The Pennsylvania State University

The Graduate School

Department of Energy and Mineral Engineering

FEASIBILITY STUDY THROUGH NUMERICAL SIMULATION OF WATERFLOODING AND GAS INJECTION FOR A CARBONATE OIL FIELD

A Thesis in

Energy and Mineral Engineering

by

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Submitted in Partial Fulfillment

of the Requirements

for the Degree of

Master of Science

August 2015

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Abstract

The goal of the project was to select between the application of waterflooding and gas injection in an actual carbonate field to ascertain which method would yield the highest recovery. This was done by performing reservoir simulation studies to observe the reservoir's response to each of these methods. Various injection schemes, which included injection rates and location of injection wells, were simulated to obtain optimal recovery based on the setup of the injection wells, allowing for observation of the effects of injection rate, injection location, and injection start time on recovery. The performance of these enhanced oil recovery methods applied to the carbonate field studied in this report are captured and described.

Acknowledgement

I want to thank the geologists and engineers from field operator, as well as Dr Wang for providing geological and engineering data as well as the validated reservoir simulation model used for this project. I also again want to thank my advisor, Dr Wang, and my committee for their continued support and encouragement through all my difficulties during the duration of project. Their help was instrumental in the completion of the project.

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Chapter 1: Introduction

The carbonate field studied here is an actual field currently producing and is operated by the field operator who wishes to increase recovery by the implementation of either waterflooding or gas injection due to declining reservoir pressures. In order to maintain the anonymity of the field, we call the field the PSU field. The need to increase recovery from the field has prompted the interest in the simulation study carried out in this report, which simulates waterflooding and gas injection.

Reservoir simulation is an integral and invaluable tool for field development because it provides insights into the effects of various field operations before they are implemented in the field. Reservoir simulation also helps to provide data such as estimated recoveries of oil, gas, and water which allow for the estimation of various critical properties, such as the costs and revenues from various possible implemented operation initiatives. The reservoir was modeled and simulated from the data provided by the operator. The modeled field consisted of 9 wells of which 2 will be injectors and 7 will be producers.

The gas used for gas injection was modeled to be the same composition as the produced gas, which for intensive purpose was lean natural gas with a high methane concentration. Gas injection was also modeled to account for miscibility. Along with simulating waterflooding and gas injection operations, an alternative, Water-Alternating-Gas (WAG) injection was studied as a third option. The project also compared the economic analysis for each method.

This project would allow the selection of either a waterflooding and gas injection operation that would both increase recovery and be cost effective.

Chapter 2: Literature Review

Reservoir Simulation is an invaluable tool in field development. Reservoir management and simulation help develop richer, more accurate description of the reservoir thus providing a foundation for better decisions; consequently leading to increased confidence, reduced risks and increase in reserves.

Langston & Shirer (1985) presented a paper where they describe the development of EOR methods for a mature carbonate reservoir. They implement waterflooding, gas injection, and nitrogen water alternating gas injection (WAG). They reported good results from water flooding with a recovery of 51% OOIP, recovery was increased by 27 million barrels. With tertiary oil recovery, gas and WAG injection were able to further increase recovery to 57% OOIP. They reported that key to success was proper reservoir surveillance and management.

Manrique, Muci, & Gurfinkel (2007) discussed various EOR methods applied to a number of carbonate reservoirs in the United States of America in a chronological order. They reported that waterflooding, CO_2 gas injection, and WAG were the most common choice for EOR in carbonate reservoir. They also reported that for the past decade, gas injection has become more dominant in EOR for carbonate reservoirs, especially those with low permeabilities and injectivity. They described hydrocarbon gas injection as effective and widely used in the USA but with one main drawback; its high cost.

Lawrence, Corwin, & Idol (2002) discussed the importance of early, thorough, and extensive data collection and coring. Because of this they were able to better visualize the reservoir and capture the impermeable zones. With this information they were able to make adjustments to the EOR design; they were able to have an overall recovery of 60% OOIP and 70% OOIP in some zones. They reported tertiary oil recovery from nitrogen WAG and gas injection contributing an incremental 7% – 10% increase in recovery.

Alhuthali, Datta-Gupta, Yuen and Fontanilla (2010) discussed waterflooding optimization through the use of inflow control valves to control the injection and production rates. They try and equalize the streamline time of flight at the producers to maximize waterflood sweep efficiency and delay water breakthrough. Optimization is achieved through proper control of the injection rate.

Schulte (2005) lists the characteristics of fields with high recoveries below:

- Homogeneous at all scales
- Good connectivity
- Good fluid mobility
- Appropriate natural drive
- Non-fractured/homogeneous or densely fractured
- Sweet clean oil
- Thick oil column
- Consolidated sands
- Low residual oil saturation.

The point is, if done right, proper EOR implementation stands to significantly increase the expected recovery from oil fields and assets.

2.1: Evaluating Residual Oil Saturation

Before any comprehensive field operation is carried out, one should have an estimate as to how much oil is left in the reservoir after both primary and secondary depletion. *T. Babadagli (2005)* (1) describes various methods used to evaluate residual oil. These methods are listed below:

- Core Analysis (distillation and extraction)
- Logs
- Volumentric Reservoir Engineering Studies

- Production Data
- Well Testing
- Chemical Tracers

These methods were all evaluated (1) and compared in terms of residual oil saturation (ROS) measurements. The conclusions (1) are summarized below:

- The value of ROS from cores, logs and tracers is less than that from material balance
- The value of ROS from pulsed neutron capture is equal to that from resistivity logs
- The value of ROS from a single well tracer is less than that from logs.

Verma (1991) (2) observed the residual oil in carbonate reservoirs, and after a series of tests concluded that special core analysis (SCAL) yielded the most reliable results. They also came up with a correlation to determine the residual oil after waterflooding.

2.2: Miscibility Vs Immiscibility

There are 2 main categories of gas injection displacement: miscible and immiscible displacement. In miscible displacement, the low interfacial tension between the injected gas and reservoir fluids (oil) improve oil recovery by increasing the capillary number of the flood (3) and vice versa for immiscible displacement. The Spreading coefficient S_{ow}, sometimes provides a qualitative insight as to recovery performance from an immiscible gas flood operation (1) (4).

$$S_{ow} = \sigma_{wg} - \sigma_{og} - \sigma_{ow},$$

Where $\sigma_{wg}, \sigma_{wg}, \sigma_{wg}$ $are\ the\ interfacial\ tension\ between\ water - gas, oil - gas, and\ oil - water\ resprectively$. And S_{ow} $is\ the\ spreading\ coefficient.$

They (1) (4) found that recoveries in systems with positive spread coefficients were higher than those in systems with negative spreading coefficients. It was noted that when the spreading coefficient is positive, oil tends to form a continuous film by spreading on water (1). When negative, the oil tends to amass and form blobs which occupy multiple pore spaces (1). By stopping injection and shutting in the wells after breakthrough occurred, then restarting the system after a couple of days with waterflooding, significant recoveries were observed. This process was referred to as Second Contact Water Displacement (SCWD) (1)

Miscibility affects the microscopic displacement efficiency in gas injection (3). A zero interfacial tension is needed for miscibility, thus during miscible displacement, there is infinite capillary number which results in higher recoveries (3) . In miscible floods, increase in oil recovery is obtained by a combination of the 3 mechanisms:

- Oil swelling (Condensing gas drive)
- Reduction in oil viscosity (Vaporizing gas drive)
- Oil displacement by the injected solvent/gas through the generation of miscibility (i.e. zero interfacial tension between oil and injected solvent/gas)

Miscibility is achieved by pressurizing the reservoir above the minimum miscible pressure (MMP) of the fluid. It has been noted that once pressure is above the MMP oil recovery was reported to significantly increase (1). It was also noted that in a number of applications, miscible displacement took place at pressures slightly below the MMP (1). At these slightly lower pressures, partial miscibility and not complete miscibility occurs. This pressure range was called “Near-Miscible Zone”. It was observed that having pressure drop to the region of partial miscibility from complete miscibility, recovery was negatively impacted (1). *Kasraie and Farouq Ali (1984)* (5) studied the effect of an immobile phase during a miscible flooding operation. They observed that dispersion of the miscible solvent within a porous medium was reduced in the presence of a wetting immobile phase and opposite in the presence of a non-wetting immobile phase.

Experiments from literature (3) show miscible floods were found to recover over 60 to 70% more of the waterflood residual oil than immiscible floods. Miscibility can be obtained by either managing the reservoir pressure or by changing the composition of the injected gas (6).

2.2.1 Factors Affecting the Performance of Gas Injection

- Reservoir Pressure: The reservoir pressure is key in determining if the injected gas will be miscible with the reservoir fluid
- Fluid Composition: Lighter oil tends to develop miscibility more easily with the injected gas compared to heavier oil. Lighter oil also has higher mobility ratio due to its lower viscosity.
- Reservoir Characteristics: The conditions of the reservoir affect the performance of gas injection. Below are some reservoir characteristics that are beneficial to gas injection (6):
    - High dip angles
    - Lower degree of permeability heterogeneity
    - The presence of vertical permeability barriers or baffles to slow the rate of vertical segregation of injected gas.
    - Fining upwards deposits (low permeability overlying the higher permeability)

  Gas injection also tends to have a lower sweep efficiency compared to waterflooding due to the larger tendency of gas to finger through the more viscous in-place fluids. Consequently, it more easily channels through high permeability zones and can breakthrough prematurely into the producing wells (6).
- Relative Permeability: The relative permeability is an important factor as the mobilities of the in-place and the injected displacing fluid depend on it.

2.3: Field Analog

In order to develop a metric for the simulation study, it was important to identify an analog field in which comparisons could be made. A carbonate field which had similar reservoir properties and had gone through extensive waterflooding and gas-injection operations was selected. The field operator identified such an analog as the Jay/Lec field. *T.Babadagli (2005)* (1) lists some examples of fields where various waterflooding, gas injection, and other EOR operations have been implemented.

2.3.1: The Jay/Lec Field

The Jay/Lec field was an analog choice selected by the operator. The fluid, rock and reservoir properties of the Jay/Lec field are shown in Table 1 below:

Table 1: Jay/Lec Rock, Fluid and Reservoir Properties (7) Vs PSU Field

Properties	**Jay/Lec**	**PSU**
Porosity, %	14	8
Permeability, md	35.4	20
Original Pressure, Psia	7800	5148
Original Temperature, F	285	208
Oil FVF, RB/STB	1.76	1.87
Injected gas FVF	0.66 (Nitrogen)	0.00052 (Reservoir gas)
Solution Gas-Oil Ratio, scf/stb	1806	1273
Oil Viscosity, cp	0.18	0.17
Oil Gravity, API	51	42.2
Injected Gas/Oil Miscibility Pressure, Psi	3600	3698
Water Saturation, %	0.127	0.15
Oil Saturation		0.85
Bubble Point/Saturation Pressure, Psia	2830	2640

The Jay/Lec field was discovered in 1970 and is located between the Florida-Alabama border. Production from the field began in Dec. 1970. The field section within the Alabama region is called Little Escambia Creek (LEC). The reservoir is an upper Jurassic smackover carbonate.

Water injection started in 1974 and yielded good results. The total reserves from both primary and secondary (waterflood) depletion was 373 MMBBL which was had outperformed the initial recoverable reserves of 346 MMBBL.

Tertiary recovery using gas injection began in Jan. 1980. The initial plan was to perform miscible gas injection with N_2, but due to issues with supply and availability, methane gas was used till Dec. 1980 when they began injecting N_2. They injected N_2 at certain locations at maximum or near maximum rate until the target injection volume was reached, which took about 1 to 2 weeks for individual wells. After the target volume was reached, they killed the wells and began injecting water at 6500psig. Water injection was adjusted to maintain the desired pressure within the field pattern area. The operator had issues with N_2 supply which was always less than the demanded amount. Water injection was active until target N_2 volumes were supplied to the active injection wells, then injection would be switched back to N_2. The field wide pattern contained 37 injectors. Due to the gas supply constraints only four to five injection wells were injecting N_2 while the others were either injecting water or shut-in. As of 2003, cumulative production from the Jay/Lec field was 440MMBBL and recoverable reserves were estimated to be 500MMBBL. Incremental oil recovery due tertiary recovery was initially estimated to be about 47MMBBL, but as of 2003 that number was increased to almost 70MMBBL (6). The production and performance curves for the Jay/Lec field are shown in Figure 1 and Figure 2 respectively.

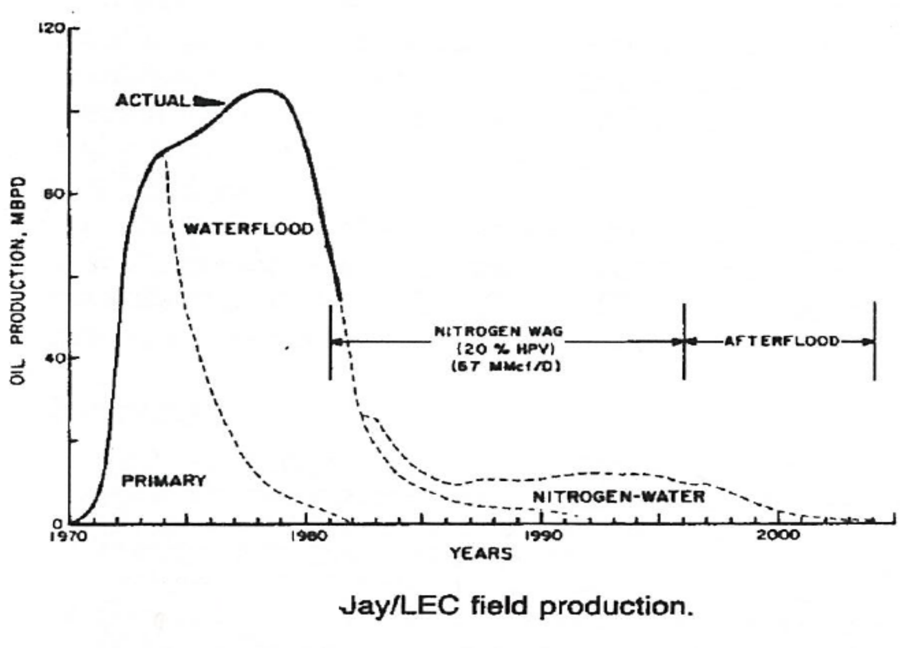
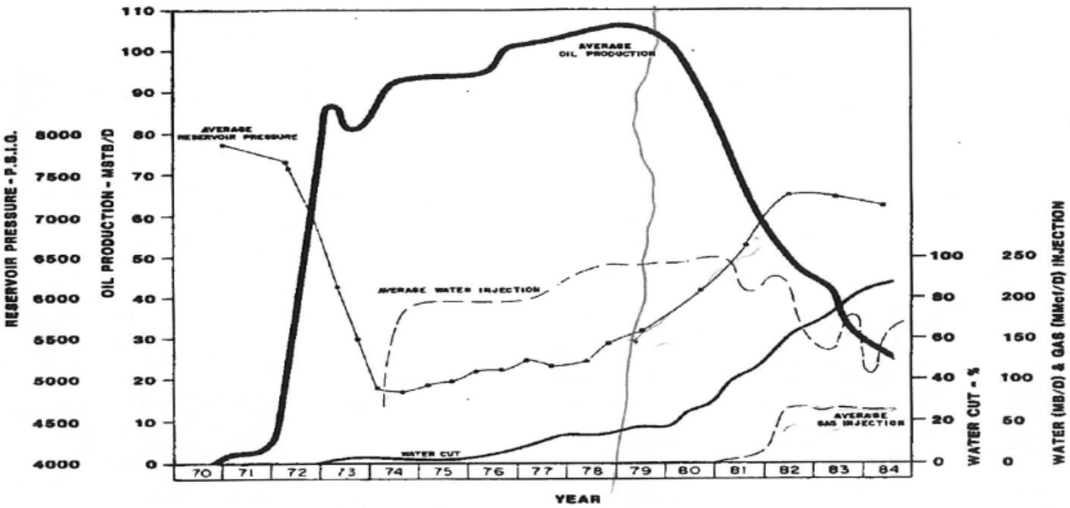


Figure 1: Jay/LEC Production Profile (7)



Jay/LEC Unit performance.

Figure 2: Jay/Lec Performance Profile (7)

From Figure 1and Figure 2, water injection began close to the peak oil production during the primary depletion phase. The reservoir experienced sharp pressure drop during the primary depletion phase, very similar behavior to the PSU field. After water injection began in 1974, the peak oil rate increased, also, as the injection rate increased in 1978 so did the oil production rate. The reservoir pressure also increases when water injection began. Observed in 1978, increase in water injection rate results in further increase in reservoir pressure. Gas injection began in 1980, close to 2 years after oil production began to decline. Gas injection reached its peak in 1982. As gas was injected, water injection rate was sequentially reduced. During the gas injection phase, reservoir pressure begins to drop, however the rate of the drop in pressure was not as steep as it could have been thanks to the continued water injection, though at a reduced rate.

2.3.1.1: Jay/Lec Reservoir Surveillance:

Radioactive tracers were used in the waterflood operations. For the gas injection/WAG operations both radioactive and chemical tracers were used. The radioactive isotope tracers used were:

- Krypton 85
- Tritiated Hydrogen, ethane, methane, and propane

The chemical tracer used was:

- Sulfur Hexafluoride

A total of 373 Ci radioactive isotope tracers and 1430 lbm chemical tracers were used in 34 injection wells. Produced N_2 were analyzed and allowed the operator to determine the source of breakthroughs and also provided insight on how to adjust injection volumes and rates to provide optimal areal convergence on the production wells (7). The injection and tracer distribution system maps are shown in Figure 3 below:

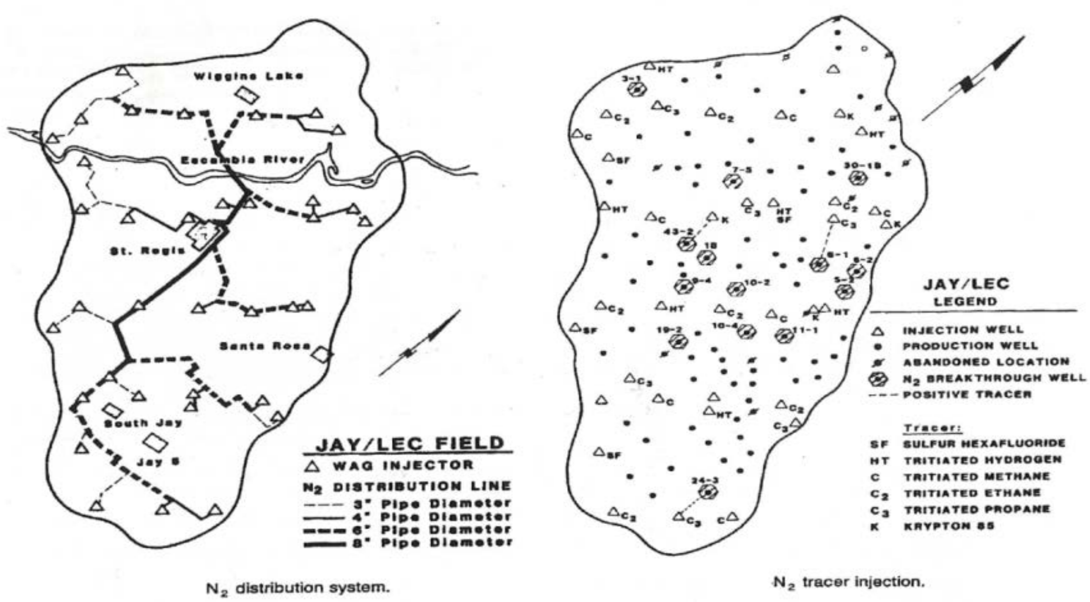


Figure 3: N_2 distribution and tracer system (7)

Chapter 3: Field Properties

3.1: Reservoir Properties

The field is a carbonate reservoir mainly made up of dolomite. The geological survey by the field geologists provided the data necessary with the Cartesian grid coordinates to build the model. They also provided information about the depth, thickness, net pay of the reservoir, and other geological properties for the field. The depth and thickness distributions are shown in Figure 4.

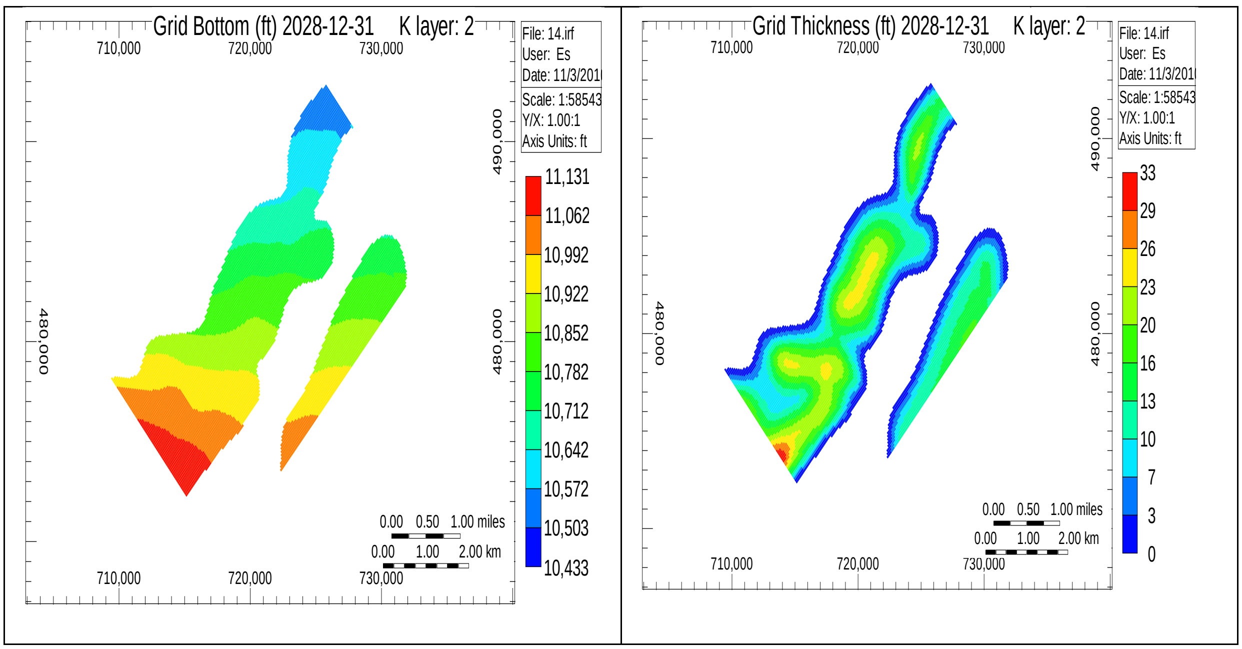


Figure 4: Bottom top (left) and thickness distribution of the lower zone of reservoir (built and validated by the operating company's geologist, engineers and Dr Wang, 2009)

Only the lower formation is shown in all the images above because it was the focus of this study. The reservoir is homogenous in the lower formation of interest.

3.2: Rock Properties

The field is modeled as homogeneous with a porosity and permeability for the lower formation of 8% and 20md respectively. The porosity and permeability distribution for both the upper and lower zones are shown in Figure 5 below.

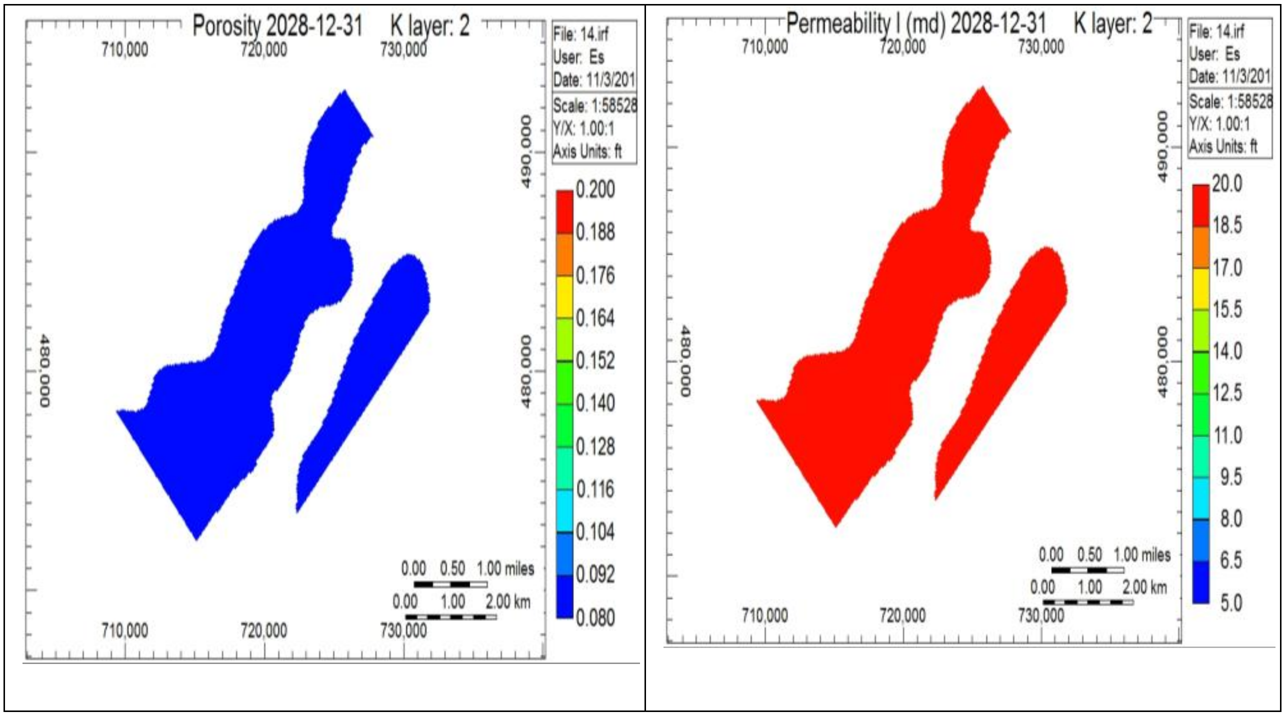


Figure 5: Porosity (left) and Permeability (right) Distribution of the lower zone/formation of the reservoir (built and validated by the operating company's geologist, engineers and Dr Wang, 2009)

3.3: Fluid Properties

The PVT data was gotten from fluid analysis by the operators of the field. This data was put into the model to capture the phase behavior of the reservoir fluids. The reservoir properties are shown in the table below

Table 2: Reservoir Property Summary (Courtesy of the operating company, 2008)

Properties	**Values**
Original Pressure, Psi	5148
Original Temperature, F	208
Oil FVF, RB/STB	1.87
Injected gas FVF	0.00052 (Reservoir gas)
Solution Gas-Oil Ratio, scf/stb	1273
Oil Viscosity, cp	0.17
Oil Gravity, API	42.2
Injected Gas/Oil Miscibility Pressure, Psi	3698
Water Saturation, %	0.15
Oil Saturation	0.85
Bubble Point/Saturation Pressure, Psi	2640

The PVT table used is shown in the Table below:

Table 3: PVT Table (courtesy of the operating company, 2008)

Pressure (Psi)	**Solution Oil-Gas Ratio, Rs (ft3/bbl)**	**Saturated Oil Formation Volume factor, Bo**	**Gas Compressibility, Zg**	**Oil Viscosity (cp)**	**Gas Viscosity (cp)**
14.7	1	1.1024	0.998	0.661	0.0118
100	156	1.2964	0.943	0.437	0.0126
300	285	1.3844	0.921	0.395	0.0135
500	370	1.4315	0.907	0.367	0.014
800	486	1.4928	0.8901	0.336	0.0148
1100	596	1.5483	0.8741	0.31	0.0156
1400	706	1.6025	0.8608	0.285	0.0165
1700	821	1.6602	0.8514	0.263	0.0175
2000	968	1.7266	0.846	0.237	0.0186
2300	1116	1.7954	0.845	0.207	0.0198
2640	1273	1.8717	0.844	0.177	0.0208
2750	1273.1	1.8718	0.843	0.176	0.0218
3000	1273.2	1.8719	0.842	0.175	0.0228
3250	1273.3	1.872	0.841	0.174	0.0238
3431	1273.4	1.8721	0.84	0.173	0.0248
4000	1273.5	1.8722	0.839	0.172	0.0258
4500	1273.6	1.8723	0.838	0.171	0.0268
5000	1273.7	1.8724	0.837	0.17	0.0278
5500	1273.8	1.8725	0.836	0.169	0.0288
6000	1273.9	1.8726	0.835	0.168	0.0298

3.4: Relative Permeability

The relative permeability used for this study was obtained through core analysis. The relative permeability data was very important in accurately modeling the reservoir. The oil-water and oil-gas curves relative permeability obtained through core analysis are shown in Figure 6 and Figure 7. The main factors that affect relative permeability include:

- Pore-space geometry
- Wettability of the rock surface.
- Viscosity of the fluids
- Surface tension between the reservoir fluid phases

Core Analysis:

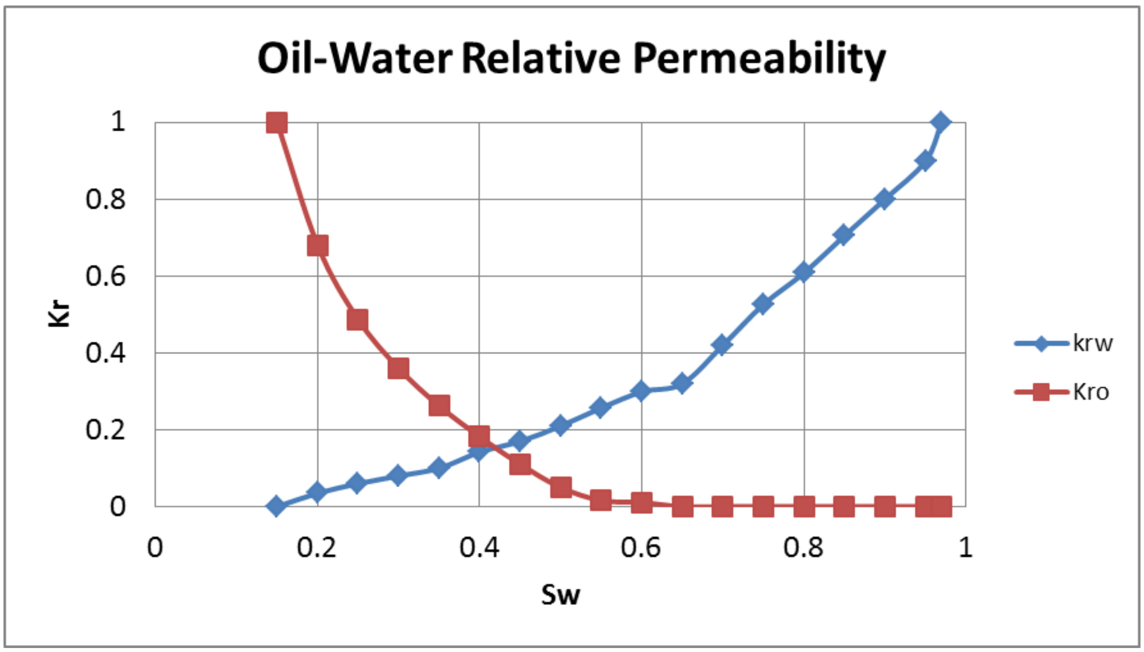


Figure 6: Core Analysis Oil-Water Relative Permeability Curve (Data courtesy of operator)

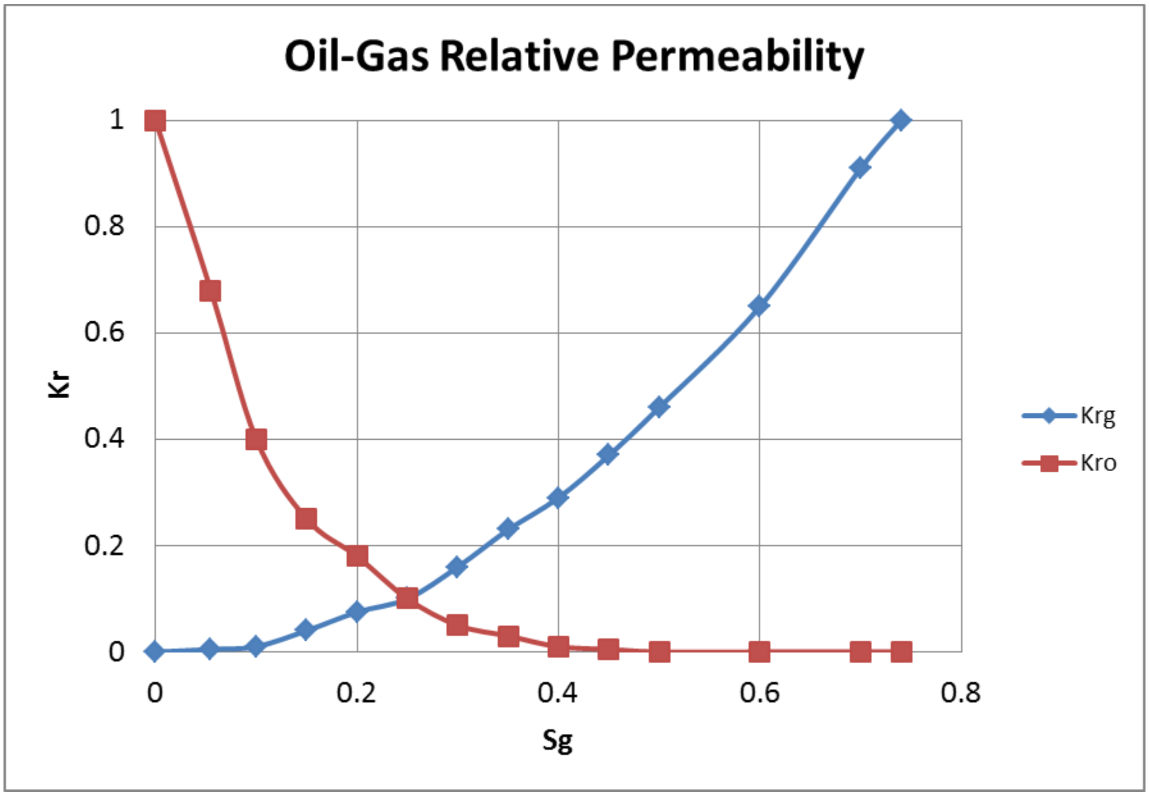


Figure 7: Core Analysis Oil-Gas Relative Permeability Curve (Data courtesy of operator)

As can be seen in Figure 6 and Figure 7 above, the oil relative permeability due to gas shows oil is less mobile as gas saturations increases compared to water saturation increases. Oil relative permeability approaches zero faster when there is an increase in gas saturation compared to when there is a similar increase in water saturation. The core analysis relative permeability data shows a connate water of about 0.15. At a gas saturation of 0.45, the oil relative permeability due to gas is approximately 0, meaning a residual oil saturation of 0.55. At a water saturation of 0.65, the oil relative permeability due to water is close to 0, meaning an irreducible oil saturation of 0.35. This implies that the flow of oil is hindered more when there is increase in the amount of gas present compared to when there is an increase in the amount of water present. It also means more oil is left behind after a gas flood compared to a waterflood. This information provides a preliminary insight as to how the reservoir would respond to waterflooding and gas injection.

Chapter 4: Model Development

4.1: Base Model Description

The reservoir is modeled using CMG: IMEX, which is a black oil simulator. The model consisted of a total of 20,000 blocks of which 200 in the i-direction, 100 in the j-direction each in the upper and lower formations (Only the lower formation is evaluated). The 3D view of the gridded model representation of the upper and lower zones is shown in Figure 8.

