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Optimum Development of a Saturated Oil Field

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Abstract

This project investigated the potential optimal development strategy for a saturated reservoir, with a gas cap. It assessed the viability of three production methods—solution gas drive (primary depletion), water flooding and gas injection, using varying injector well numbers. This project also undertook sensitivity analysis in the field, concluding that the development of another appraisal well would vastly improve the accuracy of NPV calculation. Furthermore, this project ascertained an optimized recovery method, based on numerical production simulations and economic modelling, of initial solution gas drive recovery, until reservoir pressure equals the bubble point pressure, at which point three water flooding injectors should be employed, developed at six-month intervals to maximise production while limiting CAPEX and OPEX as much as possible.

Keywords

Enhanced Oil Recovery Carbon Dioxide Storage

1. Literature Review

1.1. Saturated Reservoirs

Saturated reservoirs are hydrocarbon reservoirs where oil at the top-most level of the oil column contains as much gas as can be dissolved at that temperature and pressure, and is in contact with an overlying gas cap [1]. At the point where the oil column is in contact with the gas cap (the gas-oil contact, GOC) bubble point pressure equals reservoir pressure, making this region of oil saturated [1]. The gas-oil ratio (GOR) is typically constant throughout a saturated reservoir, but due to density differences, the dissolved gas accumulates in a gas cap at the top of the reservoir [1].

1.2. Field Development Planning

A hydrocarbon development project is typically divided into several major phases: Exploration, Field Appraisal, Feasibility Study, Project Implementation, and Field Production phases. Different technical departments, each with specific aims, usually manage these phases (**Figure 1**). The prior aim of oilfield development is to maximise ultimate oil recovery and minimise both capital expenditure (CAPEX) and operating expenditure (OPEX) resulting in a maximum net present value (NPV) and estimated monetary value (EMV) of the field [2].

1.3. Pressure, Volume and Temperature Properties

The Pressure, Volume, and Temperature (PVT) properties of reservoir fluids are key components in major reservoir engineering calculations such as reserve estimations, inflow performance calculations, material balance calculations, new formation field development-potential evaluation, well test analysis, fluid flow in porous media, numerical reservoir simulations, design of production equipment, and planning future enhanced oil recovery projects. A clear understanding of PVT helps us to know what takes place in the reservoir and at the surface during production. Besides the bubble point pressure, there are three important parameters from flash calculations that relate surface volumes to reservoir volumes and thus help determine the amount of hydrocarbon in place—oil and gas formation volume factors B_o and B_g, respectively, and the solution GOR, R_s, (all functions of pressure)obtained either by experimental measurements or by predictive equations/models. Laboratory-based determination of these is expensive and time-consuming, and results are heavily dependent on the validity of the reservoir fluid sample. In the absence of laboratory PVT data, and for cost and time efficiency, fluid properties are predicted by empirical correlations or other modelling techniques [3].

B_o is the volume of oil that must be withdrawn from the reservoir to produce one barrel of stock-tank oil at a standard surface condition of 14.7 Psia. It is expressed as reservoir barrels per stock-tank barrel (bbl/STB).

$$\text{Oil in place}(\text{STB}) = \frac{V\varnothing(1-S_w)}{B_o}$$

B_g is the volume of gas in the reservoir that will produce one cubic foot at the surface under standard conditions. It is expressed as reservoir barrels per standard cubic foot (bbl/SCF).

$$\text{Gas in place}(\text{SCF}) = \frac{V\varnothing(1-S_w)}{B_g}$$

The solution GOR is the volume of gas at standard conditions that dissolves into one STB of oil under reservoir conditions. It is expressed as standard cubic feet per stock-tank barrel (SCF/STB).

$$\text{GOR} = \frac{V\varnothing(1-S_w)R_s}{B_o}$$

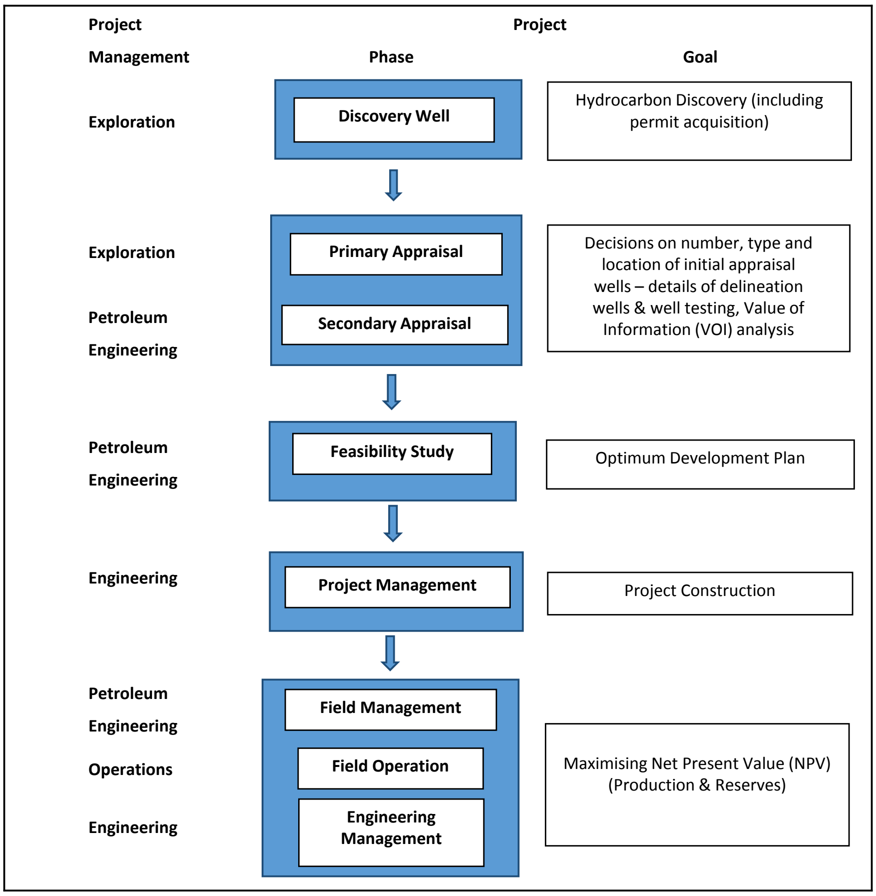


Figure 1. Systematic flow chart showing the sequence of a hydrocarbon project's life.

It is widely believed that flow in the reservoir is best simulated by differential liberation while flow up the well and through the separator is best simulated by a series of flash liberations called a flash separation. The formation volume accounts for the fact that oil below the bubble point liberates gas downhole resulting in less oil at the surface. The solution gas-oil ratio tells how much gas is dissolved in the reservoir oil (**Figure 2**).

1.4. Field Appraisal

Appraisal plays a critical role in the Field Development lifecycle. The main objective is to determine whether the discovery is technically and economically feasible [4], while the overall impact of appraisal is to improve project NPV [5]. Once exploration is successfully completed, an assessment of the potential discovery is conducted. Decisions on the initial appraisal programme (how many wells need to be drilled and where and what type of well testing will be made) are undertaken. The role of a field appraisal is to provide cost-effective data to use for subsequent decisions in the development phase [5].

During the field appraisal phase, more wells are drilled to collect information and samples from the reservoir, whilst additional seismic surveys might be conducted to further improve subsurface knowledge. These early decisions have the greatest financial impact on a project when obtaining the maximum value from an asset, "front end loading" [6].

Front-end loading plays an important role in achieving project cost, schedule, and performance targets [7], with appraisal costs guided by economic assessments relevant to field development [7].

This area of appraisal has three key functions: reduce the range of uncertainties in the recoverable hydrocarbon volumes; define of the reservoir size and configuration; and collect data for reservoir production performance predictions [6].

