460     0.216   5330.012  2*       'X'     3.757
/
  'GPW1'   24   26    4    4     'OPEN'  1*     85.469     0.216   5658.836  2*       'X'     3.750
/
  'GPW1'   24   26    3    3     'OPEN'  1*     61.446     0.216   4095.163  2*       'X'     3.838
/
  'GPW1'   23   26    3    3     'OPEN'  1*     50.982     0.216   3430.224  2*       'X'     3.972
/
  'GPW1'   23   26    2    2     'OPEN'  1*     94.260     0.216   6371.080  2*       'X'     4.038
/
  'GPW1'   22   26    1    1     'OPEN'  1*     19.713     0.216   1331.603  2*       'X'     4.029
/
   -- SIDE TRACK 1 FROM GPW1 WELL
    'GPW1'   32   26   32   32     'OPEN'  1*   1*   0.216   3*   'X'   /
    'GPW1'   31   26   32   32     'OPEN'  1*   1*   0.216   3*   'X'   /
    'GPW1'   30   26   32   32     'OPEN'  1*   1*   0.216   3*   'X'   /
    'GPW1'   29   26   34   34     'OPEN'  1*   1*   0.216   3*   'X'   /
    'GPW1'   28   26   34   34      'OPEN'  1*   1*   0.216   3*   'X'   /
    'GPW1'   27   26   34   34     'OPEN'  1*   1*   0.216   3*   'X'   /
    'GPW1'   35   26   27   40        'OPEN'  1*   1*   0.216   3*   'Z'   /

  --UP DIP WATER INJECTOR WELL
   'GPW2'    20   35    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /
   'GPW2'    20   34    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /
   'GPW2'    20   33    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /
   'GPW2'    20   32    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /
   'GPW2'    20   31    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /
   'GPW2'    20   30    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        'y'
4.029 /
   'GPW2'    20   29    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /
   'GPW2'    20   28    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        1*
4.029 /

  --NEW PRODUCTION WELL 2
  'GPW3'     19   24    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        'X'
4.029 /
   'GPW3'    18   23    5    5     'OPEN'  1*    19.713     0.216   1331.603  2*        'X'
4.029 /
```

'GPW3' 17 22 5 5 'OPEN' 1* 19.713 0.216 1331.603 2* 'X'
4.029 /
'GPW3' 16 23 5 5 'OPEN' 1* 19.713 0.216 1331.603 2* 'X'
4.029 /
'GPW3' 15 22 5 5 'OPEN' 1* 19.713 0.216 1331.603 2* 'X'
4.029 /
'GPW3' 13 18 1 5 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /

--NEW PRODUCTION WELL 3
'GPW4' 32 22 24 24 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /

+
'GPW4' 31 22 22 22 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GPW4' 29 22 19 21 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GPW4' 23 22 11 14 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GPW4' 22 22 10 14 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GPW4' 21 21 9 9 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GPW4' 20 21 8 8 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GPW4' 19 20 6 7 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
--DOWN DIP GAS INJECTOR
'GTV3' 22 12 22 22 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GTV3' 22 11 29 29 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GTV3' 22 10 29 29 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GTV3' 22 9 30 30 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GTV3' 22 8 31 31 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GTV3' 22 7 32 32 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
'GTV3' 22 6 33 33 'OPEN' 1* 19.713 0.216 1331.603 2* 1*
4.029 /
/
DATES
1 'APR' 2008
/
WCONPROD
'GPW1' 'OPEN' 'THP' 2600. 1* 1* 4500 1* 1* 70 4 200000 /
'GPW3' 'OPEN' 'THP' 2600. 1* 1* 4500 1* 1* 70 4 200000 /

```
 'GPW4'  'OPEN'  'THP'   2600.   1*    1*  4500  1*     1*   70     4      200000  /
/
WCONINJE
 'GPW2'      'WAT'     'OPEN'     'RATE'     4500000     1*    350   /
 'GTV3'      'GAS'     'OPEN'     'RATE'     2500000     1*    350   /
/
DATES
 1 'JAN' 2009 /
 1 'JAN' 2010 /
 1 'JAN' 2011 /
 1 'JAN' 2012 /
 1 'JAN' 2013 /
 1 'JAN' 2014 /
 1 'JAN' 2015 /
 1 'JAN' 2016 /
/
WCONPROD
 'GPW1'  'OPEN'  'THP'   1500.  1*   1*  4500  1*     1*   70     4      200000  /
 'GPW3'  'OPEN'  'THP'   1500.   1*    1*  4500  1*     1*   70     4      200000  /
 'GPW4'  'OPEN'  'THP'   1500.   1*    1*  4500  1*     1*   70     4      200000  /
/
WCONINJE
 'GPW2'      'WAT'     'OPEN'     'RATE'     4500000     1*    350   /
 'GTV3'      'GAS'     'OPEN'     'RATE'     2500000     1*    350   /
/
GCONPROD
 'FIELD'  'ORAT'  9000  3* 'RATE'  /
/
DATES
 1 'JAN' 2017 /
 1 'JAN' 2018 /
 1 'JAN' 2019 /
 1 'JAN' 2020 /
 1 'JAN' 2021 /
 1 'JAN' 2022 /
 1 'JAN' 2023 /
 1 'JAN' 2024 /
 1 'JAN' 2025 /
  1 'JAN' 2026 /
  1 'JAN' 2027 /
  1 'JAN' 2028 /
  1 'JAN' 2029 /
  1 'JAN' 2030 /
  1 'JAN' 2031 /
  1 'JAN' 2032 /
  1 'JAN' 2033 /
  1 'JAN' 2034 /
  1 'JAN' 2035 /

 /
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Appendix 3: Net Present Values (NPV) for the Base Case and the New Plans at Different Oil Prices and Well Costs

Base Case: One horizontal reservoir section well

	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
Time	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [stb]	NPV [USD]							
2008	0	0.00E+00	-8.50E+07	-8.20E+07	-7.80E+07	-7.50E+07	-7.00E+07	-6.50E+07	-6.00E+07	-5.50E+07
2009	1	5.46E+06	6.48E+08	5.25E+08	4.28E+08	3.29E+08	2.33E+08	1.88E+08	1.42E+08	9.67E+07
2010	2	1.09E+07	2.00E+09	1.65E+09	1.36E+09	1.08E+09	7.94E+08	6.55E+08	5.16E+08	3.77E+08
2011	3	1.63E+07	3.88E+09	3.20E+09	2.66E+09	2.11E+09	1.57E+09	1.30E+09	1.03E+09	7.66E+08
2012	4	2.08E+07	6.10E+09	5.04E+09	4.19E+09	3.34E+09	2.49E+09	2.07E+09	1.65E+09	1.22E+09
2013	5	2.20E+07	8.27E+09	6.83E+09	5.68E+09	4.53E+09	3.39E+09	2.81E+09	2.24E+09	1.67E+09
2014	6	2.29E+07	1.04E+10	8.56E+09	7.12E+09	5.69E+09	4.25E+09	3.54E+09	2.82E+09	2.11E+09
2015	7	2.45E+07	1.24E+10	1.03E+10	8.55E+09	6.83E+09	5.11E+09	4.25E+09	3.39E+09	2.53E+09
2016	8	2.55E+07	1.44E+10	1.19E+10	9.93E+09	7.93E+09	5.93E+09	4.94E+09	3.94E+09	2.95E+09
2017	9	2.57E+07	1.63E+10	1.35E+10	1.12E+10	8.96E+09	6.70E+09	5.58E+09	4.46E+09	3.33E+09
2018	10	2.58E+07	1.80E+10	1.49E+10	1.24E+10	9.91E+09	7.42E+09	6.18E+09	4.93E+09	3.69E+09
2019	11	2.59E+07	1.96E+10	1.62E+10	1.35E+10	1.08E+10	8.09E+09	6.73E+09	5.38E+09	4.02E+09
2020	12	2.59E+07	2.11E+10	1.75E+10	1.45E+10	1.16E+10	8.70E+09	7.25E+09	5.79E+09	4.33E+09
2021	13	2.60E+07	2.25E+10	1.86E+10	1.55E+10	1.24E+10	9.28E+09	7.73E+09	6.17E+09	4.62E+09
2022	14	2.60E+07	2.38E+10	1.97E+10	1.64E+10	1.31E+10	9.81E+09	8.17E+09	6.53E+09	4.89E+09
2023	15	2.61E+07	2.50E+10	2.07E+10	1.72E+10	1.38E+10	1.03E+10	8.58E+09	6.86E+09	5.13E+09
2024	16	2.61E+07	2.61E+10	2.16E+10	1.80E+10	1.44E+10	1.08E+10	8.96E+09	7.16E+09	5.36E+09
2025	17	2.61E+07	2.71E+10	2.24E+10	1.87E+10	1.49E+10	1.12E+10	9.31E+09	7.44E+09	5.57E+09
2026	18	2.62E+07	2.81E+10	2.32E+10	1.93E+10	1.55E+10	1.16E+10	9.64E+09	7.71E+09	5.77E+09
2027	19	2.62E+07	2.89E+10	2.39E+10	1.99E+10	1.59E+10	1.19E+10	9.94E+09	7.95E+09	5.95E+09
2028	20	2.62E+07	2.98E+10	2.46E+10	2.05E+10	1.64E+10	1.23E+10	1.02E+10	8.17E+09	6.12E+09
2029	21	2.62E+07	3.05E+10	2.52E+10	2.10E+10	1.68E+10	1.26E+10	1.05E+10	8.38E+09	6.28E+09
2030	22	2.62E+07	3.12E+10	2.58E+10	2.15E+10	1.72E+10	1.29E+10	1.07E+10	8.57E+09	6.42E+09
2031	23	2.62E+07	3.19E+10	2.64E+10	2.20E+10	1.76E+10	1.31E+10	1.10E+10	8.75E+09	6.55E+09
2032	24	2.63E+07	3.25E+10	2.69E+10	2.24E+10	1.79E+10	1.34E+10	1.12E+10	8.92E+09	6.68E+09
2033	25	2.63E+07	3.30E+10	2.73E+10	2.28E+10	1.82E+10	1.36E+10	1.13E+10	9.07E+09	6.79E+09
2034	26	2.63E+07	3.35E+10	2.77E+10	2.31E+10	1.85E+10	1.38E+10	1.15E+10	9.21E+09	6.90E+09
2035	27	2.63E+07	3.40E+10	2.81E+10	2.34E+10	1.87E+10	1.40E+10	1.17E+10	9.35E+09	7.00E+09
Net present value for the base case at each set of oil price and well cost (one production well)			3.40E+10	2.81E+10	2.34E+10	1.87E+10	1.40E+10	1.17E+10	9.35E+09	7.00E+09

