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Evaluation of Continuous and Water Alternating Gas (WAG) Co_2 Injection on X Field Recovery Factor

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Abstract

Indonesia is a country rich in natural resources. The wealth of Indonesia's natural resources is not only limited to agricultural and plantation products, but also from mineral and hydrocarbon mining or oil and gas. Indonesia's oil production has continued to decline in the last 10 years until the national consumption rate is much higher than national production. One of the causes of the decline in oil production in Indonesia is the condition of Indonesia's oil fields, which are currently mature fields. To overcome the problem of old fields that still have economic oil reserves, enhanced oil recovery (EOR) can be used. One of the EOR methods that can be used is the CO_2 injection method using continuous and WAG injection schemes. The study was conducted in X field with oil-wet carbonate rock composition with waterdrive and fluid expansion driving mechanism. The base case production scheme using 5 production wells produces a recovery factor of 34.3%, while continuous CO_2 injection produces a recovery factor of 32%, and CO_2-WAG produces a recovery factor of 42%. Continuous CO_2 injection has the lowest recovery factor because early gas breakthrough occurs due to a large mobility ratio and causes gas fingering, hindering the oil production process. The most suitable injection method is CO_2-WAG 1 cycle using a 1:1 ratio, CO_2 injection volume of 6.661 MSCF/D, injection water volume of 37.4 MBBL/D with a recovery factor of 43.46%.

INTRODUCTION

Indonesia's oil production has continued to decline in the last 10 years until the national consumption rate is much higher than national production in 2003. This caused Indonesia to turn into an oil importer and leave the Organization of the Petroleum Exporting Countries (OPEC) in 2008 (Prambudia and Nakano, 2012). The annual oil consumption rate tends to rise after 2003, while the production rate continues to fall every year. In 2020, Indonesia's oil consumption rate was recorded at 1.4 million barrels per day, while its production rate was only 743 thousand barrels per day (BP, 2022). The decline in production is not caused by oil reserves that have been depleted, but because the pressure conditions in the well cannot lift the remaining oil. This situation will have a devastating effect on the oil and gas industry in Indonesia, as these mature fields will become uneconomical to produce (Utama, 2014).

To overcome the problem of old fields that still have economic oil reserves, EOR can be used. One of the EOR methods that can be used is the CO_2 injection method using continuous and WAG injection schemes. EOR methods with CO_2 injection have been successfully implemented over the past four decades (Aryana et a., 2014). CO_2 injection was first commercially implemented in the 1950s, and today it is the second most used miscible and immiscible EOR method worldwide (Liu et al. 2016). Continuous CO_2 injection is not always better than other methods. CO_2 injection with this method usually shows very high gas mobility, requires a lot of injection gas, and the sweep efficiency is not good because of CO_2 fingering and gravity override in the vertical and areal directions (Yong, 2013). To overcome this, WAG flooding is used to improve sweep efficiency. WAG flooding will improve microscopic sweeping through gas injection and macroscopic sweeping efficiency from water injection (Carpenter 2019). This reduces gravity segregation between water and CO_2, stabilizes the flooding front, and delays water and gas breakthroughs (Liu et al. 2016).

METHOD

The research was conducted using the literature study method of experimental design and reservoir simulation. Data obtained from reservoir simulator training model in "Introduction to CMG Modeling" by Thanh Nguyen. The data obtained will be input into the simulator to create a reservoir model. The completed model will be carried out with a base case simulation with 5 production wells to determine the recovery factor before CO_2 injection by continuous or WAG methods. The results of the three simulations will be compared to determine the most suitable production method to be used in the x field. The next step is to conduct sensitivity analysis and optimization using the sobol analysis method and particle swarm optimization using CMOST to determine the optimum injection parameters for each case. The reason for choosing this method is because the Sobol sensitivity method considers interactions between parameters, or what is known as interaction effects (Zhang et al. 2015). Input parameters for continuous CO_2 injection sensitivity are gas injection rate, injection pressure, and injection temperature. Input parameters for

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CO_2-WAG are gas and water injection rate, injection pressure, gas and water injection temperature, WAG ratio, and WAG cycle.

RESULT AND DISCUSSION

Field X is an oil field formed from carbonate rock formations with a driving mechanism consisting of waterdrive and fluid expansion. The reservoir is located at a depth of 9800 ft, with a thickness of ±200 ft with porosity of 12% - 23.8%, permeability of 181 - 578 mD. Initial reservoir pressure ranges from 4860 to 5000 psi and temperature of 150o Fahrenheit. Fluid data shows that the oil has an API gravity of 35 °API with a viscosity of 0.38 cp. The reservoir is divided into 2 sectors, namely the north and south. This research is only focused on the southern sector with an original oil in place of 57 MMSTB. This is because the distribution of porosity, permeability, and oil saturation in the southern sector is much better than in the northern sector as can be seen in Figure 1.

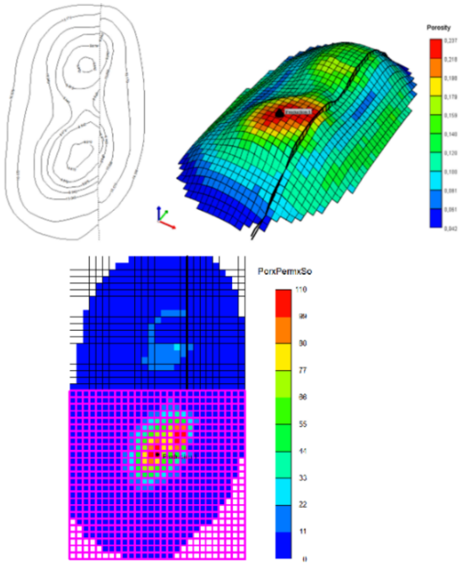

Figure 1. Reservoir Simulation Grid.

The relative permeability data were obtained from core analysis. The oil-water-gas relative permeability curve can be seen in Figure 2. The graph shows connate water saturation at 0.2 and irreducible oil saturation located when water saturation is at 0.6. The intersection of the curves between the imbibition and drainage processes occurs below 0.5, which means that the wettability in this reservoir is oil-wet.