In order to access development options and potential asset value, four approaches are used [6]: 1) Analogue Field Data—taking assumptions from geographically local reservoirs with similar characteristics; 2) Decline Curve Analysis—empirical equations using a number of variables to fit numerous good behaviours, the most common being Arp's Equation (**Figure 3**):

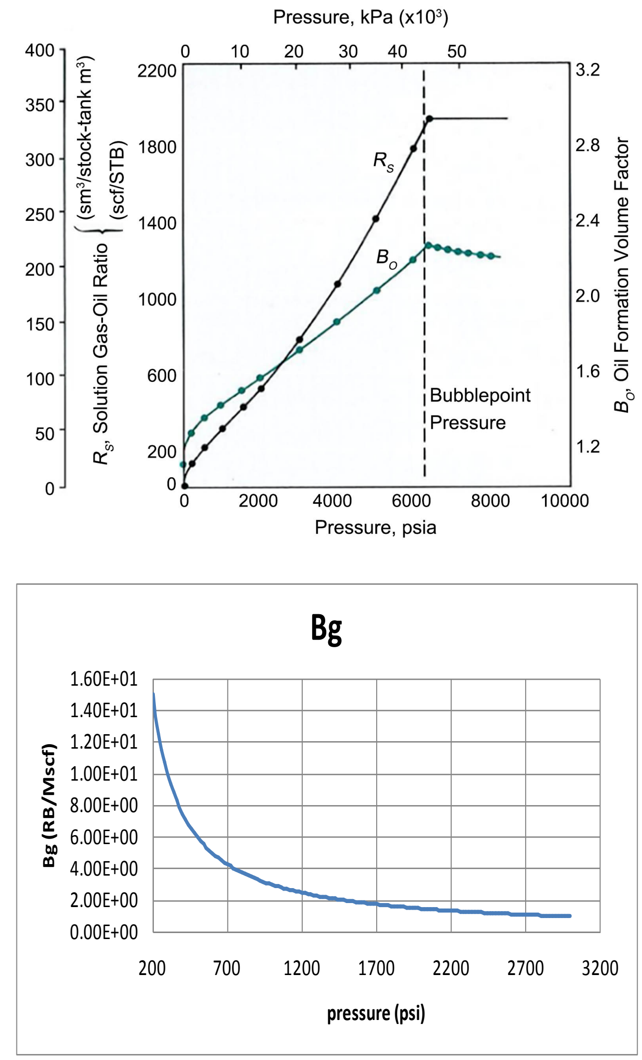


Figure 2. Graphs outlining the relationships between pressure and formation volume factor in a reservoir.

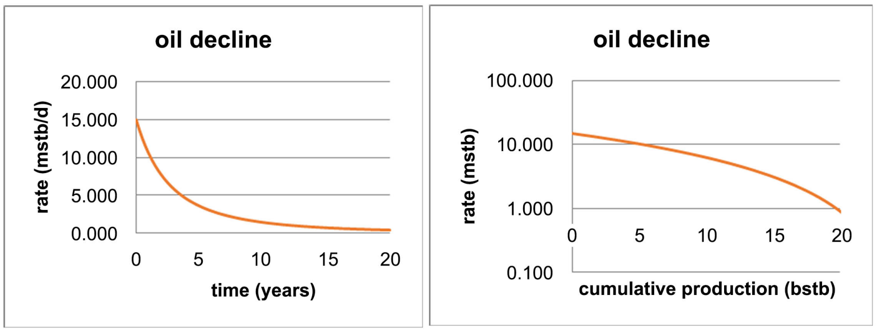


Figure 3. Graphs outlining the Arp's decline curves and their effects on oil production over time. From Wheaton (2016) [6].

$$q = q_o \frac{1}{(1+bD_o t)^{1/b}}$$

where q_o = initial production rate; D_o = early decline parameter; b = long term decline parameter or Arps decline curve exponent.

3) Analytical Methods—mathematical equations and models, such as material balance or Buckley-Leverett (for water flooding), are used to predict reservoir performance. The Buckley-Leverett and Welge Tangent Methods were developed to predict the performance of water flooding stratified reservoirs. This is done via obtaining the outlet and average saturations in each layer, then using this to obtain the fractional oil recovery and water cut of each layer [8], taking three assumptions—a homogenous reservoir, no mass-transfer between phases, and incompressible fluids (**Figure 4**) [8]:

$$(q_w \rho_w)_x - (q_w \rho_w)_{x+\Delta x} = A\phi (S_w \rho_w) \Delta x$$

mass of water entering − mass leaving = mass accumulation rate of water

where q_w = water flow rate; S_w = water saturation; x = distance along reservoir; ρ_w = water density; ϕ = porosity.

4) Simple numerical methods—after discovery and early appraisal, field development and field management can be conducted using numerical simulators such as CMG and Schlumberger Eclipse. These are used to develop complete field-life production profiles, depending on the parameters and properties included within. This project used Schlumberger Eclipse to run simulations for field development (**Figure 5**).

1.5. Development Planning

Data gathering is critical to obtain the right structure for developing oilfield(s), as the more data available, the lower the assumptions are, thus the more accurate models and analysis can be. This is done through sensitivity analysis followed by Value of Information (VOI), used to assess field profitability and limit the collection of superfluous [5]. Sensitivity analysis is the assessment of the impact on production from various characteristics, typically reservoir properties such as

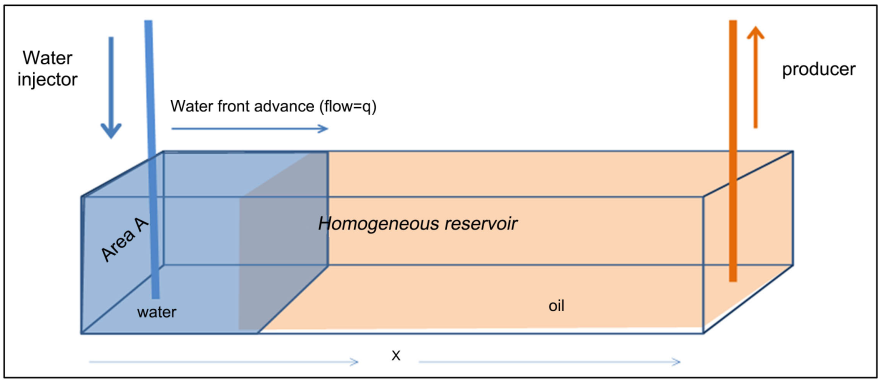


Figure 4. Systematic diagram of a reservoir and the relationships within the Buckley-Leverett analytical method. From Wheaton (2016) [6].

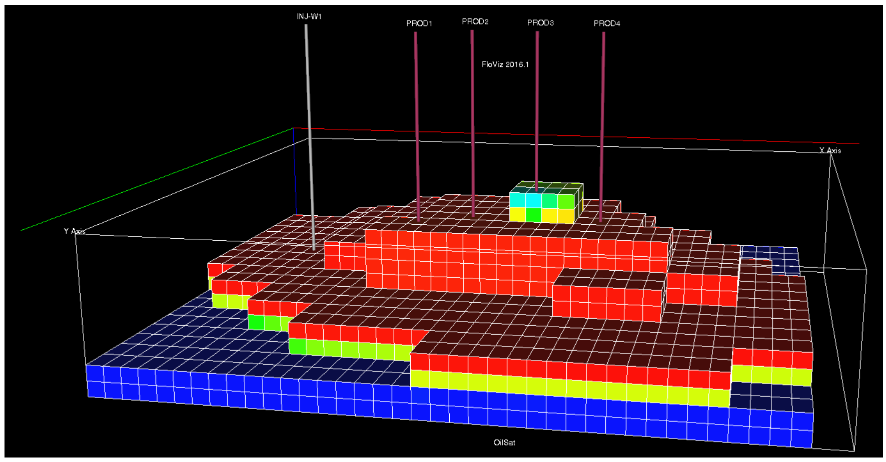


Figure 5. Image of this project's field, viewed in the FloViz imager, within Schlumberger Eclipse, used as an example of a numerical simulation model.

gross-rock volume and petrophysics. It takes worst-case (P90), best-case (P10), and most-likely (P50) scenarios for each characteristic and then compares the NPV they produce. VOI is then used to analyse if the variations in the assumptions taken in the different scenarios are significant enough to warrant sanctioning the drilling of another appraisal well. Once this has been done, and evaluation and analysis have been undertaken, all potential development options are considered [5].