Plan 1: Three production wells and one side-track

	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
Time	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-2.55E+08	-2.55E+08	-2.40E+08	-2.25E+08	-2.10E+08	-1.95E+08	-1.80E+08	-1.65E+08
2009	1	1.08E+07	1.20E+09	9.49E+08	7.63E+08	5.78E+08	3.92E+08	3.07E+08	2.21E+08	1.36E+08
2010	2	1.96E+07	3.64E+09	2.96E+09	2.44E+09	1.92E+09	1.40E+09	1.15E+09	8.93E+08	6.40E+08
2011	3	2.28E+07	6.25E+09	5.13E+09	4.25E+09	3.37E+09	2.48E+09	2.05E+09	1.62E+09	1.18E+09
2012	4	2.45E+07	8.86E+09	7.29E+09	6.05E+09	4.80E+09	3.56E+09	2.95E+09	2.33E+09	1.72E+09
2013	5	2.55E+07	1.14E+10	9.37E+09	7.78E+09	6.19E+09	4.60E+09	3.82E+09	3.03E+09	2.24E+09
2014	6	2.63E+07	1.38E+10	1.14E+10	9.44E+09	7.52E+09	5.60E+09	4.64E+09	3.69E+09	2.74E+09
2015	7	2.69E+07	1.60E+10	1.32E+10	1.10E+10	8.77E+09	6.54E+09	5.43E+09	4.32E+09	3.21E+09
2016	8	2.73E+07	1.82E+10	1.50E+10	1.25E+10	9.95E+09	7.42E+09	6.16E+09	4.91E+09	3.65E+09
2017	9	2.77E+07	2.02E+10	1.67E+10	1.39E+10	1.11E+10	8.25E+09	6.86E+09	5.46E+09	4.07E+09
2018	10	2.80E+07	2.21E+10	1.82E+10	1.52E+10	1.21E+10	9.03E+09	7.50E+09	5.98E+09	4.45E+09
2019	11	2.82E+07	2.38E+10	1.97E+10	1.64E+10	1.31E+10	9.75E+09	8.11E+09	6.46E+09	4.82E+09
2020	12	2.84E+07	2.55E+10	2.10E+10	1.75E+10	1.40E+10	1.04E+10	8.67E+09	6.91E+09	5.16E+09
2021	13	2.85E+07	2.70E+10	2.23E+10	1.85E+10	1.48E+10	1.11E+10	9.20E+09	7.33E+09	5.47E+09
2022	14	2.86E+07	2.84E+10	2.35E+10	1.95E+10	1.56E+10	1.16E+10	9.68E+09	7.72E+09	5.76E+09
2023	15	2.87E+07	2.97E+10	2.45E+10	2.04E+10	1.63E+10	1.22E+10	1.01E+10	8.08E+09	6.03E+09
2024	16	2.87E+07	3.09E+10	2.55E+10	2.13E+10	1.70E+10	1.27E+10	1.06E+10	8.42E+09	6.28E+09
2025	17	2.87E+07	3.20E+10	2.65E+10	2.20E+10	1.76E+10	1.32E+10	1.09E+10	8.73E+09	6.52E+09
2026	18	2.87E+07	3.31E+10	2.73E+10	2.27E+10	1.82E+10	1.36E+10	1.13E+10	9.01E+09	6.73E+09
2027	19	2.87E+07	3.40E+10	2.81E+10	2.34E+10	1.87E+10	1.40E+10	1.16E+10	9.28E+09	6.93E+09
2028	20	2.87E+07	3.49E+10	2.89E+10	2.40E+10	1.92E+10	1.43E+10	1.19E+10	9.53E+09	7.11E+09
2029	21	2.87E+07	3.58E+10	2.95E+10	2.46E+10	1.96E+10	1.47E+10	1.22E+10	9.75E+09	7.29E+09
2030	22	2.87E+07	3.65E+10	3.02E+10	2.51E+10	2.01E+10	1.50E+10	1.25E+10	9.97E+09	7.44E+09
2031	23	2.87E+07	3.72E+10	3.08E+10	2.56E+10	2.05E+10	1.53E+10	1.27E+10	1.02E+10	7.59E+09
2032	24	2.87E+07	3.79E+10	3.13E+10	2.61E+10	2.08E+10	1.56E+10	1.30E+10	1.03E+10	7.73E+09
2033	25	2.87E+07	3.85E+10	3.18E+10	2.65E+10	2.12E+10	1.58E+10	1.32E+10	1.05E+10	7.85E+09
2034	26	2.87E+07	3.91E+10	3.23E+10	2.69E+10	2.15E+10	1.61E+10	1.34E+10	1.07E+10	7.97E+09
2035	27	2.87E+07	3.96E+10	3.27E+10	2.72E+10	2.17E+10	1.63E+10	1.35E+10	1.08E+10	8.08E+09
Net present value for plan 1 at each set of oil price and well cost (3production wells with one side track)			**3.96E+10**	**3.27E+10**	**2.72E+10**	**2.17E+10**	**1.63E+10**	**1.35E+10**	**1.08E+10**	**8.08E+09**