Figure 8: 3D View of gridded reservoir (both upper and lower zones) (built and validated by the operating company's geologist, engineers and Dr Wang, 2009)

The model begins operation in 2006-08-21 and runs for about 20 years (22years and 4months exactly). The time step control for the model is shown in the table below

Table 4: Time Step control for the model

Max Number of Time Steps	3000
Max Time Step Size	30days
Min Time Step size	10^{-8} day

All the activities evaluated in this report and model is restricted to the lower zone. The upper and lower zones are isolated from each other. The lower zone of the model consists of 9 producing wells of which 2 would be converted to injection wells during any EOR process. The locations of all nine wells are shown in Figure 9

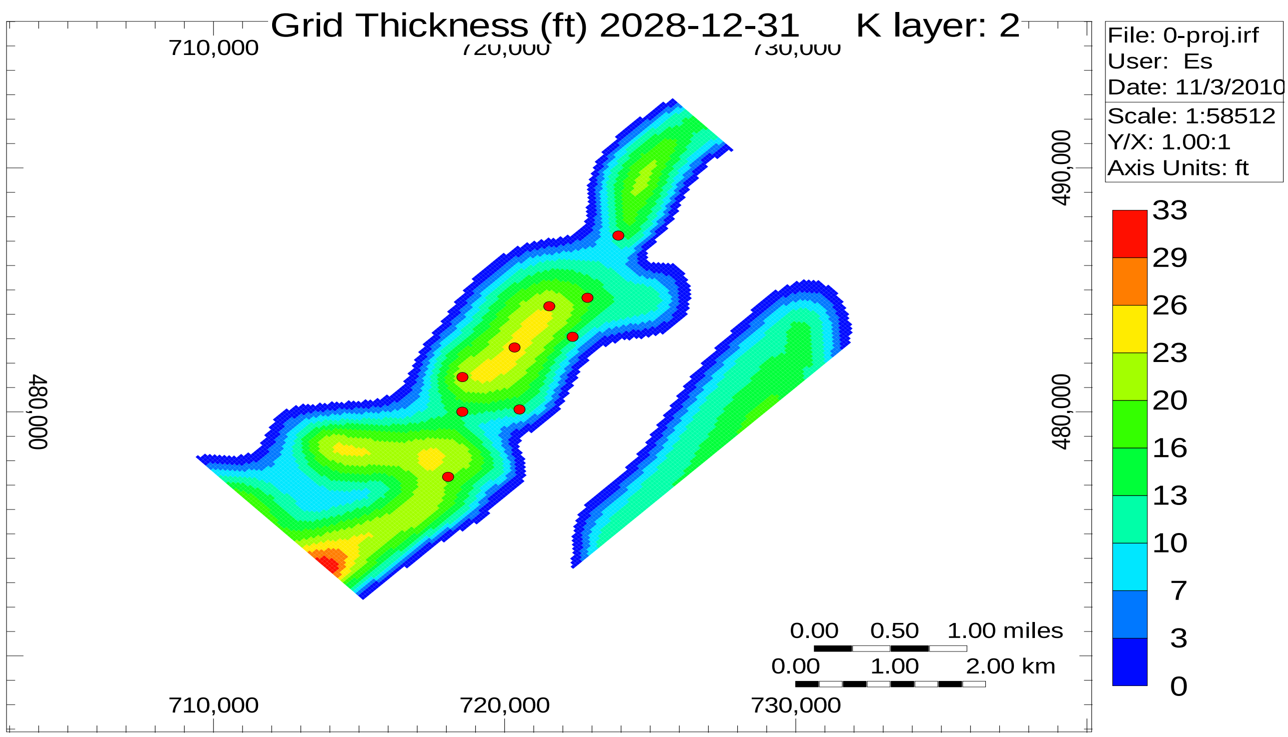


Figure 9: Well distribution (Courtesy of operator, 2008)

The reservoir will be modeled for about 20 years (22.3 years exact). As shown in the table 9 above the cumulative production through primary depletion alone is 3.64MMSTB. In order to increase the overall recovery, enhanced oil recovery (EOR) methods are employed. For this project, focus is given to waterflooding and gas injection.

As mentioned above, 2 of the 9 wells will be converted into injection wells during any EOR process. In this project, all possible combinations of those 2 injection wells out of the 9 wells are simulated. A total of 36 total combinations are possible.

The injection wells were modeled as mobility weighted (Mob-weight) injectors, meaning that the total mobility of the grid block of the injectors is taken into account during the numerical computations.

$$q = wi * (phase\ mobility) * (P_{block} - \ P_{block})$$

$$phase\ mobility = \frac{k_i}{\mu_i}\ where\ i = oil, water, gas, e.t.c$$

$$Well\ index, wi = \frac{2 * \pi * h * \sqrt{k_x k_y}}{\ln\frac{r_o}{r_w} + \ s}\ , where\ s\ is\ skin\ factor$$

Both waterflooding and gas injection were implemented using this injection well design.

4.2 Water Flooding

In designing each injector well, one universal constraint is the maximum allowable bottom-hole pressure (BHP) which is set to 10,000psi. The maximum injection rates will depend on the injection scheme selected for each model and the BHP. The general injection schemes for each well in regards to target rates are:

- 1000bbl/d
- 2000bbl/d
- 3000bbl/d

If the injection rate of any of the injection wells tries to raise the BHP above 10,000psia, the injection rate will be automatically reduced such that the BHP does not go above 10,000psia. An example is shown in Figure 10 below:

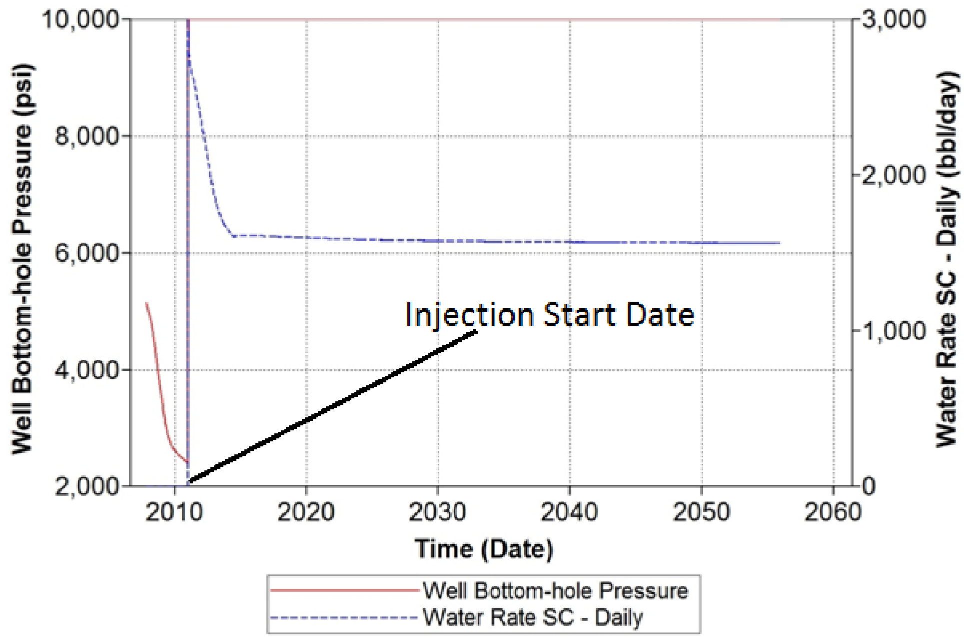


Figure 10: Well injection rate as it is affected by max BHP constraint

The injection rate for this well is 3,000bbl/d, but shortly after injection starts, the BHP attempts to exceed the 10,000psia constraint. Prior to the injection start date, the rapid decline in pressure can also be observed in Figure 10. The pressure decreases due to production and shoots up as soon as injection starts. This causes the injection rate to be reduced to about 1600bbl/d due to the maximum BHP constraint set. In short, if a well is trying to honor its rate target but violates the BHP constraint, the well switches from rate control to BHP control.

The 10,000psia constraint was due to maximum pressure the reservoir could support without inducing fractures. The model ran into computational issues when BHP got this high due injection. The models had a hard time converging at these high rates; as the grid blocks were too large and not fine enough to allow proper numerical evaluation of reservoir properties. As a result local grid refinement

(LGR) was used around these injection wells with high rates. An example of LGR application on an injector is shown in the figure below:

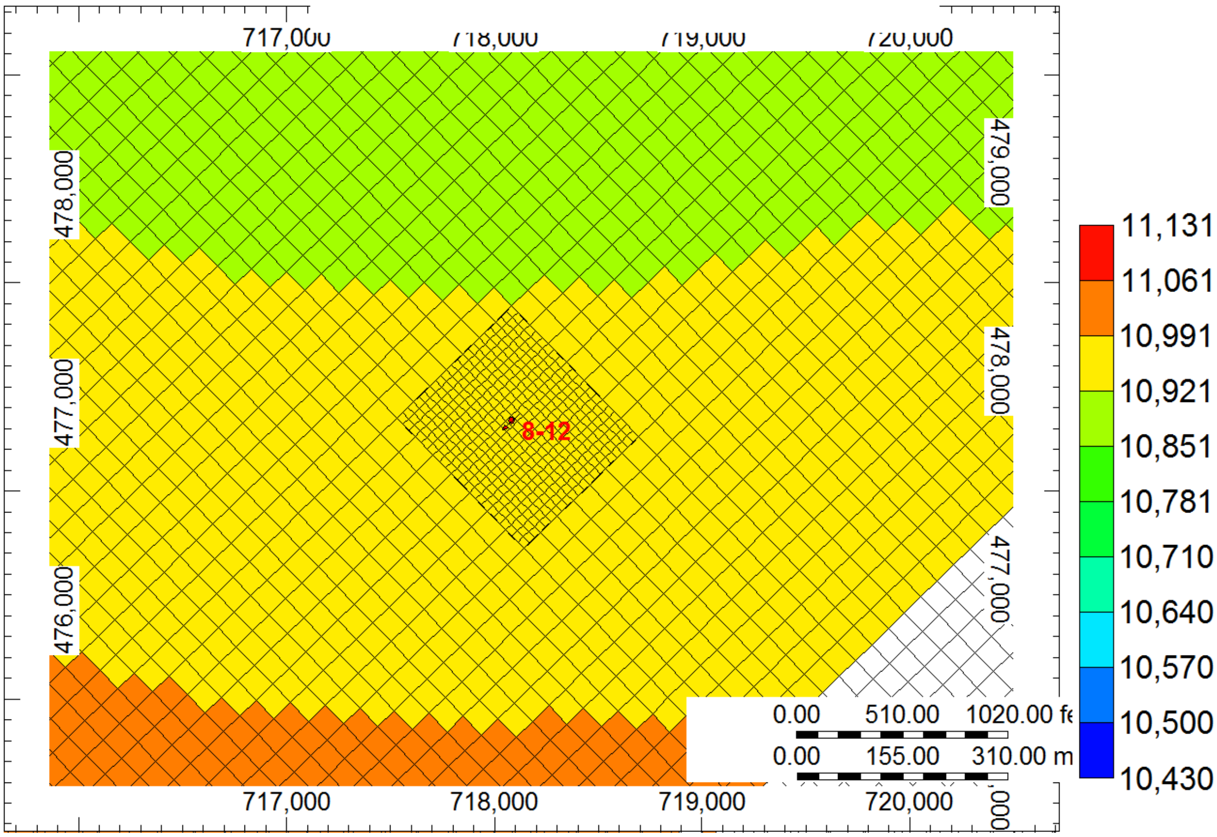


Figure 11: Local Grid Refinement (LGR) around an injector with high rates

Each block around the injection wells was refined to an average of 9 sub-blocks, for the span of 3 blocks in every direction of the well. LGR was only applied to wells that were scheduled for high injection rates of 2500bbl/d and up and had difficulty converging due to the high injection rates. This 3x3 refined grid size was selected as it allowed convergence of time steps. The consequence of LGR was that numerical computational time was longer for each affected run.

4.2.1 Optimization and Scheme Design

As stated in the earlier sections of this report, in designing the injection scheme, 2 out of the 9 wells will be injection wells. This meant that there were a total of 36 distinct combinations of injection wells.

Also, as mentioned previously, there will be on average 3 water injection rate schemes evaluated. As a result, for every distinct combination of injection wells, there will be 3 models built, 1 for each distinct injection rate. Therefore there will be a total of 108 waterflood models/runs. This would cover every possible outcome set by the defining the constraints and requirements of the model.

4.3 Gas Injection

Similar to the water injection model design, 2 out of the 9 wells will be set as injectors, both having a BHP constraint of 10,000psia as the primary constraint. Due to operational feasibility constraint (in regards to supply of gas), and economics, the rate of 750Mcf/d was used as the main injection rate scheme. However, to capture the effects of varied gas injection rate, multiple rates were taken into consideration and discussed in the result section below. Local Grid Refinement (LGR) was not required for convergence and numerical stability of the gas injection models/runs. By default, the model was designed for immiscible gas injection, however in order to account for miscible displacement by the injected gas, the model was modified to a pseudo-miscible black oil model.

4.3.1 Optimization and Miscibility Design

In defining the pseudo miscible model, a fourth phase, solvent, had to be characterized. As mentioned in previous sections, the injection gas is the same as the produced reservoir gas, meaning that the PVT properties for both will be the same. However, 2 dimensionless parameters had to be described;

the solvent-oil mixing parameter, wo, and the solvent-gas mixing parameter, wg. Since the solvent injected and reservoir gas are one in the same, they are considered to be fully miscible. The table below shows the PVT of the solvent along with the solvent-oil mixing parameter.

Table 5: Solvent PVT table (Courtesy of operator, 2008)

Pressure (Psi)	**Rss (ft3/bbl)**	**Zs**	**Solvent Viscosity (cp)**	**wo**
14.7	0	0.998	0.0118	0
100	0	0.943	0.0126	0
300	0	0.921	0.0135	0
500	0	0.907	0.014	0
800	0	0.8901	0.0148	0
1100	0	0.8741	0.0156	0
1400	0	0.8608	0.0165	0
1700	0	0.8514	0.0175	0
2000	0	0.846	0.0186	0
2300	0	0.845	0.0198	0
2640	0	0.844	0.0208	0
2750	0	0.843	0.0218	0
3000	0	0.842	0.0228	0
3250	0	0.841	0.0238	.2
3431	0	0.84	0.0248	.34
4000	0	0.839	0.0258	.7
4500	0	0.838	0.0268	.73

The Minimum Miscibility Pressure was evaluated using a correlation presented by *Abbas Firoozabadi and Khalid Aziz (1986)* (8) and shown below:

Equation 1: MMP Correlation for Nitrogen and Lean Gas (8)

$$MMP = 9433 - (188 * 10^3)\left(\frac{X_{C2} - X_{C5}}{M_{C7+} * T^{0.25}}\right) + (1430 * 10^3)\left(\frac{X_{C2} - X_{C5}}{M_{C7+} * T^{0.25}}\right)^2$$

MMP: Minimum Miscible Pressure (Psia)

T: Temperature (°F)

$X_{C2} – X_{C5}$: Concentration of intermediates (mol %)

M_{C7+}: Molecular Weight of Heptane plus (lb/mol)

Equation 1 was derived from the MMP correlation curve by *Abbas Firoozabadi and Khalid Aziz (1986)* (8) shown in Figure 12 below:

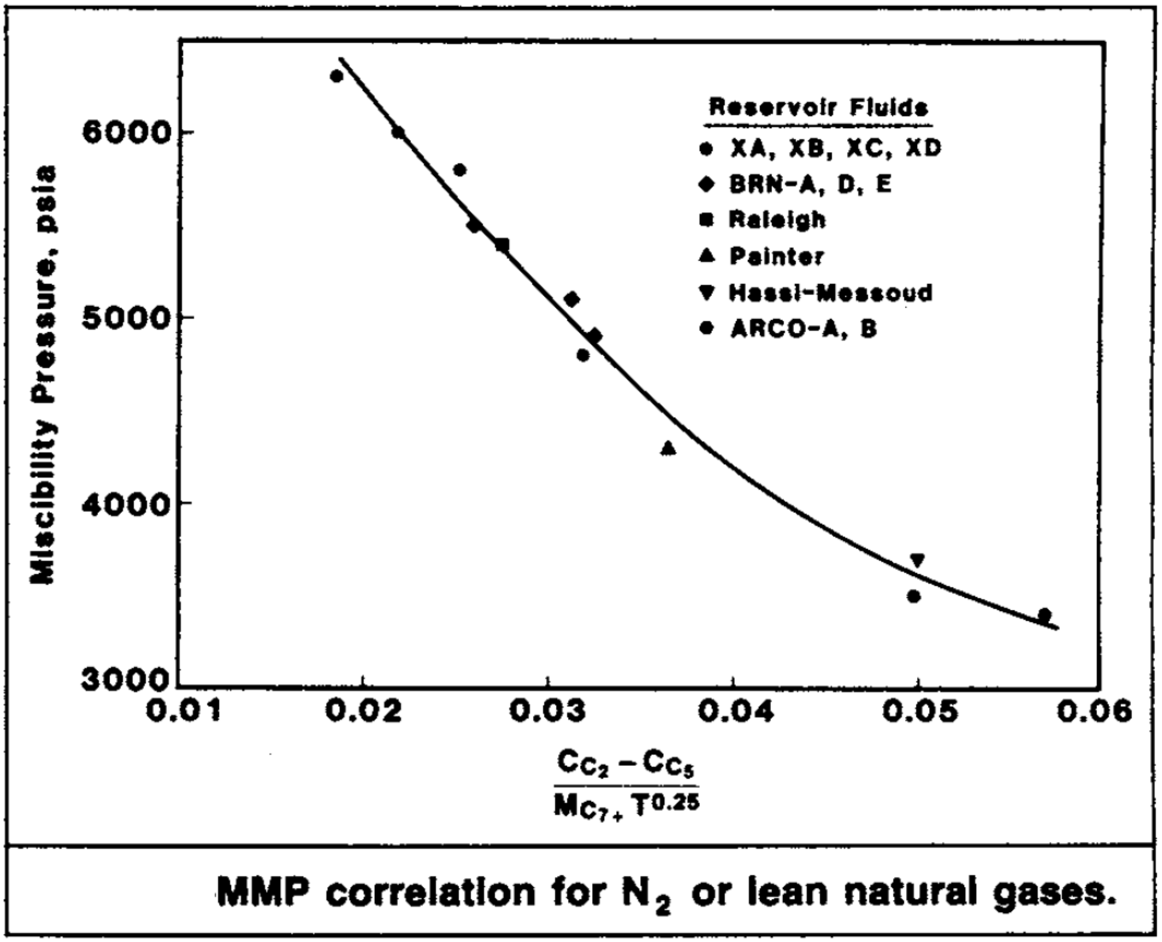


Figure 12: Abbas Firoozabadi and Khalid Aziz Correlation for N2 and lean Natural Gases (8)

Table below shows the mole concentration of the reservoir fluid.

Table 6: Mole concentration of reservoir fluid (Courtesy of the operating company)

C1	C2	C3	C4	C5	C6	C7+
29.831	9.891	7.375	2.196	2.26	2.201	34.093
			4.768	2.928	1.036	
				0.017	0.598	
					0.055	
					0.221	

In using the correlation, the intermediate component was modified to be $X_{C2} - X_{C6}$ and not $X_{C2} - X_{C5}$.

Using the MMP correlation shown in Equation 1 and mole concentration data in Table 6, the MMP of the reservoir was estimated to be 3698.41 psi which is very close the MMP of the Jay-Lec analog field which had an MMP of 3600psi. This MMP value was used in building the pseudo-miscible black oil model.

After implementing pseudo-miscibility functionality into the black oil model, there was a change in the production profile of the field. The figure below shows the production profile of miscible vs immiscible for 3 sample gas injection models/runs, each with different injector placement.

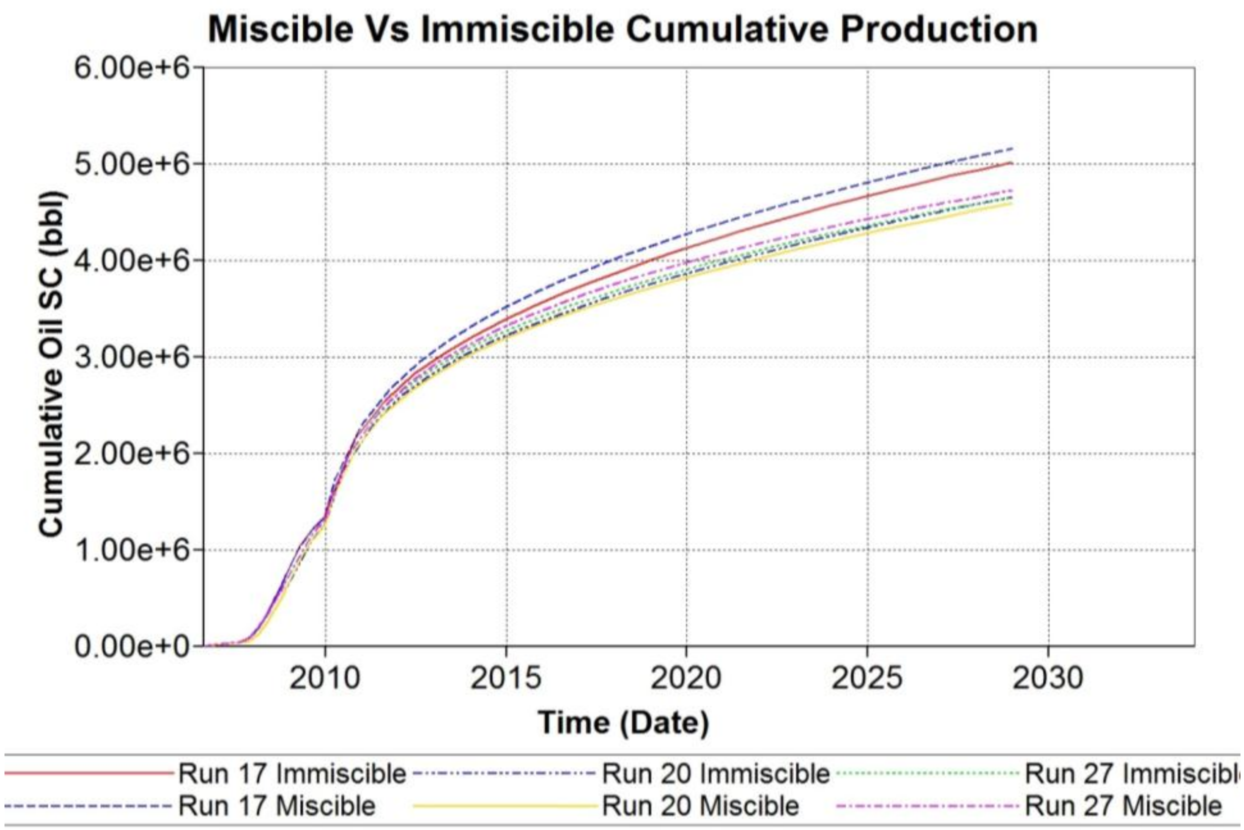


Figure 13: Oil recovery: Miscible vs Immiscible

As shown above, miscible gas injection offers marginal increase in oil recovery compared to immiscible gas injection due to the zero interfacial tension between the oil and gas.

In defining a pseudo-miscible black oil model, there are modifications to the equations of relative permeabilities, viscosity, density, and capillary pressure (9):

The effective relative permeability is:

$k_{rP}^{eff} = \frac{\omega_{o(P)}}{\omega_{o\,max}} k_{rp}^{m} + \left(1 - \frac{\omega_o(P)}{\omega_{o\,max}}\right) k_{rP}^{Im}$, Where P = oil, solvent, or gas

k_{rp}^{m} *is the miscible portion of the effective relative permeability*

$k_{rp}^{m} = F_P^m\, k_{row}(S_w)$

F_P^m *is the miscible partioning function* which partitions $k_{row}(S_w)$ *based on* the saturations of each hydrocarbon phase

k_{rp}^{im} *is the immiscible portion of the effective relative permeability*

$k_{rp}^{im} = F_P^{im}\, k_{rg}(S_g + S_g)$ Where P = gas or solvent

$k_{rp}^{im} = k_{ro}(S_w, S_L)$ Where P = oil

F_P^{im} *is the immiscible partioning function* which partitions $k_{rg}(S_g + S_g)$ *based on* the saturations of the gas and solvent

$$F_o^m = \frac{\omega_o^{Frac}\, S_o^*}{\omega_o^{Frac}\, S_o^* + \omega_o^{Frac}\, S_g + \omega_{sol}^{Frac}\, S_{sol}}$$

$$F_g^m = \frac{\omega_g^{Frac}\, S_g}{\omega_o^{Frac}\, S_o^* + \omega_o^{Frac}\, S_g + \omega_{sol}^{Frac}\, S_{sol}}$$

$$F_{sol}^m = 1 - F_o^m - F_g^m$$

$$F_g^{im} = \left(\frac{S_g}{S_g + S_{sol}}\right)$$

$$F_{sol}^{im} = 1 - F_g^{Im}$$

$$S_o^* = S_o - S_{orm}(S_w)$$

But,

$$\omega_P^{Frac} = \frac{\omega_P}{\omega_{Pmax}}\ where\ P = oil, gas, or\ solvent$$

And $\omega_P$is the solvent to hydrocarbon mixing parameter.

Computer Modeling Group (2009) (9) suggests that when no data is available a data range of 0.5 to 0.7 may be a good initial value for ω_o, ω_g they also mention that should be greater than or equals to

ω_o. At $\omega_o = 0$ the solvent displaces oil immiscibly and when it is 1 it is completely miscible. ω_o has a max value when pressure is equals or greater than minimum miscible pressure (MMP). It is also suggested that to in order to estimate the max ω_o Koval formular should be used:

$$\omega_{o\,max} = 1 - \frac{4Log\left(0.78 + 0.22M^{\frac{1}{4}}\right)}{Log(M)}, where\ M = \frac{\mu_{oil}}{\mu_{solvent}}, \mu\ is\ the\ viscosity$$

ω_{sol}^{Frac} is calculated by:

$$\omega_{sol}^{Frac} = \left(\frac{\omega_o^{Frac}\ S_o^*}{\omega_o^{Frac}\ S_o^* + \ \omega_o^{Frac}\ S_g}\right)\omega_o^{Frac} + \ (\frac{\omega_g^{Frac}\ S_g}{\omega_o^{Frac}\ S_o^* + \ \omega_o^{Frac}\ S_g})\omega_g^{Frac}$$

$$\omega_{sol} = \left(\frac{\omega_o S_o^*}{\omega_o S_o^* + \ \omega_g S_g}\right)\omega_o + \left(\frac{\omega_g}{\omega_o S_o^* + \ \omega_g S_g}\right)\omega_g$$

The effective capillary pressure between oil and gas is modified (9) to:

$P_{cog}^{eff} = \frac{\omega_o}{\omega_{o\,max}} P_{cog} S_g + \left(1 - \frac{\omega_o}{\omega_{o\,max}}\right) P_{cog}(S_g - \ S_{sol})$ where P_{cog} is the capilliary pressure between oil and gas

The effective densities are modified (9) and shown below. They are a function of the pure component densities (9).

$\rho_P^{eff} = \ \omega_p \rho_P^m + \ (1 - \ \omega_p)\rho_P^{im}$ where P = oil, gas, or solvent.

ρ_P^{im} represent the pure component densities of the oil, gas, and solvent.

$$\rho_o^m = \left(\frac{S_o^*}{S_o^* + \ S_{sol}}\right)\rho_o + \ (\frac{S_{sol}}{S_o^* + \ S_{sol}})\rho_{sol}$$

$$\rho_g^m = \left(\frac{S_g}{S_g + \ S_{sol}}\right)\rho_o + \ (\frac{S_{sol}}{S_g + \ S_{sol}})\rho_{sol}$$

$$\rho_{sol}^m = \left(\frac{\omega_o S_o^*}{\omega_o S_o^* + \ \omega_g S_g + \omega_{sol} S_{sol}}\right)\rho_o + \left(\frac{\omega_g S_g}{\omega_o S_o^* + \ \omega_g S_g + \omega_{sol} S_{sol}}\right)\rho_g + \left(\frac{\omega_{sol} S_{sol}}{\omega_o S_o^* + \ \omega_g S_g + \omega_{sol} S_{sol}}\right)\rho_{sol}$$

The effective viscosities are modified (9) and shown below:

$\mu_P^{eff} = (\mu_P^m)^{\omega_p} * \ (\mu_P^{im})^{1-\omega_p}$ Where P = oil, solvent or gas

$$\mu_o^m = \frac{\mu_o\,\mu_{sol}}{\left(\left(\frac{S_o^*}{S_o^*+S_{sol}}\right)\mu_{sol}^{1/4} + \left(\frac{S_{sol}}{S_o^*+S_{sol}}\right)\mu_o^{1/4}\right)^4}$$

$$\mu_g^m = \frac{\mu_g\,\mu_{sol}}{\left(\left(\frac{S_g}{S_g+S_{sol}}\right)\mu_{sol}^{1/4} + \left(\frac{S_{sol}}{S_g+S_{sol}}\right)\mu_g^{1/4}\right)^4}$$

$$\mu_{sol}^m = \frac{\mu_g\,\mu_{sol}\mu_o}{\left(\frac{\omega_o S_o^*}{S_n}\right)\mu_{sol}^{1/4}\mu_g^{1/4} + \left(\frac{\omega_g S_g}{S_n}\right)\mu_o^{1/4}\mu_{sol}^{1/4} + \left(\frac{\omega_{sol} S_{sol}}{S_n}\right)\mu_o^{1/4}\mu_g^{1/4}}$$

Where

$$S_n = \omega_o S_o^* + \omega_g S_g + \omega_{sol} S_{sol}$$

μ_P^{im} represents the viscosities of the pure components

4.3.2: Scheme Design

As mentioned above, 2 out of the 9 wells will be used for gas injection and a main injection rate scheme of 750Mcf/d for each injection well will be used. This rate selected due to supply and economic constraints. However the effects of various gas injection rates was studied in the section "Effect of Gas Injection on Oil Recovery". This meant that the total possible distinct combination of gas injection schemes were 36. The model used to simulate gas injection was designed using both immiscible and pseudo-miscible options. However due to the inability of gas injection to sustain minimum miscibility pressure (MMP) the immiscibility option was used moving forward for gas injection runs. This is explained in more details in the gas injection results section.

4.4: Water Alternating Gas Injection (WAG)

WAG was introduced to bring the best out of both water flooding and gas injection. Constraints were the same as both the water flood and gas injection models; maximum bottom hole pressure (BHP) of

10,000psia. The pseudo miscible black oil model was used to simulate WAG runs to capture the miscible displacement of oil. Also, local grid refinement (LGR) was used around the injection wells due the complex fluid interaction around the well as well as the high block pressure during the waterflooding cycle.

4.4.1: Scheme Design

In WAG only 3 injection schemes were developed. These were based on the best 3 models/runs from both waterflooding and miscible (pseudo-miscible model) gas injection which yielded the highest recovery. In designing a WAG well, two injection wells were designed right on top of each other in the same grid block. One well was modeled to be a gas injector while the other was modeled to be a water injector. Both wells were tied as a well group and set to alternate. Meaning, when one well was active, the other was shut-in. This way both wells act like a single WAG well. The duration of each cycle (water and gas) was set as 240 days. The injection rates will depend on the base model from which the WAG model was developed from. Figure 14 shows an example WAG injection profile.

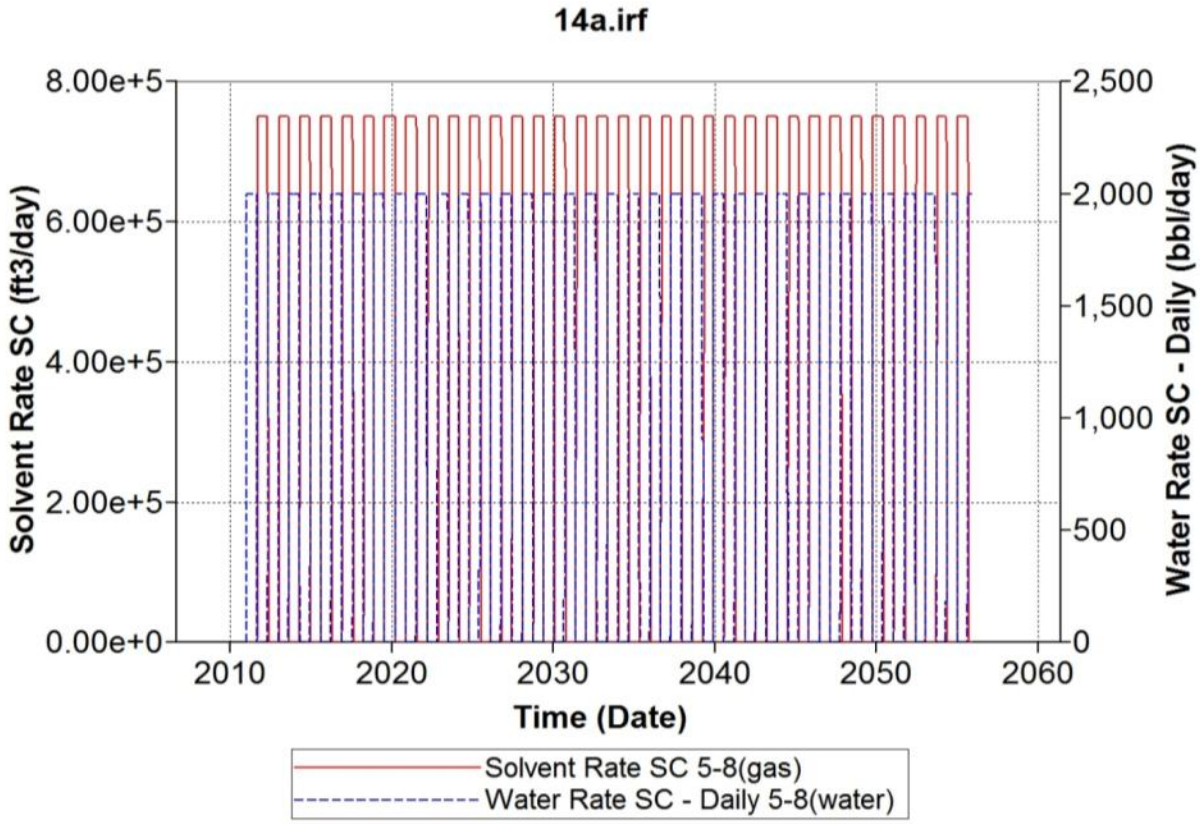


Figure 14: Example of WAG injection. Injection rates of 2000bbl/d during the water cycle and 750Mcf/d during the gas injection cycle per injector

WAG runs were simulated using the pseudo miscible black oil model to ensure miscible displacement when pressure was within the near-miscible zone (1) and above the MMP during the gas injection cycle.

4.5: Timing of Waterflooding and Gas Injection

The injection start time was observed to see what effects it had on oil recovery. By default, the start time of the injection well depended on when it was drilled by the operator. In order to properly observe the effects of injection start time, the start time for all the injection wells were normalized to be the same and varied every five years. The start time of injection affects the amount of injected fluid, the earlier injection starts the more the amount of fluid that will be injected into the reservoir. This could mean better pressure support as well as a higher sweep efficiency as the fluid would have more time to sweep the reservoir if injection starts early. It could also consequently mean that premature washout of the oil from the region of producers.

