Optimization on number of wells for preparing a field for Underground Gas Storage

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Abstract

In past few decades, energy consumption grows rapidly. The demand for energy resources such as fuel gas increases, especially during cold months. Besides, pipelines carrying the refined natural gas to costumers have limitations on their capacity. Storing excess gas in geological formations, Underground Gas Storage (UGS), is a crucial technique used to satisfy these constraints.

Field preparation for UGS requires injecting gas known as cushion gas during target time to prepare adequate pressure and deliverability. The number of wells is a key parameter for preparing the field since a larger number of wells leads to faster preparation. On the other hand, using more wells costs higher. Thus, an optimum number of wells for preparing a field for UGS must be found.

This work is a case study of preparing a field for UGS. Different scenarios are investigated by parallel simulation and the optimum number of wells is measured.

Keywords*: Underground Gas Storage; Optimization; Reservoir Simulation, Number of Wells*

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1. Introduction

The first successful underground gas storage was in 1915 in Ontario, Canada by changing the conditions of some wells in a depleted reservoir.[1,2] After a year, another experience was in a field in south of Buffalo in New York State which was active until 1979. Third one was in Kentucky in 1919 and later in 1920, the reservoir known as Queen Pennsylvania. In 1930, nine reservoirs were created in six U.S. states. Before 1950, almost all underground gas storages were depleted gas reservoirs. Between 1998 and 2005, 42 underground gas storage reservoirs were excluded and 26 new sites were used for production. Now, in Europe there are about 120 operating storage reservoirs during the winter season and every year, about one fifth of the natural gas consumed in U.S. produced from underground gas storage reserves. [1,2]

Reducing oil resources, relatively large reserves of natural gas and being less polluting fuel compared to oil and coal, are the reasons that cause global markets to show more interest to natural gas. Active gas reservoirs are producing in mostly all months of a year, however, gas usage varies in different seasons [3]. Because of this reason, like other fossil fuels, natural gas storage is taken into consideration. Thus, as in winter the demand for natural gas increases, gas is produced from geological formations where gas has been already stored. [4]

UGS technique is generally used for:

- Satisfying peak demand for gas in winter
- Strategical issues
- Providing the required gas in emergency conditions of a state
- Continuing gas consumption especially when there is a technical problem in a facility [5]

Nowadays, reservoir simulation is widely used in gas and oil industry. Simulation can be used as the ability to solve problems that are not resolvable by other methods. It can be the best method for describing fluid flow in a non-homogenous reservoir with a time schedule for injection and production. Simulation could predict reservoir performance and is used as an important tool in fields of making decisions and managements. In this work, UGS is simulated by a reservoir simulator (Eclipse version 2010).

Ahmadi anticline is a structure placed in south of Iran. It is an appropriate structure for underground gas storage. Khami, Kazeroun and Dehram geological groups are investigated for feasibility of UGS. Khami is nearly filled by water and Kazeroun and Deharm groups contain a non-combustive gas with more than 85 % nitrogen. Kazeroun group seems to be more suitable for UGS. In this study, static model of Kazeroun group was prepared and different dynamic scenarios are simulated by fluid flow simulator (Eclipse). The most important factor in this simulation is multiphase flow equations for porous media used in the simulator. These equations are partial derivatives. Thus solving these equations by an appropriate numerical method is important. However, numerical simulation has two main difficulties:

a. Large amount of data
b. Time consuming

Nowadays these difficulties are solved by parallelizing systems. Due to large amount of data of the static model, fluid flow simulating takes a lot of time. As a result, in this study, calculations are carried out by parallelizing systems.

2. Research Method

Ahmadi formation includes two anticlines, one of which is bigger than the other. Simulating this formation and investigating injection and withdrawal cycles requires a suitable distribution of wells. For storing gas in anticline in a limited period of time, number of wells must be drilled. To avoid increasing the reservoir pressure at the time of injection some wells for producing nitrogen gas must be considered [6]. In this study, four different scenarios are considered for different distribution and to optimize the number of injection and production wells [7].