Plan 2: Three production wells and side-tracks with added perforations

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Calender Year	Project Year	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-2.9E+07	-2.6E+07	-2.3E+07	-2.3E+07	-2.1E+07	-2.0E+07	-1.8E+07	-1.7E+07
2009	1	1.55E+07	2.0E+09	1.7E+09	1.4E+09	1.1E+09	8.4E+08	7.0E+08	5.6E+08	4.1E+08
2010	2	2.29E+07	4.9E+09	4.0E+09	3.4E+09	2.7E+09	2.0E+09	1.7E+09	1.3E+09	1.0E+09
2011	3	2.51E+07	7.8E+09	6.4E+09	5.4E+09	4.3E+09	3.2E+09	2.7E+09	2.1E+09	1.6E+09
2012	4	2.64E+07	1.1E+10	8.8E+09	7.3E+09	5.8E+09	4.4E+09	3.6E+09	2.9E+09	2.2E+09
2013	5	2.73E+07	1.3E+10	1.1E+10	9.2E+09	7.3E+09	5.5E+09	4.6E+09	3.7E+09	2.7E+09
2014	6	2.79E+07	1.6E+10	1.3E+10	1.1E+10	8.7E+09	6.5E+09	5.5E+09	4.4E+09	3.3E+09
2015	7	2.85E+07	1.8E+10	1.5E+10	1.3E+10	1.0E+10	7.5E+09	6.3E+09	5.0E+09	3.8E+09
2016	8	2.88E+07	2.1E+10	1.7E+10	1.4E+10	1.1E+10	8.5E+09	7.1E+09	5.6E+09	4.2E+09
2017	9	2.89E+07	2.3E+10	1.9E+10	1.6E+10	1.2E+10	9.3E+09	7.8E+09	6.2E+09	4.7E+09
2018	10	2.90E+07	2.5E+10	2.0E+10	1.7E+10	1.4E+10	1.0E+10	8.5E+09	6.8E+09	5.1E+09
2019	11	2.91E+07	2.6E+10	2.2E+10	1.8E+10	1.5E+10	1.1E+10	9.1E+09	7.3E+09	5.4E+09
2020	12	2.92E+07	2.8E+10	2.3E+10	1.9E+10	1.5E+10	1.2E+10	9.7E+09	7.7E+09	5.8E+09
2021	13	2.92E+07	3.0E+10	2.5E+10	2.0E+10	1.6E+10	1.2E+10	1.0E+10	8.2E+09	6.1E+09
2022	14	2.93E+07	3.1E+10	2.6E+10	2.1E+10	1.7E+10	1.3E+10	1.1E+10	8.6E+09	6.4E+09
2023	15	2.93E+07	3.2E+10	2.7E+10	2.2E+10	1.8E+10	1.3E+10	1.1E+10	8.9E+09	6.7E+09
2024	16	2.93E+07	3.4E+10	2.8E+10	2.3E+10	1.9E+10	1.4E+10	1.2E+10	9.3E+09	6.9E+09
2025	17	2.93E+07	3.5E+10	2.9E+10	2.4E+10	1.9E+10	1.4E+10	1.2E+10	9.6E+09	7.2E+09
2026	18	2.93E+07	3.6E+10	3.0E+10	2.5E+10	2.0E+10	1.5E+10	1.2E+10	9.9E+09	7.4E+09
2027	19	2.93E+07	3.7E+10	3.0E+10	2.5E+10	2.0E+10	1.5E+10	1.3E+10	1.0E+10	7.6E+09
2028	20	2.93E+07	3.8E+10	3.1E+10	2.6E+10	2.1E+10	1.6E+10	1.3E+10	1.0E+10	7.8E+09
2029	21	2.93E+07	3.9E+10	3.2E+10	2.7E+10	2.1E+10	1.6E+10	1.3E+10	1.1E+10	8.0E+09
2030	22	2.93E+07	3.9E+10	3.3E+10	2.7E+10	2.2E+10	1.6E+10	1.4E+10	1.1E+10	8.1E+09
2031	23	2.93E+07	4.0E+10	3.3E+10	2.8E+10	2.2E+10	1.7E+10	1.4E+10	1.1E+10	8.3E+09
2032	24	2.93E+07	4.1E+10	3.4E+10	2.8E+10	2.2E+10	1.7E+10	1.4E+10	1.1E+10	8.4E+09
2033	25	2.93E+07	4.1E+10	3.4E+10	2.9E+10	2.3E+10	1.7E+10	1.4E+10	1.1E+10	8.5E+09
2034	26	2.93E+07	4.2E+10	3.5E+10	2.9E+10	2.3E+10	1.7E+10	1.4E+10	1.2E+10	8.7E+09
2035	27	2.93E+07	4.2E+10	3.5E+10	2.9E+10	2.3E+10	1.8E+10	1.5E+10	1.2E+10	8.8E+09
Net present value for plan 2 at each set of oil price and well cost (3 production wells with 2 sidetracks + added perforations)			**4.2E+10**	**3.5E+10**	**2.9E+10**	**2.3E+10**	**1.8E+10**	**1.5E+10**	**1.2E+10**	**8.8E+09**

Plan 3: Four production wells and one side-track

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-3.40E+08	-3.3E+08	-3.1E+08	-3.0E+08	-2.80E+08	-2.60E+08	-2.40E+08	-2.20E+08
2009	1	1.59E+07	1.79E+09	1.4E+09	1.2E+09	8.8E+08	6.02E+08	4.75E+08	3.48E+08	2.21E+08
2010	2	2.28E+07	4.62E+09	3.8E+09	3.1E+09	2.4E+09	1.77E+09	1.45E+09	1.13E+09	8.06E+08
2011	3	2.51E+07	7.51E+09	6.2E+09	5.1E+09	4.0E+09	2.97E+09	2.45E+09	1.92E+09	1.40E+09
2012	4	2.64E+07	1.03E+10	8.5E+09	7.0E+09	5.6E+09	4.13E+09	3.41E+09	2.70E+09	1.98E+09
2013	5	2.72E+07	1.30E+10	1.1E+10	8.9E+09	7.1E+09	5.24E+09	4.34E+09	3.44E+09	2.54E+09
2014	6	2.78E+07	1.55E+10	1.3E+10	1.1E+10	8.5E+09	6.29E+09	5.22E+09	4.14E+09	3.07E+09
2015	7	2.83E+07	1.79E+10	1.5E+10	1.2E+10	9.8E+09	7.29E+09	6.04E+09	4.80E+09	3.56E+09
2016	8	2.87E+07	2.02E+10	1.7E+10	1.4E+10	1.1E+10	8.22E+09	6.82E+09	5.42E+09	4.03E+09
2017	9	2.90E+07	2.23E+10	1.8E+10	1.5E+10	1.2E+10	9.09E+09	7.55E+09	6.00E+09	4.46E+09
2018	10	2.93E+07	2.43E+10	2.0E+10	1.7E+10	1.3E+10	9.90E+09	8.22E+09	6.55E+09	4.87E+09
2019	11	2.95E+07	2.61E+10	2.2E+10	1.8E+10	1.4E+10	1.07E+10	8.86E+09	7.05E+09	5.25E+09
2020	12	2.97E+07	2.78E+10	2.3E+10	1.9E+10	1.5E+10	1.14E+10	9.45E+09	7.53E+09	5.60E+09
2021	13	2.99E+07	2.94E+10	2.4E+10	2.0E+10	1.6E+10	1.20E+10	1.00E+10	7.97E+09	5.93E+09
2022	14	3.00E+07	3.09E+10	2.6E+10	2.1E+10	1.7E+10	1.26E+10	1.05E+10	8.37E+09	6.24E+09
2023	15	3.01E+07	3.23E+10	2.7E+10	2.2E+10	1.8E+10	1.32E+10	1.10E+10	8.75E+09	6.53E+09
2024	16	3.02E+07	3.35E+10	2.8E+10	2.3E+10	1.8E+10	1.37E+10	1.14E+10	9.11E+09	6.79E+09
2025	17	3.02E+07	3.47E+10	2.9E+10	2.4E+10	1.9E+10	1.42E+10	1.18E+10	9.43E+09	7.04E+09
2026	18	3.02E+07	3.58E+10	3.0E+10	2.5E+10	2.0E+10	1.47E+10	1.22E+10	9.74E+09	7.26E+09
2027	19	3.02E+07	3.68E+10	3.0E+10	2.5E+10	2.0E+10	1.51E+10	1.26E+10	1.00E+10	7.47E+09
2028	20	3.02E+07	3.78E+10	3.1E+10	2.6E+10	2.1E+10	1.55E+10	1.29E+10	1.03E+10	7.67E+09
2029	21	3.02E+07	3.87E+10	3.2E+10	2.7E+10	2.1E+10	1.59E+10	1.32E+10	1.05E+10	7.85E+09
2030	22	3.02E+07	3.95E+10	3.3E+10	2.7E+10	2.2E+10	1.62E+10	1.35E+10	1.07E+10	8.01E+09
2031	23	3.02E+07	4.02E+10	3.3E+10	2.8E+10	2.2E+10	1.65E+10	1.37E+10	1.09E+10	8.17E+09
2032	24	3.02E+07	4.09E+10	3.4E+10	2.8E+10	2.2E+10	1.68E+10	1.40E+10	1.11E+10	8.31E+09
2033	25	3.02E+07	4.15E+10	3.4E+10	2.9E+10	2.3E+10	1.70E+10	1.42E+10	1.13E+10	8.44E+09
2034	26	3.02E+07	4.21E+10	3.5E+10	2.9E+10	2.3E+10	1.73E+10	1.44E+10	1.15E+10	8.57E+09
2035	27	3.02E+07	4.27E+10	3.5E+10	2.9E+10	2.3E+10	1.75E+10	1.46E+10	1.16E+10	8.68E+09
Net present value for plan 3 at each set of oil price and well cost (4 production wells with side track)			**4.27E+10**	**3.5E+10**	**2.9E+10**	**2.3E+10**	**1.75E+10**	**1.46E+10**	**1.16E+10**	**8.68E+09**

