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Well Placement Optimization through the Triple-Completion Gas and Downhole Water Sink-Assisted Gravity Drainage (TC-GDWS-AGD) EOR Process

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Abstract: Gas and downhole water sink-assisted gravity drainage (GDWS-AGD) is a new process of enhanced oil recovery (EOR) in oil reservoirs underlain by large bottom aquifers. The process is capital intensive as it requires the construction of dual-completed wells for oil production and water drainage and additional multiple vertical gas-injection wells. The costs could be substantially reduced by eliminating the gas-injection wells and using triple-completed multi-functional wells. These wells are dubbed triple-completion-GDWS-AGD (TC-GDWS-AGD). In this work, we design and optimize the TC-GDWS-AGD oil recovery process in a fictitious oil reservoir (Punq-S3) that emulates a real North Sea oil field. The design aims at maximum oil recovery using a minimum number of triple-completed wells with a gas-injection completion in the vertical section of the well, and two horizontal well sections—the upper section for producing oil (from above the oil/water contact) and the lower section for draining water below the oil/water contact. The three well completions are isolated with hydraulic packers and water is drained from below the oil–water contact using the electric submersible pump. Well placement is optimized using the particle swarm optimization (PSO) technique by considering only 1 or 2 TC-GDWS-AGD wells to maximize a 12-year oil recovery with a minimum volume of produced water. The best well placement was found by considering hundreds of possible well locations throughout the reservoir for the single-well and two-well scenarios. The results show 58% oil recovery and 0.28 water cut for the single-well scenario and 63.5% oil recovery and 0.45 water cut for the two-well scenario. Interestingly, the base-case scenario using two wells without the TC-GDWS-AGD process would give the smallest oil recovery of 55.5% and the largest 70% water cut. The study indicates that the TC-GDWS-AGD process could be more productive by reducing the number of wells and increasing recovery with less water production.

Keywords: gas injection; downhole water sink; assisted gravity drainage; particle swarm optimization; well placement optimization; enhanced oil recovery

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1. Introduction

In the petroleum industry, enhanced oil recovery (EOR) technologies sometimes make it possible to substantially increase ultimate resource recovery (50–70%, or more) of the initial oil in place (IOIP) from a reservoir, thereby improving on the performances of primary and secondary oil recovery technologies [1]. Gas-injection technologies have become some of the most effective EOR processes applied. Natural gas, carbon dioxide, nitrogen, and other gases have all been successfully used in multiple oil reservoirs for EOR purposes in either miscible or immiscible processes. These gases can increase or maintain reservoir energy and reduce the viscosity of oil [2,3]. Many factors affecting the gas-injection process must be taken into account, such as reservoir inhomogeneity and unwanted movements within the reservoir of oil and/or gas, including gas coning problems and issues of low sweep efficiency [4–8].

There are several applicable gas-injection methods, and each tends to work best in specific types of oil reservoirs. Each method has its own characteristics, advantages, and disadvantages. The established gas-injection-EOR methods include continuous gas injection (CGI), huff-n-puff or intermittent gas injection (H-n-P), water-alternating gas (WAG) [9], gas-assisted gravity drainage (GAGD), and gas-downhole water sink-assisted gravity drainage (GDWS-AGD). GAGD exploits the gravity impacts of gas injection in either immiscible or miscible conditions. Applied in field tests, GAGD has achieved about 70% recovery of IOIP [2]. Such performance has also been achieved by laboratory-based GAGD core-flooding tests [3]. In this method, typically, vertical gas-injection wells are completed close to the top of the reservoir. These injectors are accompanied by horizontal oil-production wells positioned close to the base of the pay zone but crucially above the oil/water contact (OWC) [10,11].

The injected gas in the GAGD process tends to accumulate at the top of the reservoir and gradually results in gas cap formation. This growing gas cap provides additional reservoir energy that assists the downward drainage of oil towards the horizontal-water-producer wells, exploiting gravity impacts on the contrasting fluid densities (gas < oil < water). Figure 1 presents the schematic illustration of the gas-assisted gravity drainage (GAGD) process. Gravity segregation tends to enhance reservoir sweep efficiency and thereby achieve its EOR objectives [12]. An additional benefit of the GAGD process is that it delays gas breakthrough into the oil-production wells [4,13–16]. However, GAGD sometimes has negative reservoir consequences resulting in high water-cut levels and/or a high tendency for water coning/cresting to occur, particularly when applied to reservoirs associated with strong water aquifers [17–20].

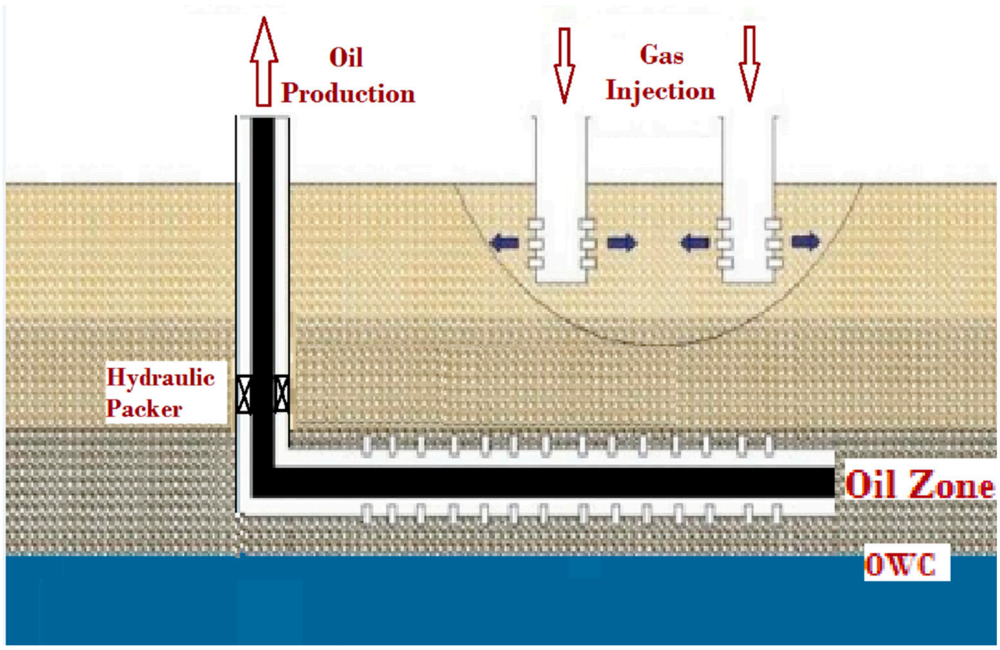

Figure 1. Schematic illustration of the GAGD process.

The GDWS-AGD method was developed specifically to address the recognized GAGD limitations. It integrates GAGD with downhole-water-sink (DWS) technology. It achieves this by injecting gas through a stand-alone near-vertical injector well completed in a top-reservoir position. This gas injector is accompanied by multiple horizontal-water-producer wells positioned beneath the OWC, and multiple horizontal-oil-producer wells positioned above the OWC. In some cases, individual horizontal wells, equipped with dual completions separated by hydraulic packers, can simultaneously produce oil from above the OWC and water from below the OWC [17,18,21]. Figure 2 provides a schematic diagram of a classic GDWS-AGD well configuration.

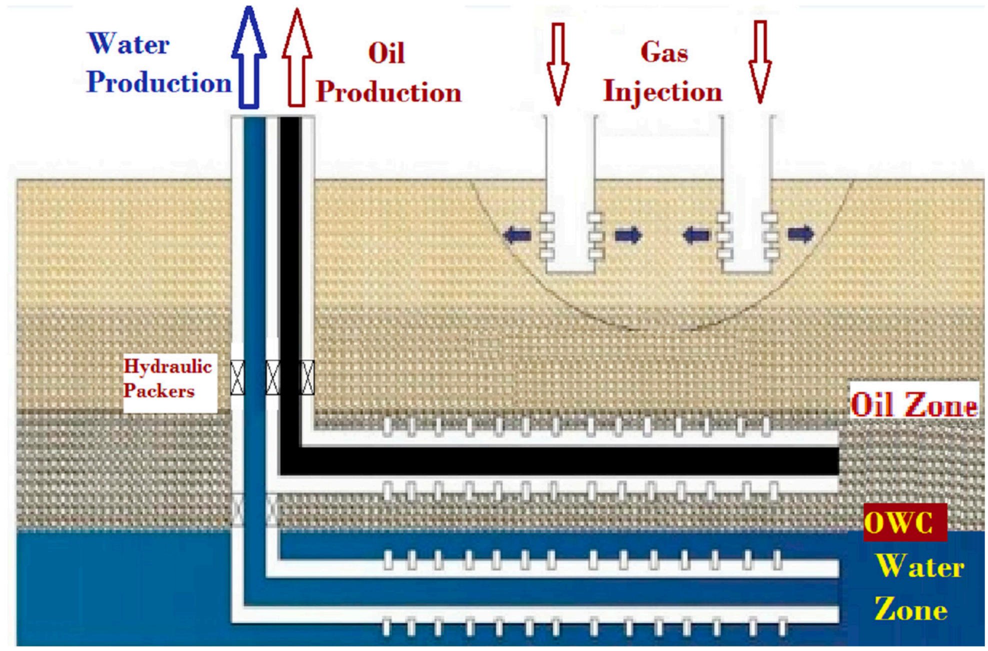

Figure 2. GDWS-AGD gas injector, oil-, and water-producer well configurations.