1.6. Depletion and Gas Cap Importance

For saturated reservoirs, water flooding is often inefficient, as the gas cap can provide good drive, thus water injection energy is typically lost in compressing the gas [9]. This means that the full knowledge of the aquifer and the gas cap size is critical to maximise the field recovery, as these determine what fluid is injected [2]. The size of the aquifer and gas cap impact fluid displacement within the reservoir, with this dependants on: aquifer size/strength; initial gas cap size; availability, composition and cost of gas and gas reinjection; residual oil saturation; oil re-saturation losses; reservoir management; dynamic factors such as coning and cusping; and reservoir geometry and heterogeneity [2]. Gas cap affectivity peaks the closer to the producing well it is, reflecting the gas cap size and its ability to expand to maintain reservoir pressure, whereas aquifer effectiveness is improved the further from the producing well it is, due to its driving mechanism on oil and reservoir pressure maintenance[2].

1.7. Recovery Techniques

Different recovery techniques have different recovery factors (**Table 1**), but the economic viability of the most appropriate method for a field depends on a range of factors. These include cost of facilities, cost of the fluid to inject, recovery totals and production rates [5]. Within this project, water flooding and gas injection were selected as the two most viable techniques.

1.7.1. Primary Depletion

Primary depletion combines gas and oil expansion, solution gas, aquifer and gas cap drives to produce hydrocarbons from a saturated field without any enhancements (such as waterflooding) [6]. Primary depletion of a gas cap reservoir derives main production energy from gas cap expansion, and solution gas drive, with slow gas cap-aided reservoir pressure reductions resulting in higher production for longer [6].

1.7.2. Water Flooding

Water flooding is an often inefficient, but inexpensive secondary recovery technique in saturated reservoirs [10], where water displaces oil from the pore space and drives it towards the producing wells [11]. Oil recovery volumes vary depending on factors such as oil viscosity, petrophysics, and the natural reservoir drive mechanisms, as these all affect the water's ability to displace and drive the oil [10]. Timing of the flooding is key as the earlier it is begun, the minimised the primary depletion becomes, thus the limited the gas saturation increase is (as higher gas saturation decreases oil recovery) [11]. Well, location is critical to maximised water flooding, with three common arrays used—peripheral/edge drive, line drive and 5-spot (**Figure 6**) [11]. The tighter the well spacing, the better the recovery and total sweep efficiency (E_T, the effectiveness of the injected water to "sweep" oil into the producers), which is affected by both local-to-well (E_I) and field-wide, areal factors (E_A), predominantly reservoir rock properties [6]:

Table 1. Table outlining the main recovery techniques applicable to saturated reservoirs. From Wheaton (2016) [6].

Drive Mechanism	RF Range (%)	RF Average (%)
Gas Expansion Drive	65 - 95	80
Oil Expansion Drive	2 - 5	3
Solution Gas Drive	12 - 25	18
Gas Cap Drive	20 - 40	30
Aquifer Drive	20 - 40	30
Water Flood	40 - 60	50

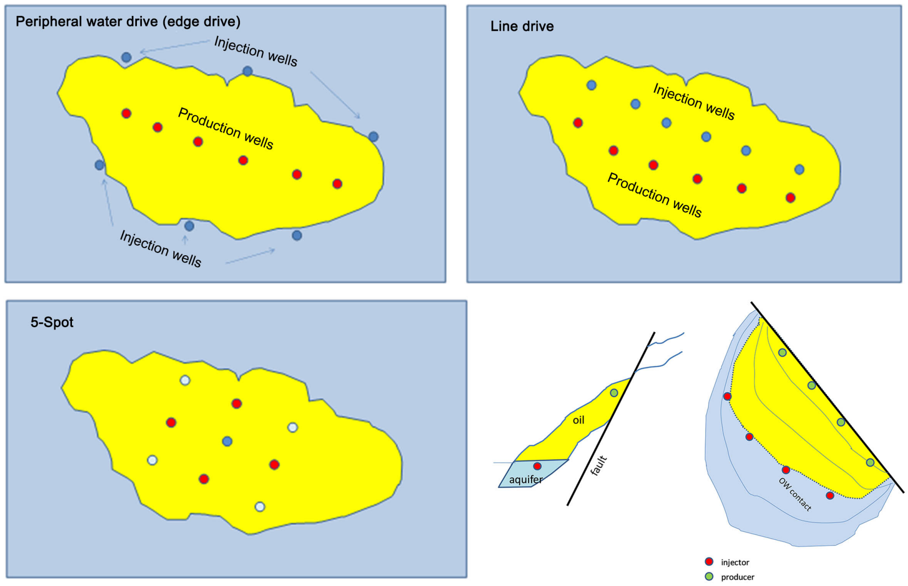


Figure 6. Systematic figures outlining the main water flood well arrays. From Wheaton (2016) [6].

$$E_T = E_A * E_L$$

The more favourable reservoirs for waterflooding are those that: are shallower (cheaper costs and often lower primary recovery); have a lower Bo (resulting in lower gas saturations and lower primary recovery); have higher permeability (to maximise water flow and utilise wider well spacing) [11].

1.7.3. Gas Injection

Like water flooding, gas injection is the dispersion of injected gas into the reservoir, either from the beginning, or when pressure begins to drop. Injection is typically done directly into the reservoir, to both increase pressure and decrease oil viscosity, but can also be done directly into the gas cap, to maintain gas cap drive mechanisms [6]. The issue with this is the added cost of an extra injector well being drilled directly into the gas cap, which adds both significant extra cost, and can lead to coning [6].

If economically viable, gas produced from a saturated field can be re-injected to aid oil production (re-cycling). However, this requires more surface facilities, such as separators and compressors, increasing costs, as well as the potential production impact from the initial gas production [6].

1.8. Economics Evaluation

The entire development of a field is dependent on the economic feasibility of any plan. All the aforementioned topics are driven by how economically viable they can become, which is reliant on various economic indicators and factors that must be considered, including: field life span; oil price; gas price; tax; government payments; discount rates; well costs; facilities costs; and pipeline costs. These are factored into two dominant values—net present value (NPV), the total monetary gain from the field; and estimated monetary value (EMV), the total profit made from a field, factoring in all the costs. These are then used to develop economic profiles of the field's life within differing scenarios, which are then ultimately compared and the most profitable chosen.

2. Appraisal Planning Optimisation

2.1. The Field

The field is a saturated reservoir at a reservoir-top depth of 6050 ft, extending through 250 ft of reservoir thickness (Figure 7). The field has a planned production life of 24 years, caused by rapidly declining production rates and lengthy cumulative production plateaus, due to the maximum delay in field abandonment as possible.

2.2. Primary Depletion and Sensitivity Analysis

2.2.1. Method

During drilling of any field, there is limited data available regarding the reservoir properties, consequently it is crucial to account for variations in the accuracy of the data to develop acceptable assumptions regarding the field's economic output. By identifying key reservoir properties, and analysing their impacts on primary production rates and totals using Schlumberger Eclipse, economic analysis can be carried out to ascertain the worst case (P90), most likely/base case (P50), and best case (P10) scenarios for the economics in terms of the field's primary recovery NPV (Table 2).

Within the saturated reservoir in this study, the location/size of the gas cap, via the location of the gas-oil contact (GOC), residual oil saturation (S_{or}), permeability and porosity were outlined as four critical properties that must be known for accurate economic analysis to be completed. This study varied a sole property at a time and ran oil production simulations to assess their impacts, after which economic analysis was run on each of the simulations (Table 3).