Plan 4: Up-dip water injection

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/wel	85	82	78	75	70	65	60	55
Calender Year	Project Year	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-3.40E+08	-3.28E+08	-3.12E+08	-3.00E+08	-2.80E+08	-2.60E+08	-2.40E+08	-2.20E+08
2009	1	1.46E+07	1.63E+09	1.30E+09	1.04E+09	7.85E+08	5.34E+08	4.18E+08	3.02E+08	1.87E+08
2010	2	1.97E+07	4.08E+09	3.33E+09	2.74E+09	2.14E+09	1.55E+09	1.26E+09	9.79E+08	6.94E+08
2011	3	2.25E+07	6.67E+09	5.47E+09	4.52E+09	3.56E+09	2.62E+09	2.16E+09	1.69E+09	1.23E+09
2012	4	2.42E+07	9.24E+09	7.60E+09	6.30E+09	4.99E+09	3.69E+09	3.04E+09	2.40E+09	1.76E+09
2013	5	2.54E+07	1.18E+10	9.68E+09	8.03E+09	6.37E+09	4.72E+09	3.91E+09	3.10E+09	2.28E+09
2014	6	2.64E+07	1.42E+10	1.17E+10	9.69E+09	7.70E+09	5.72E+09	4.74E+09	3.76E+09	2.78E+09
2015	7	2.72E+07	1.65E+10	1.36E+10	1.13E+10	8.97E+09	6.67E+09	5.53E+09	4.40E+09	3.26E+09
2016	8	2.77E+07	1.86E+10	1.54E+10	1.28E+10	1.02E+10	7.57E+09	6.28E+09	4.99E+09	3.71E+09
2017	9	2.82E+07	2.07E+10	1.71E+10	1.42E+10	1.13E+10	8.42E+09	6.99E+09	5.56E+09	4.13E+09
2018	10	2.86E+07	2.26E+10	1.87E+10	1.55E+10	1.24E+10	9.21E+09	7.65E+09	6.09E+09	4.53E+09
2019	11	2.89E+07	2.44E+10	2.01E+10	1.67E+10	1.33E+10	9.95E+09	8.27E+09	6.58E+09	4.90E+09
2020	12	2.92E+07	2.61E+10	2.15E+10	1.79E+10	1.43E+10	1.06E+10	8.85E+09	7.05E+09	5.24E+09
2021	13	2.94E+07	2.76E+10	2.28E+10	1.90E+10	1.51E+10	1.13E+10	9.39E+09	7.48E+09	5.57E+09
2022	14	2.96E+07	2.91E+10	2.40E+10	2.00E+10	1.59E+10	1.19E+10	9.89E+09	7.88E+09	5.87E+09
2023	15	2.98E+07	3.05E+10	2.52E+10	2.09E+10	1.67E+10	1.25E+10	1.04E+10	8.26E+09	6.15E+09
2024	16	3.00E+07	3.17E+10	2.62E+10	2.18E+10	1.74E+10	1.30E+10	1.08E+10	8.61E+09	6.42E+09
2025	17	3.01E+07	3.29E+10	2.72E+10	2.26E+10	1.80E+10	1.35E+10	1.12E+10	8.93E+09	6.66E+09
2026	18	3.03E+07	3.40E+10	2.81E+10	2.34E+10	1.87E+10	1.39E+10	1.16E+10	9.24E+09	6.89E+09
2027	19	3.04E+07	3.50E+10	2.89E+10	2.41E+10	1.92E+10	1.44E+10	1.19E+10	9.52E+09	7.10E+09
2028	20	3.05E+07	3.60E+10	2.97E+10	2.47E+10	1.97E+10	1.48E+10	1.23E+10	9.78E+09	7.30E+09
2029	21	3.07E+07	3.69E+10	3.05E+10	2.53E+10	2.02E+10	1.51E+10	1.26E+10	1.00E+10	7.48E+09
2030	22	3.08E+07	3.77E+10	3.11E+10	2.59E+10	2.07E+10	1.55E+10	1.29E+10	1.03E+10	7.65E+09
2031	23	3.09E+07	3.85E+10	3.18E+10	2.64E+10	2.11E+10	1.58E+10	1.31E+10	1.05E+10	7.81E+09
2032	24	3.10E+07	3.92E+10	3.24E+10	2.69E+10	2.15E+10	1.61E+10	1.34E+10	1.07E+10	7.95E+09
2033	25	3.11E+07	3.98E+10	3.29E+10	2.74E+10	2.19E+10	1.63E+10	1.36E+10	1.08E+10	8.09E+09
2034	26	3.12E+07	4.04E+10	3.34E+10	2.78E+10	2.22E+10	1.66E+10	1.38E+10	1.10E+10	8.22E+09
2035	27	3.12E+07	4.10E+10	3.39E+10	2.82E+10	2.25E+10	1.68E+10	1.40E+10	1.12E+10	8.33E+09
Net present value for plan 4 at each set of oil price and well cost(up dip water injection)			**4.10E+10**	**3.39E+10**	**2.82E+10**	**2.25E+10**	**1.68E+10**	**1.40E+10**	**1.12E+10**	**8.33E+09**

Plan 5: Down-dip water injection

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-3.40E+08	-3.28E+08	-3.12E+08	-3.00E+08	-2.80E+08	-2.60E+08	-2.40E+08	-2.20E+08
2009	1	1.45E+07	1.61E+09	1.29E+09	1.03E+09	7.76E+08	5.27E+08	4.12E+08	2.98E+08	1.83E+08
2010	2	2.07E+07	4.18E+09	3.41E+09	2.80E+09	2.19E+09	1.59E+09	1.30E+09	1.01E+09	7.15E+08
2011	3	2.33E+07	6.86E+09	5.63E+09	4.65E+09	3.67E+09	2.70E+09	2.22E+09	1.75E+09	1.27E+09
2012	4	2.49E+07	9.51E+09	7.83E+09	6.48E+09	5.14E+09	3.80E+09	3.14E+09	2.48E+09	1.82E+09
2013	5	2.62E+07	1.21E+10	9.97E+09	8.27E+09	6.56E+09	4.87E+09	4.03E+09	3.19E+09	2.35E+09
2014	6	2.71E+07	1.46E+10	1.20E+10	9.98E+09	7.93E+09	5.89E+09	4.88E+09	3.88E+09	2.87E+09
2015	7	2.78E+07	1.69E+10	1.40E+10	1.16E+10	9.23E+09	6.87E+09	5.70E+09	4.52E+09	3.35E+09
2016	8	2.84E+07	1.92E+10	1.58E+10	1.31E+10	1.05E+10	7.79E+09	6.46E+09	5.14E+09	3.81E+09
2017	9	2.89E+07	2.13E+10	1.75E+10	1.46E+10	1.16E+10	8.65E+09	7.19E+09	5.72E+09	4.25E+09
2018	10	2.93E+07	2.32E+10	1.92E+10	1.59E+10	1.27E+10	9.47E+09	7.86E+09	6.26E+09	4.65E+09
2019	11	2.97E+07	2.51E+10	2.07E+10	1.72E+10	1.37E+10	1.02E+10	8.50E+09	6.77E+09	5.04E+09
2020	12	3.00E+07	2.68E+10	2.21E+10	1.84E+10	1.47E+10	1.09E+10	9.10E+09	7.24E+09	5.39E+09
2021	13	3.03E+07	2.84E+10	2.35E+10	1.95E+10	1.56E+10	1.16E+10	9.65E+09	7.69E+09	5.73E+09
2022	14	3.05E+07	2.99E+10	2.47E+10	2.06E+10	1.64E+10	1.22E+10	1.02E+10	8.11E+09	6.04E+09
2023	15	3.08E+07	3.13E+10	2.59E+10	2.15E+10	1.72E+10	1.28E+10	1.07E+10	8.49E+09	6.33E+09
2024	16	3.10E+07	3.26E+10	2.70E+10	2.24E+10	1.79E+10	1.34E+10	1.11E+10	8.86E+09	6.60E+09
2025	17	3.12E+07	3.39E+10	2.80E+10	2.33E+10	1.86E+10	1.39E+10	1.15E+10	9.19E+09	6.86E+09
2026	18	3.14E+07	3.50E+10	2.89E+10	2.41E+10	1.92E+10	1.43E+10	1.19E+10	9.51E+09	7.09E+09
2027	19	3.15E+07	3.61E+10	2.98E+10	2.48E+10	1.98E+10	1.48E+10	1.23E+10	9.80E+09	7.31E+09
2028	20	3.18E+07	3.70E+10	3.06E+10	2.55E+10	2.03E+10	1.52E+10	1.26E+10	1.01E+10	7.52E+09
2029	21	3.19E+07	3.80E+10	3.14E+10	2.61E+10	2.08E+10	1.56E+10	1.29E+10	1.03E+10	7.71E+09
2030	22	3.19E+07	3.88E+10	3.21E+10	2.67E+10	2.13E+10	1.59E+10	1.32E+10	1.06E+10	7.88E+09
2031	23	3.19E+07	3.96E+10	3.27E+10	2.72E+10	2.17E+10	1.62E+10	1.35E+10	1.08E+10	8.04E+09
2032	24	3.19E+07	4.03E+10	3.33E+10	2.77E+10	2.21E+10	1.65E+10	1.38E+10	1.10E+10	8.19E+09
2033	25	3.19E+07	4.10E+10	3.39E+10	2.82E+10	2.25E+10	1.68E+10	1.40E+10	1.12E+10	8.33E+09
2034	26	3.19E+07	4.16E+10	3.44E+10	2.86E+10	2.29E+10	1.71E+10	1.42E+10	1.13E+10	8.46E+09
2035	27	3.19E+07	4.22E+10	3.49E+10	2.90E+10	2.32E+10	1.73E+10	1.44E+10	1.15E+10	8.58E+09
Net present value for plan 5 at each set of oil price and well cost (down dip water injection)			**4.22E+10**	**3.49E+10**	**2.90E+10**	**2.32E+10**	**1.73E+10**	**1.44E+10**	**1.15E+10**	**8.58E+09**