The 1st Scenario - 19 injection wells and 5 production wells

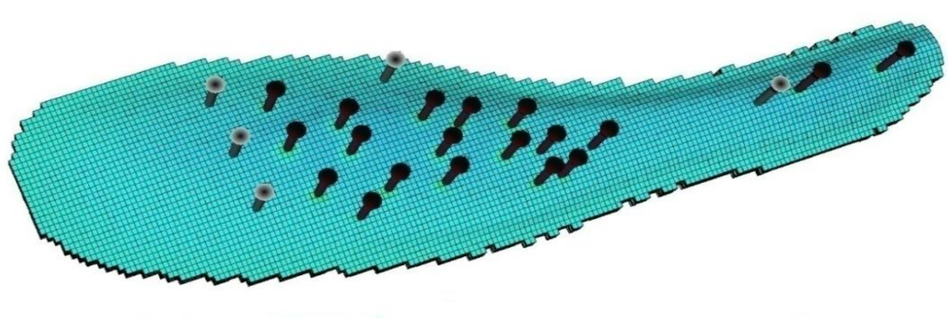

Figure 1. Schematic for injection and production wells in 1st scenario.

As Figure 1 shows, in the first scenario 19 injection wells (black) and 5 production wells (white) was defined. Location of injection wells in the anticline was determined based on the initial permeability distribution in the field. That is, the wells are located in a more permeable zone. The bigger anticline includes 17 injection wells and two injection wells are placed in the smaller anticline. Production wells were drilled to maintain pressure in the appropriate range. At the beginning of this study, it was thought that the field is going to have a one big chamber by injecting through these wells; however, it was finally figured out that there are several smaller chambers and each well has its own radius of drainage, which leads to having separate chambers for storing gas. As a result in the scenarios, Introduced injection wells to the simulation model are placed closer to each other to prepare closer chambers. The preparation time is 5 years in this simulation.

In the first scenario, injection thorough 19 wells with a control on bottom-hole pressure (BHP) set to be at 8000 psia is started. The parallelized simulation is run for 5 years as preparation time and different parameters are investigated once the simulation was finished.

Form cost point of view, it is required to reduce the number of wells. Thus other scenarios are simulated and analyzed with less number of wells.

The 2nd Scenario - 17 injection wells and 4 production wells

In this scenario the number of injection wells is reduced to 17 and a production well is omitted as Figure 2 shows. The purpose of this scenario is to focus on gas storage in the main and biggest anticline of the structure.

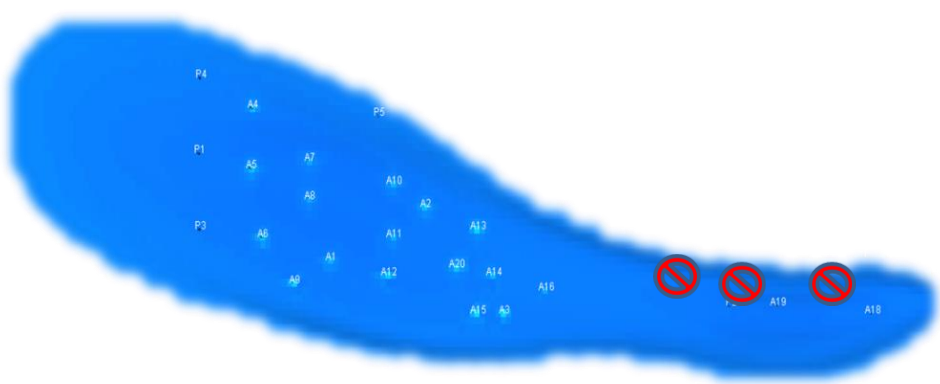

Figure 2. Schematic for injection and production wells in the 2nd scenario.