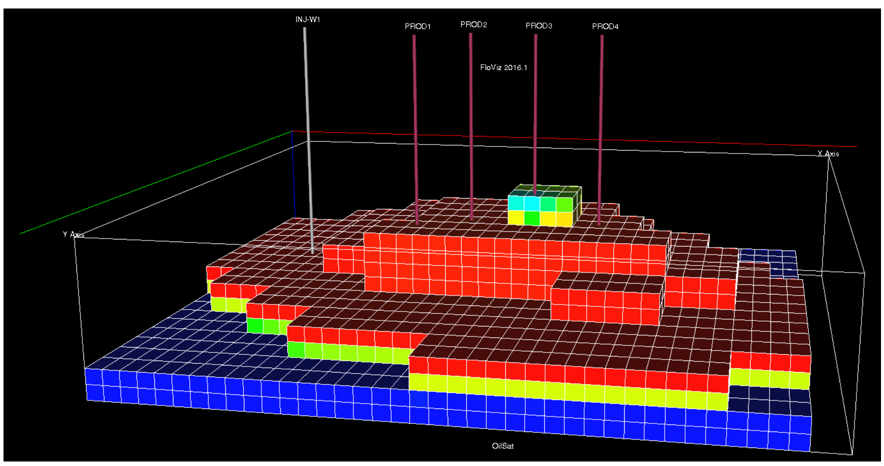


Figure 7. Image showing the numerically-simulated model of this project's field, created in Schlumberger Eclipse, viewed in FloViz.

Table 2. Table showing the key reservoir properties varied during the primary recovery production simulations and the values used within the simulations, representing the uncertainty associated with reservoir data.

Property	Worst Case (P90)	Base Case (P50)	Best Case (P10)
Gas Cap Thickness(ft)	75	50	25
S_{or} (%)	35	25	15
Porosity (%)	16	20	24
Permeability (kv/kh) (md)	5/50	10/100	15/150

Table 3. Table outlining the different properties varied in different cases and simulations run for primary depletion/sensitivity analysis.

	Gas Cap Thickness	Residual Oil Sat.	Porosity	Permeability
Case 1 (C1)	BASE CASE—P50 everything			
Case 2 (C2)	**P90**	P50	P50	P50
Case 3 (C3)	**P10**	P50	P50	P50
Case 4 (C4)	P50	**P90**	P50	P50
Case 5 (C5)	P50	**P10**	P50	P50
Case 6 (C6)	P50	P50	**P90**	P50
Case 7 (C7)	P50	P50	**P10**	P50
Case 8 (C8)	P50	P50	P50	**P90**
Case 9 (C9)	P50	P50	P50	**P10**

2.2.2. Results

The results show that varying reservoir porosity has the largest impact in production totals, with the P90 and P10 scenarios (porosity of 16% and 24%, respectively) resulted in recovery of 31753.79 × 10^3 STB and 47582.60 × 10^3 STB, respectively, a variation of approximately 15.8 million STB. In comparison, permeability fluctuations have relatively negligible effect on recovery totals, with the P90 and P10 scenarios (kv/kh of 5/50md and 15/150md, respectively) producing 39337.63 × 10^3 STB and 39694.52 × 10^3 STB, respectively, a variation of approximately 0.35 million STB (Table 4).

Both GOC location and S_{or} show one scenario veering significantly from the base case (P50) and one approximately tracking along it. The GOC P90 (gas cap of 125 ft) shows a significantly lower recovery than both the P50 (100 ft gas cap) and P10 (75 ft gas cap), whereas the residual oil saturation P10 (15%) recovery total is significantly higher than both the P50 (25%) and P90 (35%). These variations, from both the GOC and S_{or}, and the porosity, means that further investigation into the reservoir properties would be highly beneficial, providing the gathering of the data is economically viable (Figure 8).

2.2.3. Sensitivity Analysis

The sensitivity analysis ran on the primary depletion simulations, using P50, P90 and P10 variables, produced the NPV's for each scenario (Table 5). These values clearly show how different properties impact recoverable totals, and how they also impact NPV. Each property impacts the NPV to a different degree, with Figure 9 outlining to what extent, within this project. The figure compares the NPV of each scenario against the base case, most likely NPV outcome (P50), from this, analysis can be undertaken to assess the impact of each property on the field's potential value. This analysis took several assumptions regarding costs, outlined in Appendix 1.

Table 4. Table outlining the maximum reserves generated within the different production simulations carried out on a saturated reservoir.

MAXIMUM RESERVES (FOPT) (STB ×10^3)			
Property	**Worst Case (P90)**	**Base Case (P50)**	**Best Case (P10)**
Gas Cap Thickness	35151.90 (C2)	39679.35 (C1)	40160.37 (C3)
S_{or}	37630.99 (C4)		45818.24 (C5)
Porosity	31753.79 (C6)		47582.60 (C7)
Permeability	39337.63 (C8)		39694.52 (C9)

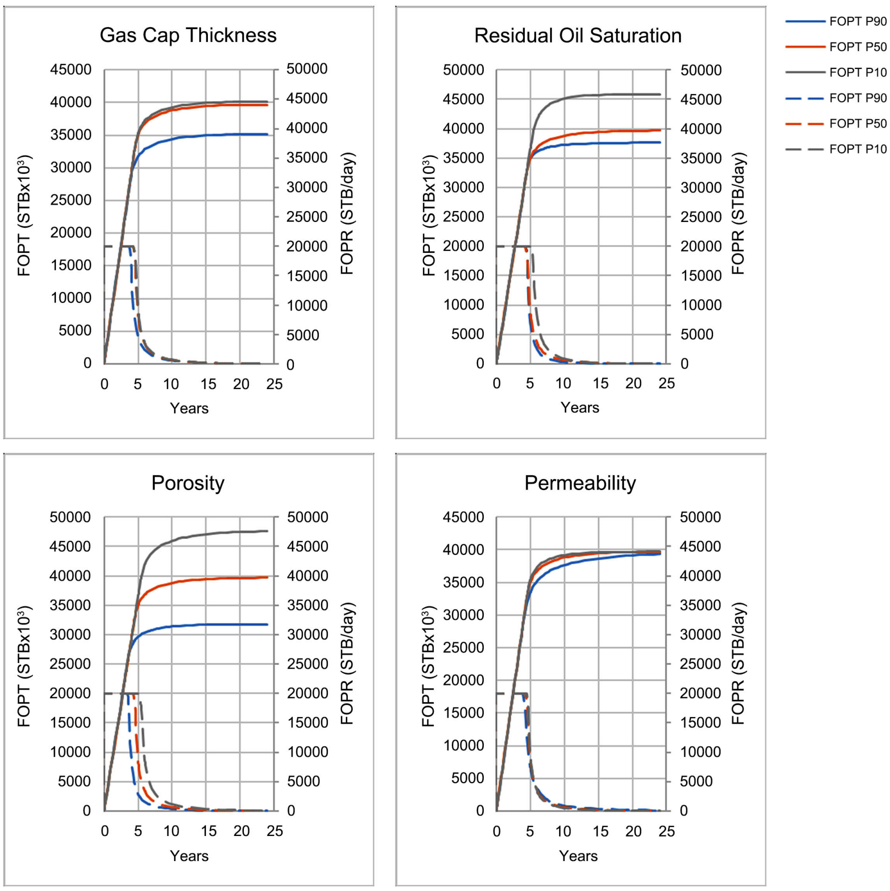


Figure 8. Graphs summarising the primary depletion production profiles (total and daily rate), for different reservoir properties. Note how the results vary significantly between most P90/P50/P10 scenarios, but not as much for permeability. See Table 4 for final FOPT values. See right for legend.

Table 5. Table summarising the sensitivity analysis undertaken on the saturated field. Shows clear variation in NPV totals caused by each variation of reservoir properties.