Plan 6: Up-dip gas injection

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0	-3.40E+08	-3.28E+08	-3.12E+08	-3.00E+08	-2.80E+08	-2.60E+08	-2.40E+08	-2.20E+08
2009	1	1.13E+07	1.18E+09	9.27E+08	7.34E+08	5.36E+08	3.47E+08	2.63E+08	1.78E+08	9.37E+07
2010	2	1.90E+07	3.53E+09	2.88E+09	2.36E+09	1.84E+09	1.32E+09	1.08E+09	8.28E+08	5.81E+08
2011	3	2.35E+07	6.24E+09	5.12E+09	4.22E+09	3.33E+09	2.44E+09	2.01E+09	1.57E+09	1.14E+09
2012	4	2.66E+07	9.07E+09	7.46E+09	6.18E+09	4.89E+09	3.61E+09	2.99E+09	2.36E+09	1.73E+09
2013	5	2.79E+07	1.18E+10	9.74E+09	8.08E+09	6.41E+09	4.75E+09	3.93E+09	3.12E+09	2.30E+09
2014	6	2.86E+07	1.44E+10	1.19E+10	9.88E+09	7.85E+09	5.84E+09	4.84E+09	3.84E+09	2.84E+09
2015	7	2.92E+07	1.69E+10	1.40E+10	1.16E+10	9.22E+09	6.86E+09	5.69E+09	4.52E+09	3.35E+09
2016	8	2.97E+07	1.92E+10	1.59E+10	1.32E+10	1.05E+10	7.82E+09	6.49E+09	5.16E+09	3.83E+09
2017	9	3.02E+07	2.14E+10	1.77E+10	1.47E+10	1.17E+10	8.73E+09	7.25E+09	5.77E+09	4.28E+09
2018	10	3.05E+07	2.35E+10	1.94E+10	1.61E+10	1.28E+10	9.58E+09	7.95E+09	6.33E+09	4.71E+09
2019	11	3.09E+07	2.54E+10	2.10E+10	1.74E+10	1.39E+10	1.04E+10	8.62E+09	6.86E+09	5.11E+09
2020	12	3.12E+07	2.72E+10	2.25E+10	1.87E+10	1.49E+10	1.11E+10	9.24E+09	7.36E+09	5.48E+09
2021	13	3.15E+07	2.89E+10	2.39E+10	1.98E+10	1.58E+10	1.18E+10	9.82E+09	7.82E+09	5.83E+09
2022	14	3.18E+07	3.04E+10	2.52E+10	2.09E+10	1.67E+10	1.25E+10	1.04E+10	8.25E+09	6.15E+09
2023	15	3.20E+07	3.19E+10	2.64E+10	2.19E+10	1.75E+10	1.31E+10	1.09E+10	8.66E+09	6.45E+09
2024	16	3.22E+07	3.33E+10	2.75E+10	2.29E+10	1.82E+10	1.36E+10	1.13E+10	9.03E+09	6.73E+09
2025	17	3.23E+07	3.45E+10	2.85E+10	2.37E+10	1.89E+10	1.42E+10	1.18E+10	9.38E+09	7.00E+09
2026	18	3.24E+07	3.57E+10	2.95E+10	2.46E+10	1.96E+10	1.46E+10	1.22E+10	9.71E+09	7.24E+09
2027	19	3.25E+07	3.68E+10	3.04E+10	2.53E+10	2.02E+10	1.51E+10	1.25E+10	1.00E+10	7.47E+09
2028	20	3.25E+07	3.78E+10	3.13E+10	2.60E+10	2.08E+10	1.55E+10	1.29E+10	1.03E+10	7.67E+09
2029	21	3.25E+07	3.88E+10	3.20E+10	2.66E+10	2.13E+10	1.59E+10	1.32E+10	1.05E+10	7.87E+09
2030	22	3.25E+07	3.96E+10	3.27E+10	2.72E+10	2.17E+10	1.63E+10	1.35E+10	1.08E+10	8.05E+09
2031	23	3.25E+07	4.04E+10	3.34E+10	2.78E+10	2.22E+10	1.66E+10	1.38E+10	1.10E+10	8.21E+09
2032	24	3.25E+07	4.12E+10	3.40E+10	2.83E+10	2.26E+10	1.69E+10	1.41E+10	1.12E+10	8.37E+09
2033	25	3.25E+07	4.19E+10	3.46E+10	2.88E+10	2.30E+10	1.72E+10	1.43E+10	1.14E+10	8.51E+09
2034	26	3.25E+07	4.25E+10	3.51E+10	2.92E+10	2.33E+10	1.74E+10	1.45E+10	1.16E+10	8.64E+09
2035	27	3.25E+07	4.31E+10	3.56E+10	2.96E+10	2.37E+10	1.77E+10	1.47E+10	1.17E+10	8.76E+09
Net present value for plan 6 at each set of oil price and well cost (up dip gas injection)			**4.31E+10**	**3.56E+10**	**2.96E+10**	**2.37E+10**	**1.77E+10**	**1.47E+10**	**1.17E+10**	**8.76E+09**