4.6: Relative Permeability

Other than the relative permeability data obtained through core analysis, two other sets of relative permeability data were previously generated through estimation and various correlations and provided by the operating company's field geologists. These two sets of relative permeability data were generated prior to core analysis in lieu of core data. The relative permeability curves of the old data are shown below:

Set 1 Relative Permeability:

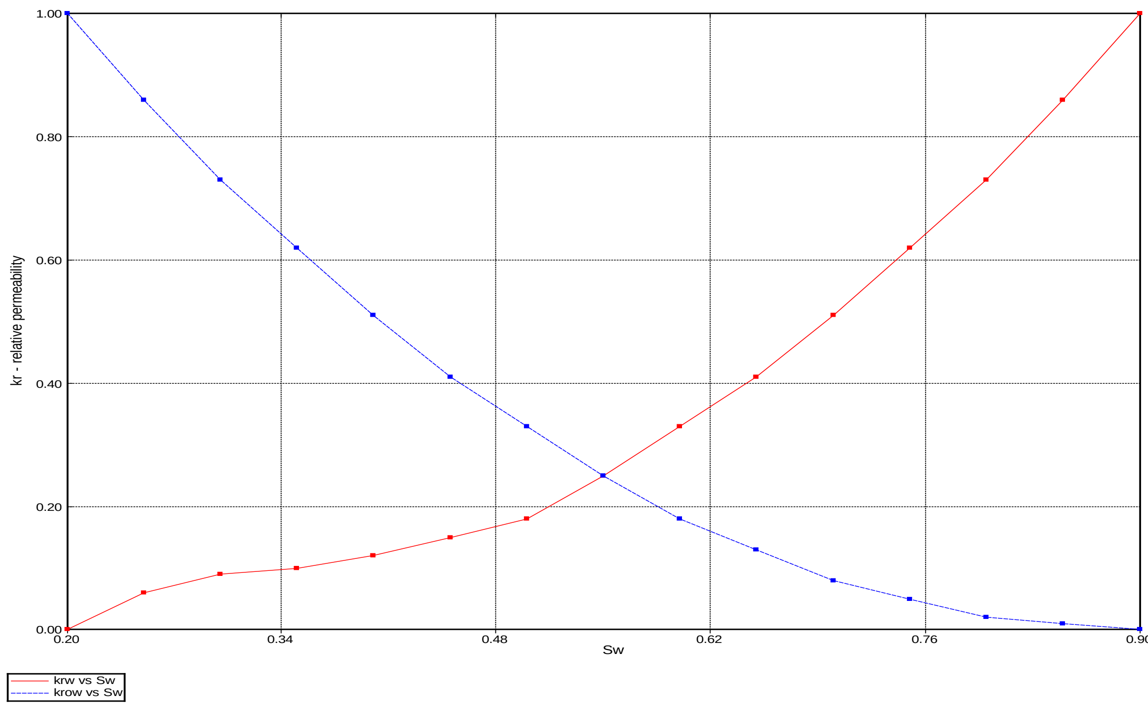


Figure 15: Set 1 Oil-Water Relative Permeability Curve (Data courtesy of operator, 2008)

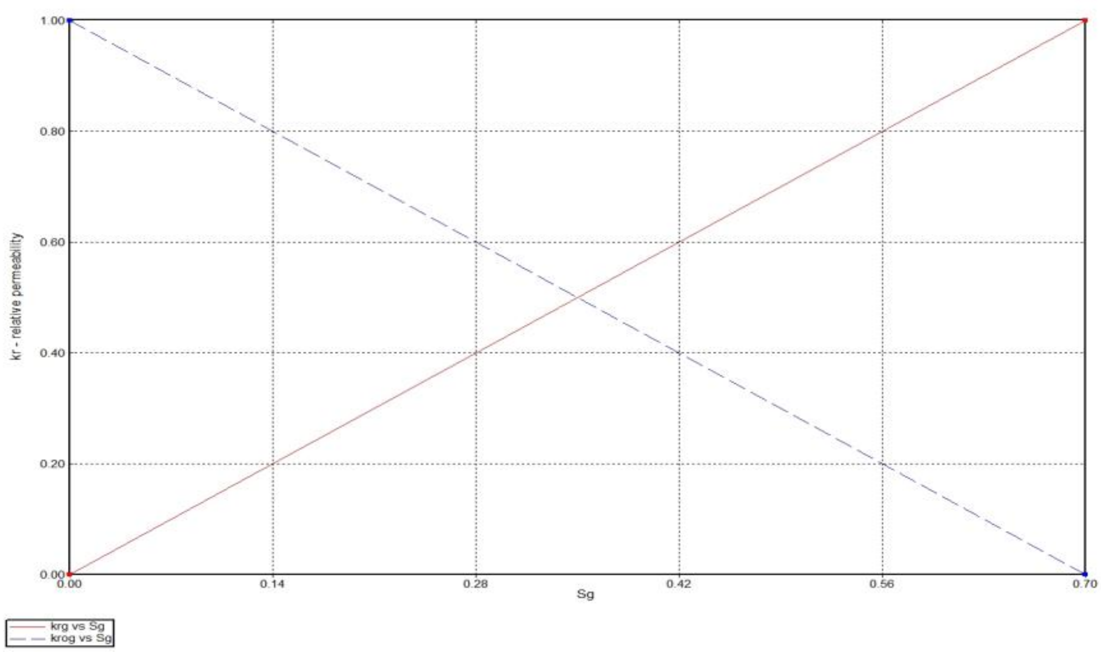


Figure 16: Set 1 Oil-Gas Relative Permeability Curve (Data courtesy of operator, 2008)

Set 2 Relative Permeability:

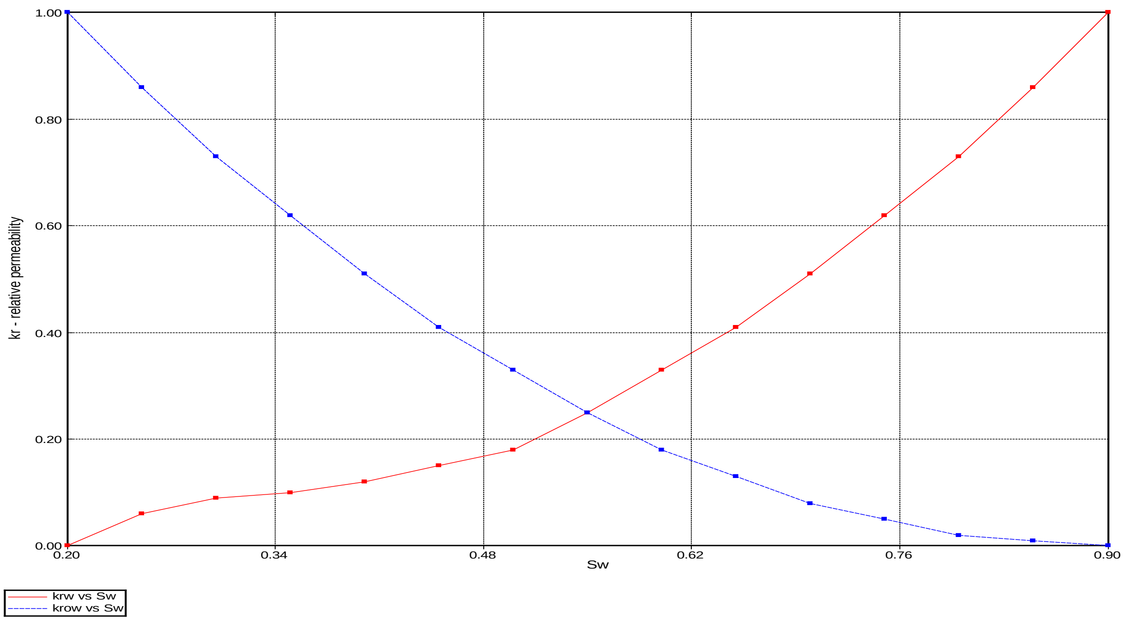


Figure 17: Set 2 Oil-Water Relative Permeability Curve (Data courtesy of operator, 2008)

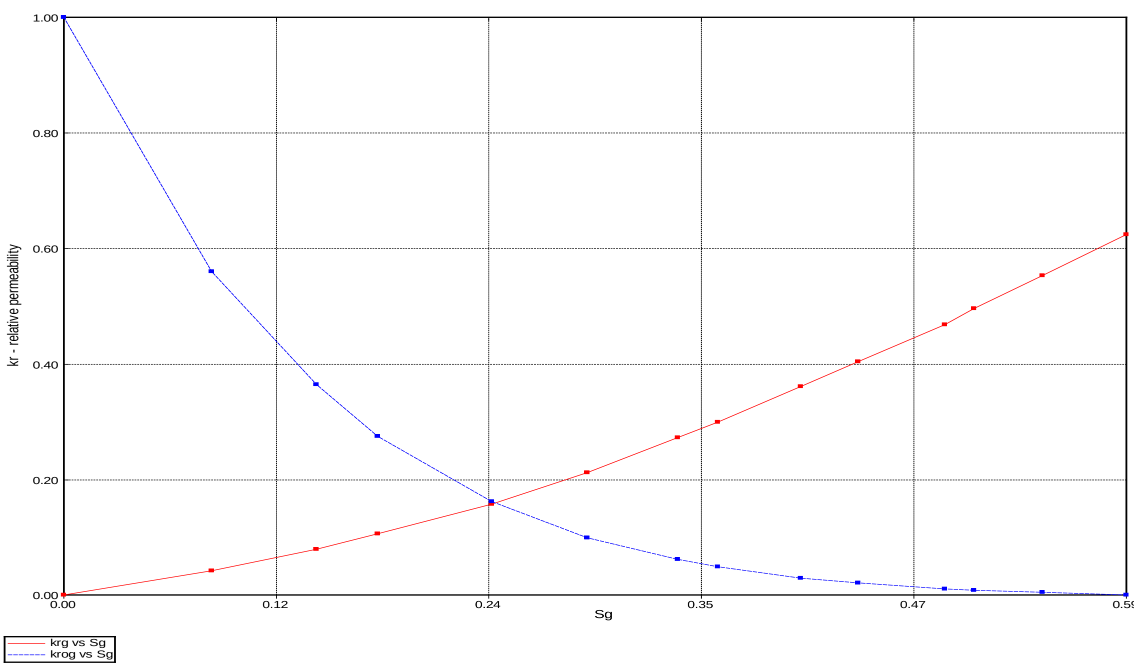


Figure 18: Set 2 Oil-Gas Relative Permeability Curve (Data courtesy of operator, 2008)

Table 7 below summarizes and compares some of the properties of the relative permeability curves of all 3 datasets.

Table 7: Comparison of properties of the 3 relative permeability sets

Data Set	**(Oil- water)** **Irreducible Oil**	**(Oil – Gas)** **Irreducible Oil**	**Connate water**
Core Analysis	0.35	0.55	0.15
Set 1	0.1	0.30	0.2
Set 2	0.1	0.41	0.2

The reservoir was modeled and simulated using not only the accurate relative permeability obtained from core analysis but also the 2 sets of estimated relative permeability to observe the effects of relative permeability on the reservoir. Based on the irreducible oil saturations, it would be expected that Set 1 would yield the highest recovery as it has the lowest irreducible oil saturations.

Chapter 5: Results and Analysis

5.1: Base Model (Primary Production)

In the base model under just primary depletion, all 9 wells acted as producers. The performance of the field for 20 years under primary depletion is shown in the figure below:

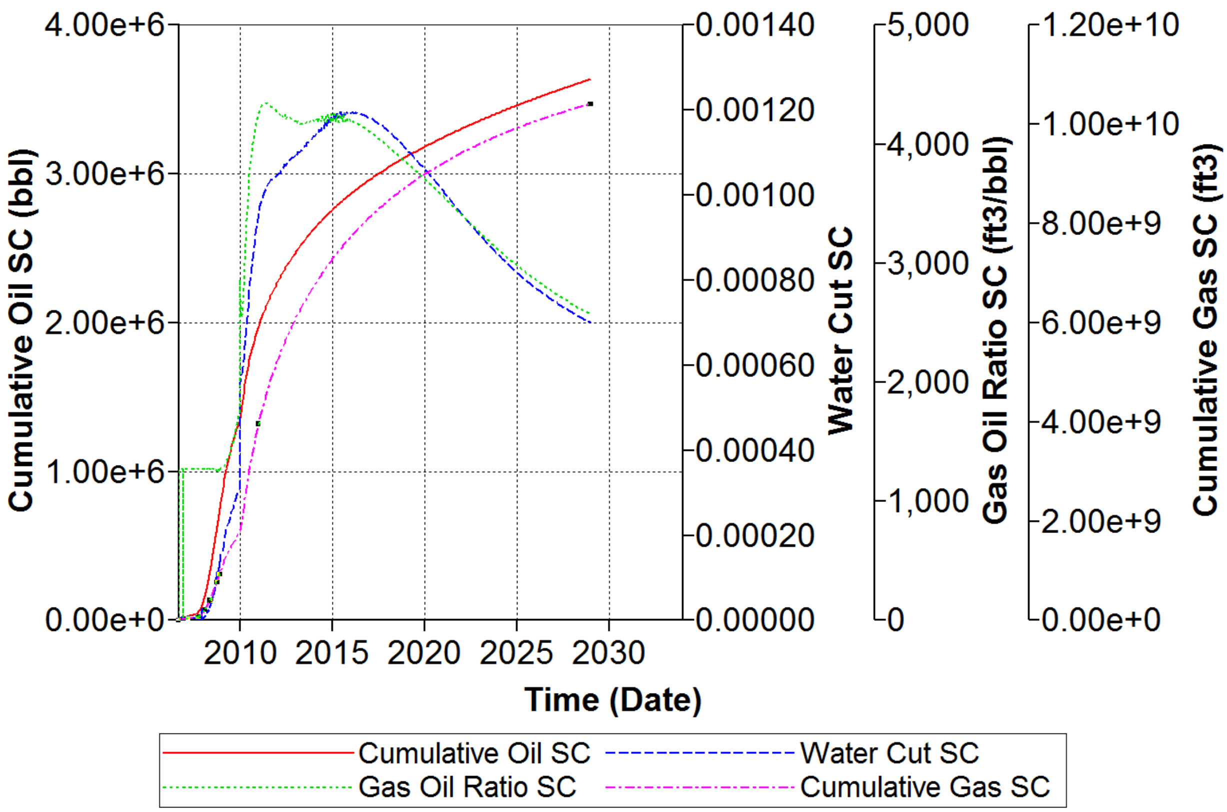


Figure 19: Field production performance under primary depletion

Field production started in Aug. 2006. Between Aug. 2006 and Dec. 2009, production on all the wells was constrained as per actual data. Post Dec. 2009, these constraints were removed, thus the slight jump in production shown in Dec.2009 and represented in Figure 19. The watercut rises to its highest value of 0.12% in Feb. 2015 and starts declining shortly after due to the reduction of water produced as a result of declining reservoir pressure. The GOR is constant (1273ft^3/bbl) at the start of production but starts increasing at Jan. 2009 due to pressure falling below bubble point around sections of the reservoir. GOR hits its max (4344 ft^3/bbl) in May. 2011 and begins to decline after that due to the reduction reservoir energy (pressure). The cumulative oil, gas, and water recovered over the 20 year period are: 3.64MMSTB, 10.4BCF, and 2.4MSTB respectively.

The pressure distribution under primary depletion is shown below:

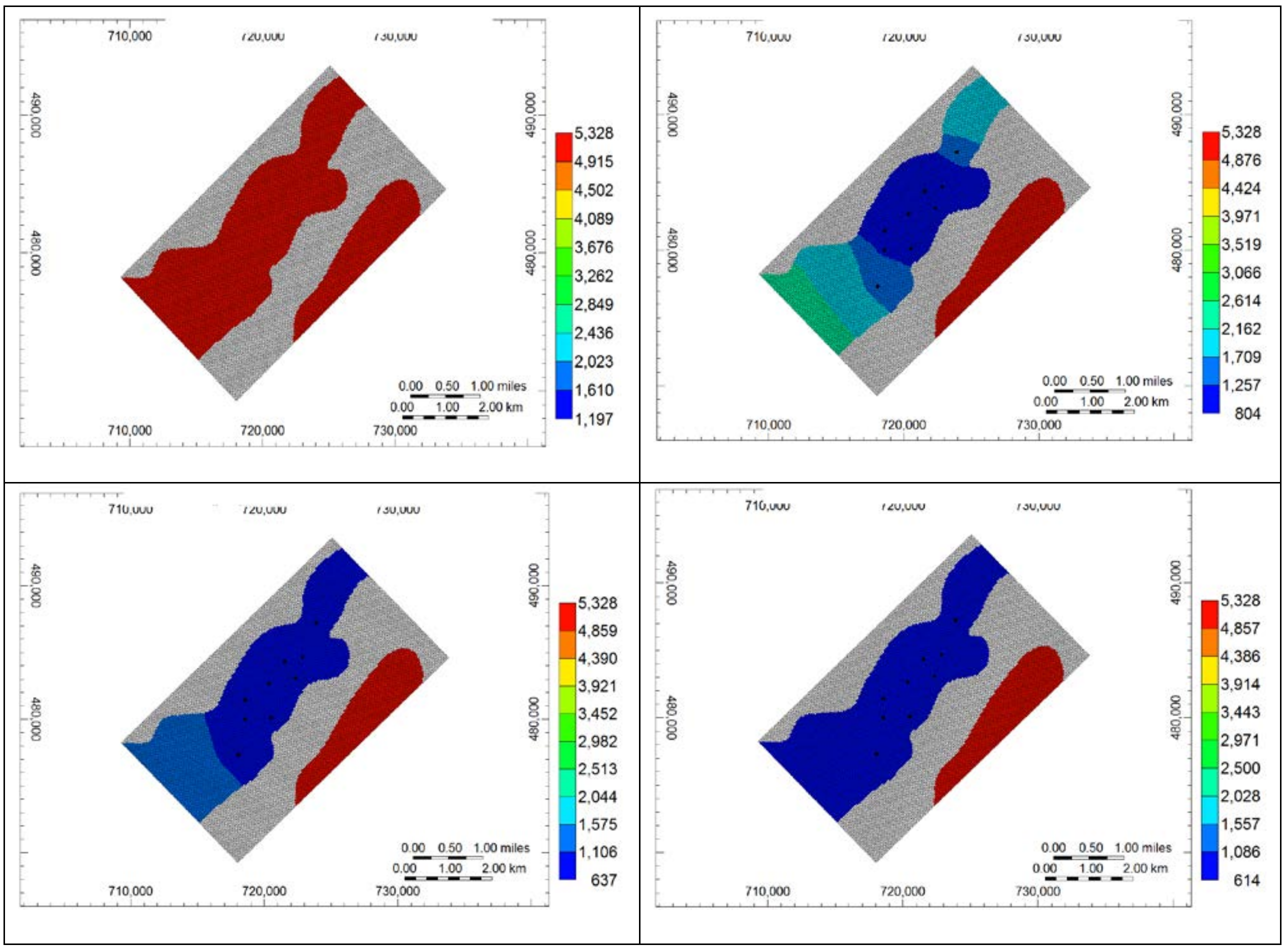


Figure 20: Primary depletion Pressure distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

As shown in Figure 20, the reservoir experiences very strong pressure decline; after 5 years the average reservoir pressure is well below 2000psi.

5.2: Effect of Waterflooding on Oil Recovery

Before running a full comprehensive scale simulation study on all the possible water injection and gas injection schemes, it is important to understand the different effects of the fluids injected into reservoir have on oil recovery. For this, two cases shown in the figure below were used to observe the various effects. Each case has a different placement of injection well location.

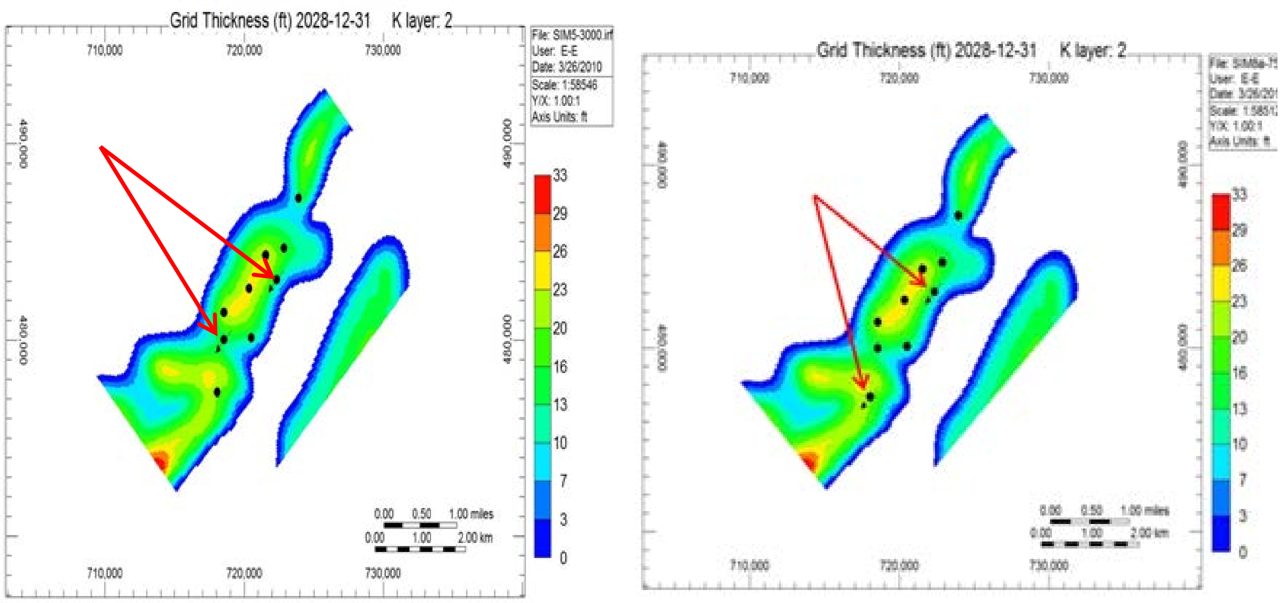


Figure 21: Injection Well Distribution for Case 1 (right) and Case 2 (left)

In this preliminary phase, before the full simulation study, the effects of injection rate and injection location were studied. This was done to provide insight as to the setup of parameters and allow for a better understanding of the results to be obtained after the full simulation study. This test was performed for both waterflooding and gas injection scenarios.

5.2.1: Effects of Injection Rate on Recovery during Waterflooding

The injection rate was varied to see its effect on recovery. The rates per injector well used were 1000bbl/d, 1500bbl/d, 2000bbl/d, 2500bbl/d, and 3000bbl/d of water. Recovery from case 1 was observed and shown in Figure 22. Recovery from case 2 with respect to injection rate is shown in the “Effects of Injection Location” section. The setup and injection location for case 1 and 2 are shown in Figure 21.

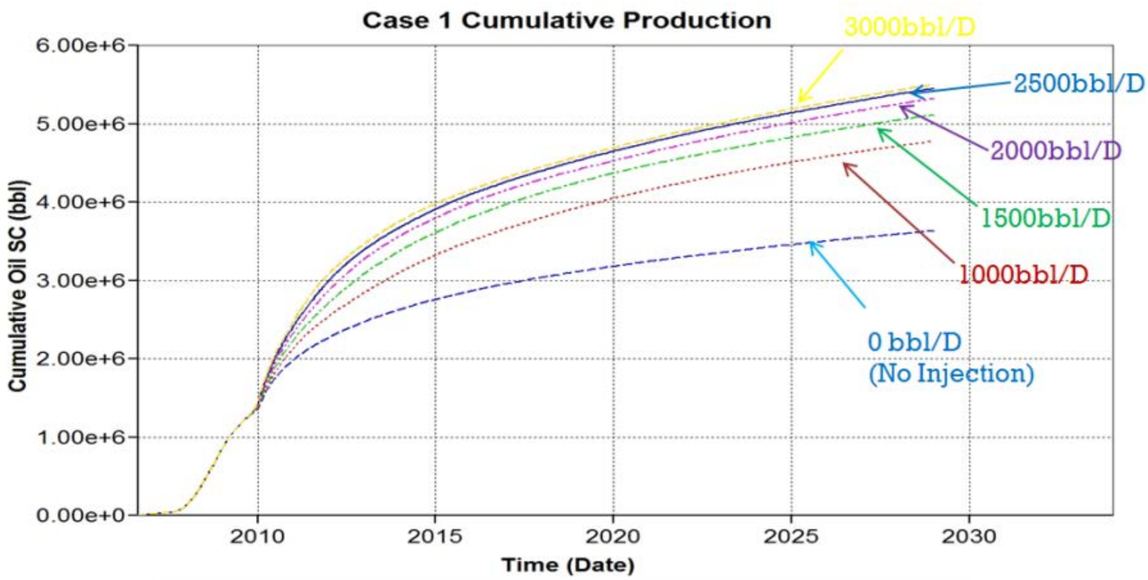


Figure 22: Effects of injection rate

As shown above, recovery increases with respect to an increase in the water injection rate. However the percentage increase decreases as the injection rate increases. This means that there is a point when an injection rate increase will not yield any increase in recovery. In the figure above, there is a significant increase in recovery by increasing the injection rate for each injector from 1000bbl/d to 1500bbl/d; however, when observing the increase in injection rate from 2500bbl/d to 3000bbl/d, the increase in recovery is marginal to none.

5.2.2 Effects of Injection Location on Recovery during Waterflooding

Here, we observe the behavior of oil recovery due to changing the location of the injection wells. The setup and injection location for case 1 and 2 are shown in Figure 21.

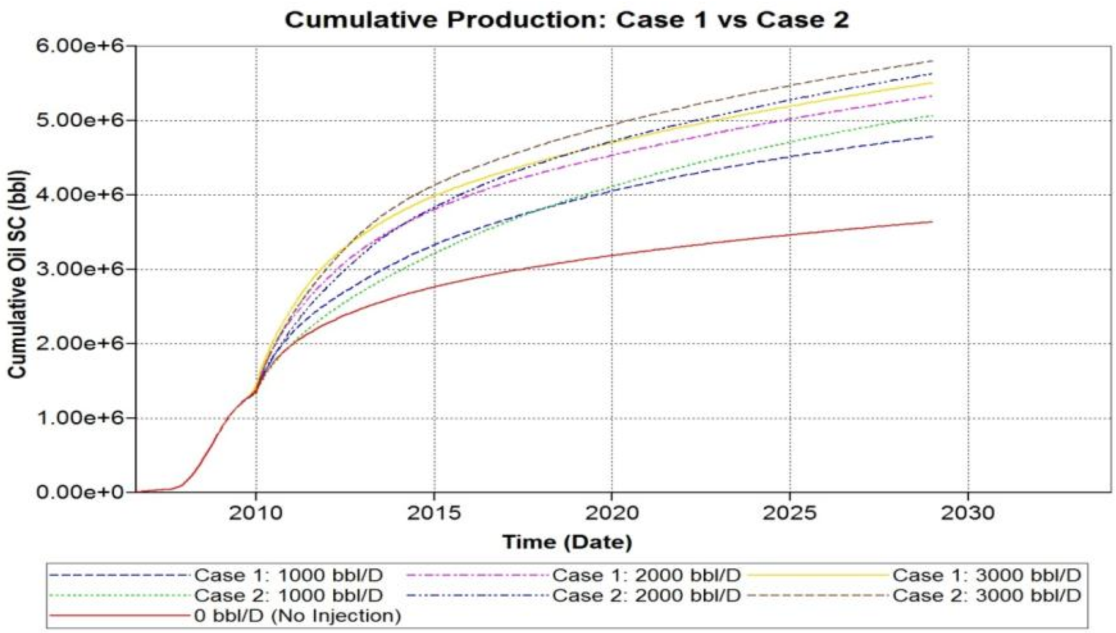


Figure 23: Waterflooding - Effects of injection location on oil recovery

As shown in the figure above, the location affects the oil recovery. The injector location setup in case in case 2 yields far better recovery than that in case 1. We also see that case 2 with a lower injection rate yields higher recovery than case 1 with a higher injection rate. For example, at an injection rate 200bbl/d per injector, case 2 yields higher recovery than the case 1 setup at an injection rate of 3000bbl/d. In case 2 you are able to save money on injection and water cleanup and still have a higher recovery than case 1.

In case 2, water production is always less than that in case 1. This is shown in the figure below.

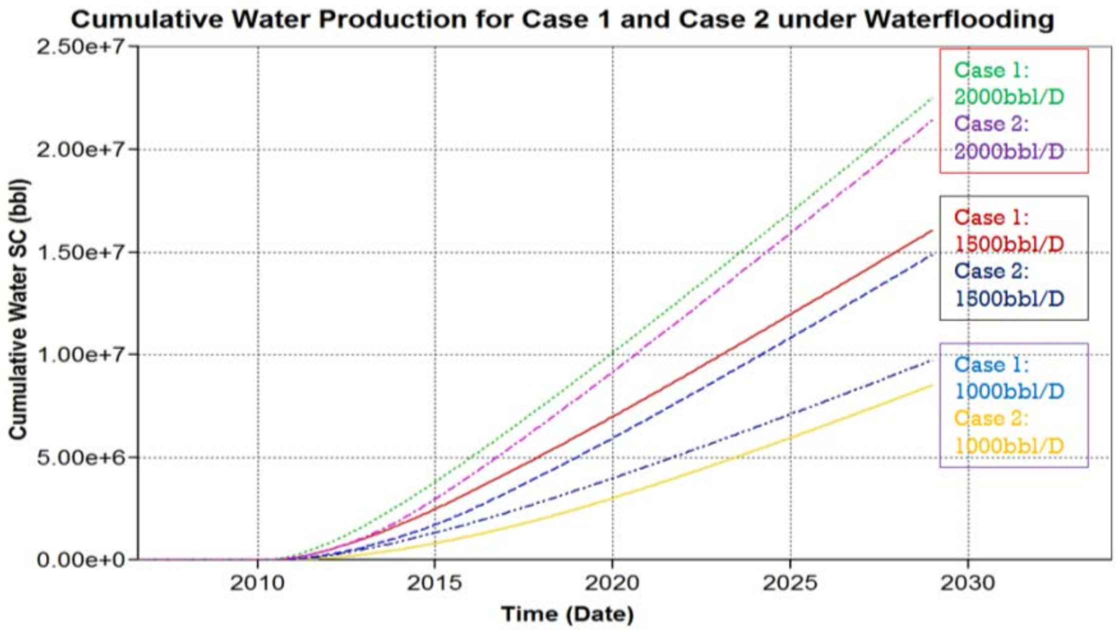


Figure 24: Waterflooding - Effects of injection location and rate on water production

Similar to case 1, oil recovery in case 2 increases with an increase in injection rate. There also exists a point where oil recovery stops increasing despite an increase in injection rates.

5.2.3: Summary of Effects of Injection Rate and Location on Recovery during Waterflooding

The effects of injection rate and injection location during waterflooding are shown in the table below.

Table 8: Waterflooding - Summary of results of the effects of injection location and rate on oil recovery

Injection Rate (Per injector)	**Case 1 Cumulative Production (MMSTB)**	**Case 2 Cumulative Production (MMSTB)**
0 bbl/D	3.64MMSTB	3.64MMSTB
1000 bbl/D	4.78MMSTB	5.06MMSTB
1500 bbl/D	5.12MMSTB	5.40MMSTB
2000 bbl/D	5.33MMSTB	5.63MMSTB
2500 bbl/D	5.45MMSTB	5.74MMSTB
3000 bbl/D	5.50MMSTB	5.80MMSTB

As shown in the above table and mentioned in the previous sections, increase in injection rate yields an increase in oil recovery, this true for both cases. However, there is a decrease in the percentage increase of oil recovery with the increase in injection rate. This means there exists a plateau point, where increasing the injection rate results in little to no increase in oil recovery.

Also, the location of the injection well plays an important role in oil recovery. Changing the injection wells location from case 1 to case 2 yields an increase in oil recovery. This is true for every injection rate studied. In fact, certain injector location placement with lower rates will yield higher recovery than that at higher rates from a different location. This is situation between case 1 and case 2. At an injection rate of 1500bbl/d per injector, oil recovery from case 2 is 5.4MMbbl while in case 1 oil recovery is 5.12MMbbl and 5.33MMbbl at injection rates of 1500bbl/d and 200bbl/d respectively. This behavior is also observed at higher injection rates of 2000bbl/d and 2500bbl/d. The case 2 setup is not just a better performer compared to case 1 in terms of oil recovery, but also in terms of water production. Case 2 recovers more oil and far less water compared to case 1.

5.2.4 Waterflooding: Full Simulation Study

As mentioned in the methodology section for the waterflooding scheme design, a total of 108 unique models were generated. There were 3 sets of relative permeability data bringing that number up to 324. However only the results from 108 models generated using the relative permeability data from core analysis (the most accurate data) will be discussed here.

The 108 runs using core data were executed and the best 3 runs were selected for further evaluation to better understand what was happening. Appendix A shows the oil recovery for each of the 108 schemes/runs designed. Appendix C and E shows the comprehensive recoveries using the other relative permeability data (Set 1 and Set 2 respectively). The recovery for the best 3 runs is shown in the table below:

Table 9: Waterflood Recovery from Top 3 models

Waterflood Run	Waterflooding			
	Cum Production (MMSTB)	**Cum Water Production (MMSTB)**	**Cum Gas Produced (MMSCF)**	**Water Injection Rates (Per Injector) (BBL/D)**
0	3.64	0.0024	10400	0
15	5.80	25.46	7701.00	3000
14	5.78	20.61	7766.54	2000
18	5.72	25.52	8005.83	3000

Run 0 is production by primary depletion. As shown in the table above, the highest recovery came from run 15 with a cumulative oil production of 5.8MMSTB. The behavior of runs 14, 15, and 18 are very similar, resulting in run 15 being used as a representative for runs 14, and 18.

5.2.4.1: Waterflood Run 15

In run 15, the placement of the injection wells are shown in the figure below. Each injection well is set to inject at a rate of 3000bbl/d.