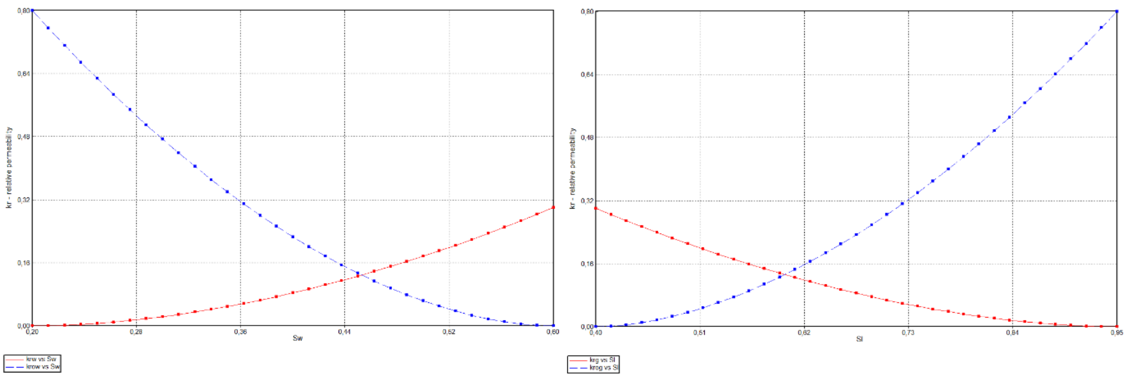

Figure 2. Krw & Sw, Krg vs Sl.

Determining the selection of EOR methods in a reservoir depends on the characteristics of the fluid and the reservoir itself. Each EOR method has its own criteria to be applied to a field. These criteria are often referred to as screening criteria for EOR methods. In general, criteria for fluid properties consist of API gravity, viscosity, and fluid composition, while for reservoir properties consist of average permeability, depth, and temperature (Taber et al., 1997). The screening criteria for each EOR method can be seen in Figure 3, while the fluid and reservoir properties for field x can be seen in Table 1.

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		Oil Properties			Reservoir Characteristics					
Detail Table in Ref. 16	EOR Method	Gravity (°API)	Viscosity (cp)	Composition	Oil Saturation (% PV)	Formation Type	Net Thickness (ft)	Average Permeability (md)	Depth (ft)	Temperature (°F)
Gas Injection Methods (Miscible)										
1	Nitrogen and flue gas	> 35 ↗ 48 ↗	< 0.4 ↘ 0.2 ↘	High percent of C_1 to C_7	> 40 ↗ 75 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 6,000	NC
2	Hydrocarbon	>23 ↗ 41 ↗	< 3 ↘ 0.5 ↘	High percent of C_2 to C_7	> 30 ↗ 80 ↗	Sandstone or carbonate	Thin unless dipping	NC	> 4,000	NC
3	CO_2	> 22 ↗ 36 ↗ [a]	< 10 ↘ 1.5 ↘	High percent of C_5 to C_{12}	> 20 ↗ 55 ↗	Sandstone or carbonate	Wide range	NC	> 2,500[a]	NC
1–3	Immiscible gases	> 12	< 600	NC	> 35 ↗ 70 ↗	NC	NC if dipping and/or good vertical permeability	NC	> 1,800	NC
(Enhanced) Waterflooding										
4	Micellar/ Polymer, ASP, and Alkaline Flooding	> 20 ↗ 35 ↗	< 35 ↘ 13 ↘	Light, intermediate, some organic acids for alkaline floods	> 35 ↗ 53 ↗	Sandstone preferred	NC	> 10 ↗ 450 ↗	> 9,000 ↘ 3,250	> 200 ↘ 80
5	Polymer Flooding	> 15	< 150, > 10	NC	> 50 ↗ 80 ↗	Sandstone preferred	NC	> 10 ↗ 800 ↗ [b]	< 9,000	> 200 ↘ 140
Thermal/Mechanical										
6	Combustion	> 10 ↗ 16 → ?	< 5,000 ↓ 1,200	Some asphaltic components	> 50 ↗ 72 ↗	High-porosity sand/ sandstone	> 10	> 50[c]	<11,500 ↘ 3,500	> 100 ↗ 135
7	Steam	> 8 to 13.5 → ?	< 200,000 ↓ 4,700	NC	> 40 ↗ 66 ↗	High-porosity sand/ sandstone	> 20	>200 ↗ 2,540 ↗ [d]	< 4,500 ↘ 1,500	NC
—	Surface mining	7 to 11	Zero cold flow	NC	>8 wt% sand	Mineable tar sand	> 10[e]	NC	> 3 :1 overburden to sand ratio	NC

Figure 3. Screening Method Criteria (Taber, Martin, and Seright 1997).

Table 1. Fluid and Reservoir Properties of X Field

Reservoir Properties				Fluid Properties		
Depth (ft)	Perm (md)	Temp (°F)	So (%)	Visc (cp)	API Gravity	C5+ (%)
10,100	11 - 578	150	70 - 80	0.3	35	50.41

The screening process begins by comparing the fluid data and reservoir properties of field x against the screening criteria that have been set. Nitrogen and flue gas injection methods, as well as hydrocarbons, are not suitable because the composition of light hydrocarbons must be dominant (Taber et al., 2010), while in field x, the fluid composition is dominated by intermediate hydrocarbons. Micellar/Polymer, ASP, and Alkaline Flooding are not suitable, because these methods are more preferable for reservoirs with sandstone formation types (Taber et al., 2010). Polymer flooding is less suitable because the maximum recommended reservoir depth is 9000 ft. EOR with thermal/mechanical methods is also not suitable because both EOR methods are focused on heavy oil. EOR methods that are suitable for use in field x based on the screening results are CO_2 injection and immiscible gas injection.

The next screening is to determine the type of CO_2 injection to be performed. The type of CO_2 injection is determined based on the minimum miscible pressure (MMP) value calculated using the Yellig & Metcalfe correlation. MMP or minimum miscible pressure is the minimum pressing pressure at which CO2 can be combined into one phase (dissolved) with oil (Abdurrahman et al., 2020). The reservoir temperature in field x is 150 °F, so the MMP value is 1879.75 psi. The reservoir pressure in field x is 5100 psi, so CO_2 injection can be done miscibly because the reservoir pressure has a value above the MMP. Miscible injection will produce a greater RF value than immiscible injection (Khalef 2009). Therefore, the EOR method used in this study is miscible CO_2 injection.

The base case scenario in this study is to produce oil using 5 production wells. The use of 5 production wells was decided to maximize the oil depletion process in the southern sector. The distribution of production wells and perforations can be seen in Figure 5. The selection of production well locations and perforations are based on oil saturation. The distribution of production wells uses a 5-spot pattern, where 4 production wells will be converted into injection wells for continuous injection and WAG CO_2 injection schemes. Production starts on 1 January 2016, until 1 January 2036, or for 20 years with the timeline as shown in Figure 6.

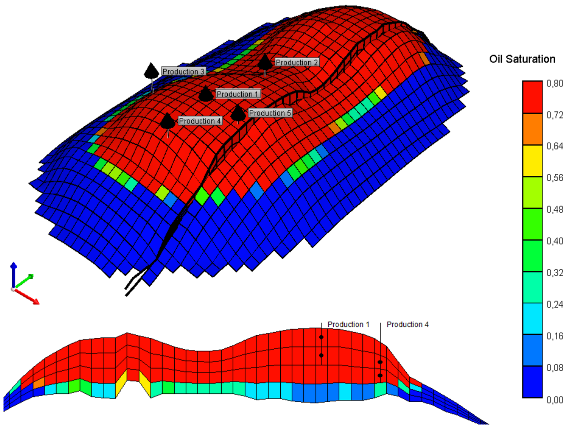

Figure 5. Well Distribution.