Plan 7: Down-dip gas injection

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0.00E+00	0.00E+00	-3.40E+08	-3.28E+08	-3.12E+08	-3.00E+08	-2.80E+08	-2.60E+08	-2.40E+08	-2.20E+08
2009	1.00E+00	1.42E+07	1.56E+09	1.25E+09	1.00E+09	7.50E+08	5.07E+08	3.96E+08	2.85E+08	1.74E+08
2010	2.00E+00	1.86E+07	3.88E+09	3.16E+09	2.60E+09	2.03E+09	1.47E+09	1.19E+09	9.23E+08	6.53E+08
2011	3.00E+00	2.11E+07	6.30E+09	5.17E+09	4.27E+09	3.37E+09	2.47E+09	2.03E+09	1.59E+09	1.15E+09
2012	4.00E+00	2.23E+07	8.68E+09	7.14E+09	5.91E+09	4.68E+09	3.45E+09	2.85E+09	2.25E+09	1.65E+09
2013	5.00E+00	2.34E+07	1.10E+10	9.05E+09	7.50E+09	5.95E+09	4.41E+09	3.65E+09	2.89E+09	2.12E+09
2014	6.00E+00	2.42E+07	1.32E+10	1.09E+10	9.03E+09	7.17E+09	5.32E+09	4.41E+09	3.50E+09	2.58E+09
2015	7.00E+00	2.49E+07	1.53E+10	1.26E+10	1.05E+10	8.34E+09	6.20E+09	5.14E+09	4.08E+09	3.02E+09
2016	8.00E+00	2.55E+07	1.73E+10	1.43E+10	1.19E+10	9.44E+09	7.02E+09	5.83E+09	4.63E+09	3.43E+09
2017	9.00E+00	2.60E+07	1.92E+10	1.58E+10	1.32E+10	1.05E+10	7.80E+09	6.48E+09	5.15E+09	3.82E+09
2018	1.00E+01	2.63E+07	2.10E+10	1.73E+10	1.44E+10	1.15E+10	8.53E+09	7.09E+09	5.64E+09	4.19E+09
2019	1.10E+01	2.67E+07	2.26E+10	1.87E+10	1.55E+10	1.24E+10	9.22E+09	7.66E+09	6.09E+09	4.53E+09
2020	1.20E+01	2.70E+07	2.42E+10	2.00E+10	1.66E+10	1.32E+10	9.86E+09	8.19E+09	6.52E+09	4.85E+09
2021	1.30E+01	2.73E+07	2.56E+10	2.12E+10	1.76E+10	1.40E+10	1.05E+10	8.69E+09	6.92E+09	5.15E+09
2022	1.40E+01	2.75E+07	2.70E+10	2.23E+10	1.85E+10	1.48E+10	1.10E+10	9.16E+09	7.30E+09	5.43E+09
2023	1.50E+01	2.76E+07	2.82E+10	2.33E+10	1.94E+10	1.55E+10	1.15E+10	9.60E+09	7.65E+09	5.69E+09
2024	1.60E+01	2.78E+07	2.94E+10	2.43E+10	2.02E+10	1.61E+10	1.20E+10	1.00E+10	7.97E+09	5.94E+09
2025	1.70E+01	2.80E+07	3.05E+10	2.52E+10	2.10E+10	1.67E+10	1.25E+10	1.04E+10	8.27E+09	6.17E+09
2026	1.80E+01	2.82E+07	3.15E+10	2.61E+10	2.17E+10	1.73E+10	1.29E+10	1.07E+10	8.56E+09	6.38E+09
2027	1.90E+01	2.83E+07	3.25E+10	2.68E+10	2.23E+10	1.78E+10	1.33E+10	1.11E+10	8.82E+09	6.57E+09
2028	2.00E+01	2.84E+07	3.34E+10	2.76E+10	2.29E+10	1.83E+10	1.37E+10	1.14E+10	9.06E+09	6.76E+09
2029	2.10E+01	2.86E+07	3.42E+10	2.83E+10	2.35E+10	1.88E+10	1.40E+10	1.17E+10	9.29E+09	6.93E+09
2030	2.20E+01	2.87E+07	3.50E+10	2.89E+10	2.40E+10	1.92E+10	1.43E+10	1.19E+10	9.50E+09	7.09E+09
2031	2.30E+01	2.88E+07	3.57E+10	2.95E+10	2.45E+10	1.96E+10	1.46E+10	1.22E+10	9.70E+09	7.23E+09
2032	2.40E+01	2.89E+07	3.63E+10	3.00E+10	2.50E+10	1.99E+10	1.49E+10	1.24E+10	9.88E+09	7.37E+09
2033	2.50E+01	2.90E+07	3.70E+10	3.05E+10	2.54E+10	2.03E+10	1.52E+10	1.26E+10	1.00E+10	7.50E+09
2034	2.60E+01	2.91E+07	3.75E+10	3.10E+10	2.58E+10	2.06E+10	1.54E+10	1.28E+10	1.02E+10	7.61E+09
2035	2.70E+01	2.91E+07	3.81E+10	3.14E+10	2.62E+10	2.09E+10	1.56E+10	1.30E+10	1.04E+10	7.72E+09
Net present value for plan 7 at each set of oil price and well cost (down dip gas injection)			**3.81E+10**	**3.14E+10**	**2.62E+10**	**2.09E+10**	**1.56E+10**	**1.30E+10**	**1.04E+10**	**7.72E+09**

Plan 8: Down-dip gas injection with changed production well location

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-3.40E+08	-3.28E+08	-3.12E+08	-3.00E+08	-2.80E+08	-2.60E+08	-2.40E+08	-2.20E+08
2009	1	1.37E+07	1.51E+09	1.20E+09	9.61E+08	7.18E+08	4.84E+08	3.76E+08	2.69E+08	1.62E+08
2010	2	2.24E+07	4.29E+09	3.50E+09	2.88E+09	2.25E+09	1.64E+09	1.34E+09	1.04E+09	7.38E+08
2011	3	2.53E+07	7.21E+09	5.92E+09	4.89E+09	3.86E+09	2.84E+09	2.34E+09	1.84E+09	1.34E+09
2012	4	2.76E+07	1.02E+10	8.35E+09	6.92E+09	5.49E+09	4.06E+09	3.36E+09	2.65E+09	1.95E+09
2013	5	2.89E+07	1.30E+10	1.07E+10	8.89E+09	7.06E+09	5.24E+09	4.34E+09	3.44E+09	2.54E+09
2014	6	2.95E+07	1.57E+10	1.29E+10	1.07E+10	8.55E+09	6.36E+09	5.27E+09	4.18E+09	3.10E+09
2015	7	3.02E+07	1.83E+10	1.51E+10	1.25E+10	9.96E+09	7.41E+09	6.15E+09	4.89E+09	3.63E+09
2016	8	3.07E+07	2.07E+10	1.71E+10	1.42E+10	1.13E+10	8.41E+09	6.98E+09	5.55E+09	4.13E+09
2017	9	3.13E+07	2.29E+10	1.89E+10	1.57E+10	1.25E+10	9.35E+09	7.77E+09	6.18E+09	4.60E+09
2018	10	3.17E+07	2.51E+10	2.07E+10	1.72E+10	1.37E+10	1.02E+10	8.50E+09	6.77E+09	5.04E+09
2019	11	3.20E+07	2.71E+10	2.23E+10	1.86E+10	1.48E+10	1.11E+10	9.19E+09	7.32E+09	5.45E+09
2020	12	3.23E+07	2.89E+10	2.39E+10	1.99E+10	1.58E+10	1.18E+10	9.83E+09	7.83E+09	5.83E+09
2021	13	3.26E+07	3.07E+10	2.53E+10	2.11E+10	1.68E+10	1.25E+10	1.04E+10	8.31E+09	6.19E+09
2022	14	3.29E+07	3.23E+10	2.67E+10	2.22E+10	1.77E+10	1.32E+10	1.10E+10	8.76E+09	6.53E+09
2023	15	3.30E+07	3.38E+10	2.79E+10	2.32E+10	1.85E+10	1.38E+10	1.15E+10	9.18E+09	6.84E+09
2024	16	3.32E+07	3.52E+10	2.91E+10	2.42E+10	1.93E+10	1.44E+10	1.20E+10	9.56E+09	7.13E+09
2025	17	3.34E+07	3.65E+10	3.02E+10	2.51E+10	2.00E+10	1.50E+10	1.24E+10	9.93E+09	7.40E+09
2026	18	3.35E+07	3.77E+10	3.12E+10	2.59E+10	2.07E+10	1.55E+10	1.29E+10	1.03E+10	7.66E+09
2027	19	3.36E+07	3.89E+10	3.21E+10	2.67E+10	2.13E+10	1.59E+10	1.33E+10	1.06E+10	7.89E+09
2028	20	3.37E+07	3.99E+10	3.30E+10	2.74E+10	2.19E+10	1.64E+10	1.36E+10	1.09E+10	8.11E+09
2029	21	3.38E+07	4.09E+10	3.38E+10	2.81E+10	2.24E+10	1.68E+10	1.40E+10	1.11E+10	8.31E+09
2030	22	3.38E+07	4.18E+10	3.45E+10	2.87E+10	2.29E+10	1.71E+10	1.43E+10	1.14E+10	8.49E+09
2031	23	3.39E+07	4.26E+10	3.52E+10	2.93E+10	2.34E+10	1.75E+10	1.46E+10	1.16E+10	8.67E+09
2032	24	3.39E+07	4.34E+10	3.59E+10	2.98E+10	2.38E+10	1.78E+10	1.48E+10	1.18E+10	8.83E+09
2033	25	3.39E+07	4.41E+10	3.65E+10	3.03E+10	2.42E+10	1.81E+10	1.51E+10	1.20E+10	8.98E+09
2034	26	3.39E+07	4.48E+10	3.70E+10	3.08E+10	2.46E+10	1.84E+10	1.53E+10	1.22E+10	9.11E+09
2035	27	3.39E+07	4.54E+10	3.75E+10	3.12E+10	2.49E+10	1.86E+10	1.55E+10	1.24E+10	9.24E+09
Net present value for plan 8 at each set of oil price and well cost (DOWN-DIP GAS INJECTION WITH CHANGED PRODUCTION WELL LOCATION)			**4.54E+10**	**3.75E+10**	**3.12E+10**	**2.49E+10**	**1.86E+10**	**1.55E+10**	**1.24E+10**	**9.24E+09**