To further reduce premature gas breakthrough and high-water-cut tendencies of GDWS-AGD, it is possible to use triple-completed (TC) wells, incorporating water/oil-production and gas-production completions in each well drilled. This TC-GDWS-AGD approach eliminates the need for drilling separate, vertical gas-injection wells. More specifically, the gas injection is implemented through the wellbore annulus, and oil and water production is accomplished through 2 $2^{3}/_{8}$ -inch strings of tubing drawing production from perforations located above and below the OWC, respectively. In order to achieve maximum performance of the TC-GDWS-AGD process, it is essential to determine the optimal well placement into the reservoir to attain maximum oil production along with minimum gas injection and minimum water cut. The well placement optimization is a challenging procedure as it is impacted by the fluid properties, reservoir heterogeneity, and the developing history of the reservoir. Thus, the optimal well placement or location has a significant impact on the economic profit of oil field development and thus on the net present value (NPV). The objective function of well placement optimization is a highly nonlinear constraint, and due to reservoir heterogeneity, the decision variables are multi-modal. These optimization problems are typically computationally expensive as they entail full reservoir heterogeneity. Thus, finding optimal well locations with less time and fewer function evaluations is crucial [22–29].

To overcome the unavailability of mathematical model-based approaches, particle swarm optimization (PSO) and genetic algorithm (GA) are commonly applied to well placement optimization problems [30–32]. Sometimes, these methodologies suffer from premature local optimization issues. Therefore, to achieve improved performance, classical techniques have been integrated with non-classical techniques to develop many hybrid algorithms [33–35]. Particles in the PSO algorithm are initialized randomly and change their position with time to identify the optimum solution in a search space [36,37]. To effectively find the global optimum, a modified GA algorithm has been implemented for well placement optimization in a gas condensate field [38], and under geological uncertainties as a multi-objective problem [39]. A combination of PSO with a local generalized pattern search (GPS) strategy was implemented to handle general constraints by establishing a ranking system [35]. However, they concluded that it is necessary to consider more sophisticated constraint-handling methods for well-placement optimization.

In this study, the feasibility of the TC-GDWS-AGD technique was evaluated through simulation-flow modeling applied on the PUNQ-S3 synthetic reservoir based on a real North Sea oil field. This process reduces the number of required injector wells by utilizing some wells for combined gas injection and oil/water production, making it more commercially viable. TC-GDWS-AGD also aims to achieve maximum oil recovery resulting from a minimum gas-injection rate and minimum water cut. PSO was employed to determine the best well completion locations and to identify the optimal production and injection control parameters. The operational decision parameters considered by the production scenarios evaluated by PSO include the maximum oil-production rate (STO) at the wellhead, the minimum bottom-hole pressure (BHP) of oil well completions, maximum surface-water-production rate (STW) at the wellhead, minimum BHP of the water-production well completions, maximum surface gas-injection rate, and maximum BHP of gas-injection well completions. These operational decision parameters govern the ultimate maximum oil recovery, gas breakthrough, and water cut achieved by the triple-completion well configurations.

Previous research on the GDWS-AGD has focused on implementing the technique by applying dual-completed, horizontal wells for oil production and water injection combined with multiple additional, vertical, gas-injection wells. This approach is expensive based on the total wellbore lengths that need to be drilled. For the first time, this study evaluates an implementation (TC-GDWS-AGD) aimed at substantially reducing well costs by eliminating the requirement for separate gas-injection wells. The new method achieves this by incorporating triple-completed wells that charge a reservoir's gas cap from the upper gas-injection completion, while simultaneously segregating production of oil and water from two lower well completions, with produced water being re-injected into the reservoir's water zone from the lowest completion. This study also demonstrates a novel application for the PSO algorithm for improving reservoir development designs relating to the TC-GDWS-AGD method by simultaneously seeking designs that optimize oil production while minimizing water cut.

2. TC-GDWS-AGD Well Configurations

Increasing oil recovery by improving sweep efficiency and reducing water cut is the main objective of the application of the GDWS-AGD technology [14,18,40]. Reducing the number of production wells is one way to improve its commercial viability. One way to achieve this is to produce oil and water from each production well through two isolated completions while in the same wellbore to inject gas via the annulus through the casing [41,42]. This TC-GDWS-AGD technique, for maximum effect, should inject gas as close to the highest point of the oil pay zone as possible to gradually cause the reservoir to develop a gas cap. This is best achieved by injecting gas through a near-vertical section of the wellbore utilizing a set of perforations isolated from the rest of the well via a packer.

For the oil and water dual completions in separate horizontal wellbore sections, depending on the diameter of the well drilled, 2 separate strings of production casing are installed (for example, each with a 7-inch diameter): one in the oil zone, and one in the water zone. Each production casing is perforated and completed, for example, with $2^3/_8$-inch diameter horizontal tubing. The oil-production section needs to be positioned near horizontally above but close to the OWC, whereas the water-production section needs to be positioned near-horizontally, below but close to the OWC. A submersible pump is required to extract water through the water-production completion at high rates, as required. Hydraulic packers are required to isolate each of the production completions. Both production well sections are typically drilled with similar horizontal lengths and wellbore diameters for the TC-GDWS-AGD to be most effective (Figure 3).

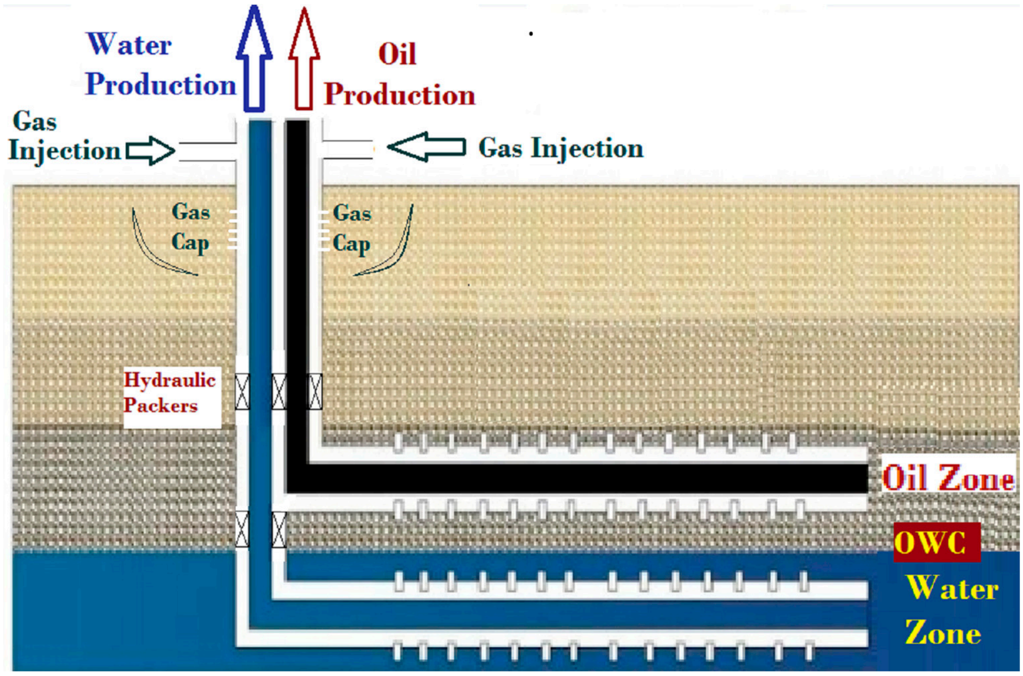

Figure 3. Schematic representation of the triple completions involved in a typical TC-GDWS-AGD-configured wellbore.