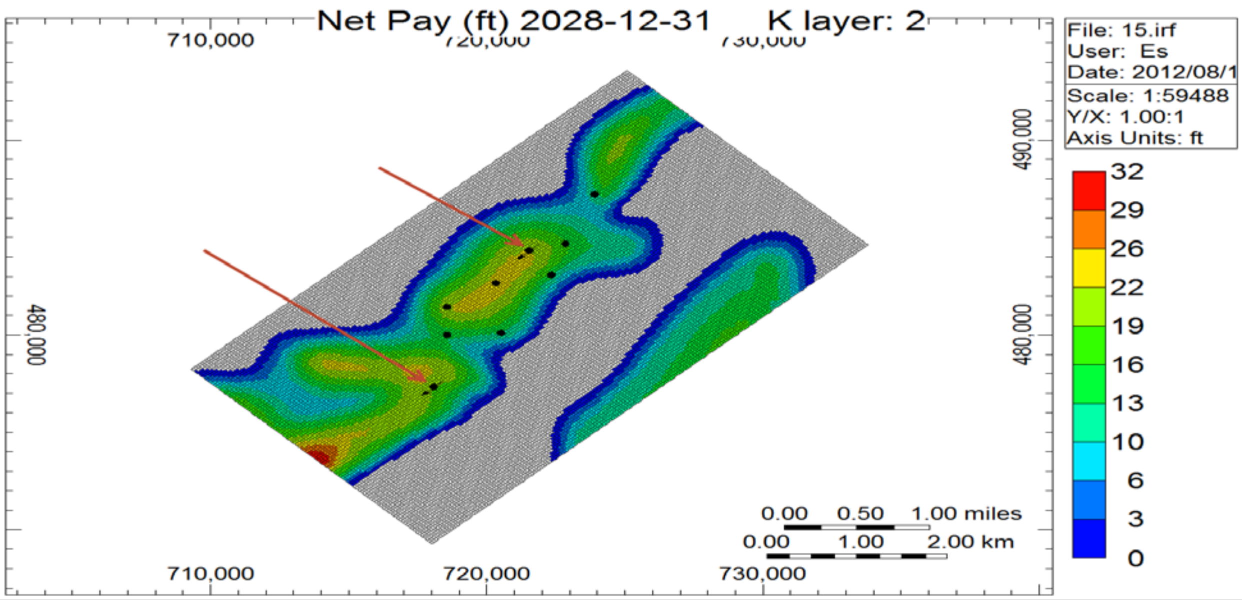


Figure 25: Injection Well Placement for Waterflood run 15

The recoveries and performance from waterflood run 15 is shown in the figure below:

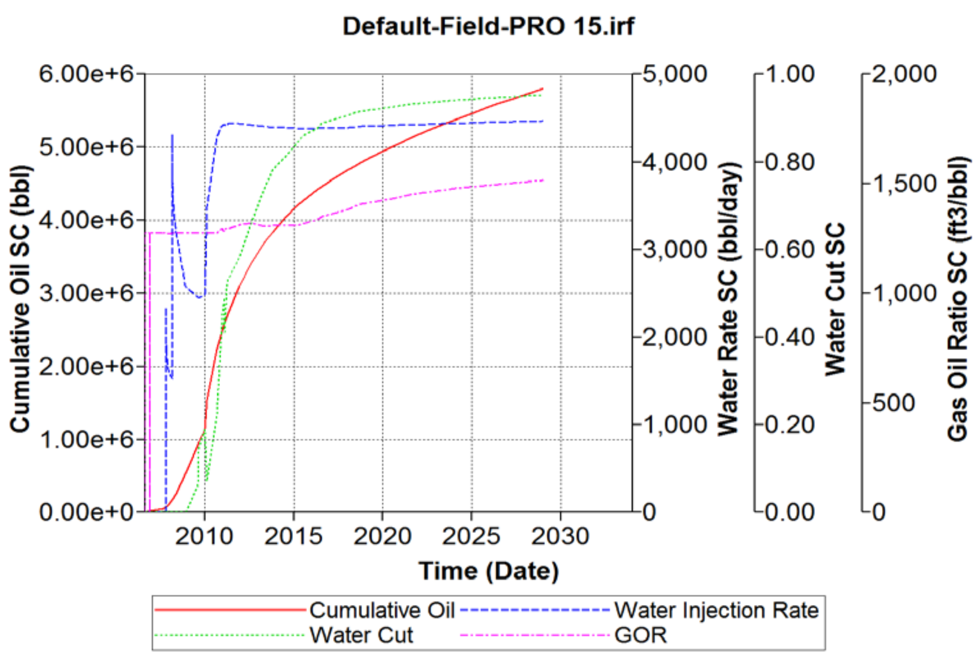


Figure 26: Waterflood run 15 recovery and performance plot

At 2015, 9 years after production the water cut is about 80%. The voidage rate ratio of run 15 is shown in the figure below:

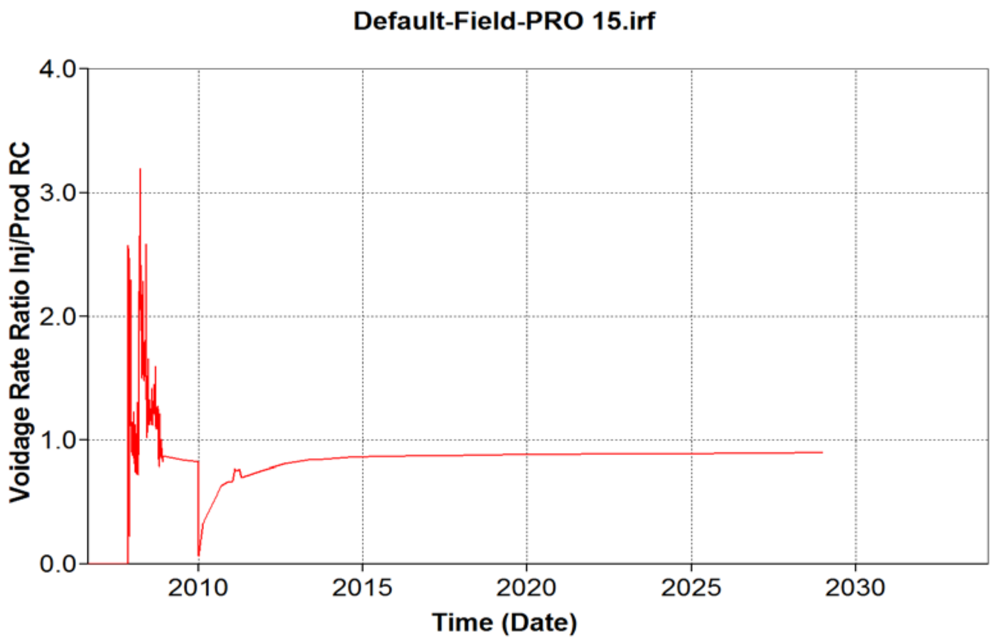


Figure 27: Waterflood run 15 voidage rate ratio

The pressure distribution for run 15 at initialization, 5 years, 10 years and 15 years after production start is shown below:

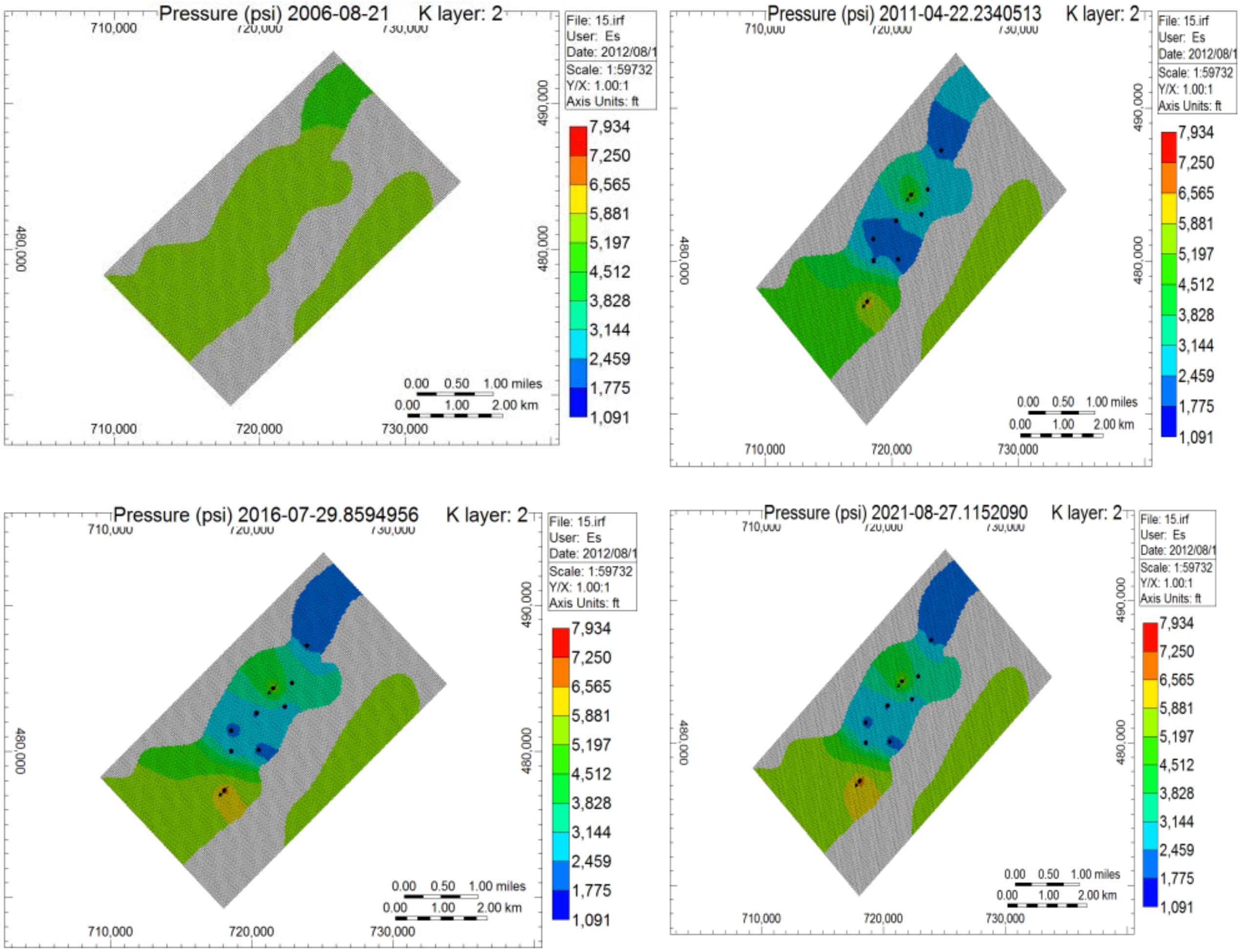


Figure 28: Waterflood run 15 Pressure distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

There is an initial strong drop in reservoir pressure, but after an extended injection duration this pressure drop is reduced and in some parts of the reservoir the pressure increases.

The oil and water saturation distribution for this run is shown below:

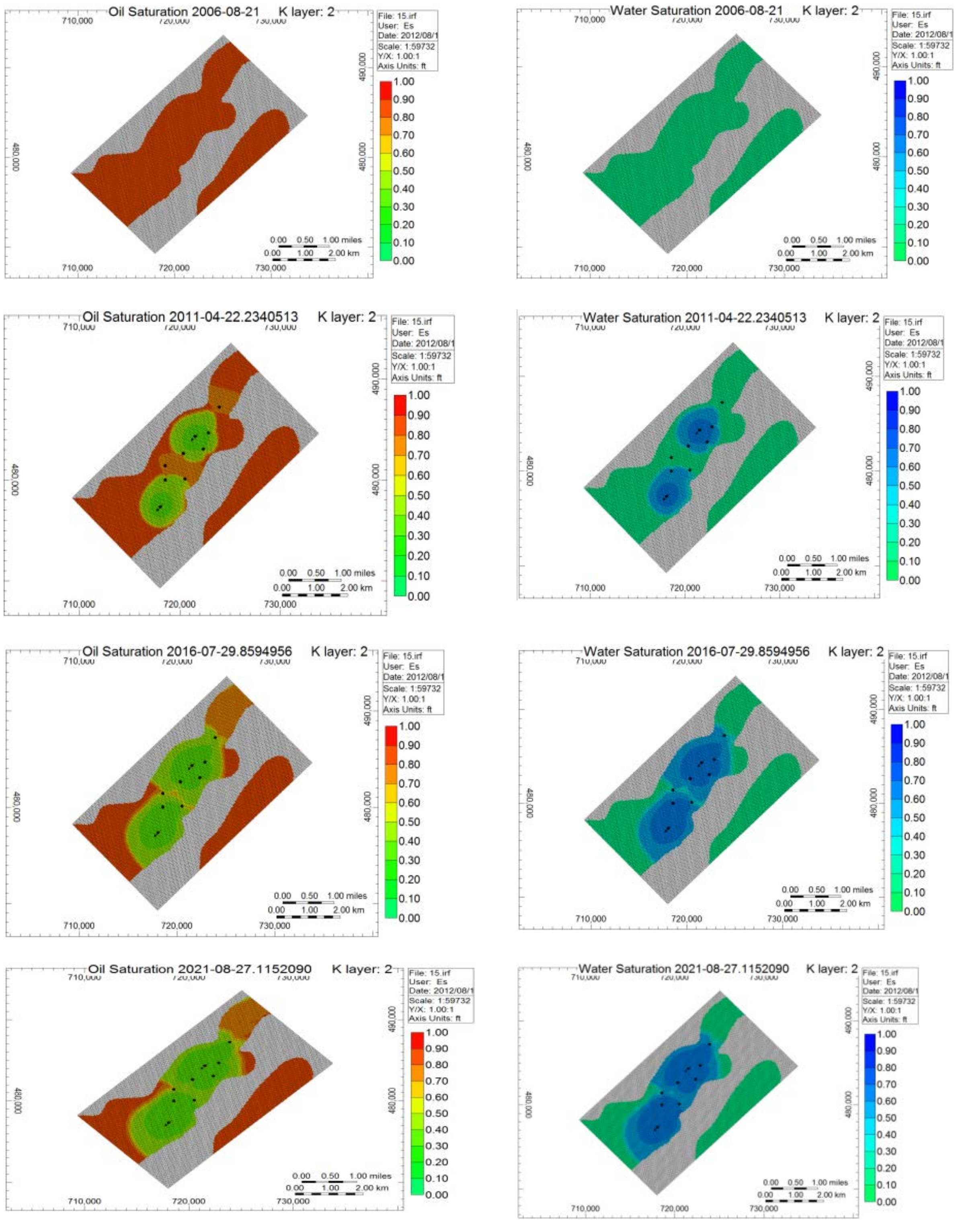


Figure 29: Waterflood run 15 Oil Saturation (left) and water saturation (right) for 0, 5, 10, and 15 years after production start (top to bottom)

5.2.5: Waterflood Runs Discussion and Possible Recommendations

Though runs 14, 15 and 18 are each unique, the general reservoir response to all 3 schemes is similar. Runs 14 and 15 are setup exactly the same, with the only difference being the injection rate. Run 14 had an injection rate of 2000bb/d and run 15 had a rate of 3000bbl/d for each injection well. This meant that run 15 would be more efficient in reservoir pressure maintenance due to a higher voidage replacement ratio as a result of having more water injected into the reservoir. Run 18 also had an injection rate of 3000bbl/d but recovered less oil than run 14 which had a lower injection rate. This implied that the injection well placement in run 18, based on the waterflood scheme design, is not as efficient as the injector placement in runs 14 and 15.

The voidage rate ratio curves of runs 14, 15, and 18 are relatively about the same and shown in Figure 48. This is due to the production rates differences and low injectivity preventing the injection of high volumes of water. Appendix A shows the actual injection rates of all the runs and we see that though runs 15 and 18 had an intended injection rate of 6000bbl/d total, the actual average injection rate was roughly 4460bbl/d for both. Run 14 also had an intended total injection rate of 4000bbl/d but actual injection rate was about 3674bbl/d. This is due to the injectivity and the BHP constraint set.

As mentioned above the reservoir response for the 3 runs with the highest recovery (runs 14, 15, and 18) is very similar in respect to trends. After production and injection operations have continued for an extended period of time, 3 areas where oil had migrated to and not effectively drained were identified. These 3 areas are shown in the pressure, oil saturation, and net pay thickness distribution maps below taken at approximately 20 years after production started.

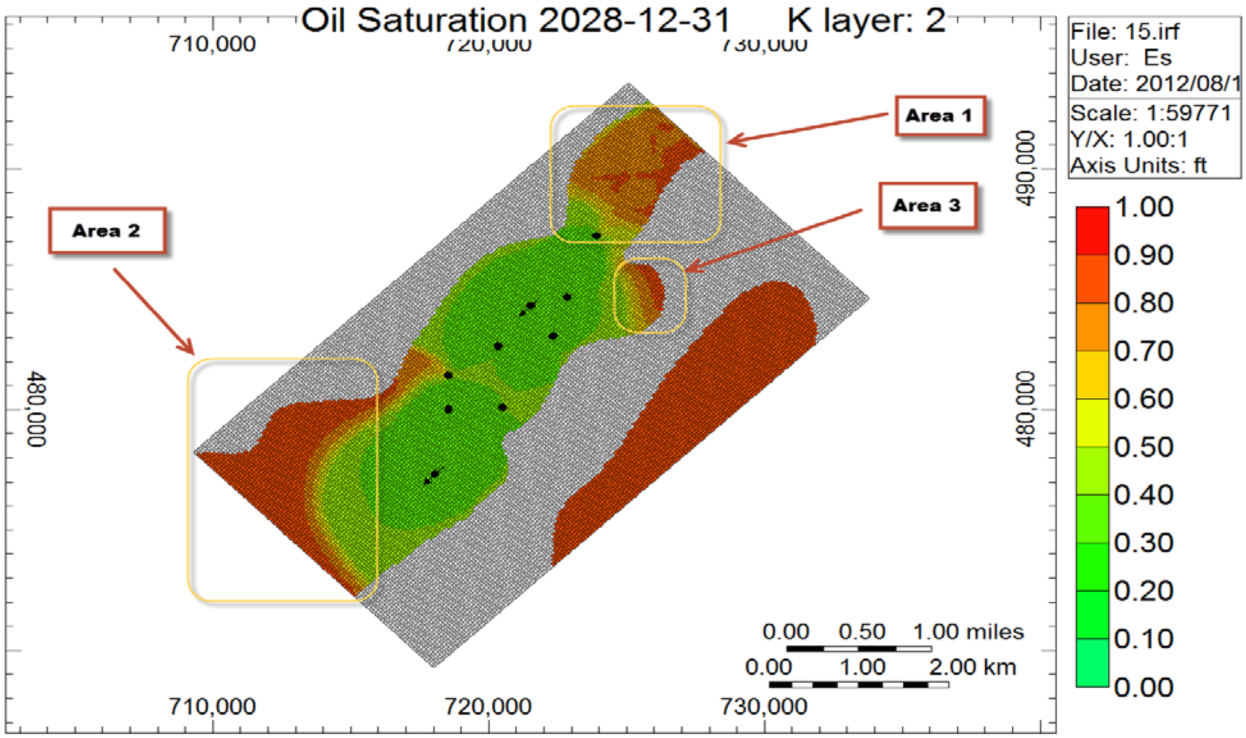


Figure 30: Oil Saturation with recommendation zones

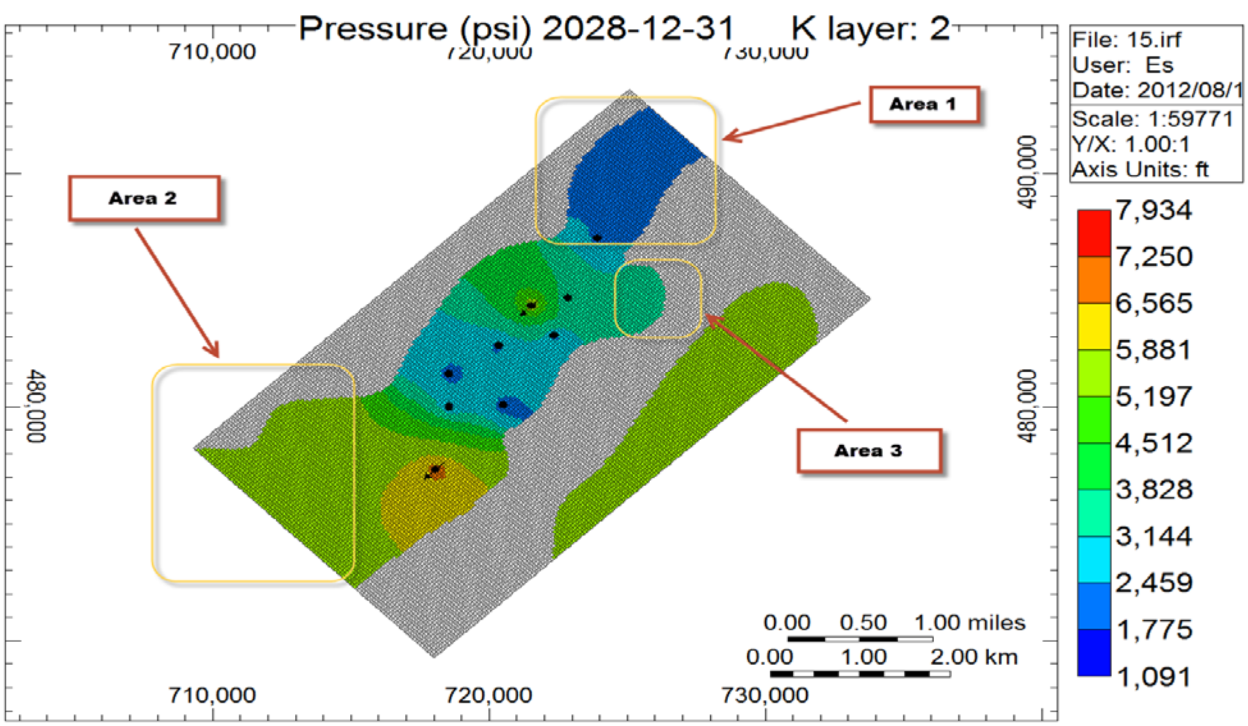


Figure 31: Pressure map with recommendation zones

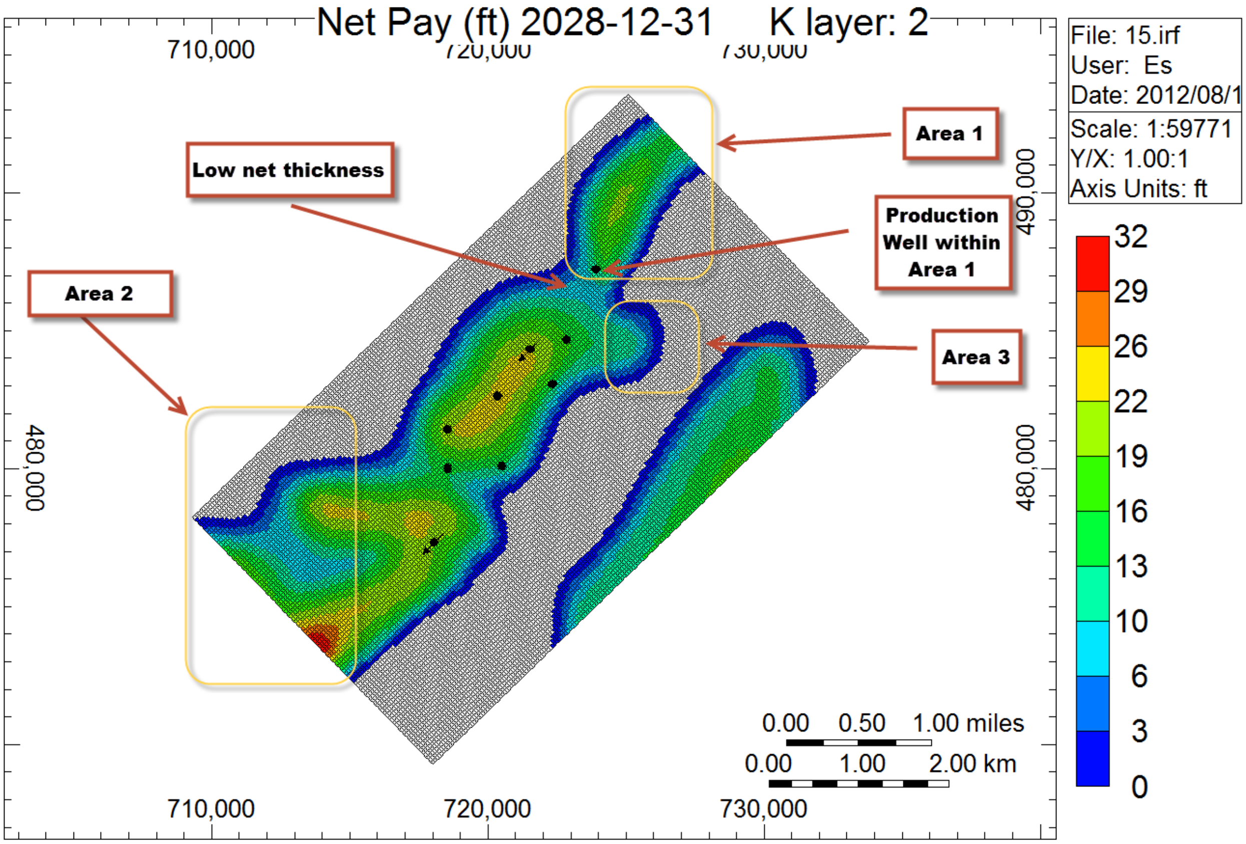


Figure 32: Thickness map with recommendation zones

In Area 1, the production well within it, is pseudo locked in that region and drains the area more than the rest of the reservoir due to the streak of low net pay thickness isolating the well from the reservoir, shown in the figure above. The well drains rest of the reservoir, but at a much lower rate compared to Area 1. As a result of all of this, the pressure in area 1 drops quickly and is shown in the pressure map above, leaving oil behind as shown in the oil saturation maps above. The recommendation will be to place an injector at north corner of Area 1 opposite the producer. This will increase the pressure within that area and will displace oil towards the producer.

In Area 2, the recommendation will be to place a new producer at the south west of the region. Area 2 has a relatively high reservoir pressure and a large undrained oil area. This is shown in the pressure and oil saturation maps.

In Area 3, if economics allow it, having a well placed there will drain the pocket of undrained oil in that region.

5.3 Effect of Gas Injection on Oil Recovery

5.3.1 Effects of Injection Rate on Recovery during Gas Injection

Similar to the water injection scenario, two cases shown in Figure 21, are used to observe the effects of injection rate on recovery. The oil recovery at injection rates of 750Mscf/d, 900Mscf/d, and 1125Mscf/d per injection well was observed. The figure below shows oil recovery at these injection rates.

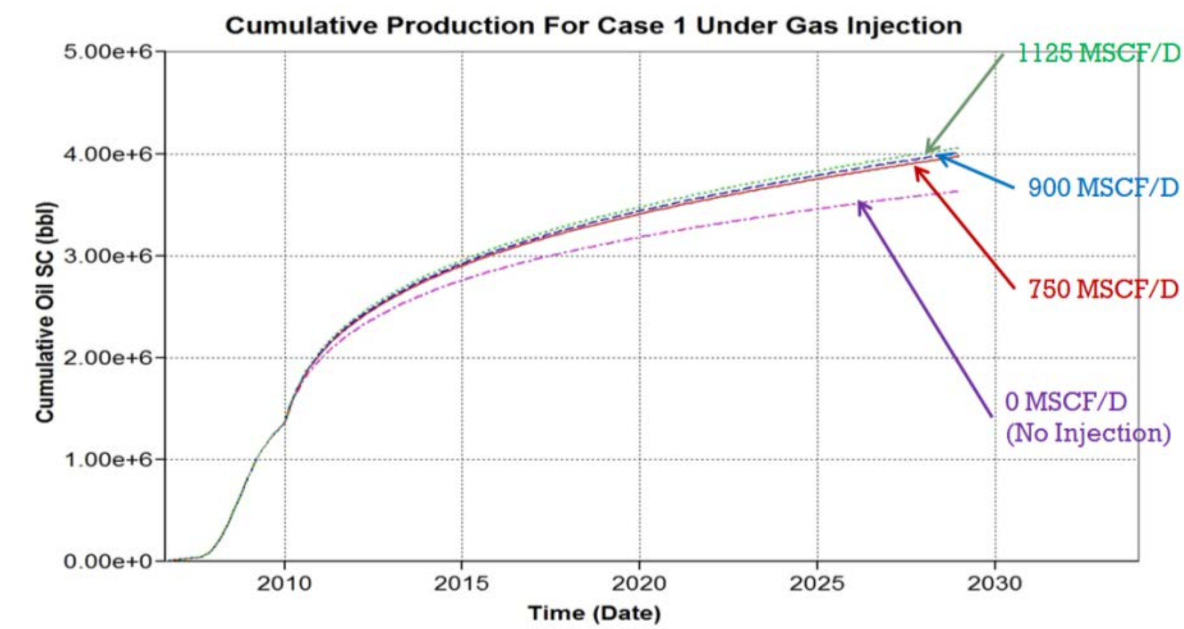


Figure 33: Gas Injection - Effects of injection rate on recovery

As shown in the figure above, similar to waterflooding, increase in injection rate leads to an increase in oil recovery. However, there is very little increase in oil recovery with increases in the injection rate. There is a marginal increase going from 750Mscf/d to 1125Mscf/d. This and gas availability constraints set the injection rate for the comprehensive simulation study at 750Mscf/d per well for the gas injection runs.

5.3.2: Effects of Injection Location on Recovery during Gas Injection

Here, just as water flooding, we have 2 cases, each with a different placement of the injection wells. Figure 21 shows the injector location for both cases. For each case, injection rates of 750Mscf/d and 1125Mscf/d per injection well were studied. The figure below shows the oil recovery for both cases.

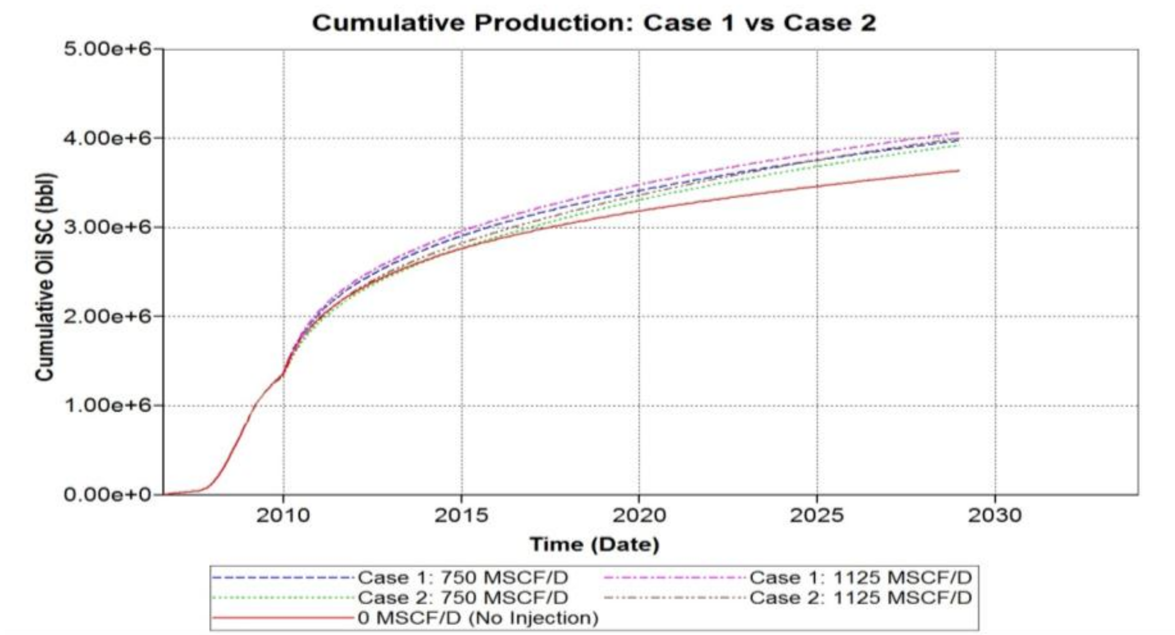


Figure 34: Gas Injection - Effects of injector location on recovery

In complete contrast to waterflooding, case 1 recovers more oil compared to case 2. Here, case 1 recovers marginally more oil compared case 2 at every injection rate. Also, similar to the waterflooding scenario, case 1 produces more water than case 2. This is shown in the figure below.

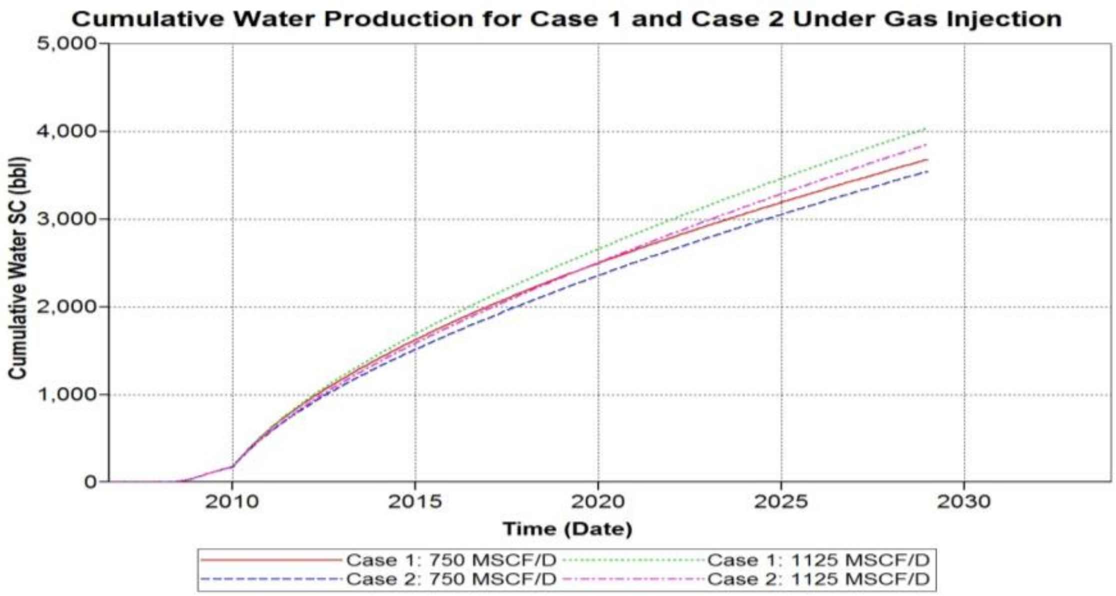


Figure 35: Gas Injection - Effects of Injection rate and location on water production

5.3.3: Summary of Effects of Injection Rate and Location on Recovery during Gas Injection

The effects of injection rate and injection location during gas injection are shown in the table below.

Table 10: Gas Injection - Summary of the effects of injection rate and location on recovery

Injection Rate (Per Injector)	Case 1: Cumulative Oil Production (MMSTB)	Case 2: Cumulative Oil Production (MMSTB)
0 MSCF/D	3.64MMSTB	3.64MMSTB
750 MSCF/D	3.98MMSTB	3.92MMSTB
900 MSCF/D	4.01MMSTB	3.96MMSTB
1125 MSCF/D	4.06MMSTB	4.00MMSTB

As shown in the table above, for gas injection, case 1 yields the higher oil recovery, but the difference between both cases is minimal. Though case 1 produced more water than case 2, the difference is also minimal. Increase in injection rate for both case 1 and 2 both yield higher recovery, but there is only little marginal gain in oil recovery due to the increase in injection rate for both cases.

5.3.4: Gas Injection: Full Simulation Study

As stated in the scheme setup for gas injection, there are 36 distinct combinations of injection schemes/designs. Only results generated using the most accurate relative permeability curves, i.e data obtained from core analysis, will be reviewed here.

Similar to waterflooding, the 3 best schemes were picked for further review. Appendix B shows the oil recovery from all the gas injection schemes. The recoveries from these 3 runs/schemes are shown in the table below:

Table 11: Gas injection summary of best 3 runs

Gas Injection Run	**Gas Injection**			
	Cumulative Production (MMSTB)	**Cum Water Production (MMSTB)**	**Cum Gas Produced (MMSCF)**	**Gas Injection Rates (Per Injector) (MSCF/D)**
0	3.640	0.002	10400.000	0
13	4.133	0.003	20656.282	750
34	4.120	0.003	20484.268	750
12	4.093	0.003	20712.839	750

Gas injection runs 13, 34 and 12 were found to have the largest oil recovery. The oil saturation, water saturation, and pressure distribution for all 3 runs were very similar in regards to trend, so as a representative, the distributions for run 13 is used to describe the other runs.