Plan 9: Non-gravity assisted simultaneous water and gas injection (NGASWAG)

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-4.25E+08	-4.10E+08	-3.90E+08	-3.75E+08	-3.50E+08	-3.25E+08	-3.00E+08	-2.75E+08
2009	1	1.36E+07	1.40E+09	1.10E+09	8.67E+08	6.31E+08	4.04E+08	3.04E+08	2.03E+08	1.02E+08
2010	2	2.33E+07	4.29E+09	3.49E+09	2.86E+09	2.23E+09	1.60E+09	1.30E+09	1.00E+09	7.01E+08
2011	3	2.64E+07	7.33E+09	6.01E+09	4.96E+09	3.91E+09	2.86E+09	2.35E+09	1.84E+09	1.33E+09
2012	4	2.91E+07	1.04E+10	8.58E+09	7.10E+09	5.62E+09	4.15E+09	3.42E+09	2.70E+09	1.97E+09
2013	5	3.05E+07	1.34E+10	1.11E+10	9.18E+09	7.28E+09	5.39E+09	4.46E+09	3.53E+09	2.60E+09
2014	6	3.13E+07	1.63E+10	1.34E+10	1.12E+10	8.86E+09	6.58E+09	5.45E+09	4.32E+09	3.19E+09
2015	7	3.20E+07	1.90E+10	1.57E+10	1.30E+10	1.04E+10	7.70E+09	6.38E+09	5.06E+09	3.75E+09
2016	8	3.25E+07	2.16E+10	1.78E+10	1.48E+10	1.18E+10	8.75E+09	7.26E+09	5.77E+09	4.28E+09
2017	9	3.29E+07	2.40E+10	1.98E+10	1.64E+10	1.31E+10	9.74E+09	8.08E+09	6.43E+09	4.77E+09
2018	10	3.33E+07	2.62E+10	2.16E+10	1.80E+10	1.43E+10	1.07E+10	8.86E+09	7.04E+09	5.23E+09
2019	11	3.36E+07	2.83E+10	2.34E+10	1.94E+10	1.55E+10	1.15E+10	9.58E+09	7.62E+09	5.67E+09
2020	12	3.40E+07	3.02E+10	2.50E+10	2.08E+10	1.65E+10	1.23E+10	1.03E+10	8.16E+09	6.07E+09
2021	13	3.42E+07	3.21E+10	2.65E+10	2.20E+10	1.76E+10	1.31E+10	1.09E+10	8.67E+09	6.45E+09
2022	14	3.44E+07	3.38E+10	2.79E+10	2.32E+10	1.85E+10	1.38E+10	1.15E+10	9.13E+09	6.80E+09
2023	15	3.46E+07	3.54E+10	2.92E+10	2.43E+10	1.94E+10	1.45E+10	1.20E+10	9.57E+09	7.13E+09
2024	16	3.47E+07	3.68E+10	3.04E+10	2.53E+10	2.02E+10	1.51E+10	1.25E+10	9.98E+09	7.43E+09
2025	17	3.49E+07	3.82E+10	3.15E+10	2.62E+10	2.09E+10	1.56E+10	1.30E+10	1.04E+10	7.71E+09
2026	18	3.50E+07	3.95E+10	3.26E+10	2.71E+10	2.16E+10	1.62E+10	1.34E+10	1.07E+10	7.98E+09
2027	19	3.51E+07	4.06E+10	3.36E+10	2.79E+10	2.23E+10	1.66E+10	1.38E+10	1.10E+10	8.22E+09
2028	20	3.52E+07	4.17E+10	3.45E+10	2.87E+10	2.29E+10	1.71E+10	1.42E+10	1.13E+10	8.45E+09
2029	21	3.53E+07	4.27E+10	3.53E+10	2.94E+10	2.34E+10	1.75E+10	1.46E+10	1.16E+10	8.66E+09
2030	22	3.54E+07	4.37E+10	3.61E+10	3.00E+10	2.40E+10	1.79E+10	1.49E+10	1.19E+10	8.85E+09
2031	23	3.55E+07	4.46E+10	3.68E+10	3.06E+10	2.44E+10	1.83E+10	1.52E+10	1.21E+10	9.03E+09
2032	24	3.55E+07	4.54E+10	3.75E+10	3.12E+10	2.49E+10	1.86E+10	1.55E+10	1.23E+10	9.20E+09
2033	25	3.56E+07	4.61E+10	3.81E+10	3.17E+10	2.53E+10	1.89E+10	1.57E+10	1.25E+10	9.36E+09
2034	26	3.57E+07	4.68E+10	3.87E+10	3.22E+10	2.57E+10	1.92E+10	1.60E+10	1.27E+10	9.50E+09
2035	27	3.57E+07	4.75E+10	3.92E+10	3.26E+10	2.61E+10	1.95E+10	1.62E+10	1.29E+10	9.64E+09
Net present value for plan 9 at each set of oil price and well cost (Simultaneous up-dip gas and down dip water injection)			**4.75E+10**	**3.92E+10**	**3.26E+10**	**2.61E+10**	**1.95E+10**	**1.62E+10**	**1.29E+10**	**9.64E+09**