3. PUNQ-S3 Truth Case Description

The viability of the TC-GDWS-AGD technique for gas injection and its efficiency in maximizing oil production and minimizing water cut are evaluated in this study with simulations applied, with the aid of an optimizer, to the PUNQ-S3, three-phase, three-dimensional, synthetic reservoir [43]. Production uncertainty quantification (PUNQ)-S3 is a heterogeneous saturated-oil synthetic reservoir with a gas cap and strong water drive based on an actual North Sea field. This synthetic reservoir has been widely used in recent years for reservoir development optimization studies [44,45].

PUNQ involves a modest-sized, 5-layered reservoir extending over 4260 acres, and simulated with 1761 active cells (originally $19 \times 28 \times 5$ grid blocks; 2660 total grid blocks). The depth to the top of the reservoir at the crest of the structure is 2430 m with flanks dipping at 1.5°. A gas cap is located beneath the crest of the structure surrounded by an oil rim. The grid block size is set to 180 m $\times$ 180 m $\times$ 4.42 m. Pressure and temperature for this reservoir are 3400 psi, 220 °F, respectively. The reservoir includes fault boundaries on its eastern and southern sides, but is fully connected to strong aquifers located to the west and north. The first (uppermost) layer incorporates a small gas cap positioned near the crest of the domal trap. A total of 6 horizontal-producing wells are positioned below the gas–oil contact (GOC) with prevailing BHPs of 1740 psi. Water injection is not required to maintain reservoir pressure due to the presence of a strong aquifer [43]. Figure 4 represents a top structure map and well locations for the PUNQ-S3 reservoir.

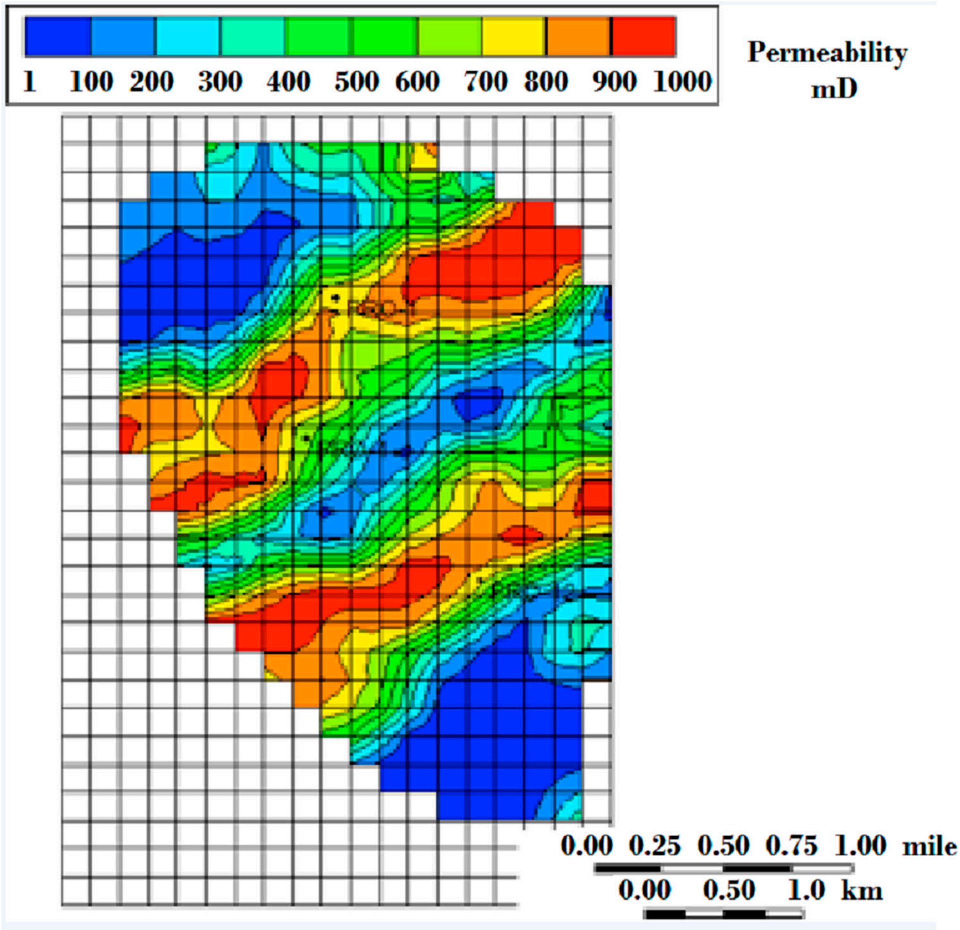

Figure 4. PUNQ-S3 top structure map and reservoir well locations [43].

Porosity and permeability maps of the reservoir were constructed with a geostatistical model. The PUNQ-S3 synthetic model lacks capillary pressure data but it does include reservoir permeability curves, PVT data, and an aquifer dataset [43]. Average porosity and vertical and horizontal permeability are provided for each reservoir layer (Table 1).

Table 1. PUNQ-S3 average of key parameters for each reservoir layer (Al-Mudhafar et al., 2021 [14]).

Reservoir Characteristic	Reservoir Layer 1	Reservoir Layer 2	Reservoir Layer 3	Reservoir Layer 4	Reservoir Layer 5
Average Porosity (ϕ%)	0.17	0.08	0.17	0.16	0.19
Average Horizontal Permeability (Kh mD)	432	33	432	196	654
Average Vertical Permeability(Kv mD)	137	13	137	64	205

4. TC-GDWS-AGD Simulation Applied to PUNQ-S3 Reservoir

A black-oil-reservoir simulation model was applied, with a twelve-year prediction horizon, to the PUNQ-S3 reservoir incorporating TC-GDWS-AGD. Horizontal wells with multiple completions were positioned in the reservoir to replace the six producing wells incorporated into the basic reservoir model. These two MC wells each include gas-injection completions (G-INJ1and G-INJ2) in the annulus of their vertical sections, horizontal oil-producing completions in a separate lateral branch above the OWC (OIL WELL1, OIL WELL2), and water-producing completions in a separate lateral branch below the OWC (DWS1, DWS2). A miscible gas injection is initiated from the two wells into the (upper) reservoir layer one. The two horizontal oil-producer wells were completed in reservoir layer four, and the two horizontal water-producer wells were completed in reservoir layer five. Figure 5 displays the trajectories of the two MC wells within the PUNQ-S3 reservoir grid. Each wellbore contains three distinct completed sections (GAS INJ1, OIL WELL1, and DWS1).

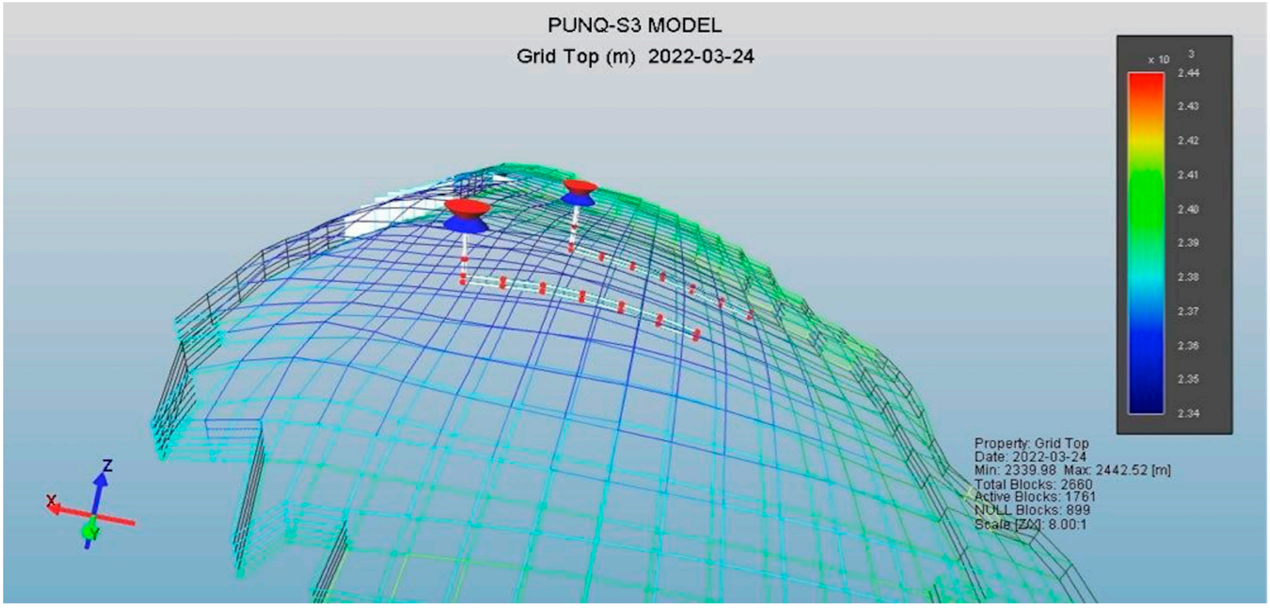

Figure 5. PUNQ-S3 reservoir grid positions of gas-injection, oil- and water-production completions.