5.3.4.1: Gas Injection Run 13

Gas injection run 13 had the highest recovery among all the gas injection runs. It had a cumulative oil recovery of 4.13MMSTB. The location of the injection wells are shown in the figure below:

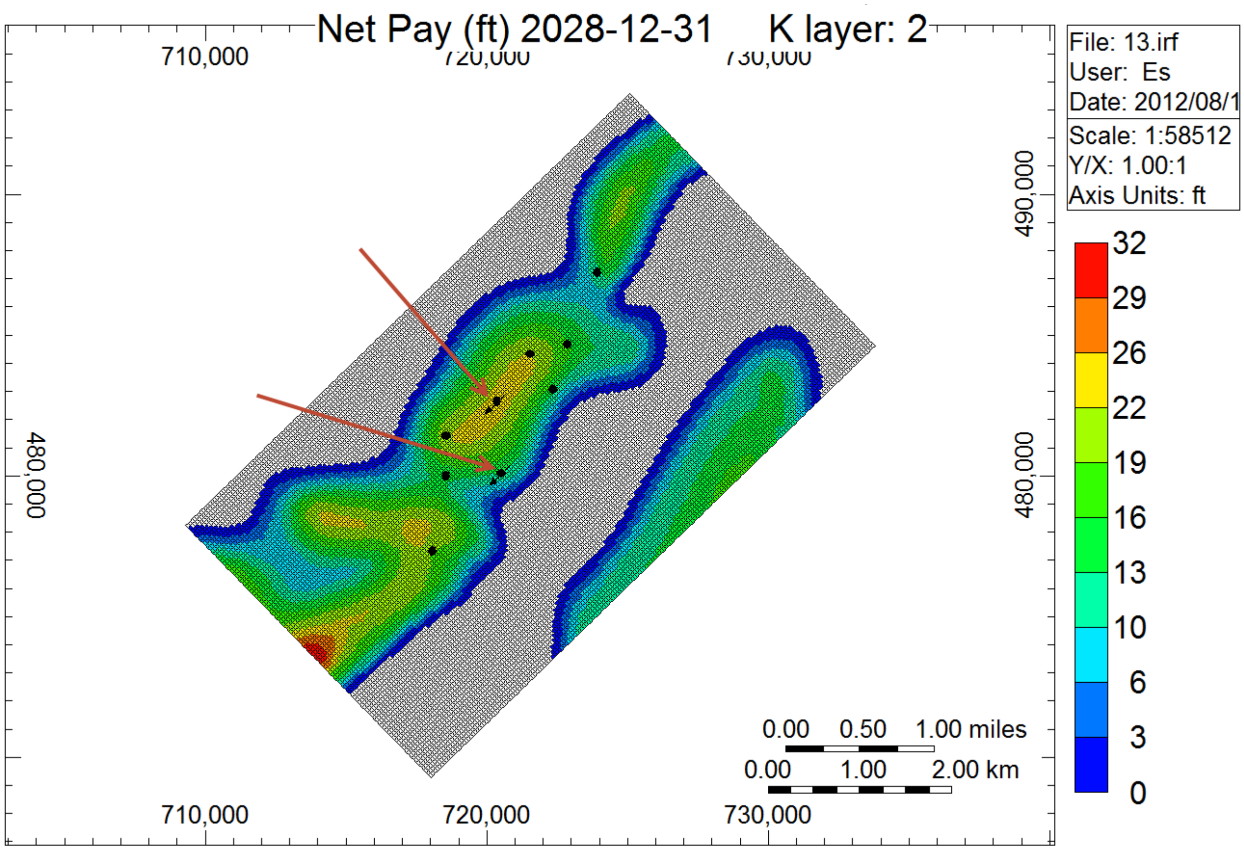


Figure 36: Gas injection run 13 Injector placement

The production/performance and voidage rate ratio profiles are shown in the figures below:

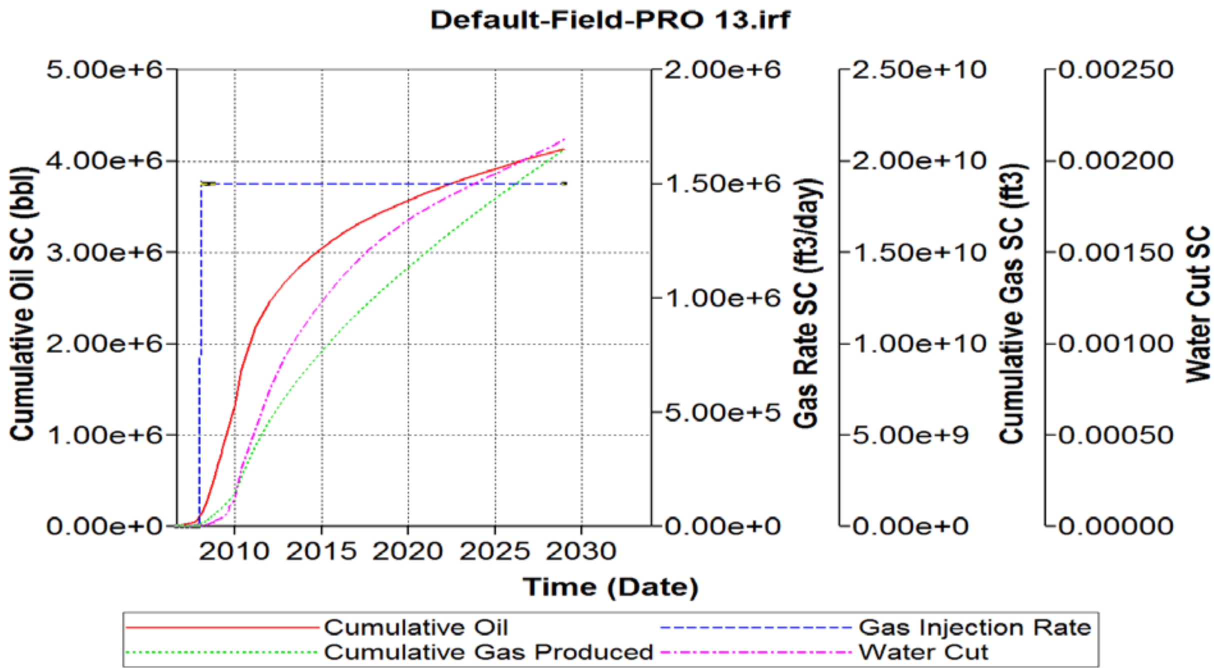


Figure 37: Gas injection run 13 production and performance profile

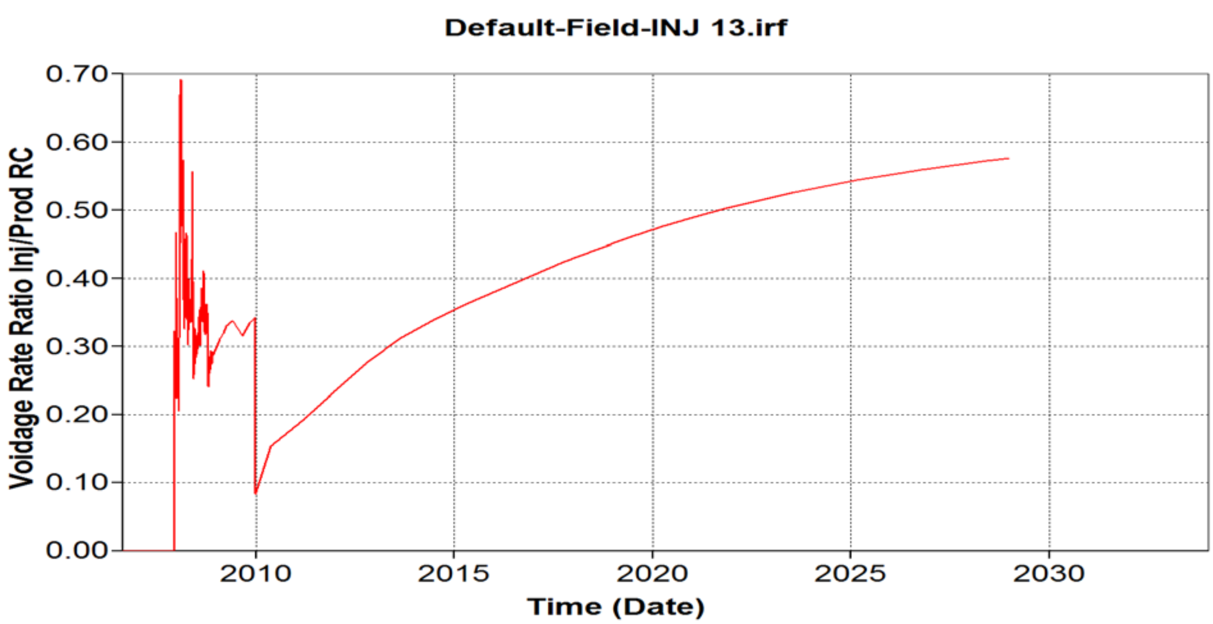


Figure 38: Gas injection run 13 voidage rate ratio

The pressure distributions are shown in the figures below:

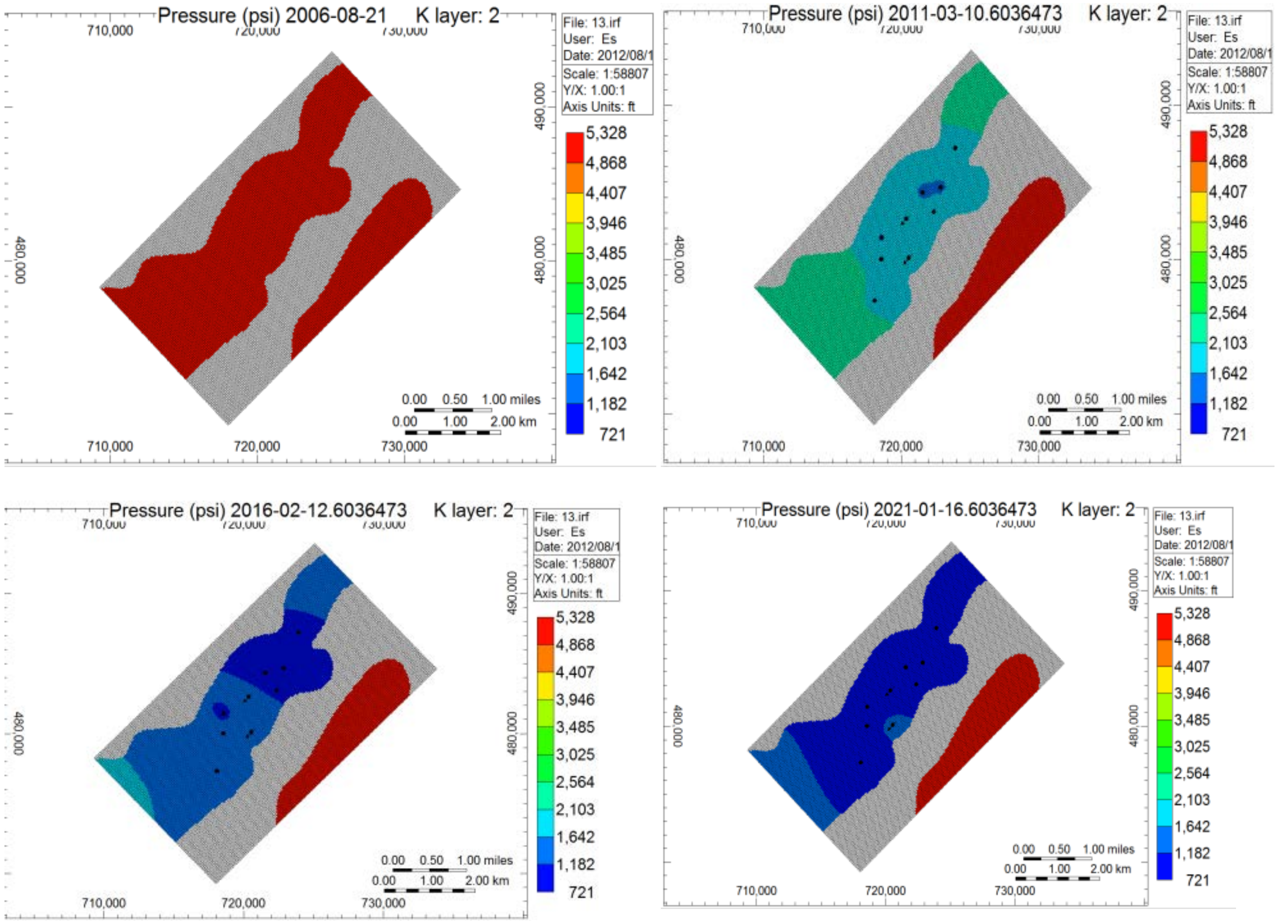


Figure 39: Gas injection run 13 pressure distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

From the figures above, it is easy to see the sharp drop in reservoir pressure due to production and how gas injection is neither able to increase reservoir pressure nor stem its sharp drop.

The oil saturation and gas saturation distributions are shown below:

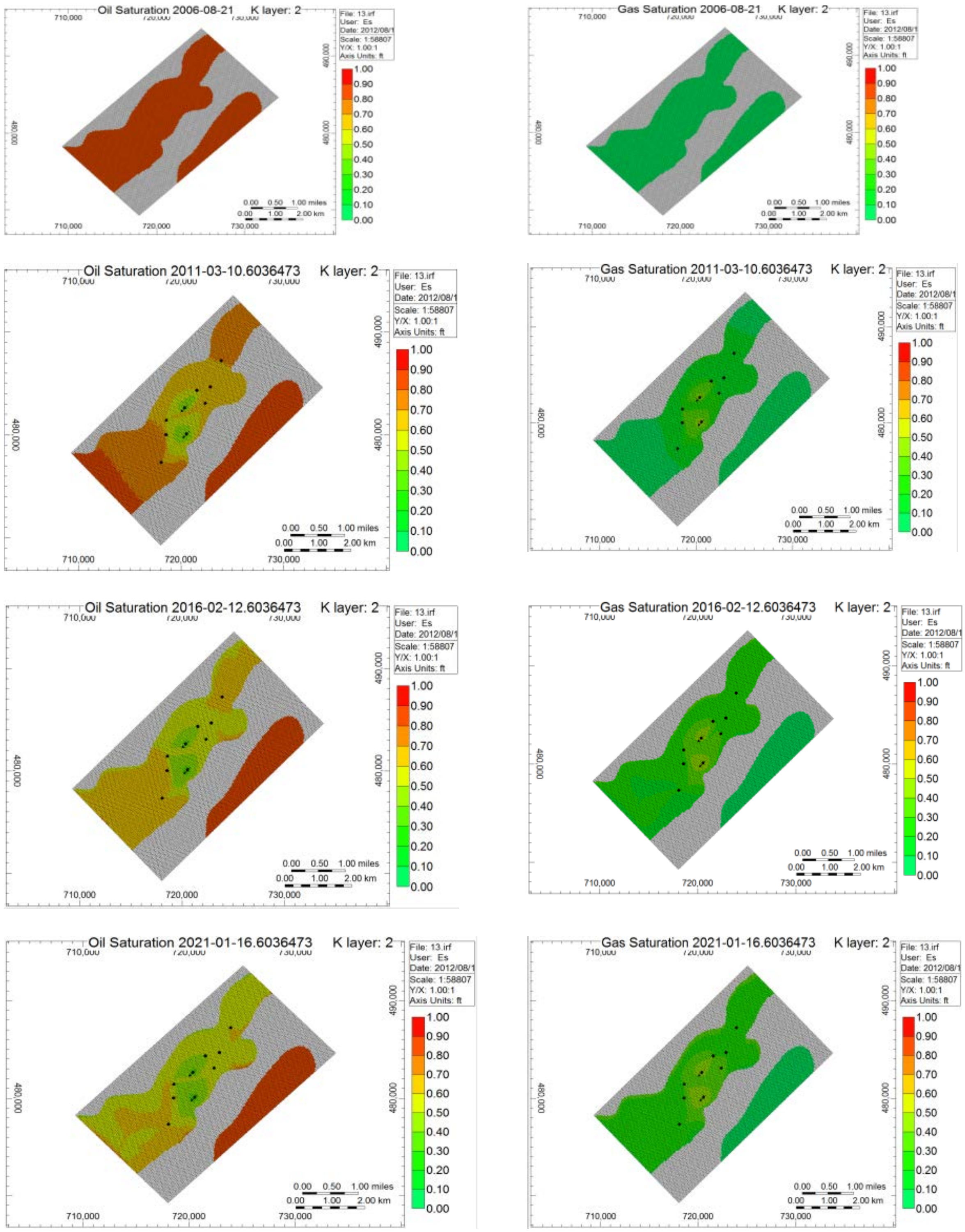


Figure 40: Gas injection run 13 Oil Saturation (left) and water saturation (right) for 0, 5, 10, and 15 years after production start (top to bottom)

5.3.5: Gas Injection Runs 13, 34, and 12 Discussion and Possible Recommendations

As mentioned above, though this 3 schemes result in the highest oil recovery compared to all the other gas injection runs, they do not provide sufficient pressure support. The average voidage rate ratio of all 3 runs is about 0.6 meaning a lot of the produced reservoir fluid is not replaced. After the fifth year of production, average reservoir pressure is below 2000psia which is far lower than the calculated minimum miscible pressure (MMP) of 3698.4psia. This means that for majority of the time, displacement by gas injection is driven by immiscible displacement. Other than insufficient pressure support, the sweep efficiency of all 3 runs appears to be poor as indicated in the oil and gas saturation distribution maps; the injected gas does not have a comprehensive sweep area. A lot of oil appears to be left behind all around the reservoir, unconsolidated and spread out as indicated in the oil saturation maps. Gas injection as a standalone solution is not a very attractive option mainly due to the fact that its role in reservoir pressure management is not effective.

5.4: Effect of Water Alternating Gas Injection (WAG) on Oil Recovery

The idea for WAG was a result of trying to merged the best of both waterflooding and gas injection. Have them complement each other to bring out the best in each injection method. Though not part of the initial goal of the project, it was decided to show a potential EOR method that could be more efficient than waterflooding and recover more oil. Since waterflooding did so well in maintaining and even raising the reservoir pressure, in some location, we do gas injection after waterflooding, so gas is injected into the reservoir at a pressure higher than the MMP, thus sustaining miscible gas injection/displacement and increasing recovery as a result (1) (7). Also, water breakthrough is reduced and delayed. Water production is thus reduced and the produced gas can be reinjected into the reservoir, allowing the recovery of more oil with less water. WAG was also used in the Jay/LEC analog field, with positive results (7).

For the basic design of the injection scheme, well placement and injection rates, we select the best 3 models/runs out of all the models that recovered the most oil. In this case, this happens to be the best 3 waterflooding models, i.e waterflood runs 14, 15 and 18; run 15 with the highest recovery and run 14 with the least. The water injection rates during the water cycle will depend on the model it was developed from and as with all the gas injection models, the gas injection rate during the gas cycle will be 750Mcf/d for each injection well. Each cycle is 240 days long, meaning a 1:1 water to gas ratio based on injection duration. The 3 WAG models will be called, WAG run 14, WAG run 15 and WAG run 18.

5.4.1: WAG Run 14

As mentioned above, this is based on the waterflood run 14 model. During the water injection cycle, 2000bbl/d of water is injected and during the gas injection cycle 750Mcf/D of gas is injected per injector with each cycle lasting 240days. The injection well placement, same as waterflood run 14, is shown in Figure 25. The production profile of WAG run 14 compared to its waterflood counterpart and Gas-injection with the same injection well placement is shown in the figure below:

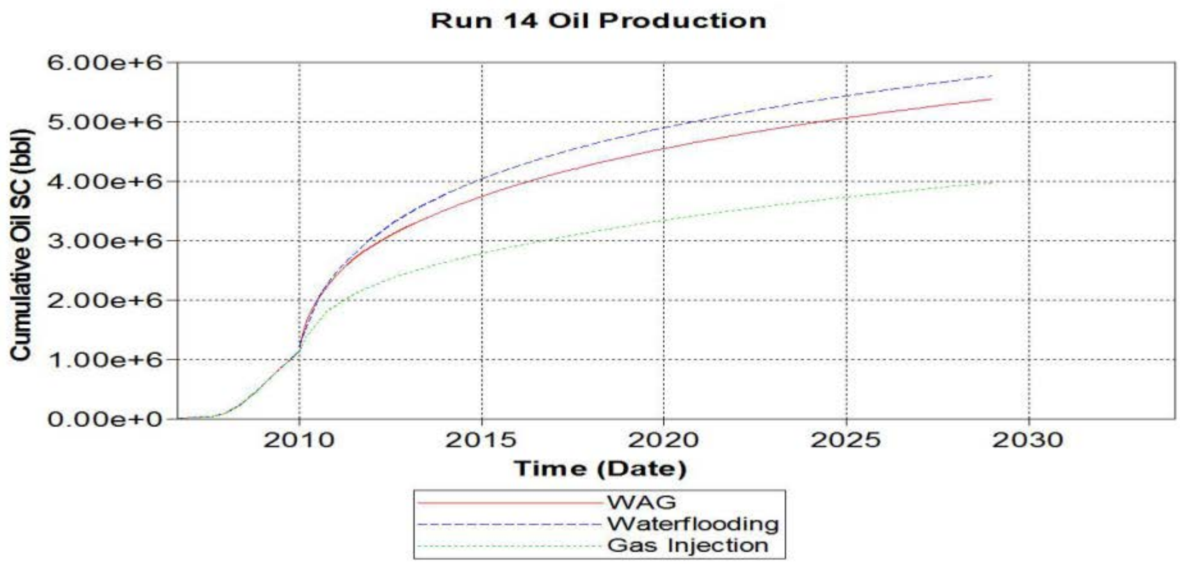


Figure 41: WAG run 14 compared to its equivalent Waterflood and Gas injection scenario

The production performance curves and voidage rate ratio are shown in the figures below:

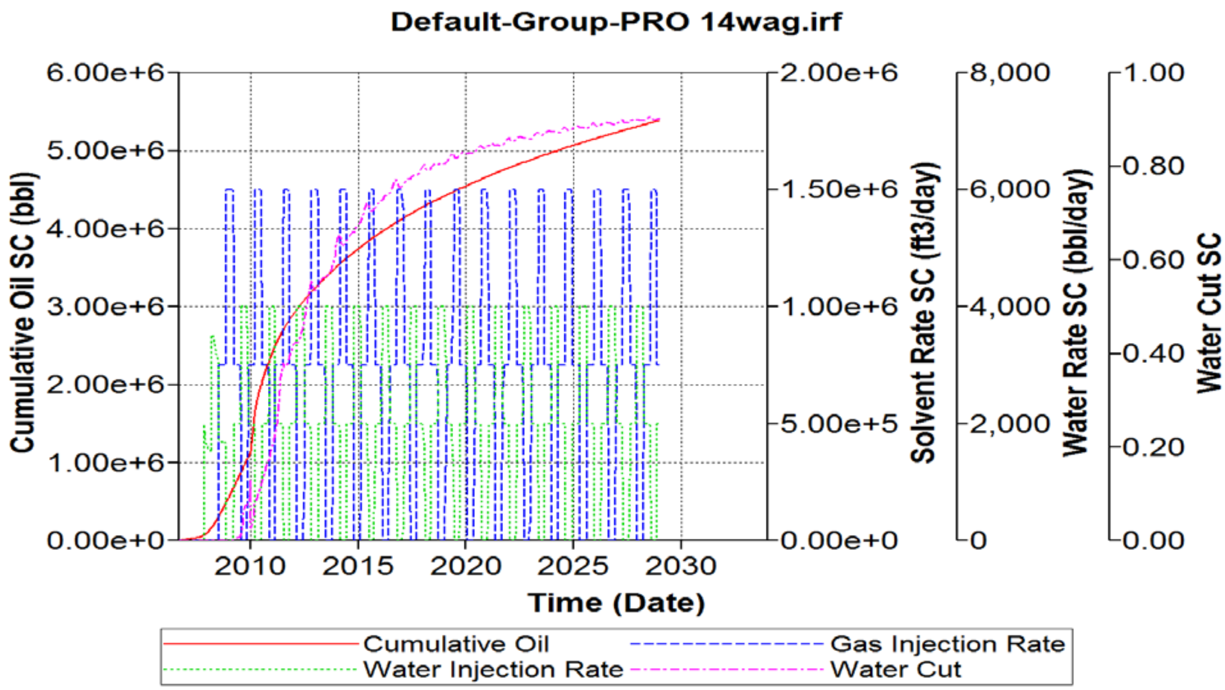


Figure 42: WAG run 14 production and performance profile

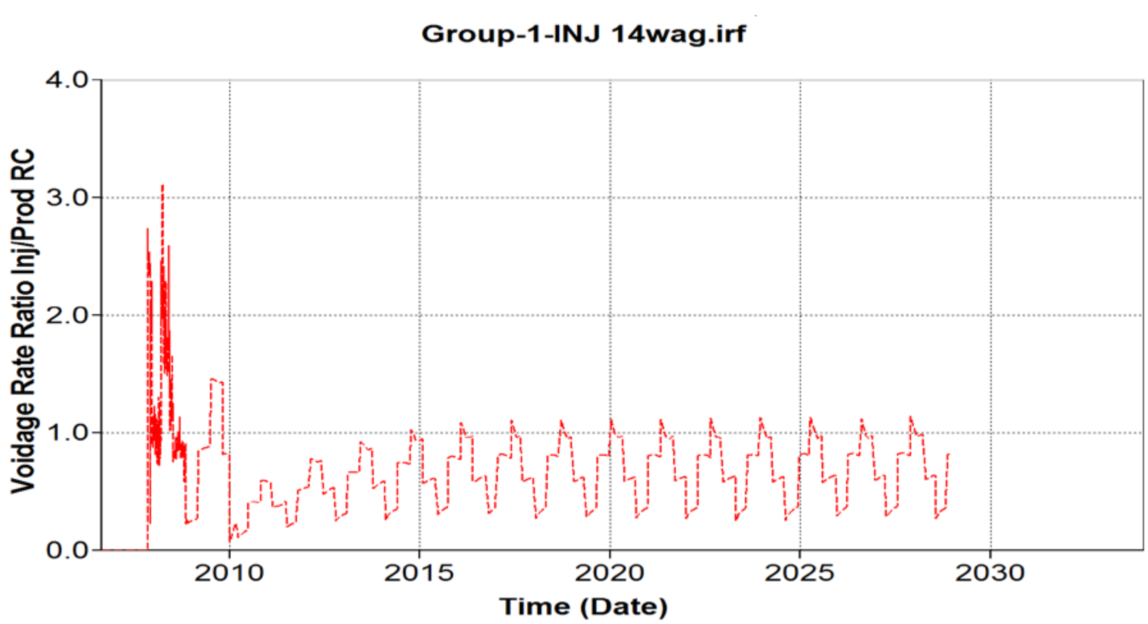


Figure 43: WAG run 14 voidage rate ratio

The spike behavior at the up until Dec. 2009, was due to rate and BHP constraints set on the producers. After Dec. 2009, the rate constraint was removed thus addressing the spike like behavior. The VRR slightly goes above one during the water injection cycle.

The production data comparing all equivalent 3 EOR methods with similar setup is shown in the table below:

Table 12: Summary of recovery of WAG run 14 vs its equivalent waterflood and gas injection scenarios

	Oil Production (MMSTB)	**Water Production (MMSTB)**	**Gas Production (BCF)**
WAG	5.39	10.06	12.33
Waterflood	5.78	20.61	7.77
Gas-injection	3.98	0.003	19.38

As shown in the figure and table above, waterflooding recovered the most oil but also produced the most water. Gas injection recovered the least amount of oil but produced the most gas. WAG fell in the middle. It recovered 400 thousand barrels less than waterflooding, but produced less than 50% the amount of water. WAG also recovered over 1.4MMSTB more oil than gas injection and produced 40% less gas. The pressure distribution at 5, 10, and 15 years after production is shown below:

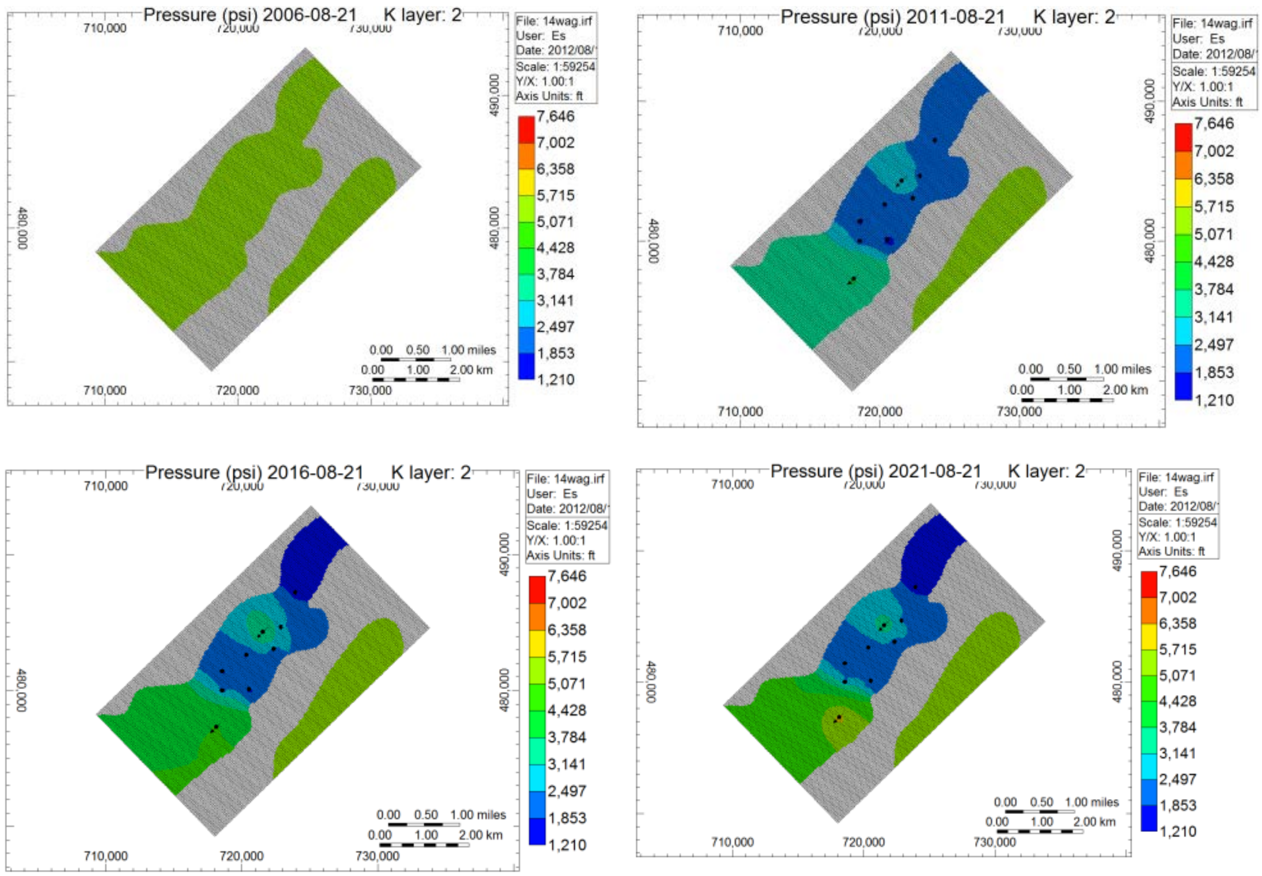


Figure 44: WAG run 14 Pressure distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

The pressure maps show what has been discussed in both waterflooding and gas injection. The reservoir experiences strong pressure drops, but during the waterflooding cycle it is noticed that the drop in reservoir pressure is stemmed and even increases especially close to the injection wells. During the Gas injection cycle, the pressure drops rapidly. The reservoir was only able to experience miscible gas injection displacement only within the first 3 years of production. The oil saturation maps are shown below:

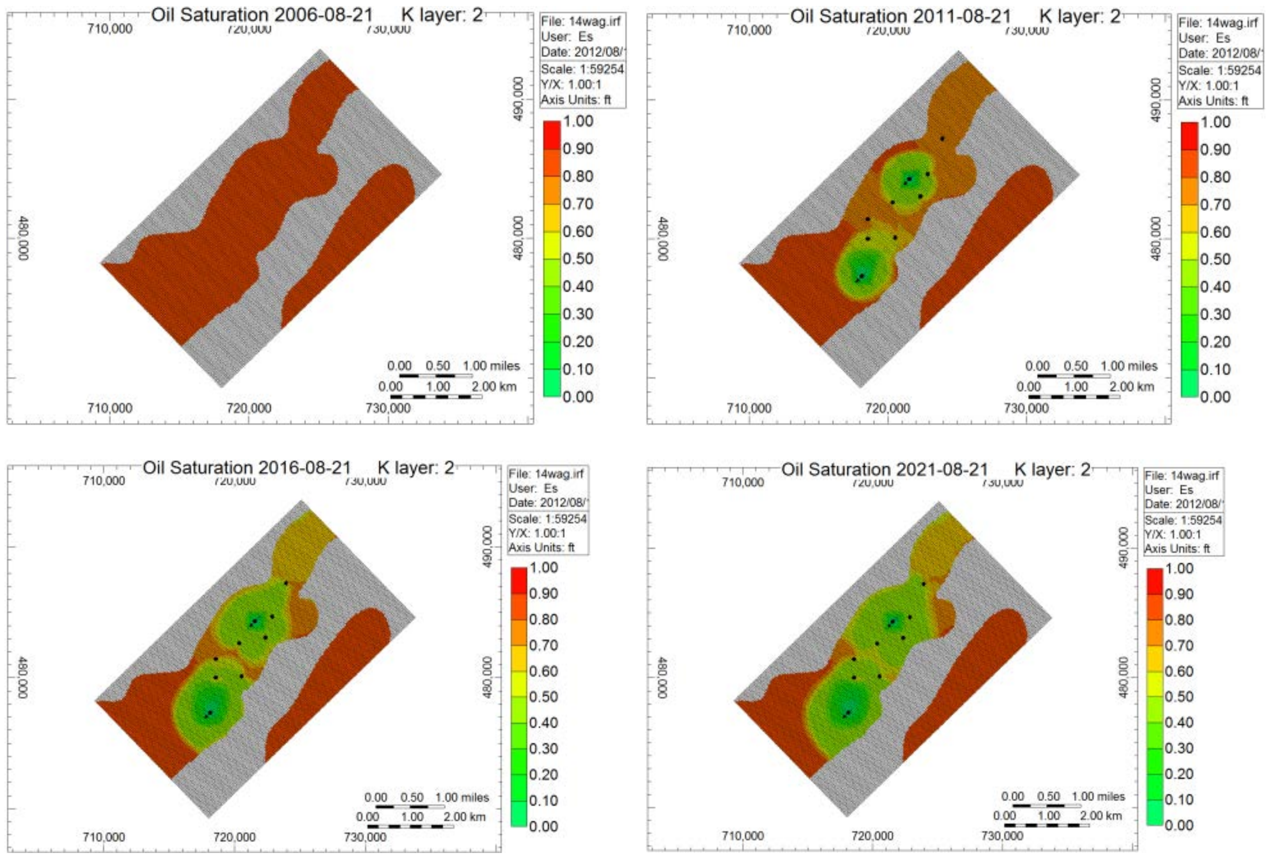


Figure 45: WAG run 14 Oil saturation distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

Here the oil saturation behaves almost the same as its waterflood counterpart, except that the waterflood equivalent model has drained more of the oil around the producers. WAG run 14 appears to have higher oil saturations around the producers but less average reservoir pressure compared to waterflood run 14.

5.4.2: WAG Run 15

As with the waterflood scenario, WAG run 14 and 15 are virtually the same setup, the only difference is in the water injection rates. Run 14 has water injection rate of 2000bbl/d while run 15 has a rate of 3000bbl/d per injection well. The well placement setup is shown in Figure 25. The production profile for this model is shown below:

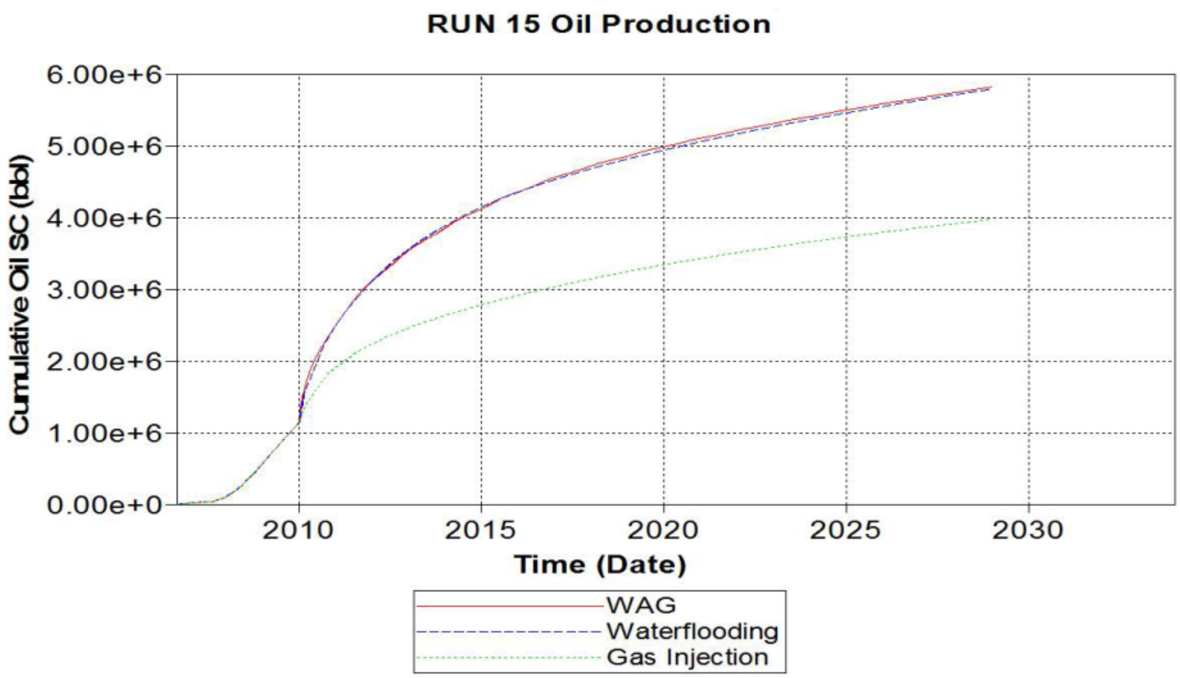


Figure 46: WAG run 15 compared to its equivalent Waterflood and Gas injection scenario

At Run 15 oil recovery from WAG and waterflooding are almost the same with WAG having a slightly higher recovery.