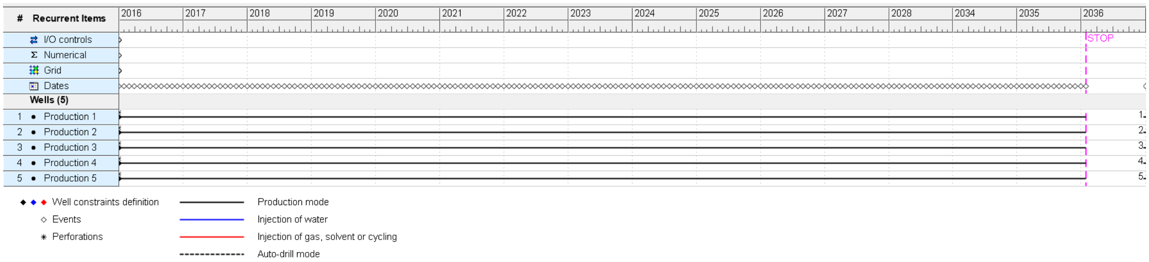

Figure 6. Base case's Timeline.

The base case production profile with 5 producing wells is shown in Figure 7. Cumulative oil production over 20 years of production is 19.5 MMBBL with a recovery factor of 34.3% and a watercut of 88%. The recovery factor value obtained is in accordance with research conducted by Arlind at al., (2015) which states that reservoirs with waterdrive driving mechanism will have RF values ranging from 35% - 75%, while for solution gas drives ranging from 5% - 30% (Arlind et al., 2015).

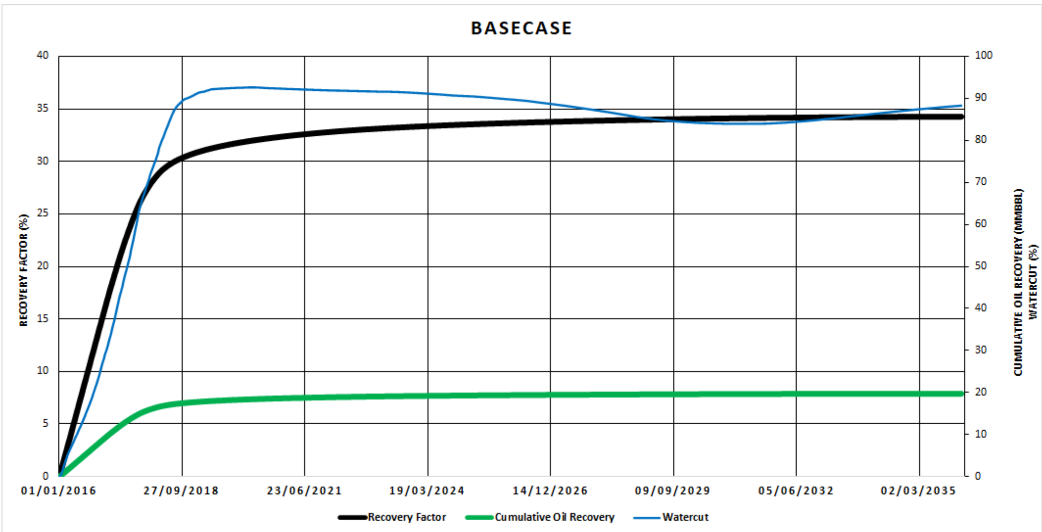

Figure 7. Base case Production Profile.

The first case is to produce the field using the continuous CO_2 injection method. This case starts by converting 4 production wells into injection wells using a 5-spot injection pattern. The well distribution and perforations are the same as those used in the first case. The injection scheme is carried out using 4 wells with CO_2 injection of 1 MMSCF/D each and carried out for 20 years. The timeline for this second case can be seen in figure 8.

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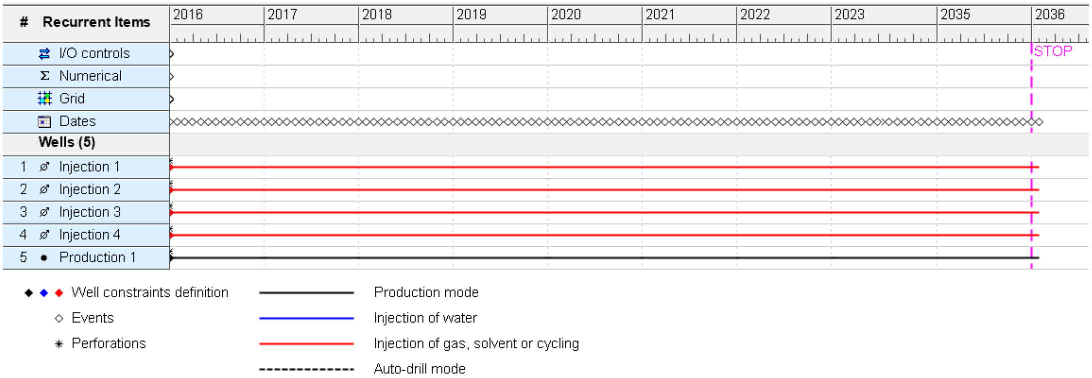

Figure 8. Continuous CO_2 Injection's Timeline.

The cumulative oil production after 20 years of production is 18.7 MMBBL, with a recovery factor of 32% and a watercut of 83.7%. There is a decrease in recovery factor when compared to the base case which has a recovery factor of 34.3%.

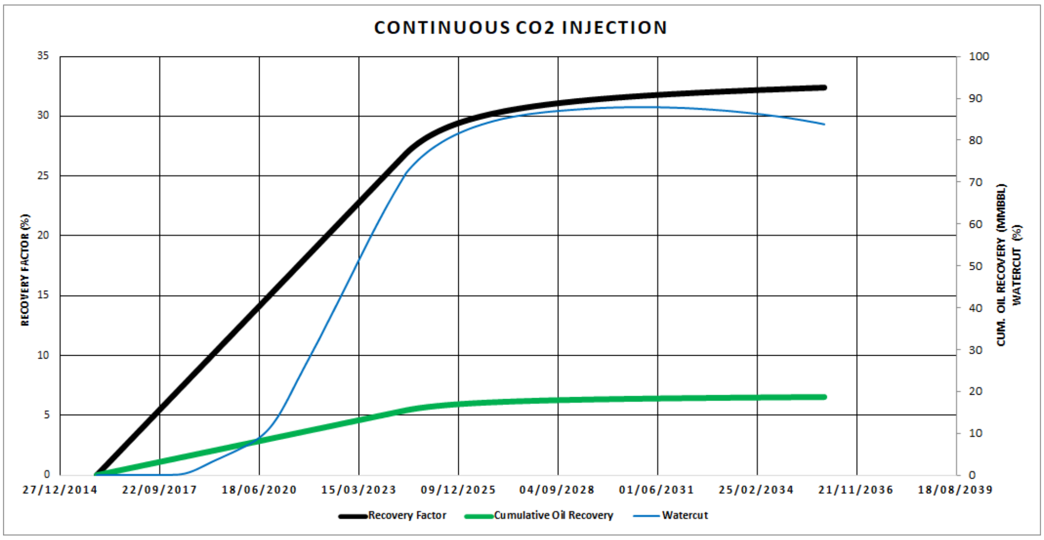

Figure 9. Continuous CO_2 Injection's Production Profile.