	Base Case P50 NPV ($mm):	1060.23
Property	**P90 NPV ($mm)**	**P10 NPV ($mm)**
Gas Cap Thickness	985.95	1069.46
Residual Oil Saturation	1024.00	1160.02
Porosity	911.18	1209.40
Permeability	1040.98	1074.49

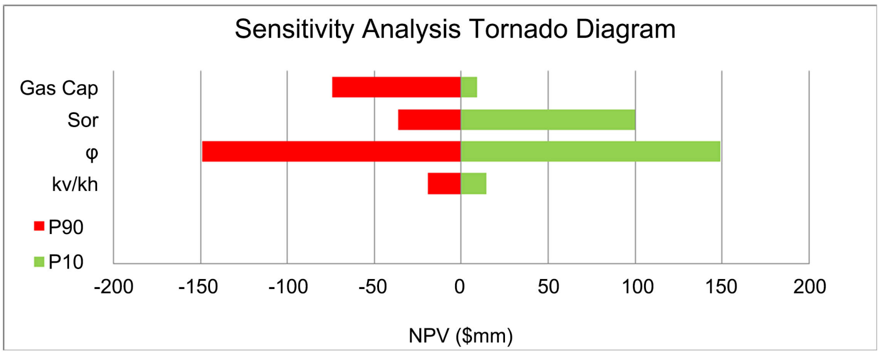


Figure 9. Tornado diagram outlining the sensitivity analysis of different reservoir properties and their comparative effects on base case NPV ($0 on the graph).

As the tornado diagram indicates, the NPV from each scenario reflects the production total variations outlined within the simulations. The gas cap thickness sees a $78.28 mm decrease in NPV for the P90, but only a $9.23 mm increase for the P10 upside, inferring that a gas cap greater than 50 ft thick can have a vast impact on total recovery, whereas a gas cap less than 50 ft has a smaller impact on NPV. On the other hand, this is reversed for residual oil saturation, where a P90, 35% S_{or} is only $36.23 mm below the baseline, compared to the P10, 15% S_{or}, which is $99.79 mm greater than the baseline NPV. Comparatively to both of these, porosity has the most extreme impacts on NPV, but with both P90 and P10 having approximately the same effect ($149.05 mm and $149.17 mm, respectively). Opposite to porosity is the impact permeability has on NPV, with both the P90 and P10 showing minimal variations in NPV, whilst both being approximately equal ($19.25 mm and $14.26 mm, respectively).

This analysis suggests that the need for further information to reduce these large variations in assumptions, and thus large variation in NPV, is generally required, though this is further investigated in the following VOI analysis.

2.2.4. Value of Information (VOI)

The VOI is used to carry out cost/benefit analysis on EMVs for potential further investment-scenarios, in this case, for another appraisal well (costing $10 mm) to gain full knowledge on a reservoir property. To do this, each reservoir property must be analysed for their EMV, and if a profit can be created through narrowing the assumptions of that property (*i.e.* if the cost of a new appraisal well is cheaper or costlier than the change in EMV caused by the P90/P10 variations in the property) (see Appendix 2).

As Table 6 shows, gas cap thickness, residual oil saturation and porosity all have monetary benefits to another appraisal well (VOI's of $11.88 mm, $24.01 mm and $64.56 mm, respectively). However, the minimal variations in permeability NPVs and EMVs in each sensitivity scenario is reflected in a VOI of −$1.62 mm, inferring that the knowledge, and thus monetary benefits gained from another appraisal well are outweighed by the cost of the well itself. Yet, as the other three properties would greatly benefit from another well, this project recommends the drilling of one in order to maximise monetary value and knowledge of the reservoir.

Table 6. Table summarising/showing the VOI calculations for each reservoir property.

Gas Cap	NPV ($mm)	EMV ($mm)	Benefit NPV ($mm)	Case Outline	Case NPV ($mm)
P10	1069.46	1059.46	9.23	6 wells	1068.69
P50	1060.23	1050.23	0	-	1050.23
P90	985.95	975.95	78.28	4 wells	1054.23
Mean EMV	1043.97	1033.97			1055.85
Cost ($mm)	10			**VOI ($mm)**	**11.88**
S_{or}	**NPV ($mm)**	**EMV($mm)**	**Benefit NPV ($mm)**	**Case Outline**	**Case NPV ($mm)**
P10	1160.02	1150.02	36.23	6 wells	1186.25
P50	1060.23	1050.23	0	-	1050.23
P90	1024.00	1014.00	99.79	4 wells	1113.79
Mean EMV	1076.12	1066.12			1100.13
Cost ($mm)	10			**VOI ($mm)**	**24.01**
Porosity	**NPV ($mm)**	**EMV($mm)**	**Benefit NPV ($mm)**	**Case Outline**	**Case NPV ($mm)**
P10	1209.40	1199.40	149.17	6 wells	1348.57
P50	1060.23	1050.23	0	-	1050.23
P90	911.18	901.18	149.05	4 wells	1050.23
Mean EMV	1060.26	1050.26			1124.82
Cost ($mm)	10			**VOI ($mm)**	**64.56**
Permeability	**NPV ($mm)**	**EMV($mm)**	**Benefit NPV ($mm)**	**Case Outline**	**Case NPV ($mm)**
P10	1074.49	1064.49	14.26	6 wells	1078.75
P50	1060.23	1050.23	0	-	1050.23
P90	1040.98	1030.98	19.25	4 wells	1050.23
Mean EMV	1058.98	1048.98			1057.36
Cost ($mm)	10			**VOI ($mm)**	**−1.62**

2.3. Water Flooding

2.3.1. Method

This project assessed the viability of water flood enhanced oil recovery through numerical simulations and economic modelling. Primary depletion, taken from the sensitivity analysis testing, was used as a benchmark, and was carried out alongside simulations with 1 - 4 injector wells. This project used a daily water injection rate of 24,000 bbl per injector. The fourth injector showed both limited production increases, and was limited by the number of producers available in the reservoir (also four), so a fifth injector was not investigated. An educated trial-and-error method was employed to identify optimum location of the injector wellsto maximise sweep efficiency, and thus to increase the final cumulative recovery value. When the maximum production total was identified, that well array was deemed the optimum arrangement for the relative well amount.

2.3.2. Results

As Table 7 and Figure 10 show, there is a clear increase in production due to the enhanced recovery from water injection, whilst water flooding also maintains higher production rates for longer.

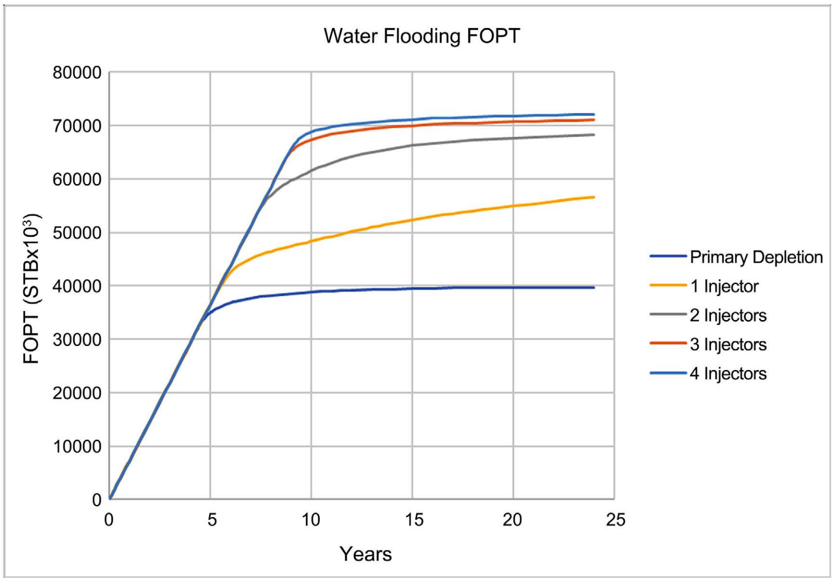
2.4. Gas Injection

2.4.1. Method

Gas injection into a saturated reservoir has one of two purposes, depending on the planning—injection into the gas cap to improve gas cap drive, and injection into the oil-producing zone to maintain reservoir pressure. This comparison is one of the many decisions involved in economic analysis. Like the waterflooding simulations, gas injection was conducted in an variety of injector numbers (1 - 4), all in a various array of wells, in attempts to maximise sweep efficiency, with the highest-producing array chosen for economic analysis. This simulation used a daily gas injection rate of 24,000 SCF per injector. The limit of four injectors was, again, caused by field limitations (four producing wells) and limited increases in production between three injectors and four. This gas injection investigation plotted the range of gas injectors against both primary depletion and waterflooding models, as well as one and two gas cap gas-injectors, with economic comparisons to be analysed in detail later in this project.