Plan 10: NGASWAG injection with injection rates reduced by 40%

Time	Oil Price	[USD/bbl]	145	120	100	80	60	50	40	30
	Well cost	Million USD/well	85	82	78	75	70	65	60	55
Year	Year Counter	Cumulative oil production [STB]	NPV [USD]							
2008	0	0.00E+00	-4.25E+08	-4.10E+08	-3.90E+08	-3.75E+08	-3.50E+08	-3.25E+08	-3.00E+08	-2.75E+08
2009	1	1.57E+07	1.48E+09	1.17E+09	9.25E+08	6.77E+08	4.39E+08	3.33E+08	2.26E+08	1.20E+08
2010	2	2.34E+07	4.27E+09	3.48E+09	2.85E+09	2.22E+09	1.59E+09	1.30E+09	9.97E+08	6.97E+08
2011	3	2.66E+07	7.28E+09	5.97E+09	4.93E+09	3.88E+09	2.84E+09	2.33E+09	1.83E+09	1.32E+09
2012	4	2.81E+07	1.02E+10	8.41E+09	6.96E+09	5.51E+09	4.06E+09	3.35E+09	2.64E+09	1.93E+09
2013	5	2.90E+07	1.31E+10	1.08E+10	8.92E+09	7.07E+09	5.24E+09	4.33E+09	3.42E+09	2.52E+09
2014	6	2.97E+07	1.58E+10	1.31E+10	1.08E+10	8.60E+09	6.38E+09	5.28E+09	4.19E+09	3.09E+09
2015	7	3.02E+07	1.84E+10	1.52E+10	1.26E+10	1.00E+10	7.46E+09	6.18E+09	4.91E+09	3.63E+09
2016	8	3.07E+07	2.09E+10	1.72E+10	1.43E+10	1.14E+10	8.47E+09	7.03E+09	5.58E+09	4.14E+09
2017	9	3.11E+07	2.32E+10	1.91E+10	1.59E+10	1.26E+10	9.42E+09	7.82E+09	6.21E+09	4.61E+09
2018	10	3.15E+07	2.53E+10	2.09E+10	1.74E+10	1.38E+10	1.03E+10	8.55E+09	6.80E+09	5.05E+09
2019	11	3.18E+07	2.73E+10	2.25E+10	1.87E+10	1.49E+10	1.11E+10	9.24E+09	7.35E+09	5.46E+09
2020	12	3.20E+07	2.92E+10	2.41E+10	2.00E+10	1.60E+10	1.19E+10	9.88E+09	7.86E+09	5.85E+09
2021	13	3.23E+07	3.09E+10	2.55E+10	2.12E+10	1.69E+10	1.26E+10	1.05E+10	8.34E+09	6.21E+09
2022	14	3.25E+07	3.25E+10	2.69E+10	2.23E+10	1.78E+10	1.33E+10	1.10E+10	8.79E+09	6.54E+09
2023	15	3.26E+07	3.40E+10	2.81E+10	2.34E+10	1.86E+10	1.39E+10	1.16E+10	9.20E+09	6.85E+09
2024	16	3.28E+07	3.54E+10	2.92E+10	2.43E+10	1.94E+10	1.45E+10	1.20E+10	9.59E+09	7.14E+09
2025	17	3.29E+07	3.67E+10	3.03E+10	2.52E+10	2.01E+10	1.50E+10	1.25E+10	9.94E+09	7.41E+09
2026	18	3.31E+07	3.79E+10	3.13E+10	2.61E+10	2.08E+10	1.55E+10	1.29E+10	1.03E+10	7.66E+09
2027	19	3.32E+07	3.90E+10	3.23E+10	2.68E+10	2.14E+10	1.60E+10	1.33E+10	1.06E+10	7.89E+09
2028	20	3.33E+07	4.01E+10	3.31E+10	2.76E+10	2.20E+10	1.64E+10	1.36E+10	1.09E+10	8.11E+09
2029	21	3.34E+07	4.11E+10	3.39E+10	2.82E+10	2.25E+10	1.68E+10	1.40E+10	1.11E+10	8.31E+09
2030	22	3.35E+07	4.20E+10	3.47E+10	2.88E+10	2.30E+10	1.72E+10	1.43E+10	1.14E+10	8.49E+09
2031	23	3.36E+07	4.28E+10	3.54E+10	2.94E+10	2.35E+10	1.75E+10	1.46E+10	1.16E+10	8.67E+09
2032	24	3.37E+07	4.36E+10	3.60E+10	3.00E+10	2.39E+10	1.79E+10	1.48E+10	1.18E+10	8.83E+09
2033	25	3.38E+07	4.43E+10	3.66E+10	3.05E+10	2.43E+10	1.82E+10	1.51E+10	1.20E+10	8.98E+09
2034	26	3.39E+07	4.50E+10	3.72E+10	3.09E+10	2.47E+10	1.84E+10	1.53E+10	1.22E+10	9.12E+09
2035	27	3.39E+07	4.56E+10	3.77E+10	3.13E+10	2.50E+10	1.87E+10	1.55E+10	1.24E+10	9.25E+09
Net present value for plan 10 at each set of oil price and well cost (Simultaneous up-dip gas and down dip water injection with injection reduced by 40%)			**4.56E+10**	**3.77E+10**	**3.13E+10**	**2.50E+10**	**1.87E+10**	**1.55E+10**	**1.24E+10**	**9.25E+09**

Plan 11: Gravity assisted simultaneous water and gas injection (GASWAG)

Time	**Oil Price**	**[USD/bbl]**	**145**	**120**	**100**	**80**	**60**	**50**	**40**	**30**
	Well cost	**Million USD/well**	**85**	**82**	**78**	**75**	**70**	**65**	**60**	**55**
Year	**Year Counter**	**Cumulative oil production [STB]**	**NPV [USD]**							
2008	0	0.00E+00	-4.3E+08	-4.10E+08	-3.90E+08	-3.75E+08	-3.50E+08	-3.25E+08	-3.00E+08	-2.75E+08
2009	1	1.74E+07	1.9E+09	1.52E+09	1.22E+09	9.12E+08	6.16E+08	4.80E+08	3.44E+08	2.08E+08
2010	2	2.67E+07	5.2E+09	4.27E+09	3.51E+09	2.75E+09	1.99E+09	1.63E+09	1.26E+09	8.95E+08
2011	3	2.87E+07	8.5E+09	7.00E+09	5.79E+09	4.57E+09	3.36E+09	2.76E+09	2.17E+09	1.58E+09
2012	4	3.01E+07	1.2E+10	9.65E+09	8.00E+09	6.33E+09	4.68E+09	3.87E+09	3.05E+09	2.24E+09
2013	5	3.06E+07	1.5E+10	1.21E+10	1.01E+10	8.00E+09	5.93E+09	4.91E+09	3.89E+09	2.86E+09
2014	6	3.11E+07	1.8E+10	1.45E+10	1.20E+10	9.56E+09	7.10E+09	5.89E+09	4.67E+09	3.45E+09
2015	7	3.15E+07	2.0E+10	1.67E+10	1.39E+10	1.10E+10	8.20E+09	6.80E+09	5.40E+09	4.00E+09
2016	8	3.31E+07	2.3E+10	1.88E+10	1.57E+10	1.25E+10	9.28E+09	7.70E+09	6.12E+09	4.54E+09
2017	9	3.39E+07	2.5E+10	2.09E+10	1.73E+10	1.38E+10	1.03E+10	8.54E+09	6.80E+09	5.05E+09
2018	10	3.43E+07	2.8E+10	2.28E+10	1.89E+10	1.51E+10	1.12E+10	9.34E+09	7.43E+09	5.52E+09
2019	11	3.47E+07	3.0E+10	2.46E+10	2.04E+10	1.63E+10	1.21E+10	1.01E+10	8.03E+09	5.97E+09
2020	12	3.50E+07	3.2E+10	2.62E+10	2.18E+10	1.74E+10	1.30E+10	1.08E+10	8.58E+09	6.39E+09
2021	13	3.52E+07	3.4E+10	2.78E+10	2.31E+10	1.84E+10	1.37E+10	1.14E+10	9.10E+09	6.77E+09
2022	14	3.54E+07	3.5E+10	2.92E+10	2.43E+10	1.94E+10	1.45E+10	1.20E+10	9.58E+09	7.14E+09
2023	15	3.55E+07	3.7E+10	3.06E+10	2.54E+10	2.03E+10	1.51E+10	1.26E+10	1.00E+10	7.47E+09
2024	16	3.57E+07	3.9E+10	3.18E+10	2.65E+10	2.11E+10	1.58E+10	1.31E+10	1.04E+10	7.78E+09
2025	17	3.58E+07	4.0E+10	3.30E+10	2.74E+10	2.19E+10	1.63E+10	1.36E+10	1.08E+10	8.07E+09
2026	18	3.60E+07	4.1E+10	3.41E+10	2.83E+10	2.26E+10	1.69E+10	1.40E+10	1.12E+10	8.34E+09
2027	19	3.61E+07	4.2E+10	3.51E+10	2.92E+10	2.33E+10	1.74E+10	1.45E+10	1.15E+10	8.60E+09
2028	20	3.62E+07	4.4E+10	3.60E+10	3.00E+10	2.39E+10	1.79E+10	1.48E+10	1.18E+10	8.83E+09
2029	21	3.63E+07	4.5E+10	3.69E+10	3.07E+10	2.45E+10	1.83E+10	1.52E+10	1.21E+10	9.05E+09
2030	22	3.64E+07	4.6E+10	3.77E+10	3.13E+10	2.50E+10	1.87E+10	1.55E+10	1.24E+10	9.25E+09
2031	23	3.65E+07	4.6E+10	3.84E+10	3.20E+10	2.55E+10	1.91E+10	1.59E+10	1.26E+10	9.43E+09
2032	24	3.66E+07	4.7E+10	3.91E+10	3.25E+10	2.60E+10	1.94E+10	1.61E+10	1.29E+10	9.61E+09
2033	25	3.67E+07	4.8E+10	3.98E+10	3.31E+10	2.64E+10	1.97E+10	1.64E+10	1.31E+10	9.77E+09
2034	26	3.68E+07	4.9E+10	4.04E+10	3.36E+10	2.68E+10	2.00E+10	1.67E+10	1.33E+10	9.92E+09
2035	27	3.68E+07	5.0E+10	4.09E+10	3.40E+10	2.72E+10	2.03E+10	1.69E+10	1.35E+10	1.01E+10
Net present value for plan 11 at each set of oil price and well cost (Simultaneous up-dip water and down dip gas injection)			**5.0E+10**	**4.09E+10**	**3.40E+10**	**2.72E+10**	**2.03E+10**	**1.69E+10**	**1.35E+10**	**1.01E+10**