Figure 10(a) is the gas saturation at the end of production which shows that the injection gas only pushes oil into layer 1. This poor sweep causes the oil in the layer below to not be swept and not produced as shown in the distribution of oil saturation at the end of production time in Figure 10(b). Gas channeling will also inhibit oil production because the oil zone is pushed by the injection gas so that it cannot flow toward the wellbore. The resulting watercut at the end of production is smaller than the base case. This is because as production progresses, there is a decrease in watercut on 1 June 2031 due to the shifting of the water zone in layer 2 which is pushed by the injection gas, resulting in less water being produced.

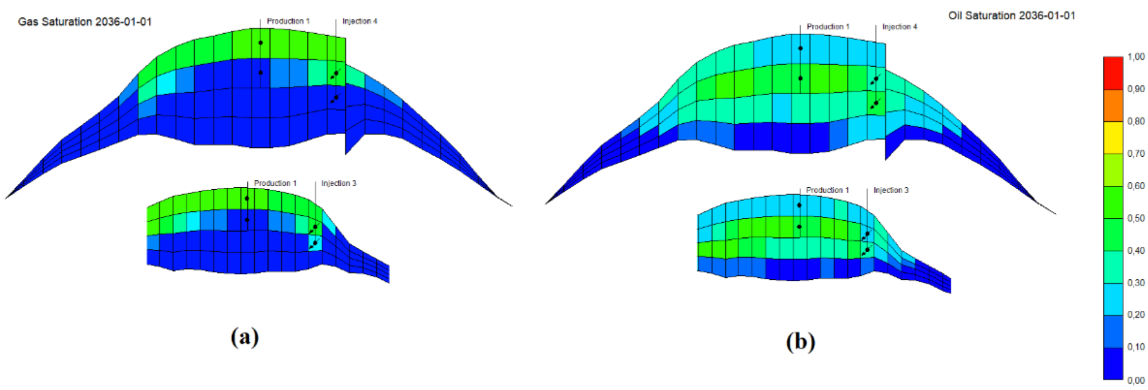

Figure 10. Change of Gas Saturation (a) and Change of Oil Saturation (b) in Continuous CO_2 Injection Process.

The next analysis is a sensitivity analysis of injection parameters in the case of continuous CO_2 injection to determine the effect of each parameter on changes in the recovery factor. Injection parameters that are tested for sensitivity include injection rate, injection pressure, and injection temperature from each injection well. The Sobol analysis method is performed to determine the most significant parameters that can affect the recovery factor value through CMOST. The Sobol method is a variation-based sensitivity analysis technique. The variation will be quantified that each input X will affect the variation of output Y. Sobol sensitivity analysis is divided into 4 steps, namely generating the parameter set, running and simulating the output model with the parameter set, calculating and analyzing the sobol sensitivity index for total, first-, and second order (Zhang et al., 2015). The first-order sensitivity index is the effect of input variation X_i on the output value Y_i. Second-order or higher-order is the effect of the input value X_i that has interacted with the output Y_i, therefore it is also called interaction effects, while the total order effect is the sum of all first- and second-order effects. The results of Sobol analysis for the case of continuous CO_2 injection can be seen in Figure 11.

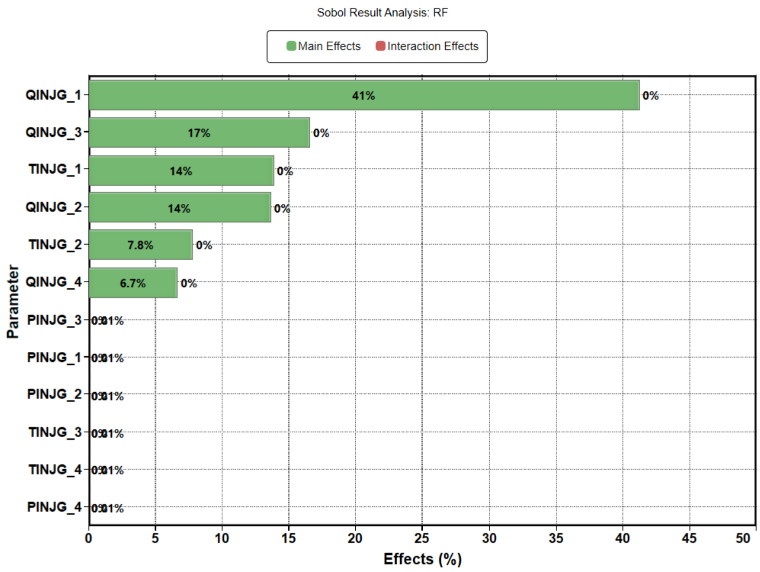

Figure 11. Sobol Chart Continuous CO_2 Injection with RF as the output.

The Sobol chart shows that for the objective function recovery factor, the most dominant input parameter to the change in recovery factor is the injection rate of injection well 1, followed by the injection rate of injection well 3, the injection temperature of injection well 1, the injection rate of injection well 2, and the injection rate of injection well 4. The injection rate parameter has a large effect, all injection rate input parameters in the four wells have an effect above 5%. A large variation value of Sobol does not always indicate that the input parameter has a positive effect on the output value. To know the effect of each input variation more clearly, it is necessary to conduct a sensitivity analysis of each input parameter.

Analysis of the effect of injection parameters from the 3 main input parameters (injection rate, temperature, and injection pressure) will be taken from the largest Sobol index, namely the flow rate in the injection well 1, the temperature in injection well 1, and injection pressure in the injection well 3. The results of the sensitivity analysis of each input parameter can be seen in Figure 12.