Table 7. Table summarising the production totals recovered from a range of simulations run with various numbers of water injection wells.

Production Scenario	Field Oil Production Total (FOPT) (STB $\times 10^3$)
Primary Depletion	39679.35
1 Injector	56599.98
2 Injectors	68220.32
3 Injectors	71009.20
4 Injectors	72061.34



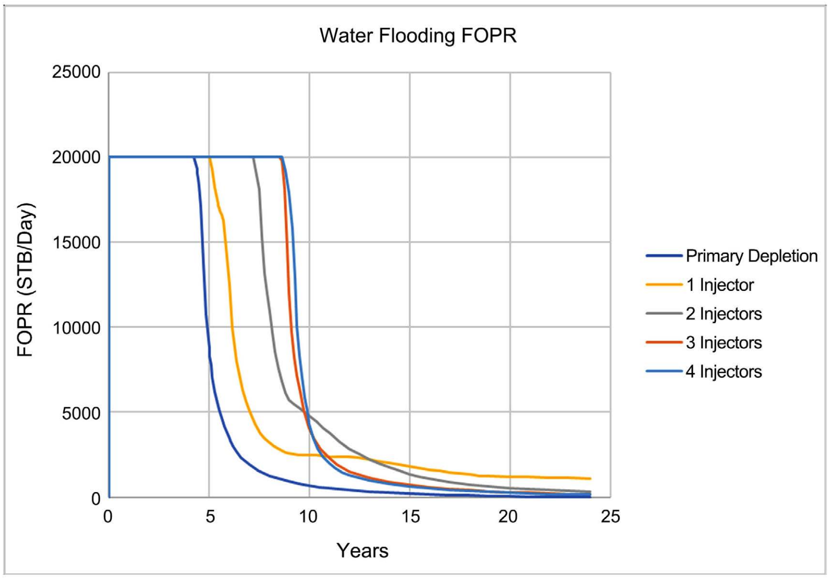
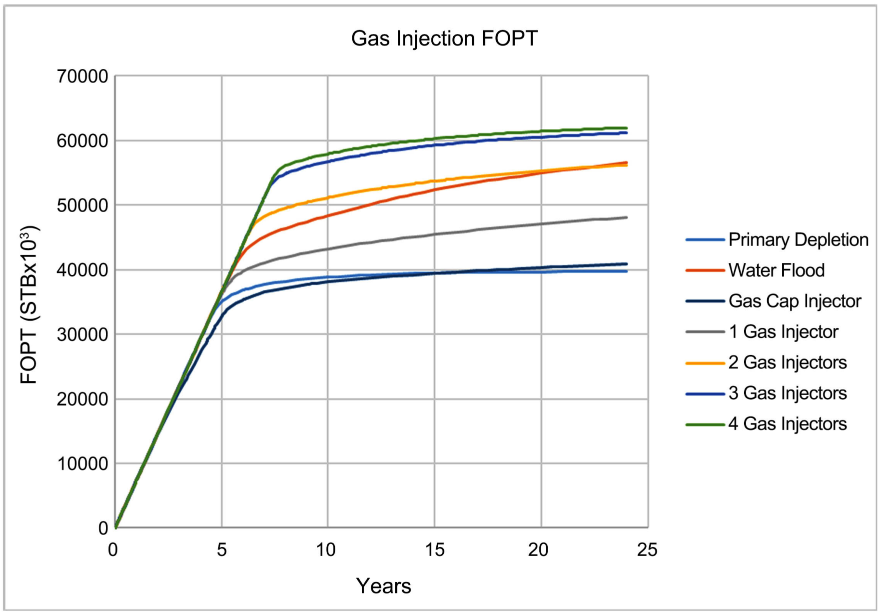


Figure 10. Graphs showing the cumulative production totals (top) and daily production rates (above) of different simulations run with a range of water injection wells, modelled in Schlumberger Eclipse. Graphs clearly shows how increasing the number of injector wells, thus injecting more water, improves production rates for longer, and improves production totals. However, note that a single injector, despite producing overall less oil, maintains a higher production rate than other methods.

2.4.2. Results

As Table 8 shows, gas cap injection into the field has a minimal improvement on recovery compared to primary depletion, suggesting that this is not a viable option due to the gas cap properties. However, gas injection directly into the oil phase does offer improved recovery techniques (Figure 11). These, like waterflooding, appear to plateau at 3 - 4 injectors. However, initial interpretations of the data highlights that two gas injector wells do not reach the total produced from a single water flood system.



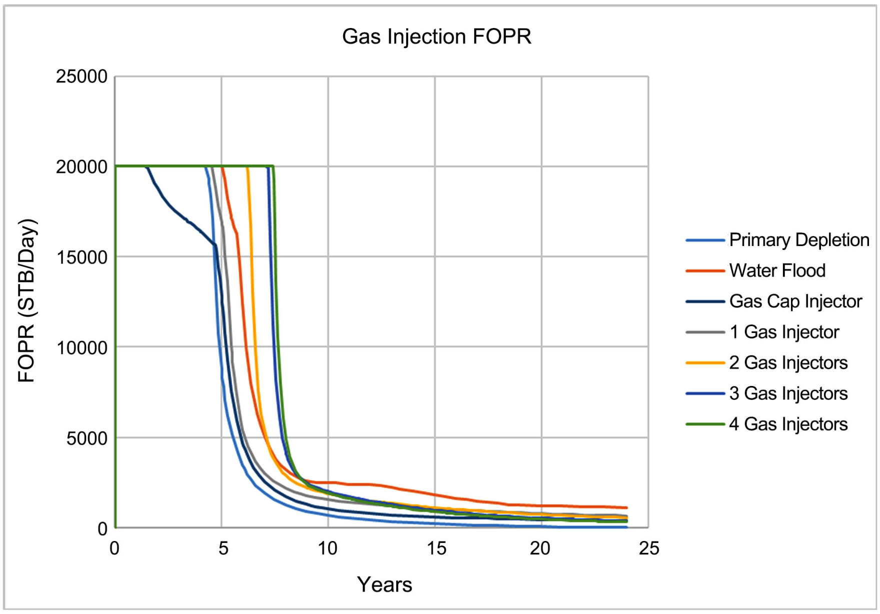


Figure 11. Graphs showing total production (top) and daily production rates (above) for various gas injector well numbers, compared to a singular water flood injector, and the primary depletion baseline, as simulated in Schlumberger Eclipse. The graphs clearly show how increasing numbers of injector wells increases production totals. Note how one water injector well has similar recovery to two gas injectors, and has overall more sustained higher production rates. Also note how the gas cap injector shows an early decrease in production rates, before reaching the typical decline level and continuing a normal path.

2.5. Economic Analysis

As Table 9 shows, water flooding produces significantly more oil than oil-phase-injected gas injection (approximately 10 mm STB per each new well), thus gas injection was not selected for full economic analysis.

Table 8. Table summarising the production totals through various gas injection scenarios, and comparative water flood and primary depletion simulation-developed production totals.

Production Scenario	Field Oil Production Total (FOPT) (STB $\times 10^3$)
Primary Depletion	39679.35
1 Water Flood Injector	56599.98
1 Gas Cap Injector	40900.39
2 Gas Cap Injectors	45277.99
1 Reservoir Injector	48087.67
2 Reservoir Injectors	56209.32
3 Reservoir Injectors	61143.37
4 Reservoir Injectors	61939.22

Table 9. Table summarising and comparing injector scenarios for water flooding and gas injection.