A key advantage of the TC-GDWS-AGD configuration over the base case PUNQ-S3 simulation is that two TC wells, each with three distinct completed zones, replace the six base-case horizontal wellbores. The Carter–Tracy approach was used to model three distinct zones associated with the active and infinite water-drive aquifer providing the naturally occurring reservoir-drive mechanism. The TC-GDWS-AGD-configured simulation, with the two MC wells, was set up to calculate reservoir pressure, recovery factor, cumulative oil production, oil-flow rate, and the cumulative water cut fraction from a two-well production system extending over 12 years. The TC-GDWS-AGD simulated results are compared with the results achieved by GDWS-AGD and GAGD simulations applied to the reservoir involving the six base-case horizontal wellbore.

The operational constraints applied to the TC-GDWS-AGD, GDWS-AGD, and GAGD simulations included maximum gas-injection rate, bottom-hole-flowing pressure each injection-well completion, maximum flow rate at the wellhead, and minimum bottom-hole-flowing pressure for each horizontal (oil and water) production completion. Table 2 lists the values of these constraints as applied to the TC-GDWS-AGD, GDWS-AGD, and GAGD EOR configurations and to the primary base-case production case.

Table 2. Well-related constraints applied to the TC-GDWS-AGD, GDWS-AGD, and GAGD EOR cases and the primary base production case for the PUNQ-S3 simulations evaluated.

Well Type	Constraints	TC-GDWS-AGD	GDWS-AGD	GAGD	Primary (Base Case)
Gas Injector	MAX STG	350,000 m^3/day	350,000 m^3/day	350,000 m^3/day	-
	MAX BHP	28,000 kpa	28,000 kpa	28,000 kpa	-
Oil Producer	MAX STO	800 m^3/day	800 m^3/day	800 m^3/day	800 m^3/day
	MIN BHP	12,000 kpa	12,000 kpa	12,000 kpa	12,000 kpa
Water Producer	MAX STW	3800 m^3/day	3800 m^3/day	-	-
	MIN BHP	12,000 kpa	12,000 kpa	-	-

Figure 6 displays a comparison between TC-GDWS-AGD, GDWS-AGD, GAGD, and primary production simulation cases. The results are shown for stock-tank cumulative oil production (m^3) and oil-production daily rate (m^3/day) extending over the twelve-year production horizon. The results reveal cumulative oil production of 1.47×10^6 m^3 generated by the primary (base-case) production simulation from 6 horizontal producers with no EOR technique applied. On the other hand, 1.6×10^6 m^3 of cumulative oil production is generated from the TC-GDWS-AGD simulation incorporating just 2 TC wells (a total of 6 completed reservoir zones), and the GDWS-AGD simulation incorporating 6 separate horizontal wells generates 1.7×10^6 m^3 of cumulative oil production. Figure 7 reveals that the overall water cut is substantially reduced from 90% for the primary (base-case) simulation, to 74% for the GAGD simulation, and to 57% for the TC-GDWS-AGD simulation.

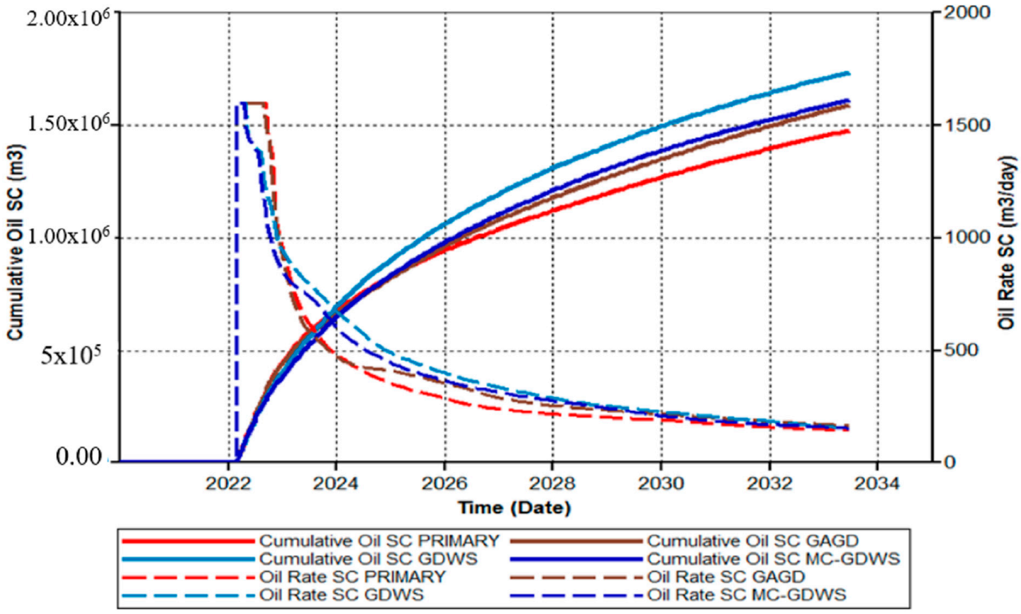

Figure 6. Cumulative oil production and daily oil production rate generated by TC-GDWS-AGD, GDWS-AGD, GAGD, and primary (base-case) PUNQ-S3 simulations.

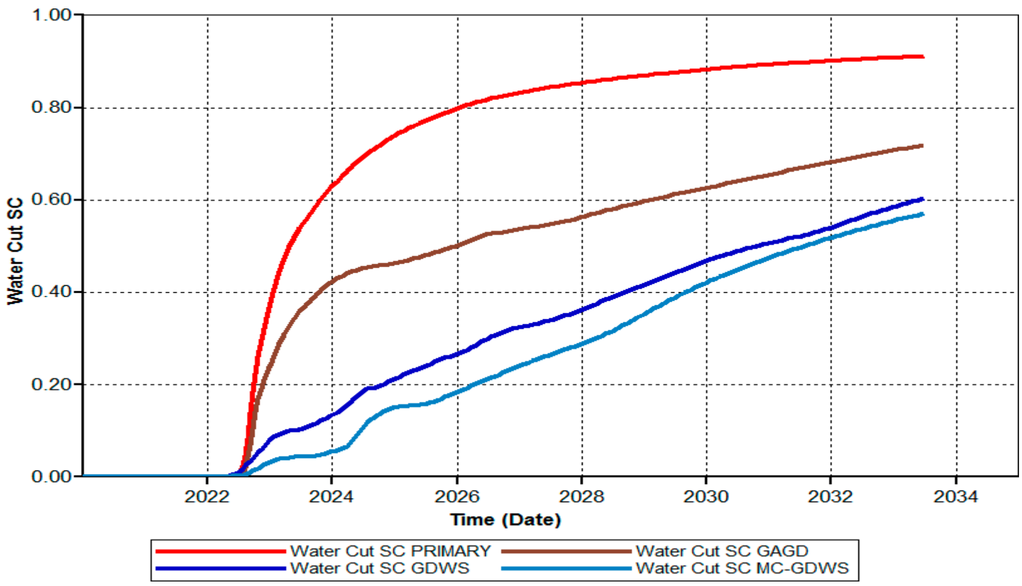

Figure 7. Water cut expressed by year in standard conditions for the TC-GDWS-AGD, GDWS-AGD, GAGD, and primary (base-case) PUNQ-S3 simulations.

Figure 8 displays the average reservoir pressure trends associated with each simulation configuration expressed over the twelve-year production horizon. In the TC-GDWS-AGD simulation, the average reservoir pressure decreased due to the DWS wells. This decrease in reservoir pressure is associated with improved cumulative oil production and a reduction in the water cut compared with the other simulated cases.