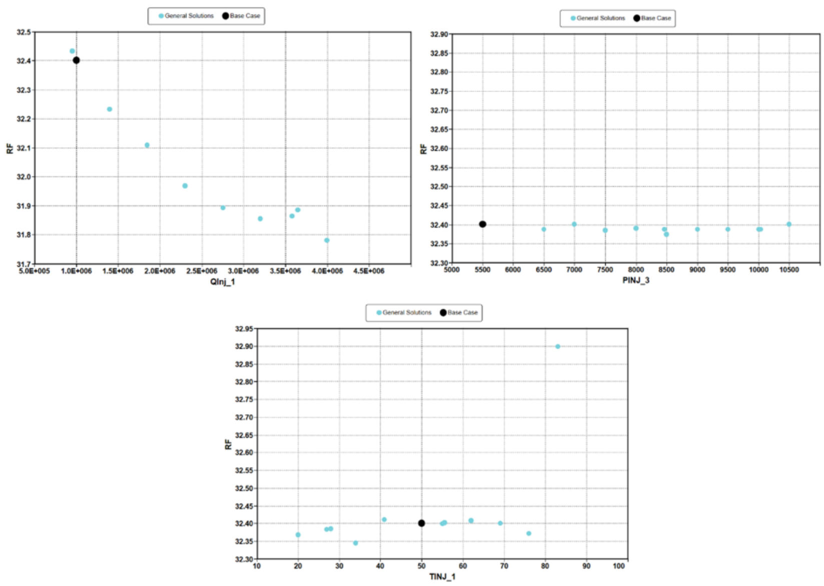

Figure 12. Continuous CO_2 Injection Sensitivity Analysis for Each Parameter.

The effect of changing the value of the injection rate on the recovery factor can be seen directly from the pattern formed, which is inversely related, the greater the CO_2 injected, the smaller the recovery factor. This is because, with a large injection rate, gas breakthrough will occur much faster, resulting in fingering at the beginning of production.

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Pressure does not really affect the recovery factor, as long as the $P_{fr} > P_{inj} > P_r$, CO_2 can be injected into the reservoir without creating new fractures in the reservoir. The injection temperature in well 1 has a Sobol index of 14%, which means that temperature has a considerable influence on the recovery factor. The pattern formed in Figure 12 shows that at a temperature of 20 °F - 80 °F fluctuations in the recovery factor value tend to stabilize between 32.35% - 32.4%, but when approaching a value of 87 °F, the recovery factor rises to 32.9%. This is because, at 87 °F, CO_2 enters a supercritical phase condition which will make its density close to the liquid phase, with a fixed viscosity so that it will slow down the early gas breakthrough process.

The next analysis is the optimization of each parameter to get the most optimal value of each parameter to the recovery factor value. The analysis is carried out through CMOST with the particle swarm optimization method. Particle swarm optimization (PSO) is a computational method to iteratively optimize a case against parameters so as to produce an optimum output value (Yang, 2021). Iteration is done 500 times until the results obtained are stable. The continuous CO_2 injection iteration process can be seen in figure 13.

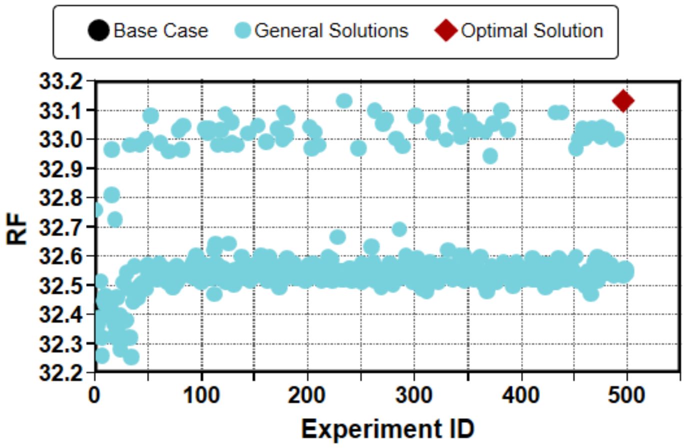

Figure 13. Iteration Process for Continuous CO_2 Injection Optimization.

The input parameters used in each iteration include CO_2 injection rate, injection pressure, and injection temperature. The range of changes in recovery factor values between base case and optimum values can be seen in Figure 13. Base case has a recovery factor value of 32%, while the optimal recovery factor value is at 33.15%, an increase of 1.15%. A comparison of basecase and optimum input parameters can be seen in Table 2, the optimization input parameter has the same value as the sensitivity analysis input parameter.

Table 2. Optimized Parameter for Continuous CO_2 Injection.

No	Parameter	Basecase				RF	WC	Optimization		RF	WC	ΔRF
		Inj. Well	Min	Value	Max			Inj. Well	Value			
1	P_{inj} (psi)	1	5500	5100	6500			1	6215			
		2	5500	5100	6500			2	5980			
		3	5500	5100	6500			3	5655			
		4	5500	5100	6500			4	5925			
2	Q_{inj} (MMSCF)	1	0.75	1	1.25			1	0.777			
		2	0.75	1	1.25	32%	83.7%	2	0.802	33.15%	85%	1.15%
		3	0.75	1	1.25			3	0.802			
		4	0.75	1	1.25			4	0.957			
3	T_{inj} (°F)	1	37.5	50	62.5			1	51.25			
		2	37.5	50	62.5			2	38.75			
		3	37.5	50	62.5			3	60.937			
		4	37.5	50	62.5			4	63.437			

The second case is to produce the field using the water-alternating gas (WAG) CO_2 injection method. This case starts by converting 4 production wells into injection wells using a 5-spot injection pattern. The well distribution and perforations are the same as those used in the first case. The injection scheme is carried out using 4 wells and will inject CO_2 and water alternately. The injection rates for water and CO_2 are 15 MBBL/D and 75 MSCF/D, respectively. The WAG cycle used is 1 cycle, by injecting CO_2 first for 6 months, then replaced with water injection for 6 months. The injection timeline can be seen in Figure 14.

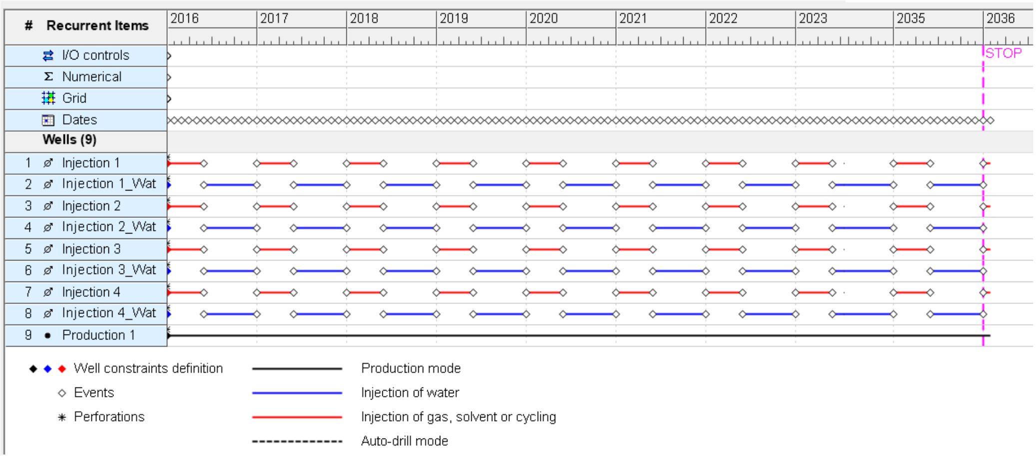

Figure 14. CO_2-WAG Injection Timeline.