The 3rd Scenario - 11 injection wells and 4 production wells

If there is a demand for reducing number of wells due to economical and strategically reasons another scenario can be proposed with less number of wells. In this scenario injection wells are reduced to 11 and production wells are 4 like the previous scenario to decrease the drilling costs (Figure 3). It may be mentioned that all the omitted wells are the ones with the lowest injection rate and the worst performance.

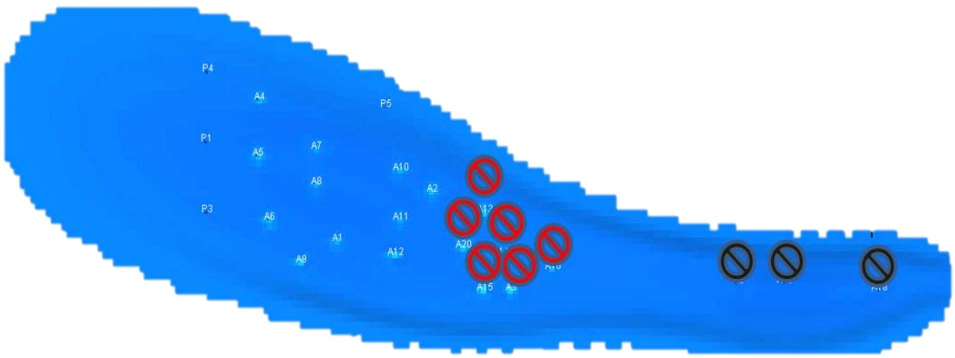

Figure 3. Schematic for injection and production wells in the 3rd scenario.

The 4th Scenario - 9 injection wells and 3 production wells

The last scenario is simulated with 9 injection wells and 3 production wells and the results are generated for this scenario to be used in case fewer wells are needed to be drilled (Figure 4). Again, the main criteria for omitting wells are low injection rate and low performance in comparison with other wells.

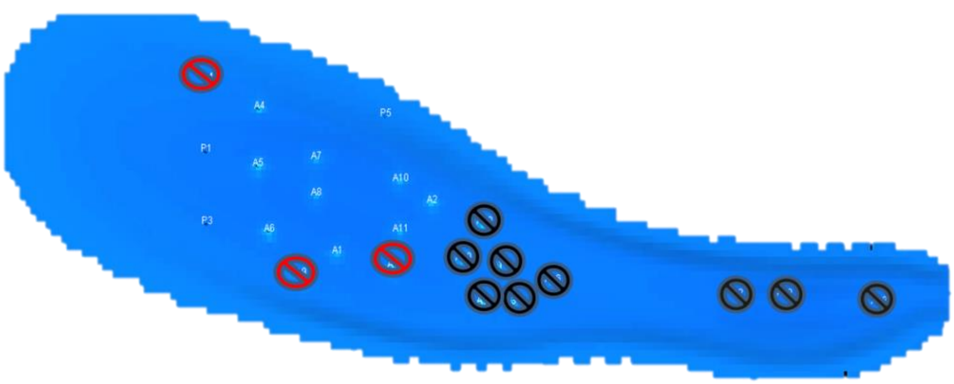

Figure 4. Schematic for injection and production wells in the 4th scenario.

3. Results and Discussion

As previously mentioned, the main aim of this study is to find the optimum number of wells drilled in the structure.

Thus, in each scenario Field Pressure (FPR) and Field Gas injection rate (FGIR) versus time are generated. The optimum scenario will be the case with highest cumulative injected gas, highest injection rates (lowest preparation time) and the lowest possible mixing. Figures 5 and 6 show the FPR and FGIR of the first scenario, respectively.