Production Scenario	Water Flood FOPT (STB $\times 10^3$)	Gas Injection FOPT (STB $\times 10^3$)
1 Injector	56599.98	48087.67
2 Injectors	68220.32	56209.32
3 Injectors	71009.20	61143.37
4 Injectors	72061.34	61939.22

This economic analysis of both primary depletion, through primary solution gas drive, and through secondary recovery waterflooding aimsto optimize and choose the best development strategy for a discovered saturated oil field based of the NPV and Profitability Index (PI).

"Waterflooding" and "Solution Gas Drive" spreadsheets (Appendixes 3-5) were used to model single well dynamics, assuming a broad range of variables, then the results were aggregated to obtain the full field production rates. The production rates were used in the economic indicator model to derive the NPV and PI for different cases of well timing and Plateau rates. To eliminate bias from this report, with water flooding known to be the most effective reservoir drive mechanism for most oil fields than solution gas drive, solution gas drive development options were optimized based on different well timing and field plateau rates to give sub-optimum economics. This made the results from the two-development options fairly and fully comparable.

2.5.1. Primary Recovery—Solution Gas Drive

Initial results showed that any plateau rate set at ±1000 STB/day from the minimum value would not allow enough production build-up time (seen within the 9000 STB/day plateau rate aggregation).In the spreadsheets used, the first variable tested was production rates, beginning at 6000 STB/day, therefore the minimum plateau rate was set at 9000 STB/day.

In solution gas drive, plateau rates of 9000 STB/day gave high NPV values of $499.33 mm, regardless of the well timing and the capped cumulative production rate became closer to the potential cumulative rate. Very high plateau rates, above 50,000 STB/day, resulted in very high facilities costs adding to the OPEX and resulting in low NPVs and PI.

However, the best well timing from this report was every 3 months (quarterly), this suggest that early investment in new wells means less expenditure on facilities in the long run. Delaying well development leads to increased costs due to inflation, reducing OPEX, but demanding an initially higher CAPEX than other options. Overall, the recovery factor of solution gas drive is 39.09% this is higher than the waterflooding at 28%. Solution gas drive is a better development option than waterflooding, as it gave a higher NPV of $499.44 mm compared to $291.22 mm. This was achieved at the optimal plateau rate of 9000 STB/day and well interval of 3 months for solution gas drive, while waterflooding was at 6 months and 9000 STB/day (**Figure 12**).

From the optimization of the saturated oil field, the best development option was based on the PI and not NPV as money is a limitation. PI of 1 is logically the lowest acceptable measure for the index, any lesser value renders the project useless and it's abandoned. Therefore, they would develop solution gas drive as it has the highest PI of 1.64 (**Table 10**).

Long well intervals are not desirable as yearly intervals gave the lowest NPV and productivity index regardless of the plateau rates and facilities cost. However, well interval of 12 months and plateau rate of 24,000 STB/day gave the worst NPV because of the cost of installing new wells increases due to inflation as time goes by, thereby adding to the facilities cost and having the same production rate causes a decline in the NPV. Therefore, cases of yearly well intervals were ignored. Since the discovery well flowed at 6000 STB/day and start the of plateau usually occurs 2 to 10 years after build up time, using plateau rate below 9000 STB/day is not considered as optimizing the well. As plateaus rate from all four producing wells would exceed 6000 STB/day. Hence, the minimum plateau rate was set at 9000 STB/day for each case. Early investment in new wells means less expenditure on facilities in the long run, give the best NPV value during development planning. As can be seen above, 3 months well interval gave the highest NPV and plateau rates of 9000 to 24,000 STB/day, making this the ideal optimal well timing and rate for the field.

2.5.2. Water Flooding

Solution Gas Drive is a better development option than waterflooding, as it gave a higher NPV of $499.44 mm compared to $291.22 mm (**Table 11**). Although the facilities cost for solution gas drive is 20% more expensive per STB/day of oil than waterflooding due to an extra cost of drilling 4 injector wells, an additional profit of $208.22 mm was made in the solution gas drive case.

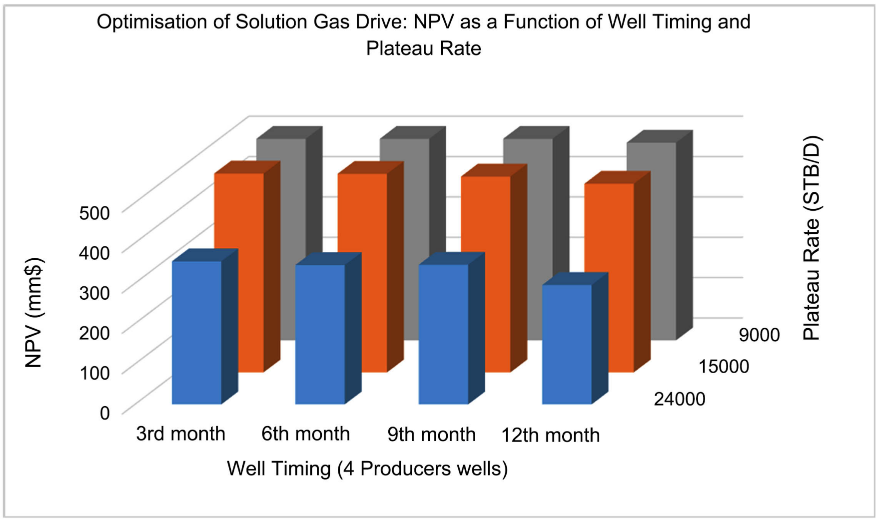


Figure 12. Graph outlining the impact of different plateau rates and different well development timings on overall NPV within solution gas driven primary recovery.

Table 10. Table outlining the different plateau rate and well development timings for primary recovery, aiming to maximise NPV and PI.

Well Interval (Time)	Plateau Rate (STB/day)	Facilities Cost ($mm)	NPV ($mm)	Profitability Index (PI) ($mm)
Best Case 3rd Month	**9000**	**300**	**499.44**	**1.64**
	15,000	500	492.56	1.02
	24,000	800	354.31	0.47
6th Month	9000	300	499.37	1.64
	15,000	500	491.84	1.02
	24,000	800	345.16	0.46
9th Month	9000	300	499.44	1.64
	15,000	500	485.13	1.01
	24,000	800	345.94	0.46
12th Month Worst Case	9000	300	489.74	1.61
	15,000	500	467.28	0.97
	24,000	**800**	**295.71**	**0.40**

During the optimization processes, the best plateau rate for solution gas drive case is 9000 STB/day and still lies in the well time of every 3 months as it gave the highest NPV. So, every 3 months, investments are made on 1 producer well and 1 injector well three times to give the total number of 8 drilled wells. Plateau rates below 15,000 STB/day for waterflooding gave a significantly lower NPV value and rate, as can be observed from Table 1; all the plateau rates of 9000 bbl/day gave an NPV less than $290 mm (Figure 13).

Table 11. Table outlining the different well plateau rates and well development timings for a waterflood injector system.