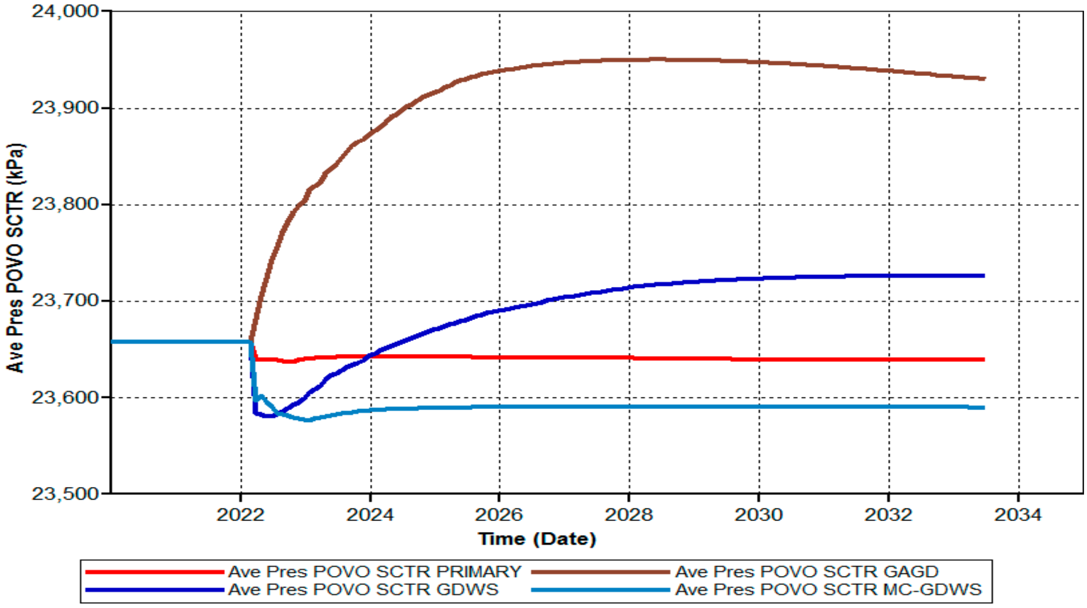

Figure 8. Average reservoir pressure expressed by year for the TC-GDWS-AGD, GDWS-AGD, GAGD, and primary (base-case) PUNQ-S3 simulations.

Figure 9 displays the oil-recovery factor trends over the twelve-year planning horizon for each of the simulated cases. After 12 years of production, the oil-recovery factor increased to 9%, 14.5%, and 15% for GAGD, TC-GDWS-AGD, and GDWS-AGD simulated cases, respectively, compared with 8% for the primary (base-case) simulation.

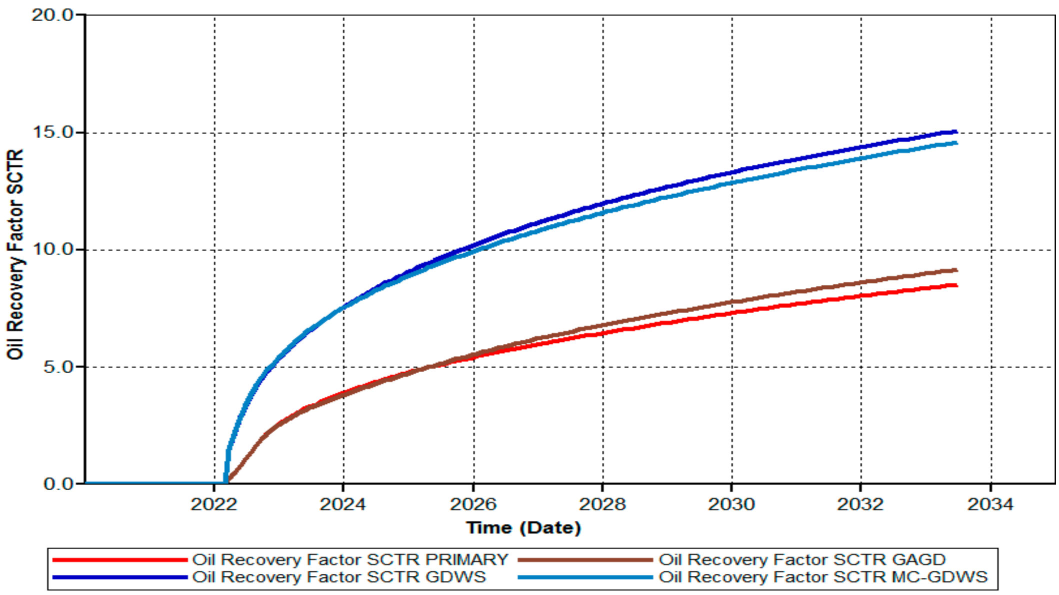

Figure 9. Oil-recovery factor expressed by year for the TC-GDWS-AGD, GDWS-AGD, GAGD, and primary (base-case) PUNQ-S3 simulations.

The GDWS simulation generates slightly superior results to TC-GDWS-AGD in the key objectives (Table 3). On the other hand, implementing the TC-GDWS-AGD configuration substantially lowers the well costs by involving just two MC wells compared with the six wells required by the GDWS configuration.

Table 3. Oil recovery and water cut after twelve years of production for the TC-GDWS-AGD, GDWS-AGD, GAGD, and primary (base-case) PUNQ-S3 simulations.

PROCESS	TC-GDWS-AGD	GDWS	GAGD	PRIMARY
Oil Recovery	14.5%	15%	9%	8.5%
Water Cut	57%	60%	70%	90%

5. Well Placement Optimization

Optimization is conducted to determine the optimal simulation solution that achieves maximum oil production, minimum gas breakthrough, and minimum water cut. The optimization of the TC-GDWS-AGD process was conducted based on a series of simulation runs using the CMG-CMOST 2015.10 package [46]. The optimization assesses each simulation solution by taking into account a range of possible uncertainties regarding the operational decision parameters affecting the reservoir fluid flows generated. In addition to the well locations, the operational parameters include BHP in each of the injection- and production-well completions, gas-injection rate, oil-production rate, and water-production rate in the production wells. The optimal case is selected based on the maximum oil-recovery factor combined with the minimum possible water cut.

6. Particle Swarm Optimization

Particle Swarm Optimization (PSO) has been adopted for the optimization of reservoir flow responses in limited petroleum engineering applications, such as well placement optimization [47], minimum miscibility pressure [48], recovery optimization in geothermal reservoirs [49], wellbore trajectory optimization [50], gas lift optimization [51], recovery optimization in shale oil reservoirs [52], and history matching and uncertainty quantification [53].

PSO was the optimizer selected to solve the uncertainties associated with the decision parameters. It conducted this by generating random solutions within the feasible solution space [54]. Each simulation solution generated represents one "particle" in the PSO algorithm's swarm of generated "particles". Each particle in the swarm has a calculated velocity that moves it progressively through the search space by updating its position in each of a series of PSO iterations to ultimately identify a global best or optimal solution. PSO particles affect each other based on the relative performance of the solutions in respect of the dependent variables (oil-recovery factor and water cut) through the sequence of iterations executed. The PSO algorithm terminates after completing a specified number of iterations. A multi-objective PSO configuration is applied to enable it to assess more than one objective in locating its optimal (global best) solution.

The PSO algorithm was configured to optimize two key objective reservoir variables: (1) maximize the oil-recovery factor; and (2) minimize water cut. For the TC-GDWS-AGD simulation cases, the well completion locations were modified in one or both MC wells by varying the reservoir locations of the completed sections in each well together with the values of specified operational decision variables used across the twelve-year production horizon. The operational decision variables modified were: maximum gas-injection rate, maximum BHP in the gas-injection completions, maximum oil-production rate and minimum BHP in the oil-production completions, and maximum water-production rate and minimum BHP in the water-production completions. The proposed triple-completion method, involving simultaneous gas injection coupled with oil and water production, can be optimized to achieve optimal reservoir flow responses that combine the highest oil production and the lowest water cut. Therefore, the aforementioned operational decision parameters that control the injection and production activities are included as part of the well placement optimization process. The incorporation of these parameters could be auto-optimized using intelligent completion technologies as part of the real-field implementation [55,56].