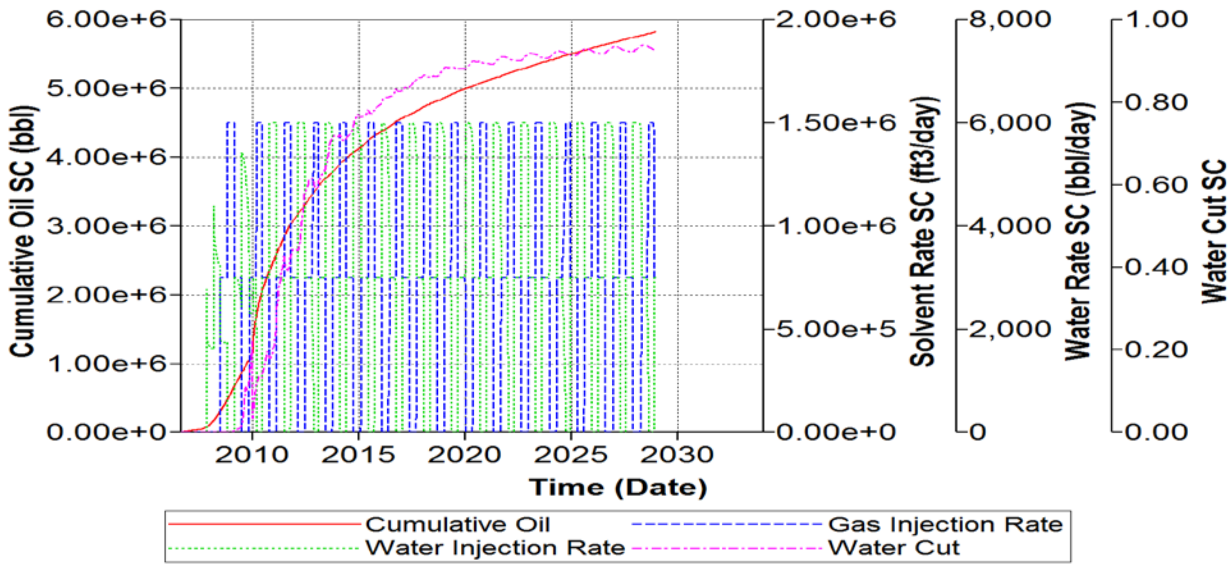


Figure 47: WAG run 15 production and performance profile

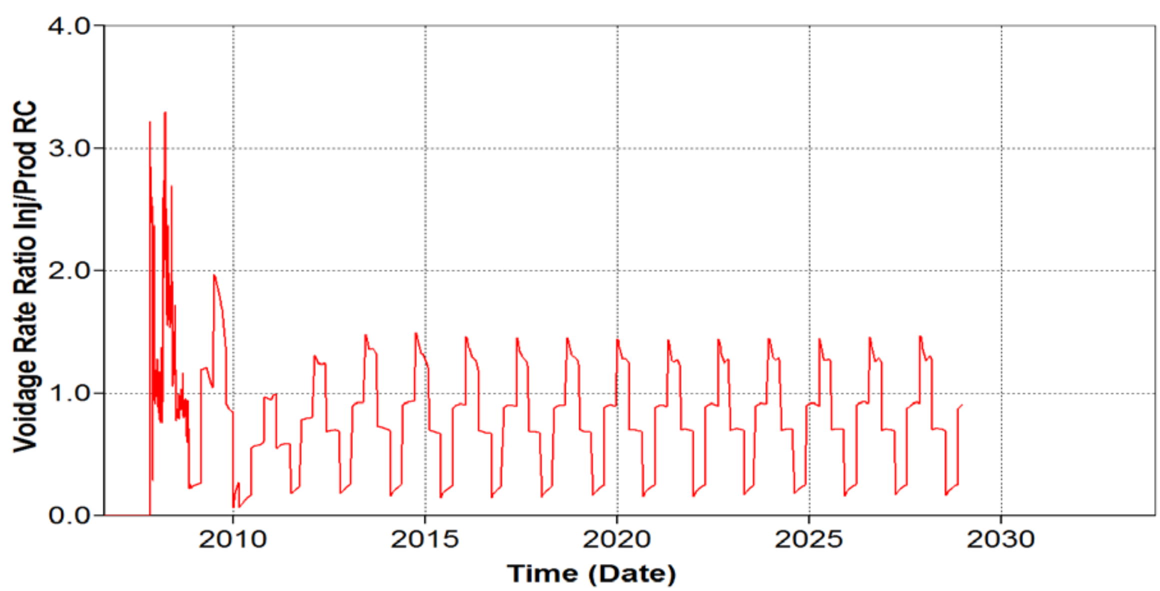


Figure 48: WAG run 15 voiadage rate ratio

The VRR for WAG run 15 goes further above 1 compared to WAG run 14, implying more fluid is injected into the reservoir. This resulted in the reservoir been pressurized more and more fluid to displace the in-place oil. This resulted in a higher recovery compared to WAG run 14.

The production numbers from this run at its waterflood and gas-injection equivalent are shown in the table below:

Table 13: Summary of recovery of WAG run 15 vs its equivalent waterflood and gas injection scenarios

	Oil Production (MMSTB)	**Water Production (MMSTB)**	**Gas Production (BCF)**
WAG	5.83	16.12	12.35
Waterflood	5.8	25.46	7.7
Gas-injection	3.98	0.003	19.38

Here, WAG has recovered the most oil and gas injection the least. WAG recovered marginally more oil, about 30,000bbl, more than water injection. It however has produced less water, about 40% less than waterflooding. The pressure maps for this model are shown in the figure below:

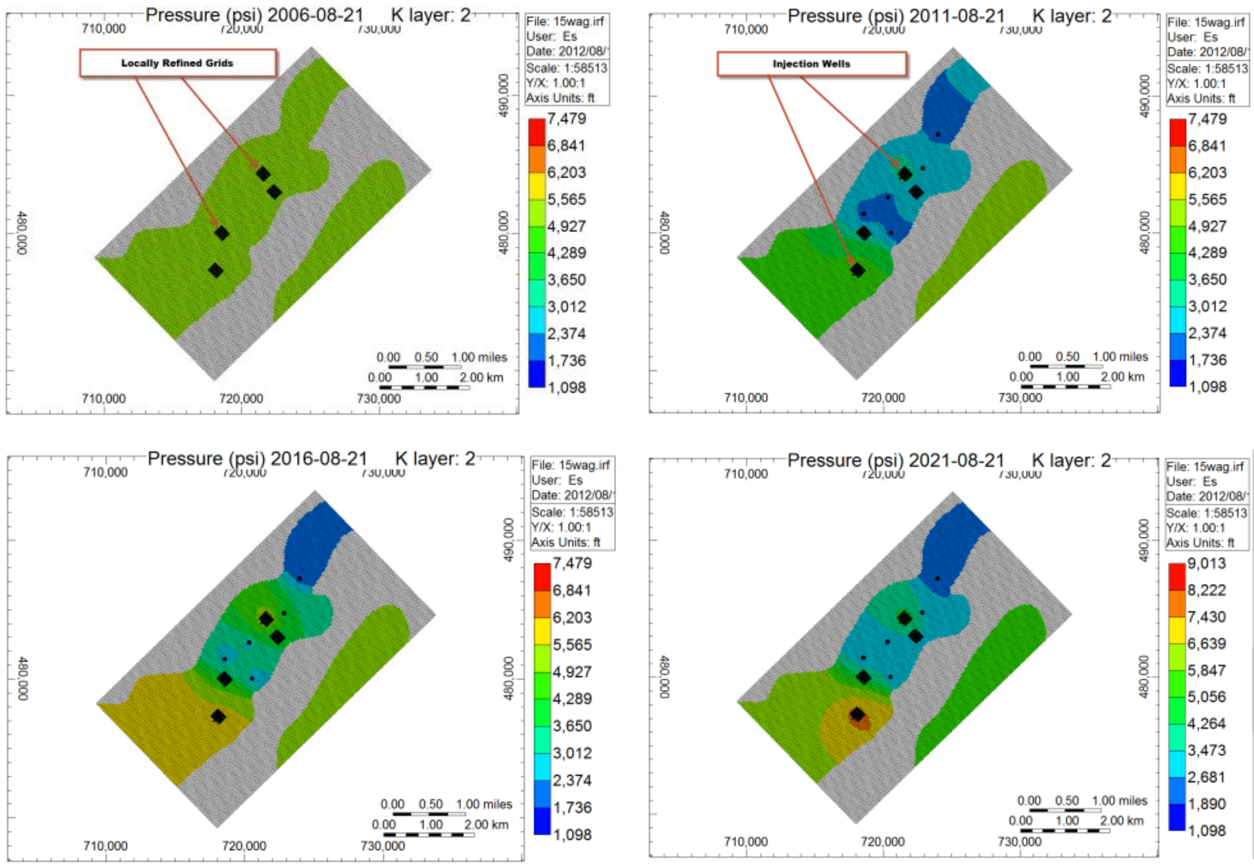


Figure 49: WAG run 15 Pressure distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

The pressure response here is more noticeable compared to WAG run 14 due to the higher water injection rate. After the first 10 years of production average reservoir pressure was higher than 3700psia. Here, during the gas injection cycle displacement was mainly miscible, especially right after the water injection cycle. Also, shown in Figure 47, WAG is able to inject the full 6000bbl/d total volume of water compared to its waterflood counterpart due to the higher injectivity.

The oil saturation maps are shown below:

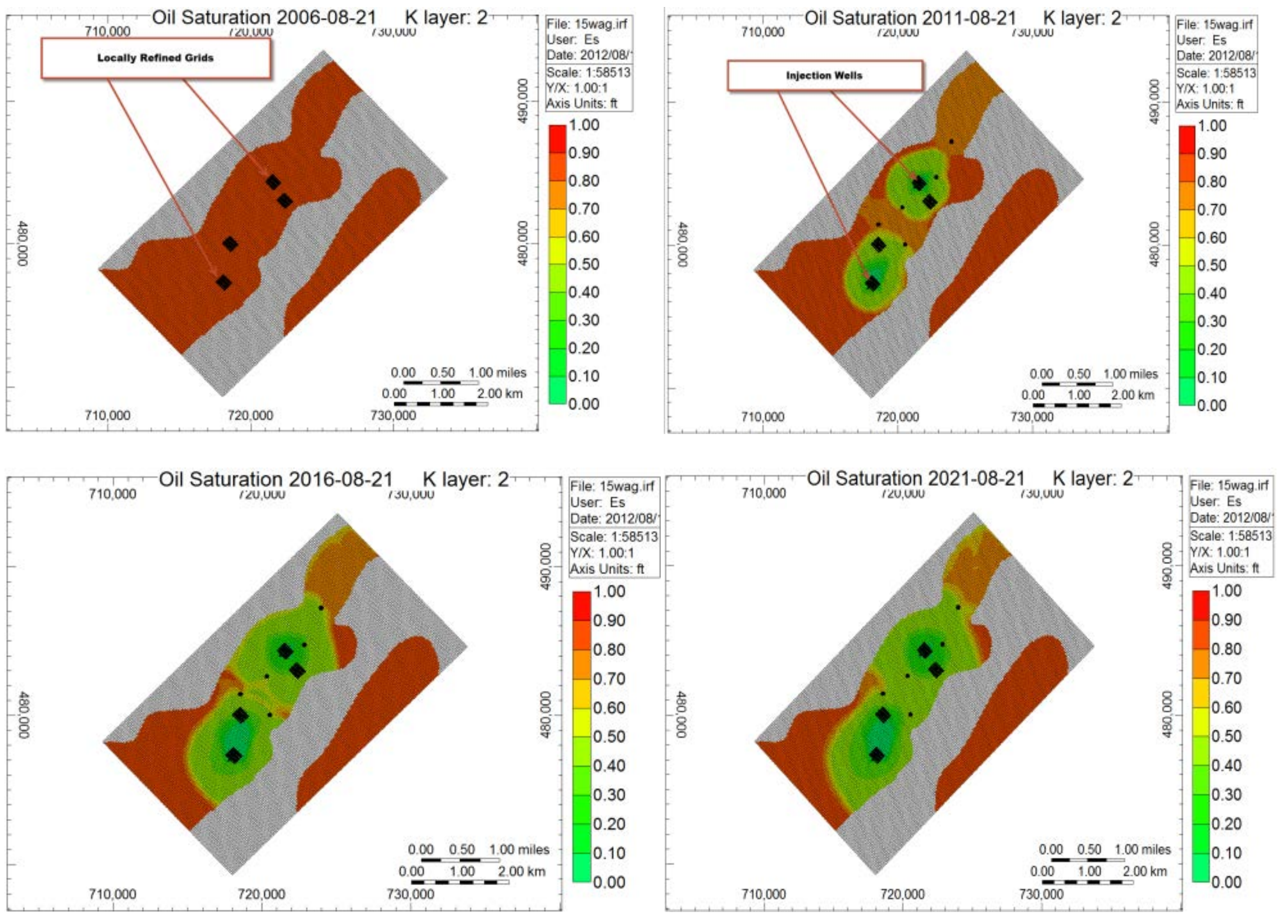


Figure 50: WAG run 15 Oil saturation distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

5.4.3: WAG Run 18

As with WAG runs 14 and 15, WAG run 18 is modeled after the waterflood run 18 model. The placement of wells is the same as waterflood run 18. During the waterflood cycle, 3000bbl/d of water was injected during the waterflood cycle and 750Mcf/d during the gas injection cycle for each injection well. The oil recovery for this run is shown in the figure below:

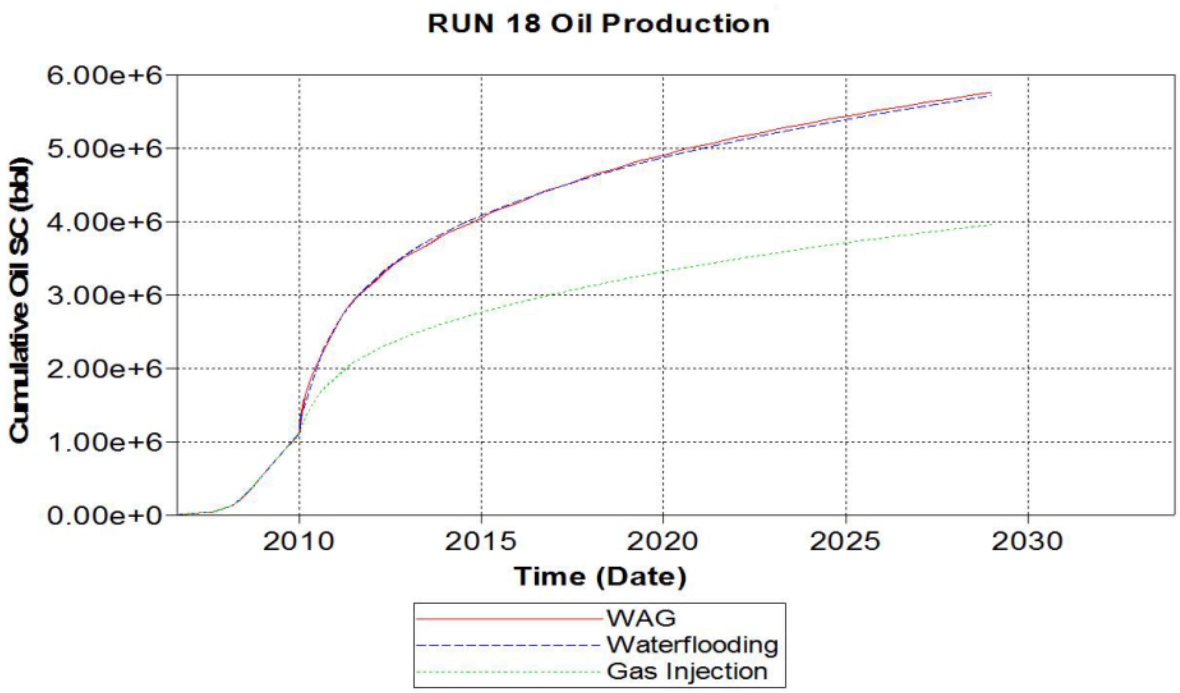


Figure 51: WAG run 18 compared to its equivalent Waterflood and Gas injection scenario

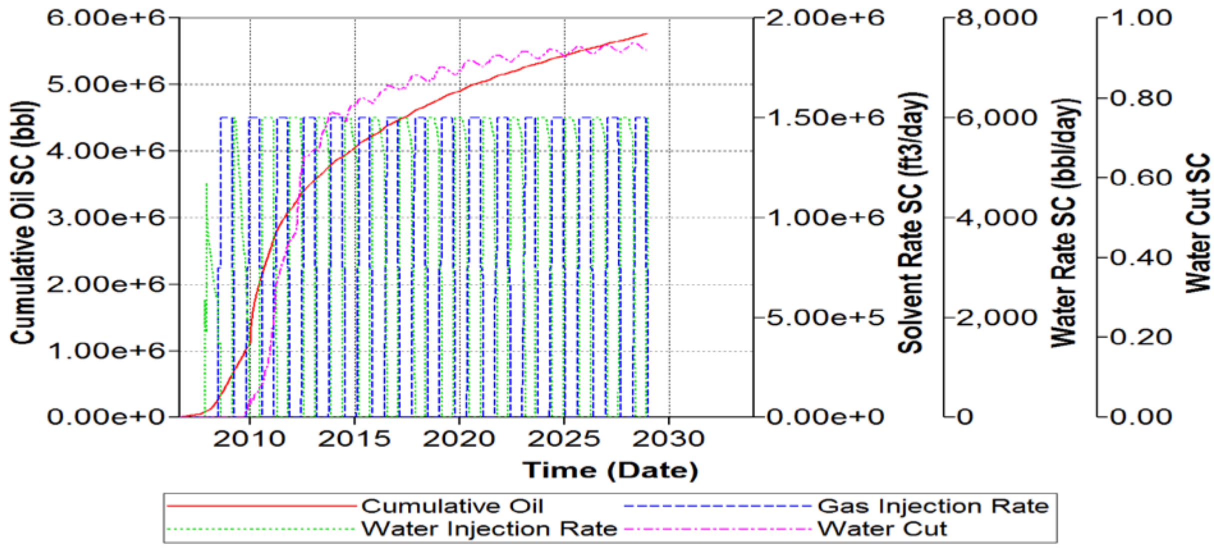


Figure 52: WAG run 18 production and performance profile

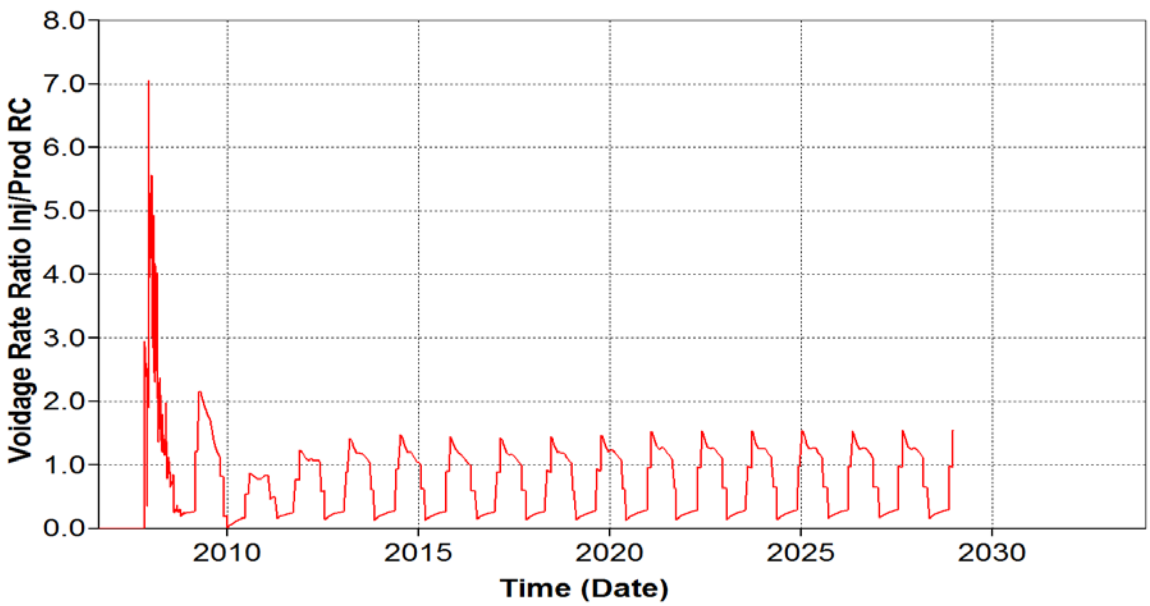


Figure 53: WAG run 18 voidage rate ratio

The production numbers are shown in the table below:

Table 14: Summary of recovery of WAG run 18 vs its equivalent waterflood and gas injection scenarios

	Oil Production (MMSTB)	**Water Production (MMSTB)**	**Gas Production (BCF)**
WAG	5.77	15.8	12.72
Waterflood	5.72	25.52	8.01
Gas-injection	3.96	0.0029	19.34

As with WAG run 15, WAG run 18 recovered more oil, about 50,000bbl, more than its waterflooding counterpart and also almost 40% less water. It produced 1.81MMbbl more oil and almost 35% less gas than its gas injection equivalent. The pressure maps for WAG run 18 are shown below:

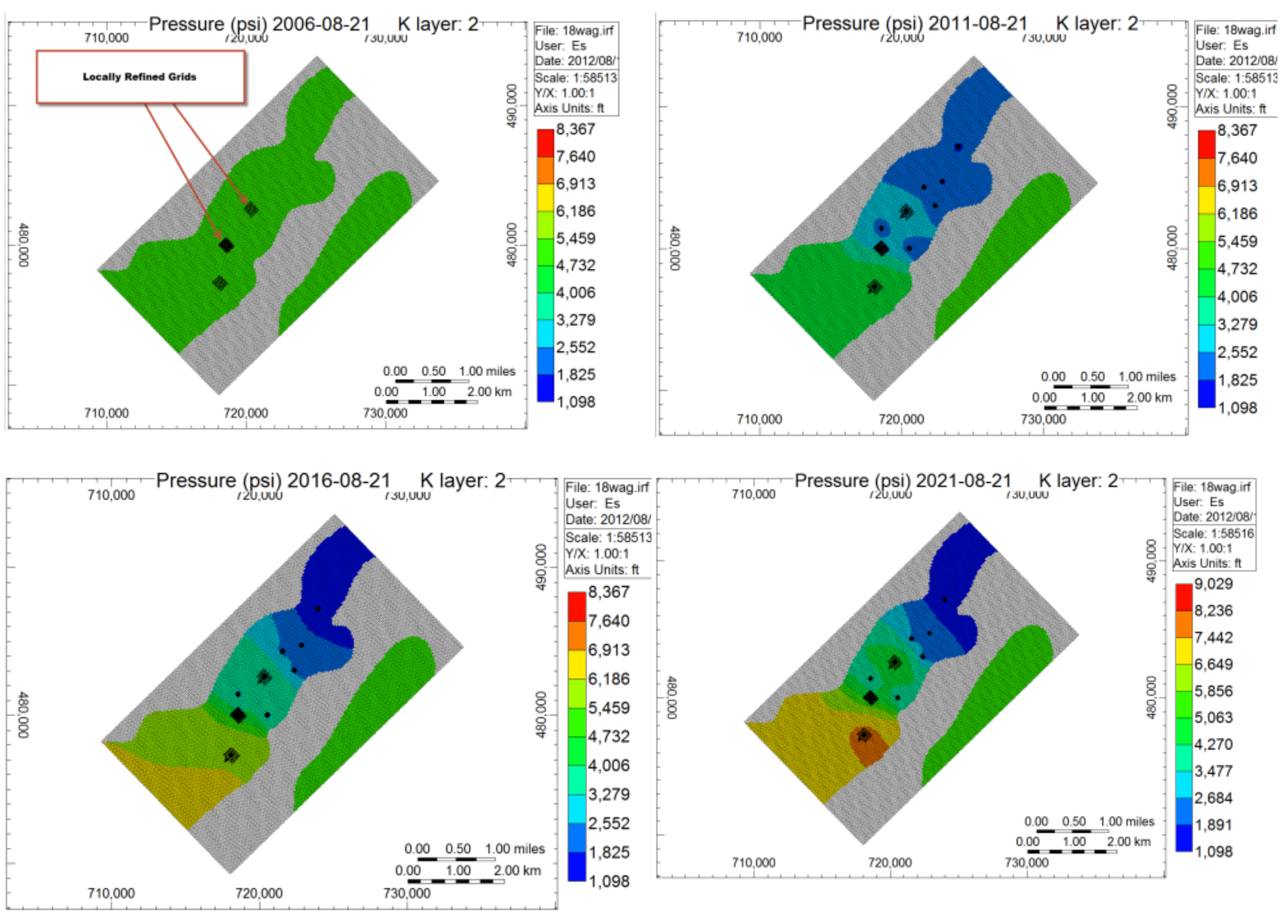


Figure 54: WAG run 18 Pressure distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

The pressure of the reservoir increases during the waterflooding cycle and decreases during the gas injection cycle. The northern section of the reservoir experiences more pressure drop than the rest because there is no injection well around that area to provide pressure support. The oil saturation maps for WAG run 18 are shown in the figure below:

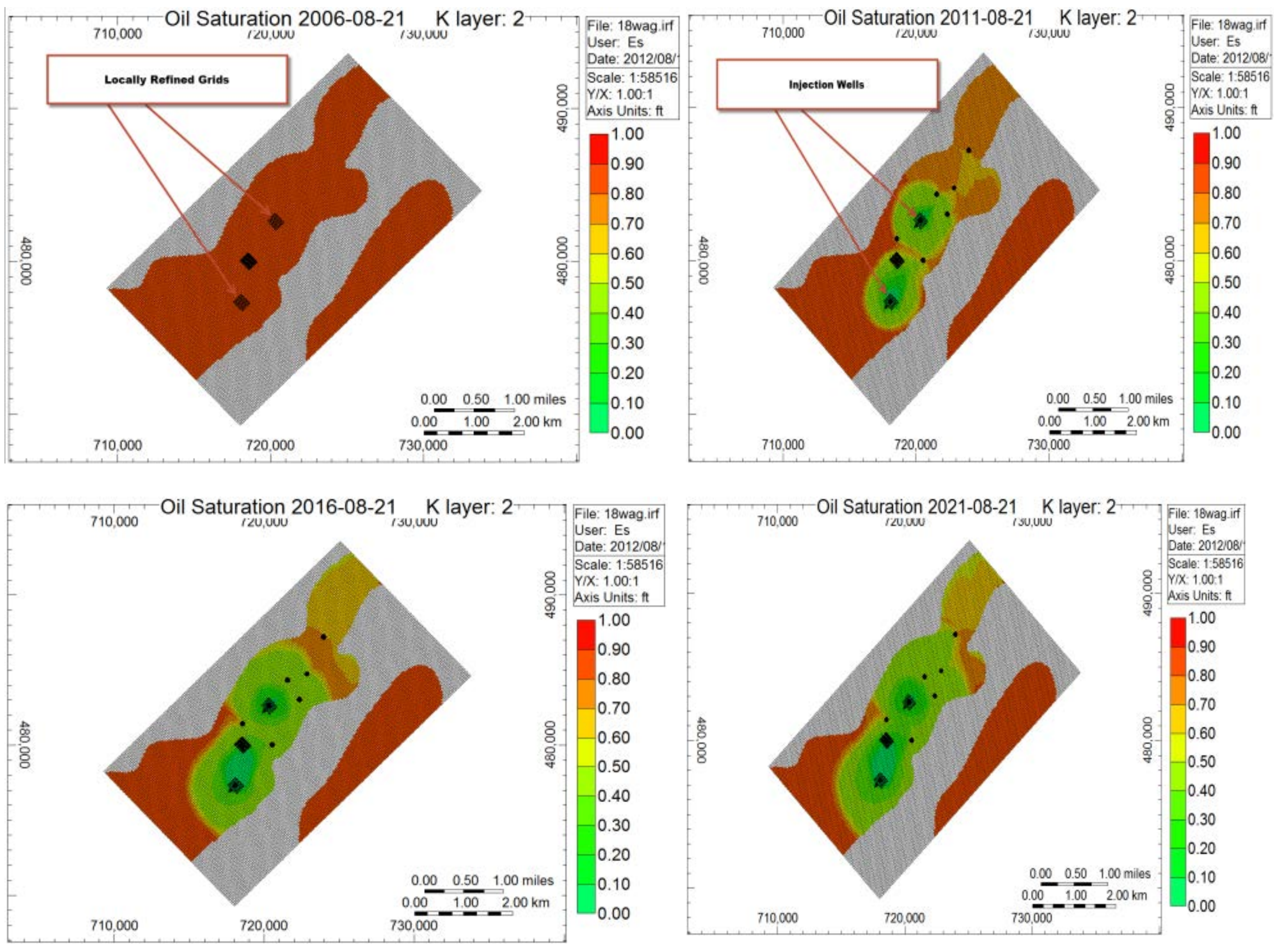


Figure 55: WAG run 18 Oil saturation distributions. Top Left to Right - 0 and 5 years after production. Bottom Left to right - 10 and 15 years after production

5.4.4: WAG Runs 14, 15, and 18 Discussion and Possible Recommendations

As shown above WAG produces results that is better than both waterflooding and gas injection. It recovers more oil except for WAG run 14 which is due to the lower water injection rate in the water cycle. Because of the lower injection rate, the reservoir pressure is not maintained as well as you would when you have higher injection rates, like in WAG runs 15, and 18. Because of this, gas injection was through immiscible displacement due to the reservoir pressure being below the minimum miscibility pressure for most of the operational life of the reservoir. With higher water injection rate, reservoir pressure is better maintained and reservoir is able to hold pressures above MMP to allow for miscible displacement. And as stated in *Aziz (1989)* (8) and in the figures above, gas injection recovers more oil during miscible conditions. This is shown in WAG runs 15 and 18. In both runs injection rates were high, 3000bbl/d per injector, they were able to inject the whole 3000bbl/d due to higher injectivity thanks to the injected gas during the gas cycle. This leads to higher VRR shown in Figure 48 and Figure 53; which meant better pressure maintenance and consequently allowed for miscible gas injection during most of the gas injection cycle. All these results to WAG runs 15 and 18's higher oil recovery.

In regards to recommendations, the same proposed in the waterflooding section will be proposed here as you have the same pockets of undrained oil here as you have during the waterflooding scenario, shown in Figure 50.

5.5: Effects of Timing of Waterflooding and Gas Injection on Oil Recovery

5.5.1: Waterflooding

The start time for the 3 runs, 14, 15, and 18 were all Nov. 2007. The injection rates for all 3 runs is shown in Figure 56 below.

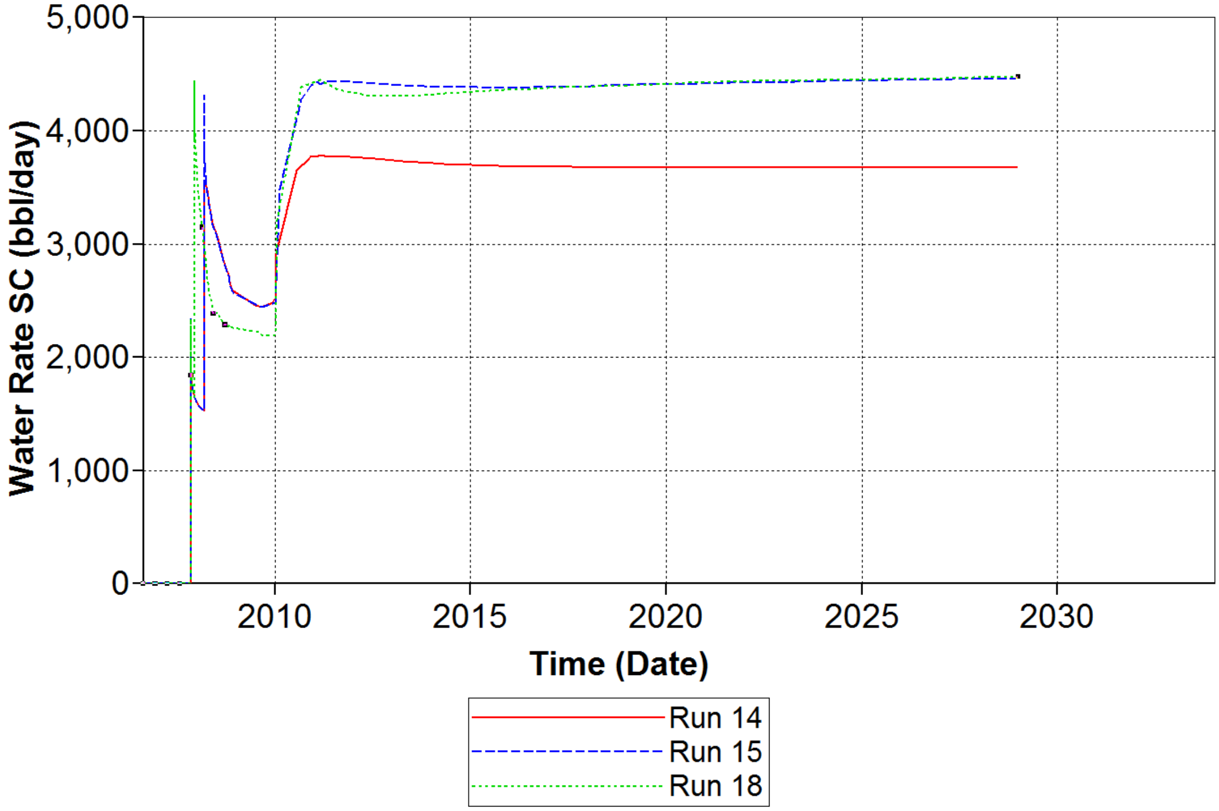


Figure 56: Waterflooding Start Time for Runs 14, 15, and 18

As mentioned in the earlier sections, Run 14 is set to inject 4000bbl/d and Runs 15 and 18 6000bbl/d total for the field. These rates were not met due to low injectivity and the BHP constraint described in the waterflood scheme design section. This is explained in detail in “Section 4.2: Waterflooding”

5.5.2: Gas Injection

The 3 runs, Runs 12, 13, and 34 began injecting gas at Jan.2008, Dec.2007, and Aug.2007 respectively. The injection start times and profiles for these runs are shown in Figure 57 below.