The cumulative oil production after 20 years of production is 24.2 MMBBL, with a recovery factor of 42% and a watercut of 100%. The CO_2-WAG scheme has the highest recovery factor compared to the base case and continuous CO_2 injection schemes. The WAG-CO_2 injection volume is much smaller than the continuous CO_2 injection to get a larger recovery factor value. This is because WAG-CO_2 works by increasing macroscopic and microscopic sweeping efficiency at the same time through water and CO_2 injection.

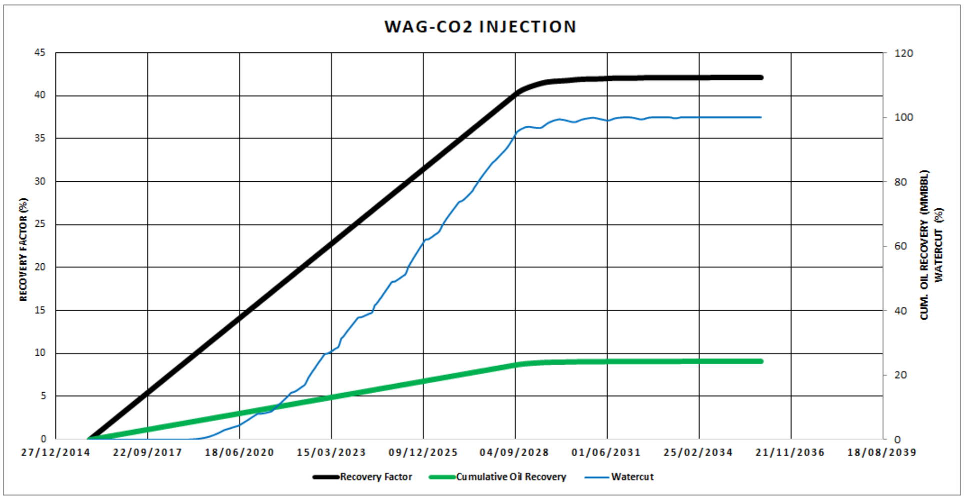

Figure 15. CO_2-WAG Injection Production Profile.

The next analysis is a sensitivity analysis using CMOST. The input parameters used for analysis include injection flow rate, injection pressure, and injection temperature for both water injection and CO_2 injection. The results of the Sobol analysis can be seen in Figure 16. The Sobol chart shows that for the objective function recovery factor, the dominant input parameters in the water or CO_2 injection section are only temperature and injection rate, both for water and gas injection. The highest injection pressure, which is the injection pressure of well 2 when injecting CO_2, only has an effect of 0.01%, so its influence can be ignored.

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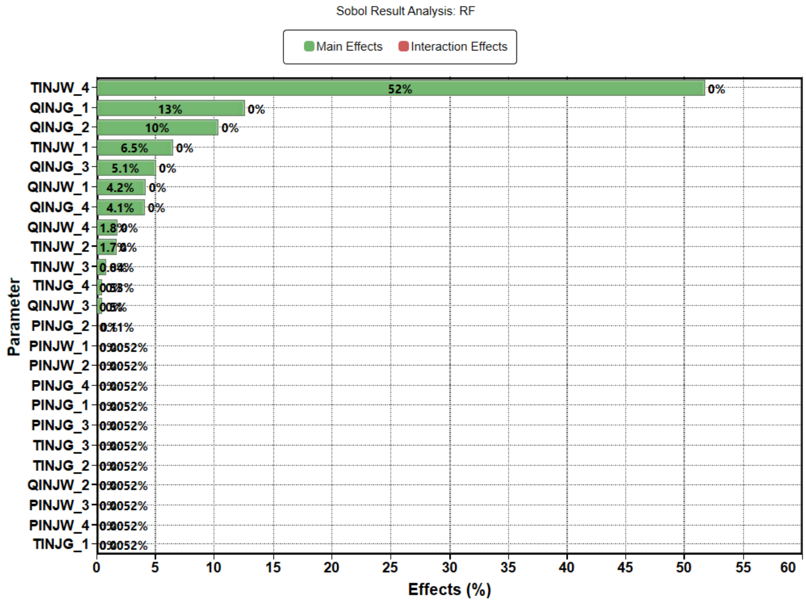

Figure 16. Sobol Chart CO_2-WAG Injection with RF as the output.

A large Sobol variation value does not always indicate that the input parameter has a positive effect on the output value. To know the influence of each input variation more clearly, it is necessary to conduct a sensitivity analysis of each input parameter. The input parameters that will be used are the injection temperature of water and CO_2 in injection well 4, and the injection rate of water and CO_2 in well 1. The injection flow rate is taken from the injection well 1, both for water and CO_2 because its Sobol index is greater than other injection wells for each type of injection fluid. The effect of changing the injection rate value on the recovery factor can be seen directly from the pattern formed. For water injection changes, when the injection rate range is 0 bbl/d to 10000 bbl/d, there is an increase in recovery factor, because, in this range, the greater the volume of water injected, the greater the oil that can be washed away by water. However, in the range of 10000 bbl/d to 40600 bbl/d, there is a decrease and finally constant up to 100000 BBL/d, because, in this range, early multi-layer water channeling occurs which causes oil sweeping to be incomplete as in the case of waterflood during the water injection process. For changes in CO_2 injection, the pattern shows that between the range of 1 MSCF/D to 91 MSCF/D, the recovery factor value tends to decrease and will be constant thereafter. This is due to the early gas breakthrough that causes gas channeling in layer 1 so that the sweeping process during the CO_2 injection part is not maximized.