In scenario one, and to achieve maximum areal coverage of the reservoir by the completion locations evaluated, each TC well was split into two trajectories: one extending to the left of the surface location, and one extending to the right sides of the surface location, as shown for one example simulation solution in Figure 10. The PSO algorithm is then deployed to determine the optimal well completion placement that achieves the maximum oil recovery and minimum water cut. Five hundred what-if-simulation runs were evaluated and fed into the PSO algorithm from which it identified the optimal case. Figure 11 displays the reservoir performance over time, in terms of water cut, reservoir pressure, and oil-recovery factor, for the historical production from the six existing wellbores for the pre-prediction period combined with that of the two TC wells for all five hundred simulation cases evaluated.

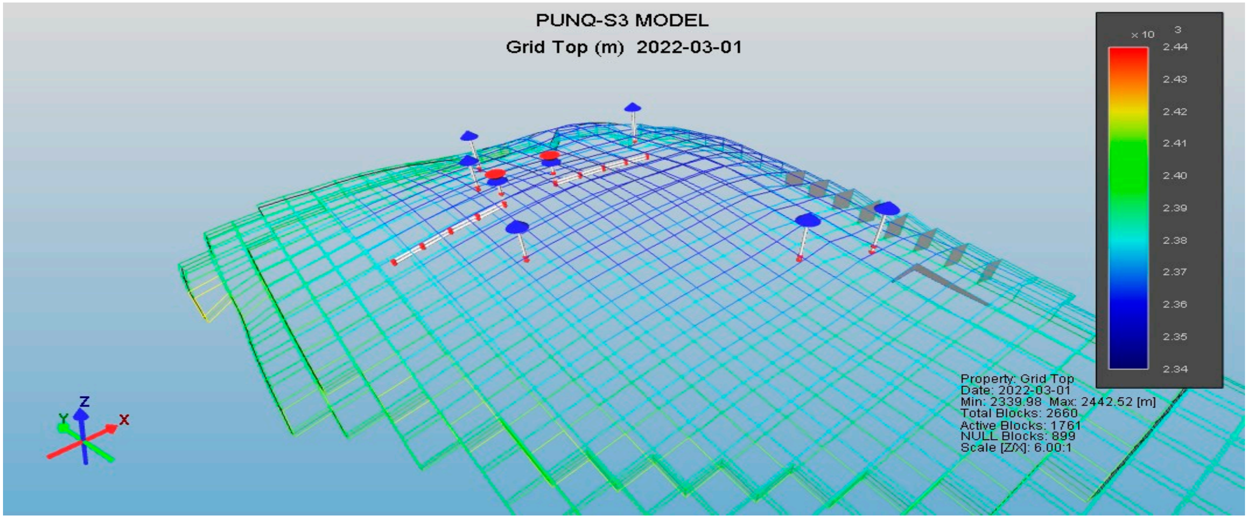

Figure 10. Well location optimization—scenario 1 for the PUNQ-S3 reservoir simulated with the TC-GDWS-AGD configuration.

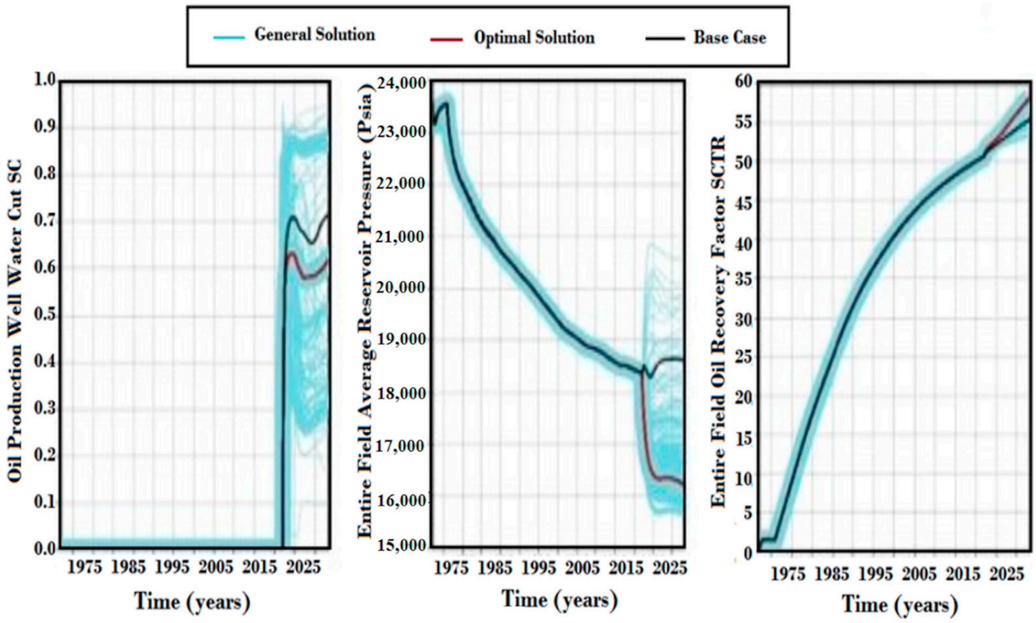

Figure 11. PSO optimal flow responses for the five hundred simulation cases evaluated. Left: oil well water cut; middle: average reservoir pressure; and right: oil recovery factor.

In Figure 11, two solutions are highlighted involving the TC wells. The dark red curve identified the PSO optimal TC-GDWS-AGD solution and the thick black curve identifies the base case TC-GDWS-AGD assumptions. The PSO optimal case is associated with the highest oil-recovery factor combined with the minimum water cut. Specifically, the oil recovery was increased from 0.55 for the base-case TC-GDWS-AGD decision variable values to 0.58 in the optimal solution, whereas the water cut decreased from 0.72 for the base-case TC-GDWS-AGD decision variable values to 0.57 in the optimal solution. A comparison of the values of the key decision variables between the base-case TC-GDWS-AGD and the optimal-case TC-GDWS-AGD simulation evaluated is presented in Table 4.

Table 4. Base-case and PSO-derived optimal-case operational decision variable values for the TC-GDWS-AGD simulation of the PUNQ-S3 reservoir.

Decision Variables	Base Case TC-GDWS-AGD	Optimal Case TC-GDWS-AGD
Maximum Oil Production Rate (MAX_STO; m^3/day)	800	967.33
Minimum Bottom Hole Pressure (Oil) (MIN_BHP; kpa)	12,000	9533.48
Maximum Gas Injection Rate (MAX_STG; m^3/day)	350,000	420,358.11
Maximum Bottom Hole Pressure (Oil) (MAX_BHP; kpa)	28,000	25,926.01
Maximum Water Production Rate (MAX_STW, m^3/day)	3800	4424.58
Minimum Bottom Hole Pressure (Water) MIN_BHPW, kpa	12,000	9058.99
Location of MC Well 1 (WELL 1_ J)	20	22
Location of MC Well 2 (WELL 2_J)	20	19

Sobol analysis was applied to identify the most influential decision variables affecting the performance of the TC-GDWS-AGD simulation. Figure 12 displays the results of the Sobol analysis for the oil-recovery factor, identifying that the minimum BHP in the DWS well completion section (Well 2) was most influential (37%) and the location of Well 2 was the next most influential decision variable (35%). On the other hand, the least influential decision variable was the maximum surface gas rate (MAX_STG). The value of permeability in the PUNQ-S3 reservoir layer two is very low; consequently, the effect of the gas-injection rate on the simulation outcomes is low because the transfer of gas from reservoir layer one to reservoir layer three cannot be effectively increased by increasing the gas-injection rate. Among the five hundred simulation cases evaluated, a completion location with the lowest possible water cut did not coincide with the best-performing oil-production completion locations, which are primarily located in relatively high water-saturation areas of the reservoir. In order to further address this conflict, the cases evaluated gradually increased the surface-water-production rate (STW) to values that generated lower water cuts (MAX_STW = 20,000 m^3/day).

Figure 13 reveals the substantial effect of STW on water cut for the TC-GDWS-AGD-simulated cases. By allowing MAX_STW to increase, the oil-recovery factor was increased from 59% to 63.5%, whereas the water cut was reduced to 0.45 coupled with a substantial decrease in reservoir pressure as a consequence of the additional produced water extracted from the reservoir.