Well Interval (Time)	Plateau Rate (STB/day)	Facilities Cost ($mm)	NPV ($mm)	Profitability Index ($mm)
3rd Month	9000	360	272.46	0.68
	15,000	600	79.38	0.13
	24,000	960	74.06	0.08
Best case 6th Month	**9000**	**360**	**291.22**	**0.74**
	15,000	600	98.14	0.16
	24,000	960	65.41	0.07
9th Month	9000	360	289.00	0.73
	15,000	600	79.34	0.13
	24,000	960	10.33	0.01
12th Month **Worst Case**	9000	360	272.67	0.69
	15,000	600	127.55	0.21
	24,000	**960**	**−38.13**	**−0.04**

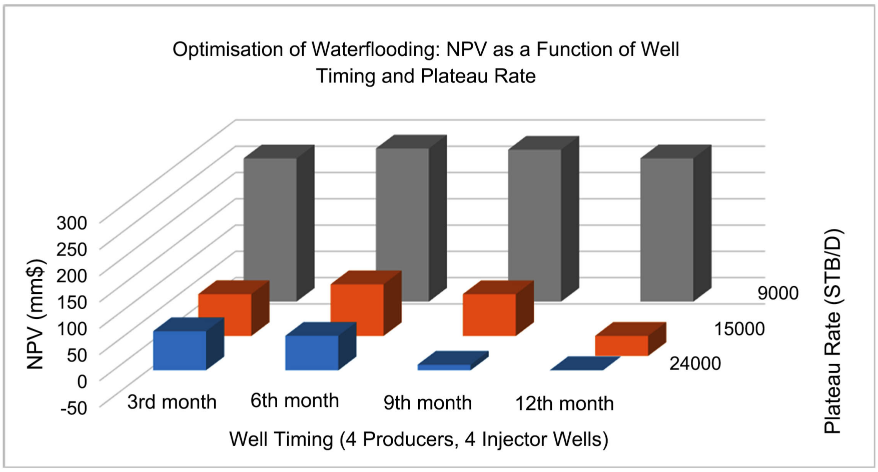


Figure 13. Graph comparing different plateau rates and well development timings within a waterflood system.

The sole purpose of waterflooding is to maintain reservoir pressure and increase sweep efficiency, however, this newly discovered saturated field's initial pressure is 6000 psi, which is well above the bubble point pressure of 3500 psi. However, it will be a wise option to postpone the use of waterflooding and rely solely on energy from the expansion of the rock and fluids until the pressure drops below the bubble point and then drill an injector well to increase and maintain the reservoir pressure. This will increase the CAPEX and the economics of the project.

3. Development Optimisation

This project initially recommends the drilling of another appraisal well, to minimise the variations in assumptions, and thus NPV, caused by the lack of knowledge surrounding the reservoir properties.

Secondly, for production, it does not recommend gas injection, either into the gas cap or oil phase, due to the severe disparity between this method and the recovery seen by waterflooding. This reduced production is then compounded by the additional CAPEX required within gas injection systems. As such, this project recommends water flooding is used as the secondary recovery technique within the field.

Following a full economic analysis of both solution gas drive and waterflooding, this project recommends that initial, solution gas drive primary recovery is used until reservoir pressure declines to around bubble point, followed by waterflooding using a three well injector system, at 6-month developmental increments. This system both maximises the drive of dissolving gas during initial reservoir pressure decline, followed by increased pressure and drive of waterflooding. Due to the lack of increase seen between three to four injector wells, the cost of adding a fourth does not reflect economic feasibility.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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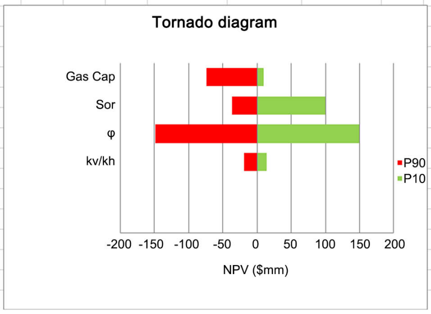
Appendix

Appendix 1. Sensitivity Analysis/Tornado Diagram Spreadsheet

	base case NPV ($mm)		1060.23									
Parameter		P90	P10	delta		P90	P50	P10				
1	Gas Cap	985.95	1069.46	83.5	Gas Cap	-74	0	9.23				
2	S_{or}	1024	1160.02	136	Sor	-36	0	99.8				
3	ϕ	911.18	1209.4	298	ϕ	-149	0	149	kv/kh	-19	0	14.3
4	kv/kh	1040.98	1074.49	33.5	kv/kh	-19	0	14.3	ϕ	-149	0	149
									Sor	-36	0	99.8
									Gas Ca	-74	0	9.23



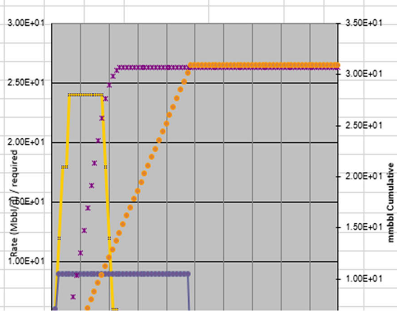
Appendix 2. Value of Information Spreadsheet Example

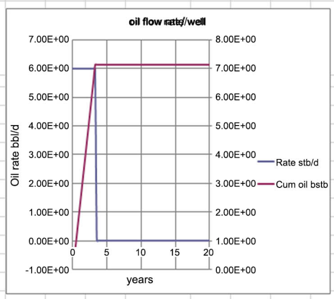
Gas Cap Uncertainty		uncertainty on reservoir extent				
current knowledge case				***perfect information case***		
details			incl cost	benefit		case
	NPV	case description		NPV	case description	NPV ($mm)
P10 ($mm)	1069.46	Gas Cap 25ft	1059.46	9.23	6 well case	1068.69
P50 ($mm)	1060.23	Gas Cap 50ft	1050.23	0		1050.23
P90 ($mm)	985.95	Gas Cap 75ft	975.95	78.28	4 well case - save cost of one well	1054.23
EMV ($mm) =	**1043.968**		**1033.9675**			**1055.845**
cost of informatic ($mm)	**10**					**VOI ($mm)= 11.88**

Appendix 3. Aggregation Spreadsheet

Direct well profile in		**Wells drille d**
me (years	Rate mstb/d	
0.00	6.00	1
0.25	6.00	1
0.50	6.00	1
0.75	6.00	
1.00	6.00	1
1.25	6.00	
1.50	6.00	
1.75	6.00	
2.00	6.00	
2.25	6.00	
2.50	6.00	
2.75	6.00	
3.00	6.00	
3.25	6.00	
3.50	0.00	
3.75	0.00	
4.00	0.00	
4.25	0.00	
4.50	0.00	

plateau rate (1000s bbl/day) = 9





Field rate

oil rat	mstb/d
year	oil rate
0	6.00E+00
1	9.00E+00
2	9.00E+00
3	9.00E+00

Appendix 4. Solution Gas Drive Spreadsheet

		pi=	6000	psi	Pb=	3500	psi		inj rate	0
Boi=	1.40				Rsi=	900	scf/stb			
Bo(Pb)=	1.43	RB/stb							years	
									time step= 0.25	
k=	100	mD	h=	150	ft	max flow rate=	20,000 RB/day	Volume (N)=	2.9E+07	RB
								Volume (N)=	2.1E+07	stb
									20.74	mmstb
viscosity=	2.00 cP	rw =	0.2	re =	1200	ft		recoverable	8.11	mmstb
								recoverable	5.65	bcf
p_o=	2000	psi		porosity	0.24	T=	180 °F	RF oil	39.09%	
									1500	

Appendix 5. Waterflood Spreadsheet

μo=	2.0 cP	μw=	0.50 cP		Bo=	1.4 RB/stb	

Sw	krw	kro
0.2	0	0.9
0.25	0.01	0.69
0.3	0.03	0.51
0.35	0.06	0.35
0.4	0.1	0.23
0.45	0.16	0.13
0.5	0.23	0.06
0.55	0.31	0.01
0.6	0.4	0
0.65	0.51	0
0.7	0.63	0
0.75	0.76	0
0.8	0.9	0

tangent	3.55
dip angle (degrees)=	0
formation width (ft)	1000
formation thickness (ft)	100
Yw	1.05
Yo	0.5
q_T (RB/d)	6,000
k (mD)	100
Swept pore vc	18.00 mmRB

Sw(bt)=	0.45	Sw(av)=	0.45	Swc=	0.20
RF (at b	25%	Sw(m	0.80		
time to break thı	2.05 years			final RF=	28%
				reserves (mı	5.096