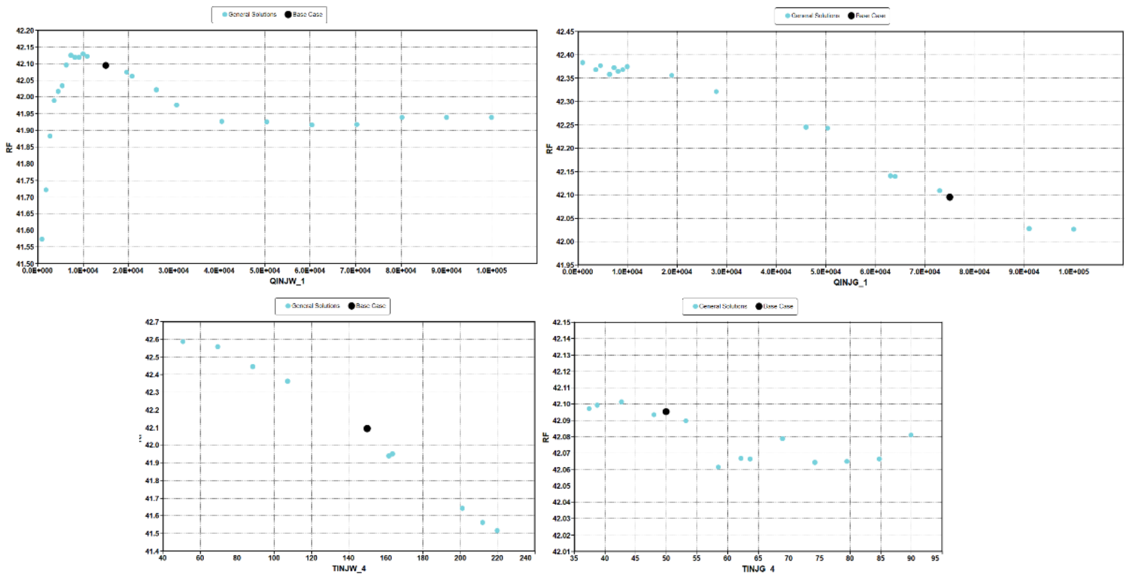

Figure 17. CO_2-WAG Injection Sensitivity Analysis for Each Parameter.

The injection temperature taken from injection well 4 is good for water injection because its Sobol index is greater than other wells for each injection fluid. CO_2 injection temperature at the injection well 4 is also shown for comparison. The effect of temperature change on the recovery factor value can be seen through the pattern formed. For the injection water temperature, an inversely proportional pattern is formed, where the greater the injection water temperature, the smaller the recovery factor value will be. This is because the greater the water temperature, the greater the mobility of the water because the viscosity is reduced so the oil pressing will be less than optimal. The effect of CO_2 temperature on the recovery factor is not too large, the Sobol index is only 0.05%, therefore the change in recovery factor that occurs only has a range of 0.035%. Water and CO_2 injection temperatures do not have a significant effect on changes in reservoir temperature, so CO_2 injection is still carried out under MMP conditions. This is shown in Figure 18, the reservoir's initial temperature which was originally 150 °F dropped to 147.7 °F, which changed the MMP to 1851.27 psi. The MMP change that occurs is not too significant, considering that the injection pressure used is 5500 psi, so the CO_2 injection process is still miscible.

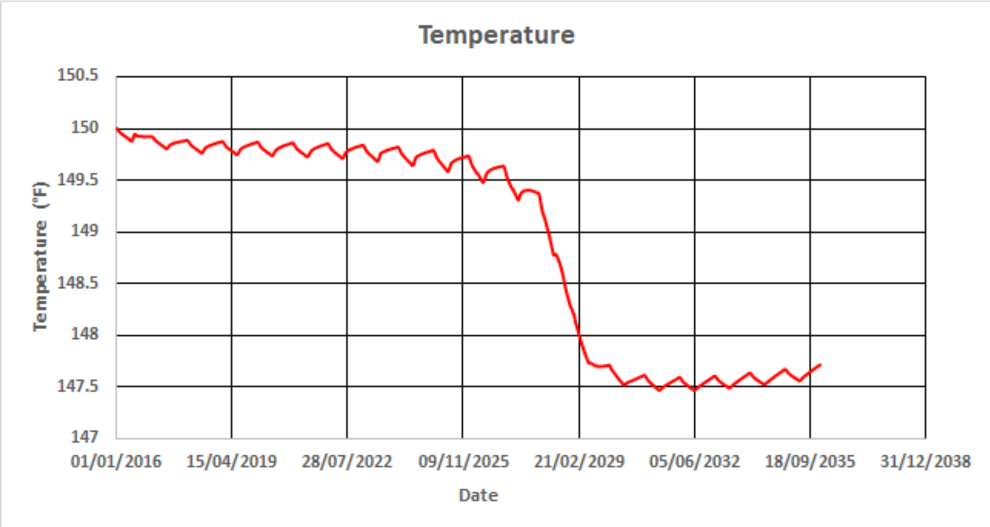

Figure 18. Reservoir Temperature Change during Production.

The next parameters that need to be analyzed are the WAG ratio and WAG cycle. The CO_2-WAG injection base case uses 1 cycle with the replacement of water and CO_2 injection every 6 months. Sensitivity analysis of the WAG cycle was conducted with variations of 1 cycle, 2 cycles, 3 cycles, and 4 cycles per year using optimal injection parameters. The optimal injection parameters were determined using particle-swarm optimization analysis through the software. The optimal total injection volume per day for both water and CO_2 will be used as the basis for sensitivity analysis of the WAG ratio (CO_2/water) with data variations of 1:1, 1:2, and 2:1. Optimization was carried out for 500 iterations until the results obtained began to slope. The optimized input parameters include water and CO_2 injection rates, water and CO_2 temperatures, and water and CO_2 injection pressures at each injection well. The CO_2-WAG iteration process can be seen in Figure 19.

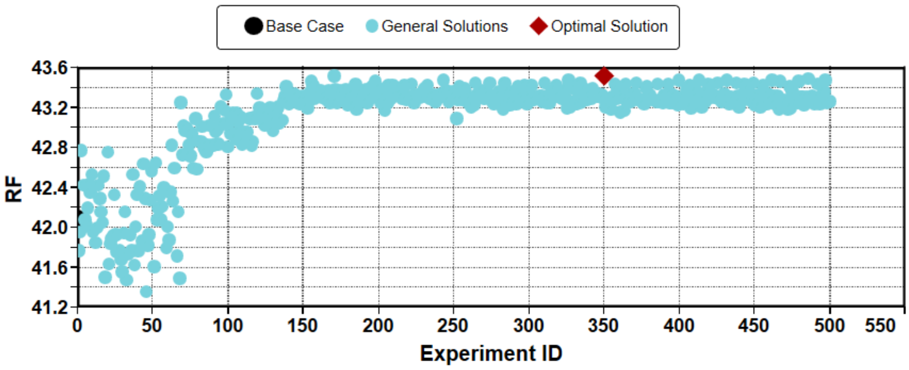

Figure 19. Iteration Process for CO_2-WAG Injection Optimization.

The range of changes in recovery factor values between base case and optimum values can be seen in Figure 19. Base case has a recovery factor value of 42%, while the optimal recovery factor value is at 43.52%, there is an increase of 1.52%. A comparison of base case and optimum input parameters can be seen in Table 3.

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Table 3. Optimized Parameter for CO_2-WAG Injection.