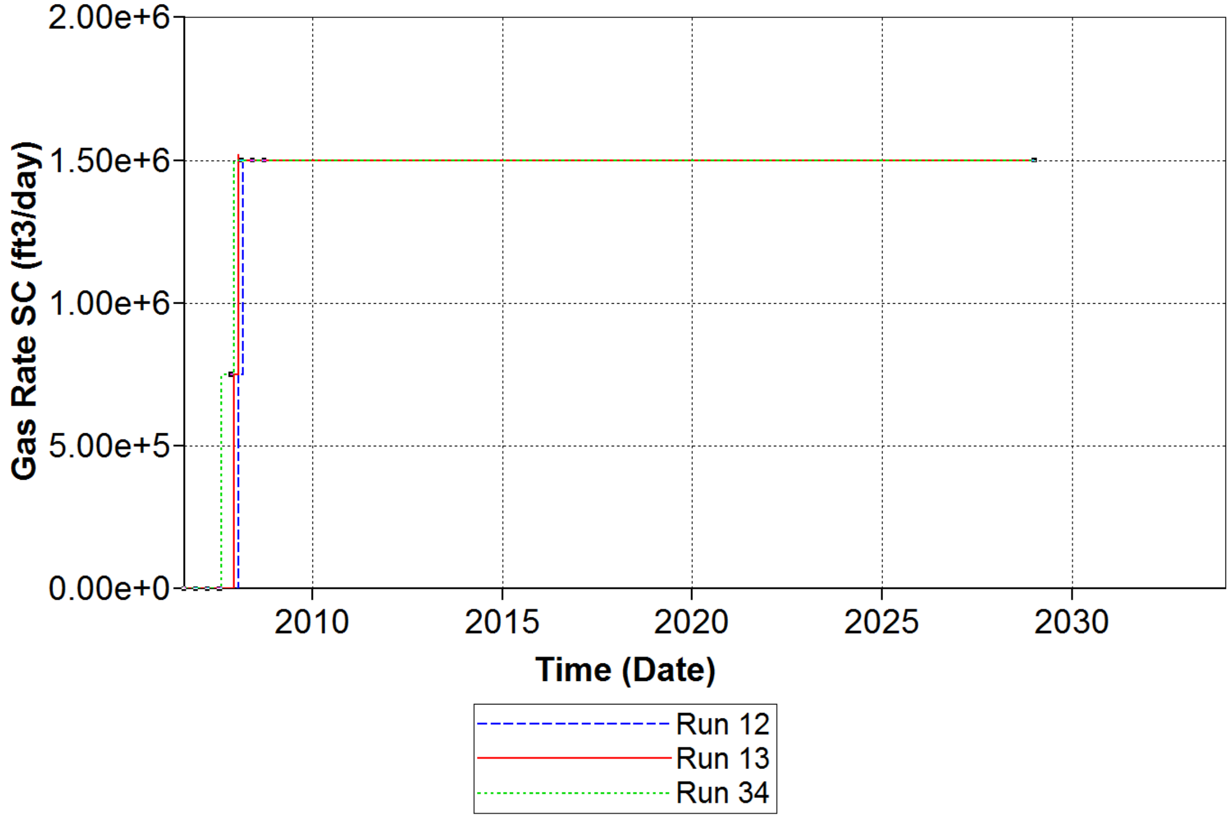


Figure 57: Gas Injection Start Time for Runs 12, 13, and 34

5.5.3: Effects of Injection Start Time on Oil Recovery

In order to further understand how injection affects oil recovery, the effects of injection start time for both waterflooding and gas injection was observed. Rather than observing production for the normal 20 years period, here production was observed for 50 years. This was done to see if the start time of injection affected recovery and if the production period was long enough, like 50 years, there would be a difference. The general results for waterflooding and gas injection are shown in the figures below:

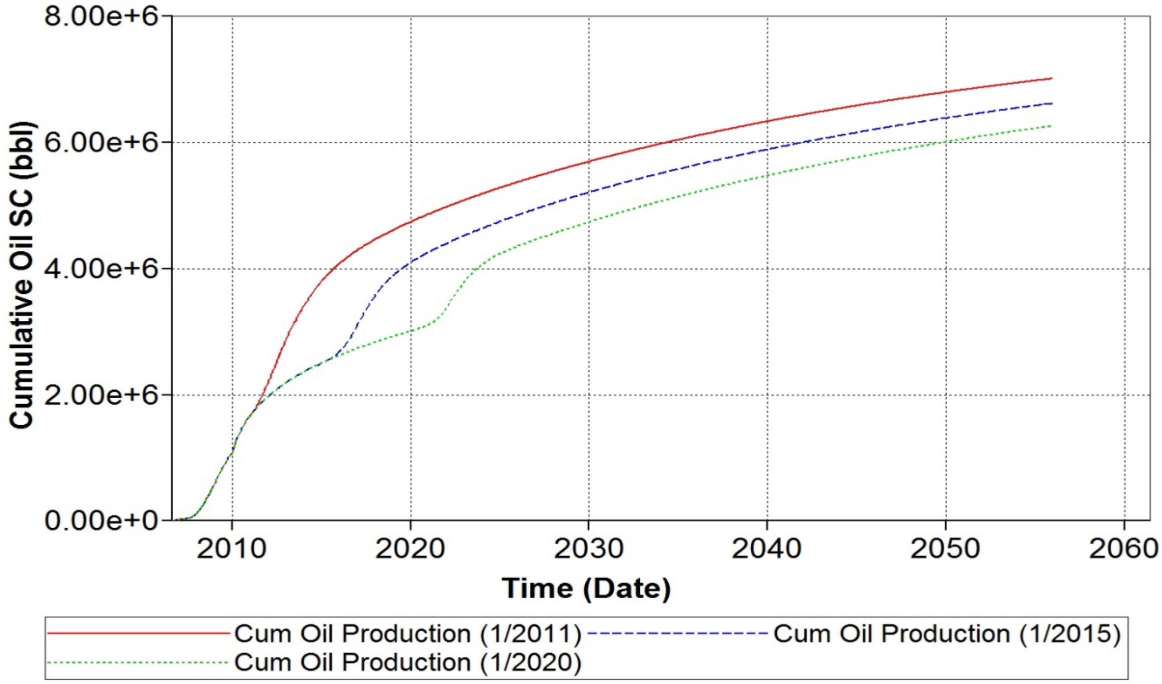


Figure 58: Waterflood. Effects of start time on recovery

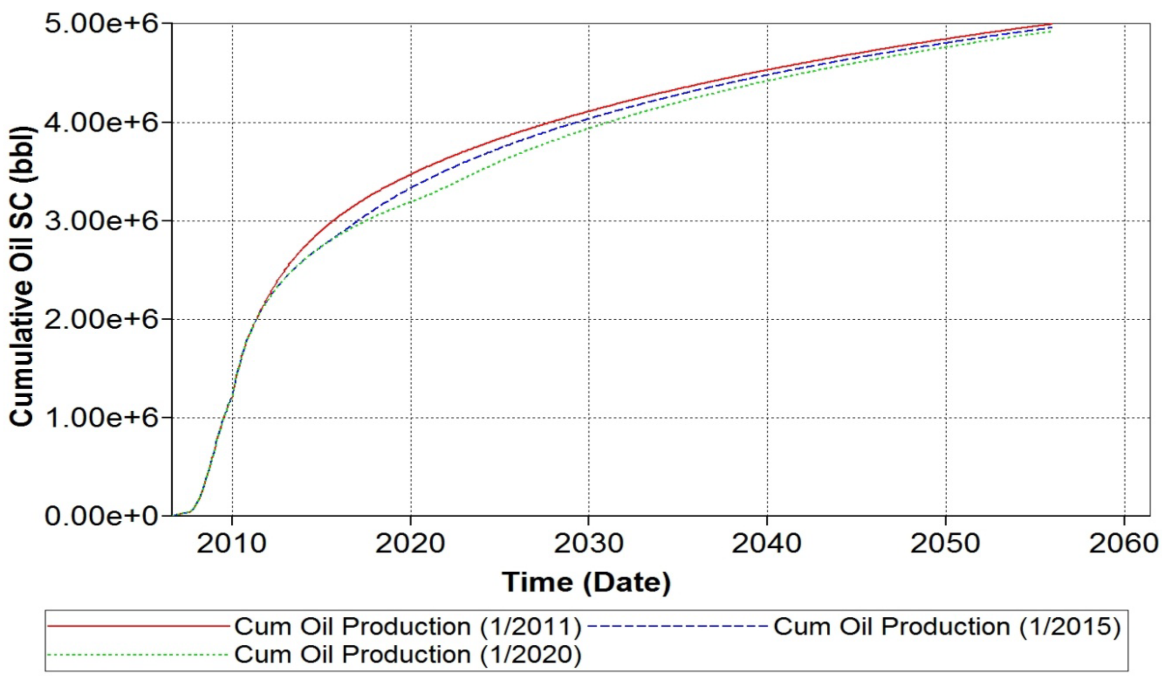


Figure 59: Gas injection. Effects of start time on recovery

As shown in the figures above, the sooner injection starts the higher the oil recovered for both waterflooding and gas injection.

5.6: Effect of Relative Permeability on Oil Recovery

The overall oil, gas and water recovery profiles comparing all available relative permeability data based on primary depletion over the 20 years is shown below. These relative permeability data are shown in Figure 6 and Figure 7 for core data and Figure 15 to Figure 18 for relative permeability data Set 1 and data Set 2.

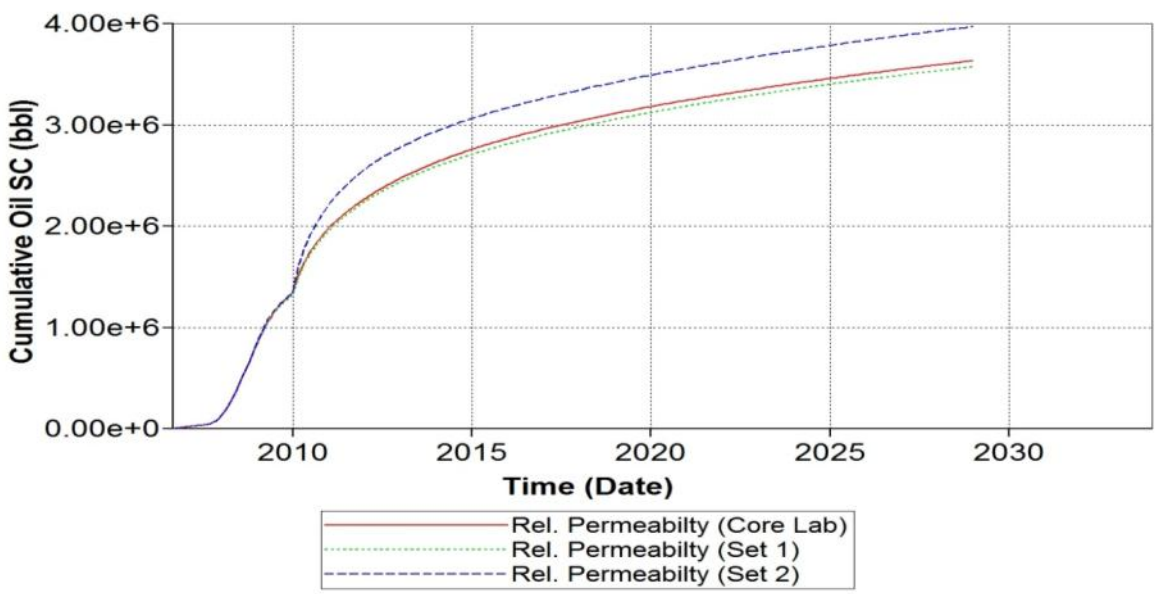


Figure 60: Oil Recovery Comparison of the Relative Permeability Data through Primary Depletion

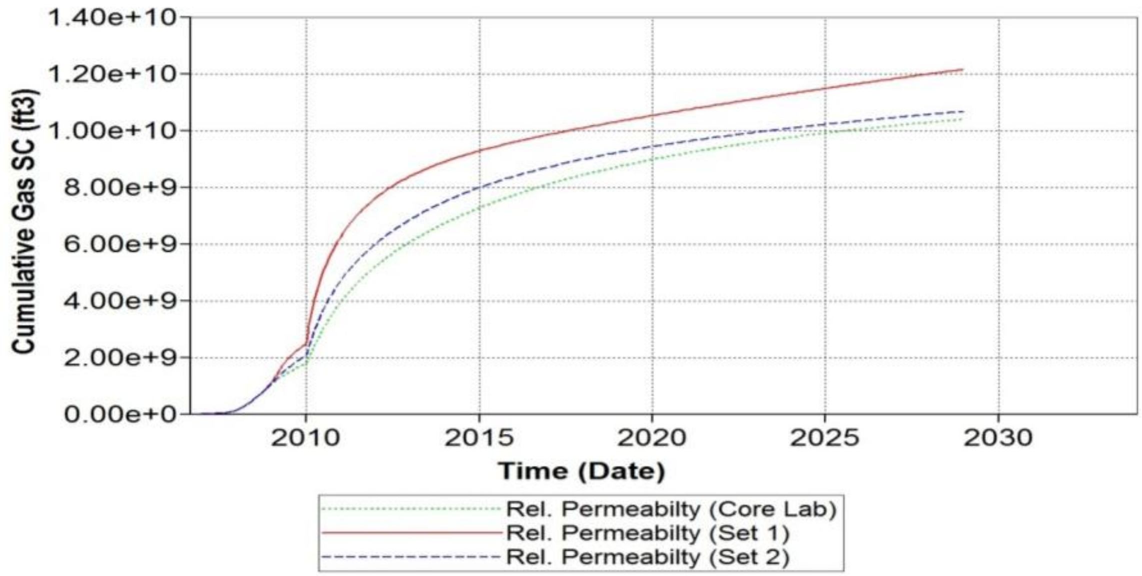


Figure 61: Gas Recovery Comparison of the Relative Permeability Data through Primary Depletion

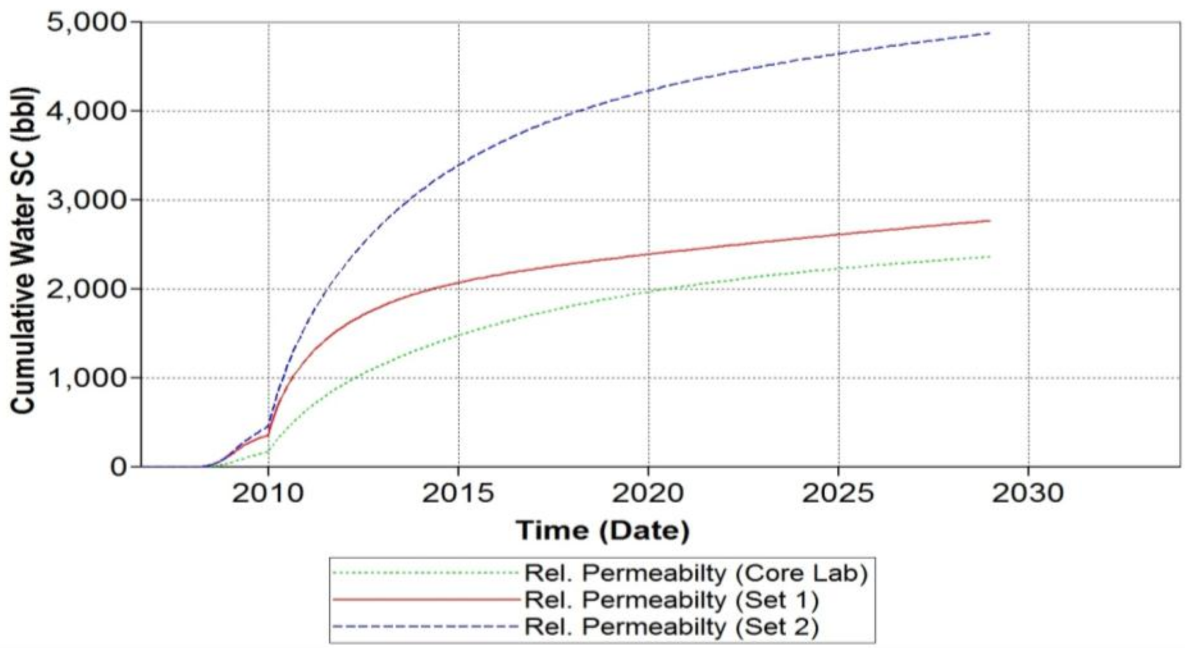


Figure 62: Water Recovery Comparison of the Relative Permeability Data through Primary Depletion

The figures above show the simulated production history of the field using all the available relative permeability data for a 22.3 years period. Production is through primary depletion. Table 15 below shows the oil, gas, and water produced over the span of the 22.3 years operation under primary depletion.

Table 15: Primary Depletion Recovery comparing all Relative Permeability Data

	Cumulative Oil Produced (MMSTB)	Cumulative Gas Produced (MMSCF)	Cumulative Water Produced (STB)
Core lab	3.64	1041	2367
Set 1	3.97	1217	2769
Set 2	3.58	1069	4874

As can be seen, the relative permeability has an effect on the amount of oil, gas, and water produced from the reservoir. The relative permeability from the core lab gives an overall oil production that is between both estimates, i.e Set 1 and 2, and also gives the lowest water production compared to the other two set of relative permeability data.

Table 16: Waterflood Recovery comparing all Relative Permeability Data

	Cumulative Oil Produced (MMSTB)	Cumulative Gas Produced (MMSCF)	Cumulative Water Produced (MMSTB)
Core lab	5.80	7701.00	25.46
Set 1	7.05	11431.47	35.35
Set 2	6.88	10206.73	35.04

Table 17: Gas Injection Recovery comparing all Relative Permeability Data

	Cumulative Oil Produced (MMSTB)	Cumulative Gas Produced (MMSCF)	Cumulative Water Produced (MMSTB)
Core lab	4.13	20656.28160	0.00313
Set 1	5.02	22518.58	0.00512
Set 2	4.18	21235.84512	0.00753

Recovery from relative permeability Set 1 was the highest in all scenarios due to the lower residual oil saturation in both water and gas flooded scenarios. As shown in the tables above, it is important to obtain accurate relative permeability information about the formation in other to capture an accurate representation of the reservoir as using the wrong relative permeability data could greatly affect the results from the model. In this full simulation study, precedence was given to the relative permeability obtained through core analysis of plugs from the reservoir.

5.7: Economic Analysis and Discussions

5.7.1: Comparison of Waterflooding, Gas Injection, and the Reason for WAG

As indicated in both the waterflooding and gas injection sections, waterflooding appears to yield the highest recovery. It provides good reservoir pressure maintenance, bigger sweep efficiency, and higher voidage replacement. The best waterflood scheme (Waterflood Run 15) recovered over 1.6MMSTB more oil compared to the best gas injection scheme (Gas Injection Run 13); it however produced over 25MMSTB more water compared to the best gas injection scheme. Appendix A shows a comprehensive distribution of the recovery from waterflooding and Appendix B shows the same for gas injection.

One observation is how different the injection location for the best waterflood and gas injection are. As shown in the figures for injection well placement for waterflooding and gas injection; the location of the waterflood injectors that yield the highest recovery is when the injection wells are placed at the north and south extremes of the reservoir, while for gas injection this is observed when they are placed in the center. The figures below show the general location of both the waterflood gas and injection well placement that yield the highest oil recovery.

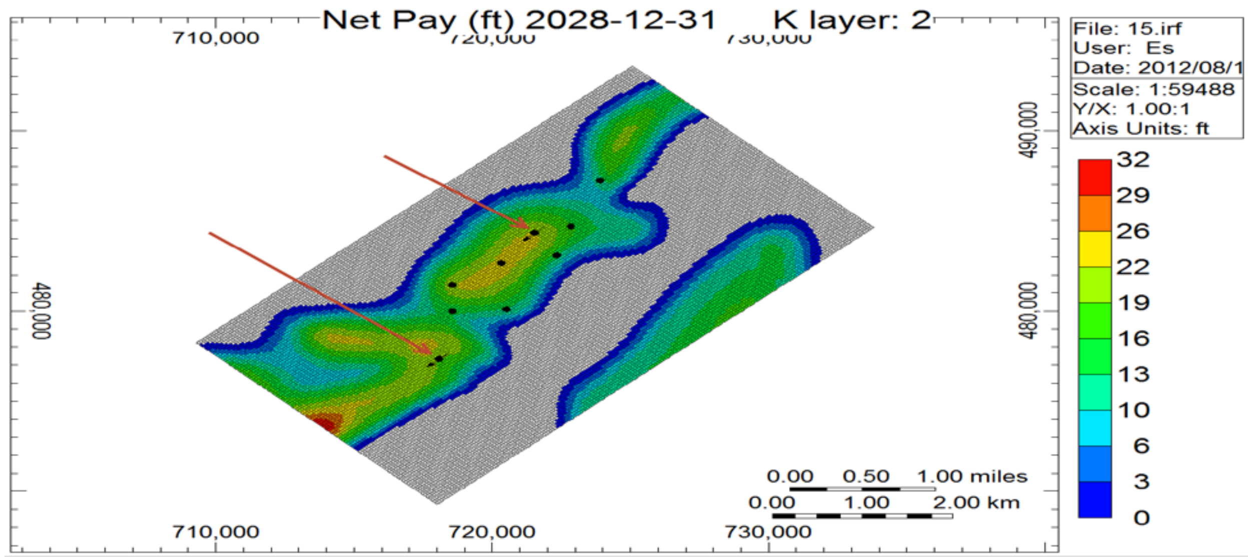


Figure 63: General waterflood injection well placement

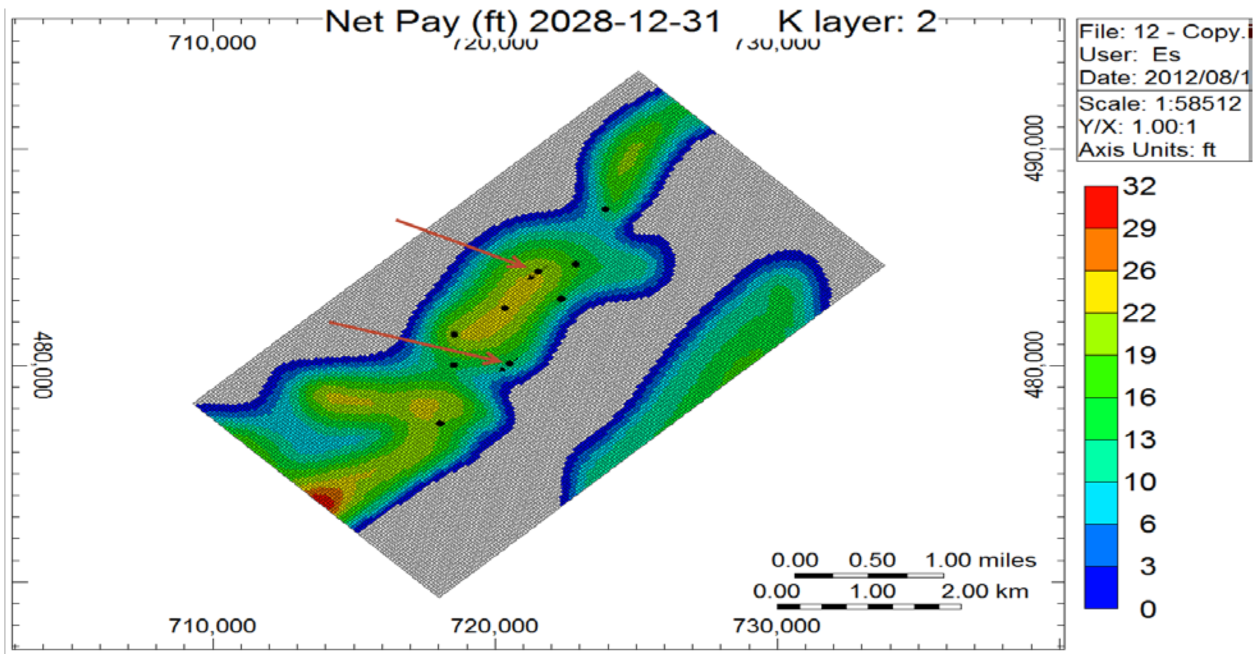


Figure 64: General gas injector well placement

In the best waterflood scenario, no injection well replaces the well in Area 1 shown in the figure above. Though the well is in the northern most part of the reservoir, the location of the well is isolated from the rest of the reservoir by a streak of thin pay (thin zone); meaning that injecting from this location will not be the very efficient in flooding the main reservoir.

In the best 3 waterflood schemes, pressure maintenance was a huge success as shown in the pressure maps. The problem of sharp reservoir decline due to production appears to be addressed by waterflooding. However, water production has been significantly increased. Significant water breakthrough, on average, for most of the producers was minimal until after about 10 years of productions, as shown in the oil and water saturation maps.

For gas injection, none of the injection schemes (including the best 3) were able to provide auxiliary pressure support to the reservoir to curtail the decline caused by production. After the first 3 years of production, average reservoir pressure is below the minimum miscible pressure (MMP) resulting in immiscible displacement for most of the injection period. Poor pressure maintenance and bad sweep efficiency resulted in poor oil recovery. The lower gas injection performance was also reflected in *P.R Nurafza (2004)* (10) where injection had a lower recovery of oil in a non-fractured reservoir, similar to our model, compared to water injection.

The high water cut in waterflooding and the lack of pressure support in gas injection, instigated the search for a third EOR solution that would address the cons of both waterflooding and gas injection as well as provide their benefits. This third solution was WAG.

5.7.1.1: Summary and Comparison of the Effects of Injection Rate and Location during both Gas Injection and Waterflooding

Table 18 and Table 19 below show the results of both waterflooding and gas injection respectively for case 1 and 2 scenarios. Case 1 and 2 are described in “Section 5.2” and “Section 5.3” and their well placement is shown in Figure 21.

Table 18: Waterflooding - Case 1 vs. Case 2

Water Injection Rates (Per injector)	Case 1 (Waterflooding)		Case 2 (Waterflooding)	
	Cumulative Production (MMSTB)	Cum Water Production (MMSTB)	Cumulative Production (MMSTB)	Cum Water Production (MMSTB)
0 bbl/D	3.64MMSTB	0.0024MMSTB	3.64MMSTB	0.0024MMSTB
1000 bbl/D	4.78MMSTB	9.75MMSTB	5.06MMSTB	8.53MMSTB
1500 bbl/D	5.12MMSTB	16.1MMSTB	5.40MMSTB	14.9MMSTB
2000 bbl/D	5.33MMSTB	22.5MMSTB	5.63MMSTB	21.4MMSTB

Table 19: Gas Injection - Case 1 vs. Case 2

Gas Injection Rates (Per Injector)	Case 1 (Gas Injection)		Case 2 (Gas Injection)	
	Cumulative Production (MMSTB)	Cum Water Production (MMSTB)	Cumulative Production (MMSTB)	Cum Water Production (MMSTB)
0 MSCF/D	3.64MMSTB	0.0024MMSTB	3.64MMSTB	0.0024MMSTB
750 MSCF/D	3.98MMSTB	0.0037MMSTB	3.92MMSTB	0.0035MMSTB
900 MSCF/D	4.01MMSTB	0.0038MMSTB	3.96MMSTB	0.0037MMSTB
1125 MSCF/D	4.06MMSTB	0.0040MMSTB	4.00MMSTB	0.0039MMSTB

As can be inferred from the tables above, waterflooding outperforms gas injection in regards to oil recovery. The best waterflooding scenario, in terms of oil recovery, is case 2 at an injection rate 3000bbl/d, shown in Table 18. This yielded a cumulative oil production of 5.8MMSTB of oil. The best gas injection scenario, again with regards to oil recovery, was case 1 with an injection rate of 1125Mscf/d per injection well. This yielded a cumulative oil production of 4.06MMSTB. Though waterflooding resulted in far higher water production, the best case waterflooding scenario recovered over 1.74MMSTB more oil than the best gas injection case.

5.7.2: Economic Analysis

Other than quantifying success based on just the amount of oil recovered, it is important to incorporate a financial aspect to the equation. The goal of most oil and gas operation is to turn a profit; reserves will not be exploited, even if considerable resources could be recovered, if it is not economical to do so.

The table below shows the simple cost and price values used to determine the profits obtained from the reservoir model. These were conservative values provided by an affiliation involved in the operations of the PSU field.

Table 20: Economic Model Specification

Cost Factors	**Cost**
Oil Price	$50/BBL
Gas Price	$4/MCF
Oil Operational Cost	$0.5/BBL
Gas Operational Cost	$0.5/MCF
Water Processing Operational Cost	$4/BBL
Water Injection Cost	$0.5/BBL
Gas Injection Cost	$5/MCF

The simple correlation used to determine the profits of the runs are shown in the equation below:

$$
\begin{aligned}
Profit = (&NP_o * Oil\ Price\ +\ NP_g * Gas\ Price \\
&- \left(NP_o * Oil\ Operational\ Cost +\ NP_g * Gas\ Operational\ \ Cost +\ NP_w \right.\\
&\left. * Water\ Processing\ Cost\right) \\
&- \left(NI_w * Water\ Injection\ Cost +\ NI_g * Gas\ Injection\ Cost\right)
\end{aligned}
$$

Where,

NP_o: Cumulative Produced Oil (bbl)

NP_w: Cumulative Produced Water (bbl)

NP_g: Cumulative Produced Gas (Mcf)

NI_w: Cumulative Injected Water (bbl)

NI_g: Cumulative Injected Gas (Mcf)

This correlation is simple and very conservative in terms of the price of oil, gas and the various operational costs. This is done partly to act as a buffer for the uncertainty in the market price and conditions of oil and gas as well as the services needed to extract them. A more detailed and asset specific economic evaluation would need to be performed if and when more pertinent data such as price decks, lease operating cost, working interest, and net revenue interest, etc is available to generate more accurate numbers. This current correlation provides a quick, and simplistic qualitative general assessment of the value of the operations captured in this report.

Using this correlation, the profits generated for waterflooding, gas injection, and WAG are shown in the tables below:

Table 21: 20 Year waterflood economic analysis

Runs	**Desired Total Injection Rate (bbl/D)**	**Actual Total Injection Rate (bbl/D)**	**Cum Oil Produced (MMSTB)**	**Cum Gas Produced (MMSCF)**	**Cum Water Produced (MMSTB)**	**CUM Water Injected (MMSTB)**	**Profit (Mil $)**
15	6000	4467.02	5.80	7701.00	25.46	33.20	199.393
14	4000	3674.1	5.78	7766.54	20.61	27.58	220.729
18	6000	4476.36	5.72	8005.83	25.52	33.05	196.659

Table 22: 20 Year gas injection economic analysis

Runs	Desired Total Injection Rate (MSCF/D)	Actual Total Injection Rate (MSCF/D)	Cum Oil Produced (MMSTB)	Cum Water Produced (MMSTB)	Cum Gas Produced (MMSCF)	Cum Gas Injected (MMSCF)	Profit (Mil $)
13	1500	1500.00	4.13	0.00313	20656.28160	11496.77158	219.3743
34	1500	1500.00	4.12	0.00299	20484.26803	11621.25005	217.5264
12	1500	1500.00	4.09	0.00317	20712.83917	11432.25139	217.9402

Table 23: 20 Year WAG injection economic analysis

Runs	Total Water Injection Rate (bbl/D)	Total Gas Injection Rate (MSCF/D)	Cum Oil Produced (MMSTB)	Cum Gas Produced (MMSCF)	Cum Water Produced (MMSTB)	Cum Gas Injected (MMSCF)	Cum Water Injected (MMSTB)	Profit (Mil $)
15	6000	1500	5.83	12350.00	16.12	5701.00	22.28	227.685
14	4000	1500	5.39	12330.00	10.06	5701.00	15.28	233.575
18	6000	1500	5.77	12720.00	15.80	5701.00	21.79	227.535

In the tables above, it can be seen that though gas injection recovered significantly less oil than waterflooding, based on the economic parameters described above, it generates higher profits compared to most of the waterflood runs due to producing significantly less water. WAG however out performed both waterflooding and gas injection. It not only recovered more oil but also yielded the highest profits. This is due to the reduction in produced water compared to waterflooding and gas compared to gas injection.

Chapter 6: Conclusions

This study has provided an addition to the list of carbonate fields available as analogs and benchmarking options. It provides insight into the behavior of this carbonate field in the presence of waterflood, miscible/immiscible gas injection, and water-alternating gas (WAG) injection. As injection rate increased the amount of oil recovered also increased; however there was a decrease in the percentage increase of oil recovered as the injection rate is increased. Without any external pressure support, the reservoir experienced sharp pressure decline during primary depletion, this was also experienced in the Jay/Lec field (11). WAG provided the best reservoir response, pressure maintenance and high oil recovery; it also produced less water and gas than waterflooding and gas injection respectively.

Pressure maintenance was one of the most important factors affecting recovery in this reservoir. Within this reservoir, other than efficient injection well placement and rates, the methods that yielded the best recovery were those that provided the best pressure maintenance and had a high (above 1) voidage rate ratios (VRR).

Waterflooding was able to reduce the rate at which pressure was decreasing and even reverse it, within certain locations of the reservoir, given an adequate injection rate. While gas injection alone was not able to manage the pressure drop, this behavior was also observed in (11). Gas injection was predominantly driven by immiscible displacement as a result of the strong pressure decline below the minimum miscibility pressure.

Injectivity was improved during WAG, high water injection rates were accommodated right after the gas injection cycle. The gas injection cycle of WAG resulted in better water injectivity, due to gas been more mobile and compressible compared to both oil and water. Under these circumstances, it can be concluded that the tertiary recovery method, WAG, may yield the best recovery, if it is initiated as soon as possible.

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Appendix A: Waterflood Recovery and Economics results using Relative Permeability from Core Analysis

Runs	Desired Total Injection Rate (bbl/D)	Actual Total Injection Rate (bbl/D)	Injector 1	Injector 2	Cum Oil (MMSTB)	Cum Gas (MMSCF)	Cum Water (MMSTB)	CUM Water Inj (MMSTB)	Profit (Mil $)
1	2000	1999.98	8_12	8_2	4.90	8,088.42	10.10	15.72	226.60
2	4000	2937.9	8_12	8_2	5.16	8,100.40	16.01	22.28	212.60
3	6000	2937.97	8_12	8_2	5.16	8,098.74	16.00	21.89	212.77
4	2000	2000	8_12	8_4	4.70	7,917.81	10.29	15.75	215.06
5	4000	2937.25	8_12	8_4	4.87	7,707.60	16.97	22.75	192.49
6	6000	2601.92	8_12	8_4	4.87	7,858.35	14.59	20.06	203.89
7	2000	2000	8_12	4_5	5.25	7,847.42	9.38	15.70	246.12
8	4000	3197.9	8_12	4_5	5.60	7,797.24	16.92	24.16	228.54
9	6000	3198.46	8_12	4_5	5.60	7,800.25	16.92	24.16	228.44
10	2000	2000	8_12	4_12	5.12	8,073.69	9.52	15.54	240.04
11	4000	3675.84	8_12	4_12	5.66	7,816.98	20.91	28.03	213.64
12	6000	3671.96	8_12	4_12	5.66	7,847.47	20.72	27.80	214.78
13	2000	2000	8_12	5_8	5.33	7,901.85	9.38	15.74	249.99
14	4000	3674.1	8_12	5_8	5.78	7,766.54	20.61	27.58	220.73
15	6000	4467.02	8_12	5_8	5.80	7,701.00	25.46	33.20	199.39
16	2000	2000	8_12	5_10	5.33	8,200.71	9.40	15.82	251.36
17	4000	3603.97	8_12	5_10	5.69	8,170.66	20.17	27.55	219.89
18	6000	4476.36	8_12	5_10	5.72	8,005.83	25.52	33.05	196.66
19	2000	2000.01	8_12	5_14	4.85	7,752.49	10.02	15.88	223.06
20	4000	3305.63	8_12	5_14	5.04	7,586.75	17.51	23.60	198.08
21	6000	3461.84	8_12	5_14	5.06	7,564.24	17.83	23.98	197.22
22	2000	1818.03	8_12	33_14	5.07	7,630.21	7.63	14.06	244.15
23	4000	2529.15	8_12	33_14	5.34	7,759.63	12.53	19.53	235.58
24	6000	2529.06	8_12	33_14	5.36	7,718.35	12.53	19.19	236.62
25	2000	2000	8_2	8_4	4.79	8,063.13	10.63	15.73	219.07
26	4000	3331.42	8_2	8_4	5.19	8,021.64	18.99	25.16	200.49
27	6000	3211.04	8_2	8_4	5.16	7,993.86	18.29	23.94	202.22
28	2000	2000.01	8_2	4_5	4.84	8,065.42	11.04	15.62	219.94
29	4000	3061.43	8_2	4_5	5.01	7,534.09	17.41	22.49	197.39
30	6000	3060.69	8_2	4_5	5.02	7,519.25	17.39	21.99	197.97
31	2000	2000	8_2	4_12	4.75	8,331.53	11.07	15.45	216.32
32	4000	3516.68	8_2	4_12	5.07	7,515.02	21.12	26.16	183.42

33	6000	3411.71	8_2	4_12	5.05	7,551.70	20.34	24.85	186.34
34	2000	2000	8_2	5_8	4.92	8,084.33	11.02	15.65	223.98
35	4000	3535.79	8_2	5_8	5.16	7,476.21	21.25	26.63	186.92
36	6000	4243.63	8_2	5_8	5.16	7,371.19	25.46	31.04	167.40
37	2000	2000	8_2	5_10	4.93	8,188.02	10.74	15.72	225.90
38	4000	3377	8_2	5_10	5.15	7,657.04	20.11	25.49	192.51
39	6000	4054.86	8_2	5_10	5.23	7,499.63	24.08	29.72	177.51
40	2000	2000	8_2	5_14	4.97	8,274.87	10.72	15.81	228.35
41	4000	3364.61	8_2	5_14	5.26	7,933.81	19.42	25.50	201.70
42	6000	3789.57	8_2	5_14	5.31	7,895.58	21.71	28.05	193.78
43	2000	1805.01	8_2	33_14	4.71	7,996.38	9.23	13.90	221.23
44	4000	2415.58	8_2	33_14	4.84	7,551.30	13.06	17.99	208.63
45	6000	2334.32	8_2	33_14	4.81	7,550.38	12.73	17.57	208.80
46	2000	2000	8_4	4_5	4.92	8,010.99	10.75	15.71	224.80
47	4000	3482.71	8_4	4_5	5.31	7,316.35	19.84	26.20	199.81
48	6000	4461.18	8_4	4_5	5.49	7,365.10	26.30	33.10	179.39
49	2000	2000	8_4	4_12	4.75	8,147.92	10.92	15.54	216.11
50	4000	4000	8_4	4_12	5.35	7,303.13	24.04	30.31	182.88
51	6000	3897.61	8_4	4_12	5.34	7,360.07	22.94	28.59	187.49
52	2000	2000.01	8_4	5_8	4.94	7,823.31	10.82	15.74	224.69
53	4000	4000	8_4	5_8	5.46	7,262.56	24.01	30.62	187.76
54	6000	4797.73	8_4	5_8	5.46	7,226.45	28.87	35.62	166.05
55	2000	2000	8_4	5_10	5.01	7,951.87	10.65	15.82	229.12
56	4000	3873.24	8_4	5_10	5.42	7,738.67	22.90	29.41	192.93
57	6000	4657.59	8_4	5_10	5.48	7,632.76	27.94	34.64	172.89
58	2000	2000.01	8_4	5_14	5.04	8,098.71	10.21	15.91	233.20
59	4000	3473.71	8_4	5_14	5.45	8,103.29	19.88	26.11	209.59
60	6000	3606.49	8_4	5_14	5.47	8,103.27	20.67	27.37	206.88
61	2000	1819.35	8_4	33_14	4.75	7,940.31	9.08	14.09	223.49
62	4000	2803.67	8_4	33_14	5.09	7,263.04	15.31	21.44	208.94
63	6000	3793.36	8_4	33_14	5.33	7,338.53	21.71	28.42	192.31
64	2000	2000.01	4_5	4_12	4.66	9,135.30	11.21	15.37	214.63
65	4000	3169.91	4_5	4_12	4.89	8,786.82	18.81	23.69	189.92
66	6000	2927.01	4_5	4_12	4.84	8,856.85	17.21	21.53	195.43
67	2000	2000	4_5	5_8	4.69	8,963.81	11.21	15.54	215.25
68	4000	3048.74	4_5	5_8	4.88	8,751.37	18.16	23.06	192.47
69	6000	3360.72	4_5	5_8	4.93	8,691.18	19.83	24.87	186.98
70	2000	2000.01	4_5	5_10	4.89	8,673.10	11.09	15.67	224.53
71	4000	3357.21	4_5	5_10	5.10	8,213.11	19.80	25.25	193.48
72	6000	4308.81	4_5	5_10	5.16	7,959.16	25.81	30.91	168.51
73	2000	2000	4_5	5_14	4.98	8,327.78	10.77	15.79	228.95
74	4000	3439.23	4_5	5_14	5.28	7,639.62	20.08	26.02	198.39
75	6000	4147.77	4_5	5_14	5.41	7,480.68	24.01	30.36	186.40