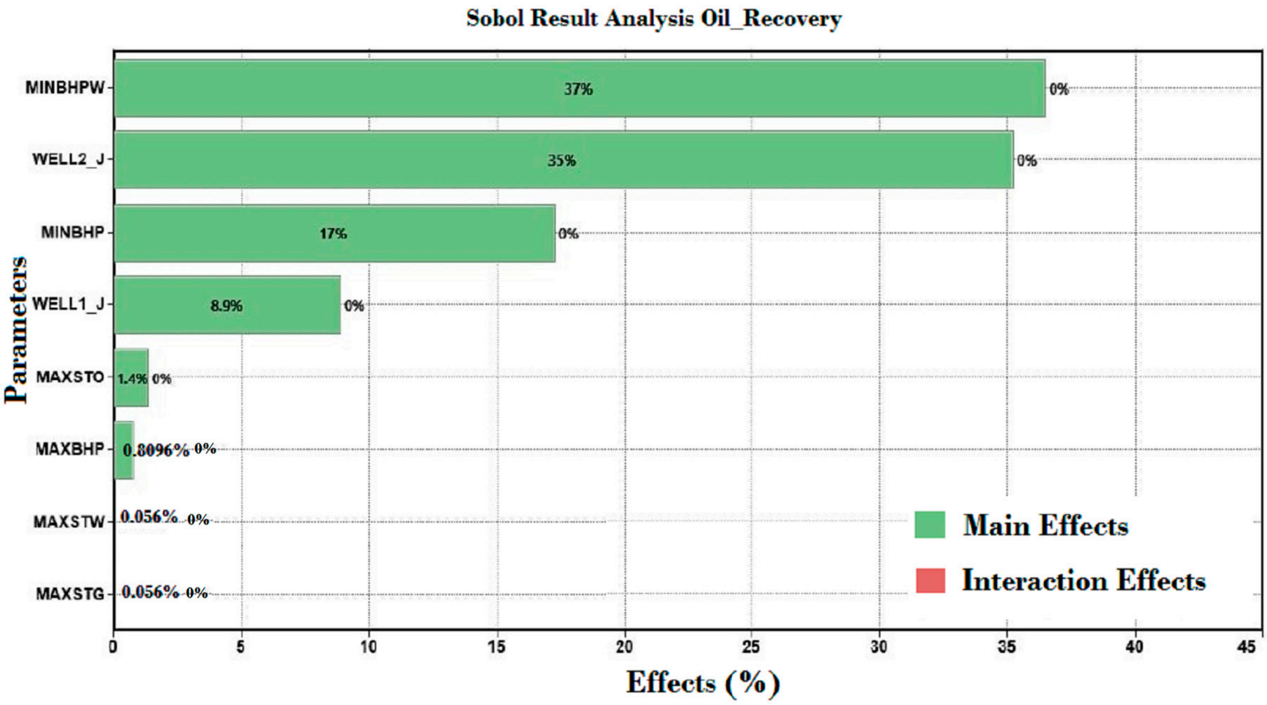

Figure 12. Sobol analysis results distinguishing the most influential decision variables affecting the TC-GDWS-AGD simulation cases evaluated by PSO.

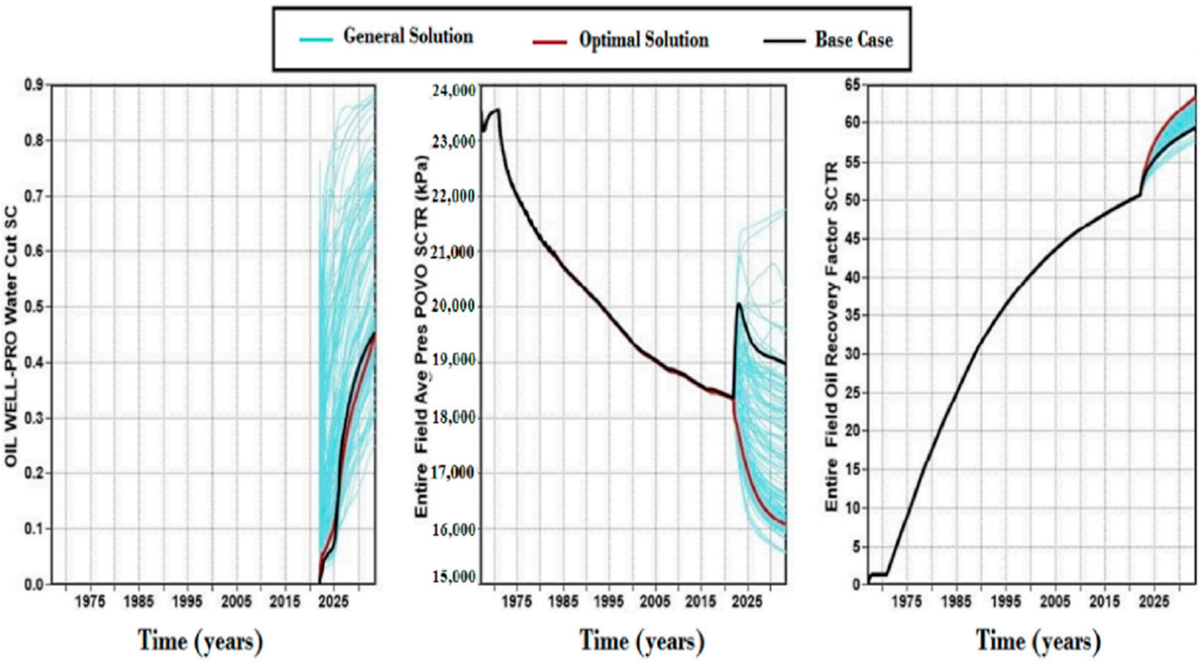

Figure 13. PSO-derived optimum water cut solution resulting from the evaluation of five hundred simulation cases. Left: oil well water cut; middle: average reservoir pressure; and right: oil recovery factor.

In scenario two of well placement optimization, two wells were placed to the right side and two wells to the left side of the reservoir, as shown in Figure 14. Table 5 shows the operational decision parameters used in this optimization scenario. The related general solutions of the oil recovery for the four new wells are illustrated in Figure 15.

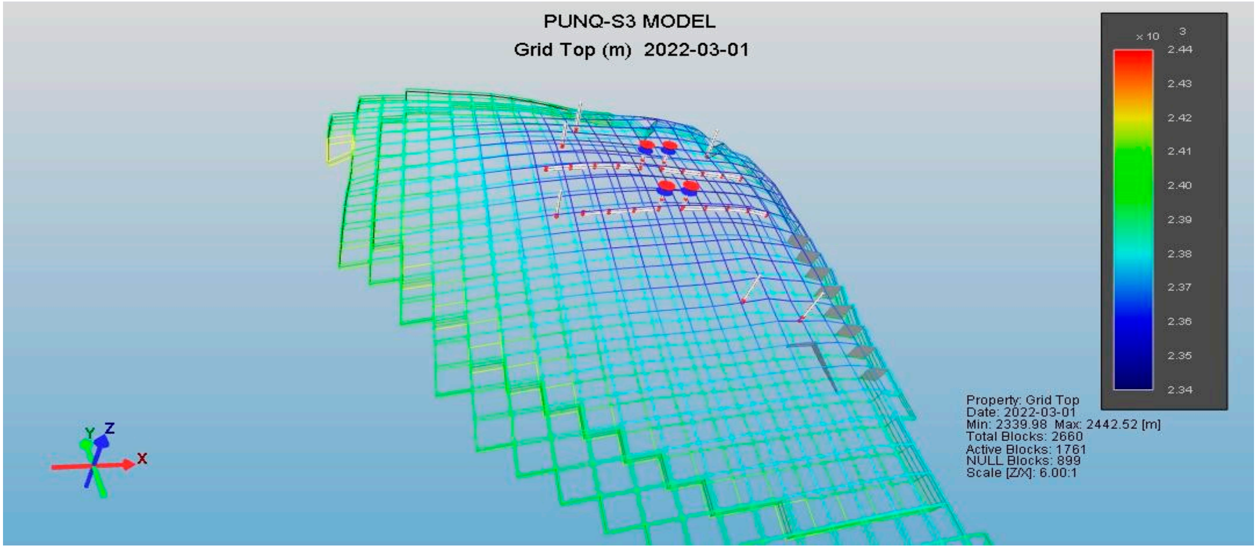

Figure 14. Well locations in PUNQ reservoir for TC-GDWS-AGD.

Table 5. Base-case and PSO-derived optimal-case operational decision variable values for TC-GDWS recovery optimization applied to scenario 2.