No	Parameter	Injection Type	Basecase Inj. Well	Basecase Min	Basecase Value	Basecase Max	RF	WC	Optimization Inj. Well	Optimization Value	RF	WC	ΔRF
1	P_{inj} (psi)	Water Injection	1	5500	5500	6500	42%	100.0%	1	6500	43.50%	100%	1.5%
			2	5500	5500	6500			2	5890			
			3	5500	5500	6500			3	6500			
			4	5500	5500	6500			4	6260			
		CO_2 Injection	1	5500	5500	6500			1	5650			
			2	5500	5500	6500			2	6180			
			3	5500	5500	6500			3	6320			
			4	5500	5500	6500			4	5560			
2	Q_{inj} (MBBL)	Water Injection	1	5	15	50			1	9.05			
			2	5	15	50			2	6.65			
			3	5	15	50			3	16.7			
			4	5	15	50			4	5			
	Q_{inj} (MSCF)	CO_2 Injection	1	10	75	100			1	10			
			2	10	75	100			2	10			
			3	10	75	100			3	10			
			4	10	75	100			4	10			
3	T_{inj} (°F)	Water Injection	1	112.5	150	220			1	118.95			
			2	112.5	150	220			2	165.75			
			3	112.5	150	220			3	174.85			
			4	112.5	150	220			4	112.5			
		CO_2 Injection	1	37.5	50	90			1	39.6			
			2	37.5	50	90			2	37.5			
			3	37.5	50	90			3	37.5			
			4	37.5	50	90			4	37.5			

The total optimal volume of water injection per day is 37400 bbl/d, and the total volume of CO_2 injection is 40000 scf/d or 7124.4 boepd/d. The WAG ratio in this optimization result is 7124.4:37400 or 1:5.2. WAG ratio variations commonly used in the field are 1:1, 1:2, and 2:1 (Muslim et al., 2019). The results of sensitivity analysis show that for the water injection rate, the highest recovery factor is at a water injection rate of 10000 bbl/d, while for CO_2 injection the highest recovery factor is at an injection rate of 1000 scf/d. The daily injection volume of water and CO_2 and the recovery factor value for each WAG ratio variation can be seen in Table 4.

Table 4. WAG Ratio Variation.

Skenario	Injection Volume CO_2 (MSCF/d)	Water Inj. Volume (MBBL/d)	Recovery Factor
Optimasi	40	37.4	43.50%
Ratio 1:1	6.66	37.4	43.46%
Ratio 1:2	6.66	74.8	43.32%
Ratio 2:1	13.32	37.4	43.48%

The optimization results have a greater recovery factor than the 1:1, 1:2, and 1:3 ratio variations. However, the difference between the optimized recovery factor value and other WAG ratio variations is not far adrift, there is only an incremental increase of about 0.02% to 0.04%. This small recovery factor difference is not comparable to the difference in the total daily CO_2 injection volume, which differs from 33 MSCF/D to 27 MSCF/D. The most likely scenario to be used is using a WAG ratio of 1:1, the difference in recovery factor with a WAG ratio of 2:1 is only 0.02%, but the total daily CO_2 injection volume requires twice the 1:1 ratio scenario.

The last sensitivity analysis is to see the effect of changing the WAG cycle on the recovery factor. The WAG cycle variations used are 1 cycle, 2 cycles, 3 cycles, and 4 cycles per year. The injection timeline for the four variations can be seen in Figure 20. The recovery factors for 1 cycle, 2 cycles, 3 cycles, and 4 cycles are 43.46%, 43.37%, 43.44%, and 43.43%, respectively. The difference in recovery factor obtained is not too significant so you can use 1 cycle because the recovery factor is greater.

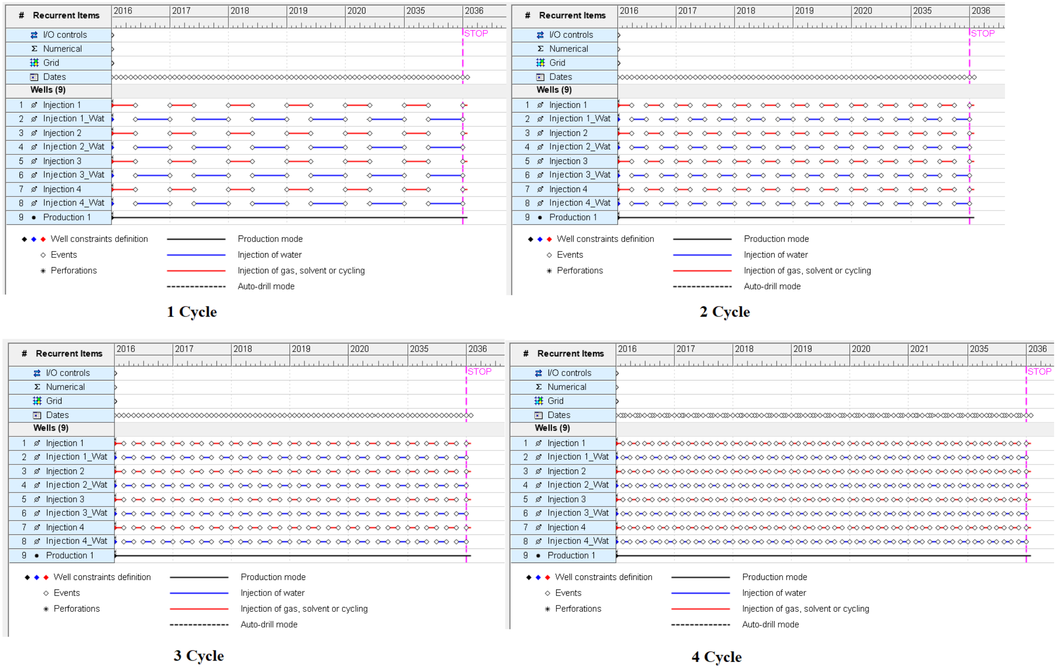

Figure 20. WAG Cycle Variation's Timeline.

CONCLUSION

The simulation results show that the case of continuous CO_2 injection is affected by the injection rate and injection temperature. The injection rate is inversely related to the recovery factor because, with a large injection rate, gas breakthrough will occur much faster, resulting in fingering at the beginning of production. Temperature affects the phase of CO_2, when the temperature touches the value of 87 °F, the recovery factor increases because CO_2 enters the supercritical phase which makes its density close to the liquid phase, so it will slow down the early gas breakthrough process. CO_2-WAG injection is affected by the injection rate and temperature of $CO_2$and water. High water injection rate and high-water temperature can cause early multi-layer water channeling because the injection volume is large and when the temperature is high, water will have greater mobility. The WAG ratio and WAG cycle do not affect the recovery factor value in this case. The suitable injection method is CO_2-WAG 1 cycle using a 1:1 ratio, injection CO_2 volume of 6.661 MSCF/D, injection water volume of 37.4 MBBL/D, with the injection temperature and pressure of each injection well adjusting to the optimization results. This method produces a recovery factor value of 43.46% with a minimum total fluid injection.

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