76	2000	1646.33	4_5	33_14	4.42	9,151.47	8.86	12.66	213.48
77	4000	1908.12	4_5	33_14	4.45	9,121.66	10.38	14.32	208.06
78	6000	1907.6	4_5	33_14	4.45	9,118.58	10.38	14.33	208.06
79	2000	2000.02	4_12	5_8	4.91	9,053.87	10.81	15.40	228.37
80	4000	3411	4_12	5_8	5.09	8,423.27	20.45	25.38	191.06
81	6000	3590.66	4_12	5_8	5.10	8,391.73	21.57	26.54	186.31
82	2000	2000	4_12	5_10	4.99	8,875.05	10.77	15.51	231.54
83	4000	3640.21	4_12	5_10	5.24	8,170.29	22.03	27.04	190.29
84	6000	4208.31	4_12	5_10	5.27	7,971.84	25.61	31.29	174.53
85	2000	2000.01	4_12	5_14	4.93	8,628.08	10.74	15.65	227.82
86	4000	4000	4_12	5_14	5.41	7,742.05	24.44	30.51	185.70
87	6000	4527.34	4_12	5_14	5.52	7,639.59	27.25	33.61	177.97
88	2000	1759.93	4_12	33_14	4.50	9,127.84	9.33	13.37	215.22
89	4000	2691.87	4_12	33_14	4.68	8,813.16	15.74	20.24	193.65
90	6000	2641.3	4_12	33_14	4.67	8,850.09	15.24	19.35	195.75
91	2000	1999.99	5_8	5_10	5.01	8,568.98	10.89	15.71	230.72
92	4000	3999.97	5_8	5_10	5.14	7,881.15	24.65	29.70	172.65
93	6000	4711.93	5_8	5_10	5.17	7,626.70	28.53	33.89	155.30
94	2000	2000	5_8	5_14	5.06	8,330.29	10.76	15.85	232.67
95	4000	3999.99	5_8	5_14	5.38	7,562.44	24.37	30.53	184.03
96	6000	5148.27	5_8	5_14	5.42	7,377.43	30.91	37.53	155.45
97	2000	1706.32	5_8	33_14	4.53	8,978.82	9.05	13.12	217.17
98	4000	2618.14	5_8	33_14	4.68	8,751.21	15.52	20.06	194.80
99	6000	3196.14	5_8	33_14	4.77	8,635.39	18.68	23.47	184.32
100	2000	2000	5_10	5_14	5.10	8,392.91	10.65	15.92	235.51
101	4000	3999.99	5_10	5_14	5.43	7,657.43	24.01	30.34	188.11
102	6000	4603.71	5_10	5_14	5.47	7,588.05	27.22	33.78	175.29
103	2000	1776.37	5_10	33_14	4.76	8,678.75	9.10	13.71	227.02
104	4000	2743.25	5_10	33_14	5.06	8,256.37	15.76	21.15	209.66
105	6000	3713.61	5_10	33_14	5.13	8,036.87	21.49	27.16	186.39
106	2000	1799.35	5_14	33_14	4.84	8,230.31	8.92	14.01	229.81
107	4000	2784.52	5_14	33_14	5.14	7,707.10	15.71	21.54	211.79
108	6000	3632.01	5_14	33_14	5.34	7,463.74	20.94	26.77	196.97

Appendix B: Gas Injection Recovery and Economics results using Relative Permeability from Core Analysis

Runs	Desired Total Injection Rate (MSCF/D)	Actual Total Injection Rate (MSCF/D)	Injector 1	Injector 2	Cum Oil (MMSTB)	Cum Water (MMSTB)	Cum Gas (MMSCF)	Cum Gas INJ (MMSCF)	Profit (Mil $)
1	1500	1500	8_12	8_2	3.85	0.0030	19210.60	11525.27	200.07
2	1500	1500	8_12	8_4	3.77	0.0031	19502.36	11570.78	197.15
3	1500	1500	8_12	4_5	3.90	0.0032	19463.08	11472.00	203.90
4	1500	1500	8_12	4_12	3.92	0.0033	19491.47	11355.00	205.43
5	1500	1500	8_12	5_8	3.98	0.0030	19377.97	11494.50	207.21
6	1500	1500	8_12	5_10	3.96	0.0029	19340.14	11559.00	205.95
7	1500	1500	8_12	5_14	3.67	0.0028	18916.61	11649.76	189.43
8	1500	1500	8_12	33_14	3.81	0.0032	19007.24	11429.25	197.85
9	1500	1500	8_2	8_4	3.98	0.0033	20833.99	11508.55	212.41
10	1500	1500	8_2	4_5	4.01	0.0033	20762.29	11409.75	213.92
11	1500	1500	8_2	4_12	4.03	0.0034	20800.71	11292.75	215.93
12	1500	1500	8_2	5_8	4.09	0.0032	20712.84	11432.25	217.94
13	1500	1500	8_2	5_10	4.13	0.0031	20656.28	11496.77	219.37
14	1500	1500	8_2	5_14	4.07	0.0031	20589.85	11587.50	215.78
15	1500	1500	8_2	33_14	3.92	0.0033	20339.26	11367.00	208.38
16	1500	1500	8_4	4_5	3.95	0.0035	20831.97	11455.28	211.03
17	1500	1500	8_4	4_12	3.99	0.0036	20855.24	11338.28	213.78
18	1500	1500	8_4	5_8	4.02	0.0034	20801.48	11477.78	214.55
19	1500	1500	8_4	5_10	4.06	0.0033	20847.33	11542.28	216.37
20	1500	1500	8_4	5_14	3.97	0.0032	20770.05	11633.01	211.16
21	1500	1500	8_4	33_14	3.85	0.0035	20391.44	11412.53	205.06
22	1500	1500	4_5	4_12	3.93	0.0035	20849.82	11239.50	211.52
23	1500	1500	4_5	5_8	4.07	0.0033	20522.92	11379.00	216.31
24	1500	1500	4_5	5_10	4.03	0.0031	20790.13	11443.50	215.12
25	1500	1500	4_5	5_14	3.98	0.0032	20748.79	11534.25	211.86
26	1500	1500	4_5	33_14	3.76	0.0032	20311.05	11313.75	200.39
27	1500	1500	4_12	5_8	4.03	0.0033	20772.25	11262.00	215.94
28	1500	1500	4_12	5_10	4.05	0.0033	20842.69	11326.50	216.86
29	1500	1500	4_12	5_14	4.01	0.0033	20793.08	11417.25	214.12
30	1500	1500	4_12	33_14	3.85	0.0034	20415.03	11196.75	206.11
31	1500	1500	5_8	5_10	4.07	0.0030	20540.39	11466.00	216.04
32	1500	1500	5_8	5_14	4.07	0.0030	20654.35	11556.75	216.10

33	1500	1500	5_8	33_14	3.81	0.0031	20240.73	11336.25	202.62
34	1500	1500	5_10	5_14	4.12	0.0030	20484.27	11621.25	217.53
35	1500	1500	5_10	33_14	3.95	0.0032	20338.27	11400.75	209.80
36	1500	1500	5_14	33_14	3.89	0.0032	20304.15	11491.50	206.26

Appendix C: Waterflooding Recovery and Economics results using Relative Permeability from Set 1

Runs	Desired Total Injection Rate (bbl/D)	Actual Total Injection Rate (bbl/D)	Injector 1	Injector 2	Cum Oil (MMSTB)	Cum Gas (MMSCF)	Cum Water (MMSTB)	Profit (Mil $)
1	2000	2000	8_12	8_2	5.64	11013.22	9.30	285.86
2	4000	4000	8_12	8_2	6.23	11377.27	22.84	262.35
3	6000	6000	8_12	8_2	6.58	11569.81	35.99	227.97
4	2000	2000	8_12	8_4	5.31	915.82	9.86	226.96
5	4000	4000	8_12	8_4	5.93	11173.66	23.63	243.51
6	6000	6000	8_12	8_4	6.33	11339.44	36.73	211.84
7	2000	2000	8_12	4_5	5.85	11519.26	8.50	301.77
8	4000	4000	8_12	4_5	6.67	11290.24	22.24	286.56
9	6000	6000	8_12	4_5	7.05	11431.47	35.35	253.48
10	2000	2000	8_12	4_12	5.86	11467.51	8.72	300.83
11	4000	4000	8_12	4_12	6.45	11346.01	22.72	273.65
13	2000	2000	8_12	5_8	5.98	11398.52	8.38	308.23
14	4000	4000	8_12	5_8	6.77	11435.67	21.73	293.97
16	2000	2000	8_12	5_10	6.00	11295.49	8.66	307.60
17	4000	4000	8_12	5_10	6.79	11600.89	21.66	295.94
19	2000	2000	8_12	5_14	5.35	10716.36	9.95	267.92
20	4000	4000	8_12	5_14	6.08	11126.00	23.02	253.28
21	6000	6000	8_12	5_14	6.48	11358.08	36.11	221.67
22	2000	2000	8_12	33_14	5.84	11005.37	8.34	299.86
23	4000	4000	8_12	33_14	6.62	957.15	21.83	244.08
24	6000	5290	8_12	33_14	6.88	11208.57	29.92	265.95
25	2000	2000	8_2	8_4	5.33	12391.17	9.67	274.85
26	4000	4000	8_2	8_4	5.97	11820.54	23.96	247.16
27	6000	6000	8_2	8_4	6.50	11348.02	37.51	217.23
28	2000	2000	8_2	4_5	5.53	12476.43	9.44	285.70
29	4000	4000	8_2	4_5	6.10	11927.55	23.77	254.62
31	2000	2000	8_2	4_12	5.44	12615.92	9.49	281.57
32	4000	4000	8_2	4_12	5.89	12093.77	23.76	244.88
33	6000	6000	8_2	4_12	6.12	11725.47	37.84	198.50
34	2000	2000	8_2	5_8	5.66	12509.02	9.18	293.50
35	4000	4000	8_2	5_8	6.17	11984.64	23.42	259.83

36	6000	6000	8_2	5_8	6.35	11668.03	37.07	212.53
37	2000	2000	8_2	5_10	5.67	12463.23	9.24	293.31
38	4000	4000	8_2	5_10	6.18	11983.74	23.24	260.91
40	2000	2000	8_2	5_14	5.75	12423.27	8.97	298.69
41	4000	4000	8_2	5_14	6.35	12144.61	22.95	270.93
42	6000	6000	8_2	5_14	6.59	11814.60	36.59	227.17
43	2000	2000	8_2	33_14	5.49	11956.97	9.31	282.54
44	4000	4000	8_2	33_14	6.02	11624.73	23.15	251.99
45	6000	5264	8_2	33_14	6.16	11392.00	31.53	224.39
46	2000	2000	8_4	4_5	5.51	12615.40	9.25	286.18
47	4000	4000	8_4	4_5	6.16	12030.24	23.55	258.81
48	6000	6000	8_4	4_5	6.49	11603.84	37.40	217.96
49	2000	2000	8_4	4_12	5.46	12638.74	9.37	283.45
50	4000	4000	8_4	4_12	5.97	12137.93	23.62	249.58
51	6000	6000	8_4	4_12	6.30	11729.05	37.98	206.60
52	2000	2000	8_4	5_8	5.65	12569.62	9.09	293.40
53	4000	4000	8_4	5_8	6.28	12048.86	23.28	265.87
55	2000	2000	8_4	5_10	5.62	12548.59	9.27	291.44
56	4000	2446	8_4	5_10	1.26	11607.94	0.02	108.87
58	2000	2000	8_4	5_14	5.52	12373.66	9.42	284.96
59	4000	4000	8_4	5_14	6.31	11773.73	23.12	266.83
61	2000	2000	8_4	33_14	5.49	12058.46	9.14	283.23
62	4000	4000	8_4	33_14	6.07	11705.18	23.00	255.26
63	6000	5299	8_4	33_14	6.33	11430.09	31.90	231.30
64	2000	2000	4_5	4_12	5.18	12734.41	10.19	266.79
65	4000	4000	4_5	4_12	5.77	12514.51	24.03	239.36
67	2000	2000	4_5	5_8	5.47	12522.91	9.81	281.64
68	4000	4000	4_5	5_8	5.92	12430.90	23.79	247.47
69	6000	6000	4_5	5_8	6.03	12168.67	37.42	197.55
70	2000	2000	4_5	5_10	5.49	12594.78	9.68	283.62
71	4000	4000	4_5	5_10	6.01	12260.55	23.68	251.80
73	2000	2000	4_5	5_14	5.71	12609.25	9.01	297.15
74	4000	4000	4_5	5_14	6.34	12117.46	23.01	270.04
75	6000	6000	4_5	5_14	6.55	11928.71	36.67	225.48
76	2000	2000	4_5	33_14	5.10	12168.14	10.33	259.71
77	4000	3967	4_5	33_14	5.52	12236.82	23.46	228.37
79	2000	2000	4_12	5_8	5.42	12834.16	9.70	280.78
80	4000	4000	4_12	5_8	6.01	12544.24	23.55	253.29
81	6000	6000	4_12	5_8	6.23	12238.44	37.51	207.19
82	2000	2000	4_12	5_10	5.48	12835.88	9.55	284.52
83	4000	4000	4_12	5_10	6.05	12555.13	23.49	255.79
85	2000	2000	4_12	5_14	5.64	12764.75	9.01	294.27
86	4000	4000	4_12	5_14	6.22	12366.30	23.15	264.90

88	2000	2000	4_12	33_14	5.18	12276.23	10.04	265.35
89	4000	4000	4_12	33_14	5.65	12277.59	23.64	234.28
90	6000	5146	4_12	33_14	5.79	12209.49	31.18	210.61
91	2000	2000	5_8	5_10	5.60	12513.77	9.34	289.84
92	4000	4000	5_8	5_10	6.09	12176.71	23.14	257.65
94	2000	2000	5_8	5_14	5.84	12591.67	8.79	304.33
95	4000	4000	5_8	5_14	6.35	12170.38	22.75	271.79
97	2000	2000	5_8	33_14	4.61	595.02	5.36	209.34
98	4000	4000	5_8	33_14	5.73	12196.85	23.36	238.88
99	6000	5000	5_8	33_14	5.84	12141.62	30.12	217.29
100	2000	2000	5_10	5_14	5.89	12508.00	8.79	306.51
101	4000	4000	5_10	5_14	6.41	12234.20	22.49	276.33
102	6000	6000	5_10	5_14	6.62	12033.79	36.02	231.64
103	2000	2000	5_10	33_14	5.42	12156.96	9.57	278.65
104	4000	4000	5_10	33_14	5.94	11999.82	23.14	249.67
105	6000	5199	5_10	33_14	6.16	11909.10	30.76	229.28
106	2000	2000	5_14	33_14	5.62	12100.29	8.93	291.00
107	4000	4000	5_14	33_14	6.27	11831.94	22.49	267.64
108	6000	5249	5_14	33_14	6.42	11761.40	30.88	241.48

Appendix D: Gas Injection Recovery and Economics results using Relative Permeability from Set 1

Runs	Desired Total Injection Rate (bbl/D)	Actual Total Injection Rate (bbl/D)	Injector 1	Injector 2	Cum Oil (MMSTB)	Cum Gas (MMSCF)	Cum Water (MMSTB)	Profit (Mil $)
1	1500	52.01	8_12	8_2	3.95	12437.67	0.00	245.40
2	1500	781.51	8_12	8_4	4.35	17345.21	0.00	284.48
3	1500	44.75	8_12	4_5	3.99	12415.14	0.00	246.92
4	1500	781.81	8_12	4_12	4.51	17509.82	0.00	293.22
5	1500	68.75	8_12	5_8	4.02	12577.87	0.00	249.30
6	1500	70.56	8_12	5_10	3.98	12579.86	0.00	247.20
7	1500	67.52	8_12	5_14	3.96	12505.96	0.00	246.13
8	1500	43.37	8_12	33_14	3.94	12410.81	0.00	244.80
9	1500	770.02	8_2	8_4	4.51	17396.54	0.00	292.87
10	1500	33.02	8_2	4_5	4.01	12394.71	0.00	248.16
11	1500	770.09	8_2	4_12	4.54	17518.65	0.00	294.71
12	1500	57.04	8_2	5_8	4.05	12571.72	0.00	250.83
13	1500	58.86	8_2	5_10	4.02	12593.88	0.00	249.48
14	1500	55.92	8_2	5_14	4.03	12551.26	0.00	249.72
15	1500	31.64	8_2	33_14	3.97	12380.65	0.00	246.19
16	1500	762.83	8_4	4_5	4.58	17374.16	0.00	296.05
17	1500	1500.00	8_4	4_12	5.02	22518.58	0.01	338.52
18	1500	786.76	8_4	5_8	4.60	17541.90	0.00	297.83
19	1500	788.52	8_4	5_10	4.52	17524.56	0.00	293.78
20	1500	785.42	8_4	5_14	4.66	17483.04	0.00	300.46
21	1500	761.45	8_4	33_14	4.53	17360.09	0.00	293.47
22	1500	762.74	4_5	4_12	4.58	17461.93	0.00	296.52
23	1500	49.68	4_5	5_8	4.05	12498.62	0.00	250.58
24	1500	51.55	4_5	5_10	4.04	12548.33	0.00	250.07
25	1500	48.63	4_5	5_14	4.04	12519.60	0.00	249.92
26	1500	24.30	4_5	33_14	3.96	12320.04	0.00	245.37
27	1500	786.52	4_12	5_8	4.66	17595.62	0.00	301.01
28	1500	788.43	4_12	5_10	4.56	17613.80	0.00	296.01
29	1500	785.64	4_12	5_14	4.58	17593.86	0.00	297.04
30	1500	761.39	4_12	33_14	4.52	17441.29	0.00	293.71
31	1500	75.51	5_8	5_10	4.05	12711.41	0.00	251.53
32	1500	72.62	5_8	5_14	4.08	12671.90	0.00	252.84
33	1500	48.32	5_8	33_14	4.00	12492.36	0.00	247.82
34	1500	74.42	5_10	5_14	4.06	12682.54	0.00	251.64

35	1500	50.17	5_10	33_14	4.00	12496.89	0.00	247.78
36	1500	47.25	5_14	33_14	4.00	12481.51	0.00	247.88

Appendix E: Waterflooding Recovery and Economics results using Relative Permeability from Set 2

Runs	Desired Total Injection Rate (bbl/D)	Actual Total Injection Rate (bbl/D)	Injector 1	Injector 2	Cum Oil (MMSTB)	Cum Gas (MMSCF)	Cum Water (MMSTB)	CUM Water Inj (MMSTB)	Profit (Mil $)
1	2000	2000	8_12	8_2	5.35	9435.96	9.52	15.37	256.94
2	4000	4000	8_12	8_2	5.95	9771.03	23.09	30.06	226.11
3	6000	6000	8_12	8_2	6.31	9965.57	36.22	43.91	185.27
4	2000	2000	8_12	8_4	5.08	9330.27	10.05	15.43	240.70
5	4000	4000	8_12	8_4	5.69	9568.30	23.79	30.48	209.51
6	6000	6000	8_12	8_4	6.11	9750.15	36.82	44.35	172.08
7	2000	2000	8_12	4_5	5.67	9389.37	8.97	15.30	274.88
8	4000	4000	8_12	4_5	6.41	9631.43	22.48	30.23	250.68
9	6000	6000	8_12	4_5	6.77	9779.51	35.10	44.06	211.74
10	2000	2000	8_12	4_12	5.53	9440.32	9.15	15.14	267.38
11	4000	4000	8_12	4_12	6.20	9746.06	22.92	30.25	239.08
12	6000	4318	8_12	4_12	6.59	9882.73	36.10	44.16	199.16
13	2000	2000	8_12	5_8	5.81	9448.88	8.75	15.33	282.96
14	4000	4000	8_12	5_8	6.50	9769.49	21.99	29.92	257.76
15	6000	6000	8_12	5_8	6.87	9941.14	35.12	43.77	217.47
16	2000	2000	8_12	5_10	5.77	9564.61	8.91	15.41	280.58
17	4000	4000	8_12	5_10	6.51	9976.31	21.86	29.82	259.73
18	6000	6000	8_12	5_10	6.88	10206.73	35.04	43.68	219.47
19	2000	2000	8_12	5_14	5.13	9160.17	10.10	15.53	242.21
20	4000	4000	8_12	5_14	5.82	9497.59	23.37	29.96	217.56
21	6000	6000	8_12	5_14	6.20	9728.50	36.28	43.77	179.00
22	2000	2000	8_12	33_14	5.60	8918.31	8.81	15.24	270.11
23	4000	4000	8_12	33_14	6.34	9389.02	22.04	29.98	248.17
24	6000	5244	8_12	33_14	6.62	9628.92	29.78	38.30	227.88
25	2000	2000	8_2	8_4	5.12	10432.88	10.26	15.34	246.41
26	4000	4000	8_2	8_4	5.74	9742.21	24.41	30.64	210.17
27	6000	6000	8_2	8_4	6.22	9715.55	37.66	44.91	173.57
28	2000	2000	8_2	4_5	5.32	10526.11	10.05	15.21	257.49
29	4000	4000	8_2	4_5	5.81	9902.36	24.35	30.43	214.34
30	6000	6000	8_2	4_5	6.01	9591.34	38.05	44.49	161.35
31	2000	2000	8_2	4_12	5.20	10695.48	10.12	15.06	252.03
32	4000	4000	8_2	4_12	5.66	10052.83	24.31	30.11	207.92
33	6000	6000	8_2	4_12	5.87	9682.24	38.44	44.59	153.28

34	2000	2000	8_2	5_8	5.48	10521.70	9.80	15.24	266.61
35	4000	4000	8_2	5_8	5.89	9968.93	24.00	30.26	220.28
36	6000	6000	8_2	5_8	6.06	9648.43	37.67	44.18	165.85
37	2000	2000	8_2	5_10	5.48	10484.27	9.82	15.33	266.14
38	4000	4000	8_2	5_10	5.91	10029.23	23.84	30.15	222.25
39	6000	6000	8_2	5_10	6.07	9718.28	37.37	44.02	168.00
40	2000	2000	8_2	5_14	5.55	10458.82	9.55	15.45	270.68
41	4000	4000	8_2	5_14	6.04	10138.49	23.64	30.33	229.72
42	6000	6000	8_2	5_14	6.32	9891.72	37.08	44.35	181.78
43	2000	2000	8_2	33_14	5.26	10091.40	9.85	15.16	253.68
44	4000	4000	8_2	33_14	5.75	9676.52	23.67	29.97	213.87
45	6000	4900	8_2	33_14	5.82	9442.09	29.65	36.09	189.27
46	2000	2000	8_4	4_5	5.32	10611.70	9.95	15.27	258.20
47	4000	4000	8_4	4_5	5.88	9940.89	24.22	30.55	218.78
48	6000	6000	8_4	4_5	6.19	9466.75	37.93	44.93	170.18
49	2000	2000	8_4	4_12	5.19	10694.59	10.11	15.12	251.53
50	4000	4000	8_4	4_12	5.70	10072.69	24.26	30.24	210.47
51	6000	6000	8_4	4_12	6.04	9548.17	38.49	45.15	160.70
52	2000	2000	8_4	5_8	5.45	10566.42	9.76	15.30	265.28
53	4000	4000	8_4	5_8	5.96	9908.02	24.02	30.46	223.48
54	6000	6000	8_4	5_8	6.29	9464.48	37.18	44.31	178.13
55	2000	2000	8_4	5_10	5.38	10583.26	9.95	15.39	260.97
56	4000	4000	8_4	5_10	6.01	9938.56	23.63	30.25	227.50
57	6000	6000	8_4	5_10	6.42	9712.84	36.59	44.12	188.16
58	2000	2000	8_4	5_14	5.33	10365.21	9.99	15.51	257.66
59	4000	4000	8_4	5_14	6.11	9811.85	23.46	30.40	232.78
60	6000	6000	8_4	5_14	6.58	10002.27	36.44	44.39	197.74
61	2000	2000	8_4	33_14	5.24	10160.84	9.77	15.22	253.46
62	4000	4000	8_4	33_14	5.81	9698.90	23.62	30.14	216.66
63	6000	5248	8_4	33_14	6.06	9354.31	32.04	39.10	189.49
64	2000	2000	4_5	4_12	4.98	10913.32	10.62	14.99	240.23
65	4000	4000	4_5	4_12	5.52	10620.95	24.54	29.97	202.38
66	6000	6000	4_5	4_12	5.78	10445.04	38.48	44.60	151.87
67	2000	2000	4_5	5_8	5.20	10665.53	10.34	15.17	251.05
68	4000	4000	4_5	5_8	5.63	10503.26	24.38	30.12	208.34
69	6000	6000	4_5	5_8	5.83	10399.04	37.91	44.22	156.56
70	2000	2000	4_5	5_10	5.27	10671.08	10.30	15.26	254.72
71	4000	4000	4_5	5_10	5.77	10288.91	24.20	30.21	215.03
72	6000	6000	4_5	5_10	6.02	10033.66	37.54	44.09	165.88
73	2000	2000	4_5	5_14	5.51	10608.85	9.69	15.38	268.59
74	4000	4000	4_5	5_14	6.03	10121.59	23.73	30.45	229.06
75	6000	6000	4_5	5_14	6.28	9898.75	37.30	44.50	178.91
76	2000	2000	4_5	33_14	4.90	10460.41	10.65	15.09	234.28

77	4000	3932	4_5	33_14	5.26	10491.11	23.45	28.87	194.31
78	6000	4804	4_5	33_14	5.38	10471.30	29.64	35.22	172.10
79	2000	2000	4_12	5_8	5.20	10953.81	10.20	15.02	252.74
80	4000	4000	4_12	5_8	5.79	10655.18	24.10	30.03	217.75
81	6000	6000	4_12	5_8	6.04	10378.55	37.99	44.57	166.09
82	2000	2000	4_12	5_10	5.25	10968.00	10.15	15.10	255.36
83	4000	4000	4_12	5_10	5.85	10561.82	24.05	30.20	220.62
84	6000	6000	4_12	5_10	6.18	10286.94	37.40	44.25	175.12
85	2000	2000	4_12	5_14	5.42	10845.17	9.68	15.22	265.46
86	4000	4000	4_12	5_14	5.95	10377.93	23.86	30.45	225.60
87	6000	6000	4_12	5_14	6.25	10122.91	37.59	44.69	177.28
88	2000	2000	4_12	33_14	4.93	10526.85	10.46	14.93	236.88
89	4000	4000	4_12	33_14	5.39	10472.67	24.12	29.60	197.34
90	6000	5094	4_12	33_14	5.56	10424.36	31.30	37.15	173.37
91	2000	2000	5_8	5_10	5.40	10619.34	9.99	15.29	262.30
92	4000	4000	5_8	5_10	5.88	10243.33	23.73	29.95	222.31
93	6000	6000	5_8	5_10	6.13	10027.19	37.06	43.82	173.28
94	2000	2000	5_8	5_14	5.65	10548.22	9.46	15.41	276.18
95	4000	4000	5_8	5_14	6.16	10120.18	22.71	30.25	239.28
96	6000	6000	5_8	5_14	6.34	9954.67	36.88	44.16	184.05
97	2000	2000	5_8	33_14	5.03	10380.93	10.37	15.12	241.26
98	4000	4000	5_8	33_14	5.49	10438.73	23.73	29.44	203.97
99	6000	4973	5_8	33_14	5.63	10394.68	30.39	36.36	180.57
100	2000	2000	5_10	5_14	5.69	10494.48	9.37	15.50	278.21
101	4000	4000	5_10	5_14	6.16	10269.75	23.11	30.10	238.50
102	6000	6000	5_10	5_14	6.41	10055.43	36.41	44.01	189.73
103	2000	2000	5_10	33_14	5.19	10337.83	10.11	15.20	250.29
104	4000	4000	5_10	33_14	5.74	10107.51	22.99	29.84	217.74
105	6000	5157	5_10	33_14	5.96	10060.94	30.90	37.59	193.05
106	2000	2000	5_14	33_14	5.41	10197.01	9.53	15.32	262.84
107	4000	4000	5_14	33_14	6.00	9909.68	23.03	30.10	229.50
108	6000	5212	5_14	33_14	6.16	9816.11	31.16	38.48	200.10

Appendix F: Gas Injection Recovery and Economics results using Relative Permeability from Set 2

Runs	Desired Total Injection Rate (bbl/D)	Actual Total Injection Rate (bbl/D)	Injector 1	Injector 2	Cum Oil (MMSTB)	Cum Water (MMSTB)	Cum Gas (MMSCF)	Cum Gas INJ (MMSCF)	Profit (Mil $)
1	1500	1500	8_12	8_2	3.95	0.01	20229.26	11525.25	208.54
2	1500	1500	8_12	8_4	3.86	0.01	20463.46	11570.75	204.83
3	1500	1500	8_12	4_5	3.98	0.01	20427.86	11472.00	211.28
4	1500	1500	8_12	4_12	4.01	0.01	20414.72	11355.00	213.35
5	1500	1500	8_12	5_8	4.06	0.01	20363.89	11494.50	214.87
6	1500	1500	8_12	5_10	4.02	0.01	20350.50	11559.00	212.53
7	1500	1500	8_12	5_14	3.77	0.01	20081.01	11649.75	198.69
8	1500	1500	8_12	33_14	3.92	0.01	20109.56	11429.25	207.37
9	1500	1500	8_2	8_4	4.04	0.01	21358.75	11508.51	217.01
10	1500	1500	8_2	4_5	4.07	0.01	21304.00	11409.75	218.84
11	1500	1500	8_2	4_12	4.10	0.01	21289.95	11292.75	220.95
12	1500	1500	8_2	5_8	4.15	0.01	21243.34	11432.25	222.78
13	1500	1500	8_2	5_10	4.18	0.01	21235.85	11496.75	223.70
14	1500	1500	8_2	5_14	4.14	0.01	21184.50	11587.50	220.93
15	1500	1500	8_2	33_14	4.01	0.01	20990.65	11367.00	214.99
16	1500	1500	8_4	4_5	4.02	0.01	21367.81	11455.26	216.27
17	1500	1500	8_4	4_12	4.06	0.01	21344.38	11338.25	219.06
18	1500	1500	8_4	5_8	4.10	0.01	21291.52	11477.75	220.13
19	1500	1500	8_4	5_10	4.12	0.01	21375.81	11542.25	221.10
20	1500	1500	8_4	5_14	4.03	0.01	21341.98	11633.01	215.95
21	1500	1500	8_4	33_14	3.95	0.01	21043.14	11412.50	212.12
22	1500	1500	4_5	4_12	3.98	0.01	21344.41	11239.50	215.70
23	1500	1500	4_5	5_8	4.11	0.01	21121.97	11379.00	220.54
24	1500	1500	4_5	5_10	4.07	0.01	21343.46	11443.50	218.93
25	1500	1500	4_5	5_14	4.04	0.01	21313.48	11534.25	216.95
26	1500	1500	4_5	33_14	3.82	0.01	20979.29	11313.75	205.85
27	1500	1500	4_12	5_8	4.09	0.01	21274.65	11262.00	220.54
28	1500	1500	4_12	5_10	4.10	0.01	21345.39	11326.50	220.93
29	1500	1500	4_12	5_14	4.08	0.01	21300.67	11417.25	219.40
30	1500	1500	4_12	33_14	3.93	0.01	21022.76	11196.75	212.23
31	1500	1500	5_8	5_10	4.10	0.01	21151.52	11466.00	219.42
32	1500	1500	5_8	5_14	4.14	0.01	21212.81	11556.75	221.45
33	1500	1500	5_8	33_14	3.87	0.01	20918.38	11336.25	208.12

34	1500	1500	5_10	5_14	4.17	0.01	21120.15	11621.25	222.01
35	1500	1500	5_10	33_14	4.02	0.01	21023.75	11400.75	215.65
36	1500	1500	5_14	33_14	3.98	0.01	21010.61	11491.50	213.02

Appendix G: Well Location and Names

The location and names of all the wells in the field is shown in the image below:

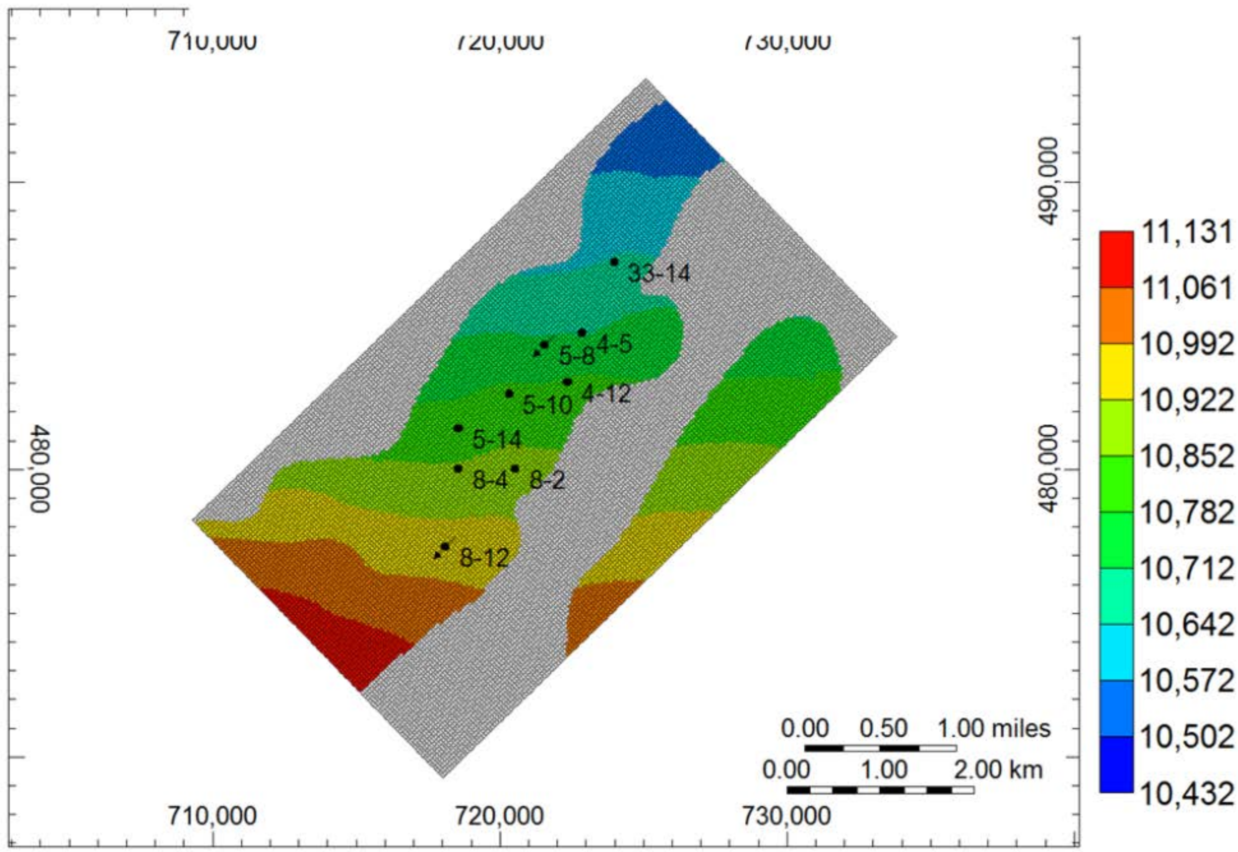

Figure 65: Well Names and Location