Parameters	Base Case	Optimum Case
MAX_STO, m^3/DAY	800	714.11
MIN_BHP, kpa	12,000	9031.55
MAX_STG, m^3/DAY	350,000	325,512.06
MAX_BHP, kpa	28,000	26,894.18
MIN_BHPW, kpa	12,000	9065.37
WELL 1_J	20	23
WELL 2_J	20	20
WELL 3_J	17	14
WELL 4_J	17	17

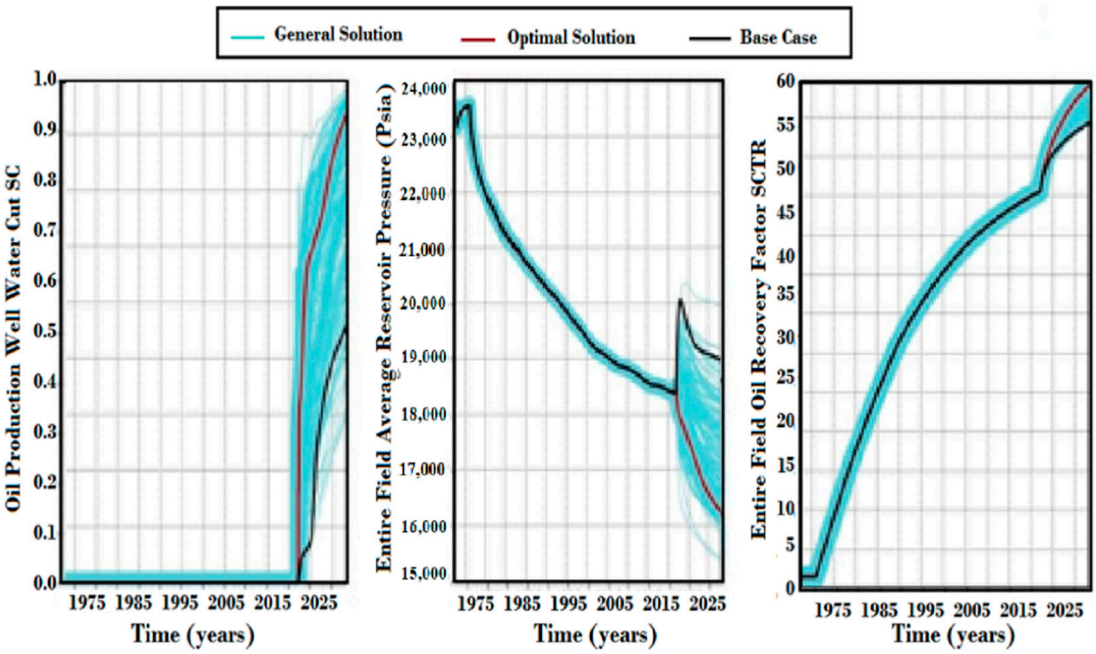

Figure 15. PSO-optimal flow responses considering 500 cases for scenario 2. Left: oil well water cut; middle: average reservoir pressure; and right: oil recovery factor.

From the Sobol analysis for scenario 2, the most influential variables with respect to oil recovery are the locations of Well 4 and Well 3 with 24% and 17% main effect and 2% and 1.7% interaction effect, respectively. The optimal locations are positioned in high-oil-saturation zones. On the other hand, the least influential decision variable was the maximum surface oil rate with only a 1.3% main effect, as illustrated in Figure 16.

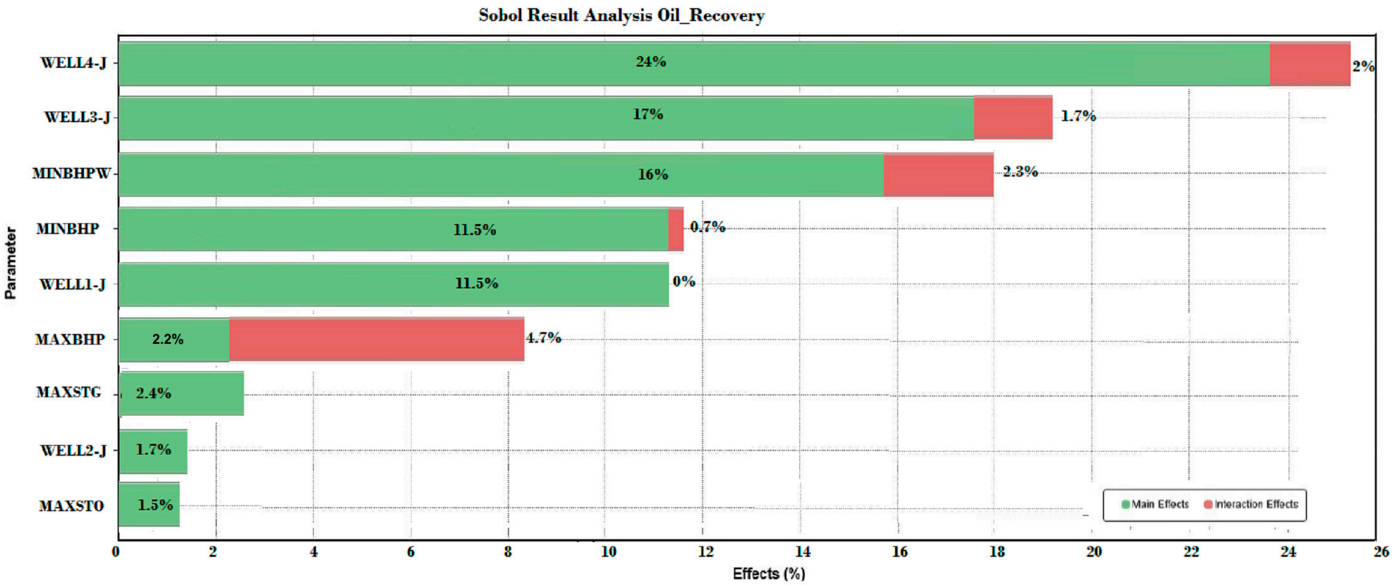

Figure 16. Sobol most influential decision variables affecting the TC-GDWS process performance using PSO, scenario 2.

7. Summary and Conclusions

In this study, a black-oil reservoir simulation was conducted on the Punq-S3 heterogeneous reservoir to evaluate and determine the optimal setting of the triple-completion gas and downhole water sink-assisted gravity drainage (TC-GDWS-AGD) process. The evaluation and well placement optimization procedures of the TC-GDWS-AGD process were conducted to achieve maximum oil production with minimum water cut through a 12-year prediction period in a comparison with GDWS-AGD and GAGD processes. The operational decision parameters that were included in the well placement optimization along with the potential well locations included maximum surface oil rate and minimum bottom hole pressure of oil producers; maximum surface water rate and minimum bottom hole pressure of water producers; and maximum surface gas rate and maximum bottom hole pressure in gas injectors. The following points are the main conclusions retrieved from the evaluation and optimization procedures:

- The effectiveness of the TC-GDWS-AGD enhanced oil recovery (EOR) technique was confirmed by this simulation study in terms of its ability to increase oil recovery and decrease water cut compared with applying gas-assisted gravity drainage (GAGD) and gas-downhole water sink (GDWS) EOR processes to the Punq-S3 synthetic reservoir.
- The TC-GDWS-AGD completions are effective in reducing water cut and increasing cumulative oil production. Cumulative oil was increased from 1.47×10^6 m^3 from the primary process to 1.6×10^6 m^3 from the best TC-GDWS-AGD case with an oil recovery factor of 0.58, whereas water cut decreased from 70% in the GAGD process to 57% in the best TC-GDWS-AGD case.
- As the TC-GDWS-AGD gas-injection rate was enhanced from 350,000 m^3 to 500,000 m^3, the water cut decreased from 0.57 to 0.50. When the maximum surface-water-production rate (STW) constraint was raised to 20,000 m^3/day, the PSO algorithm was able to find locations that achieved high oil recovery with the lowest overall water cut (0.45) for the two-TC-well cases.

- The PSO algorithm was highly effective at identifying the optimum well completion locations for maximizing oil recovery and minimizing water cut in the studied reservoir. To achieve maximum reservoir coverage, for each simulated scenario, one well completion was placed to the right side of a surface location and one well to the left side.
- The gas injection rate (STG) had only a minor impact on oil recovery volumes because the permeability of the reservoir layer two was very low. In fact, the transfer of gas from reservoir layer one to reservoir layer three was found to decrease as the gas injection rate increased.

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