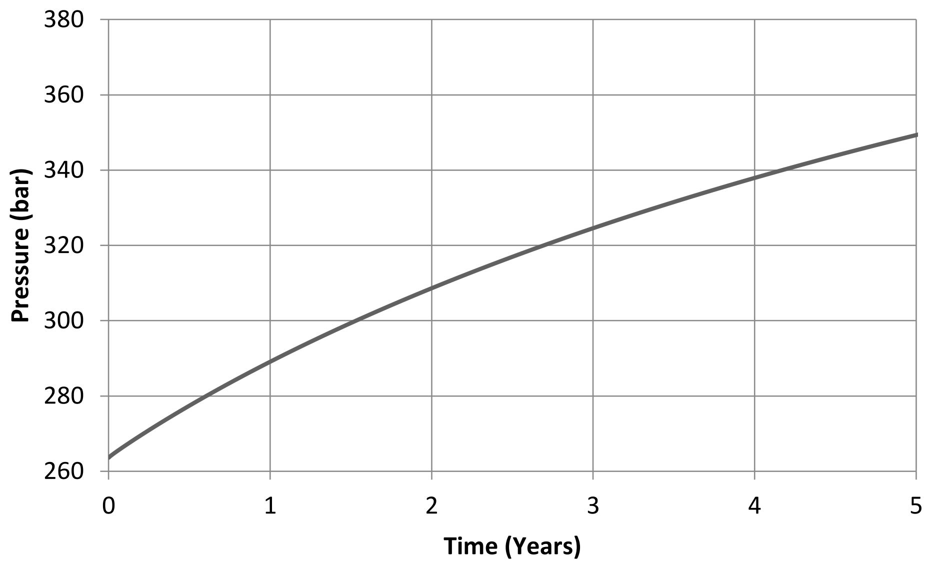

Figure 5. Field average pressure vs. time for the 1st scenario.

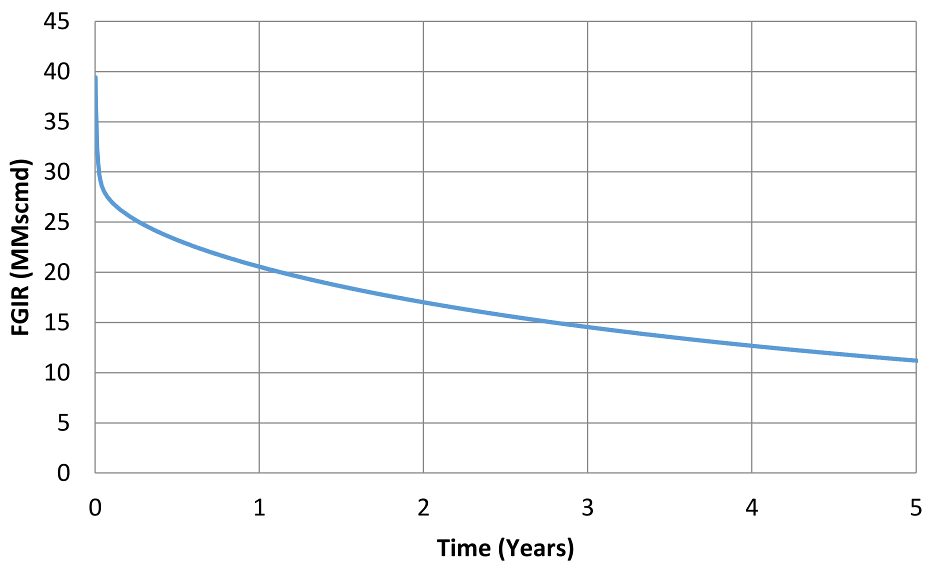

Figure 6. Field gas injection rate vs. time for the 1st scenario.

As can be seen in figure 5, during 5 years of preparation time, the field is pressurized about 90 bars and the average rate is 15.7 MMscmd during this time. The purpose is to inject a large amount of gas and store it in the anticline as the cushion gas so that it brings adequate pressure and deliverability for starting cycles. However, it must be considered whether this large amount of gas is injected through the optimum number of wells or not. As can be seen in Figure 6, FGIR is decreased rapidly, thus one cannot inject with a constant rate hence other scenarios must be investigated to find out for which scenario FGIR is approximately constant and definitely high as the goal is to inject as much gas as possible with a constant rate; a case which leads to optimum number of wells. Consequently, in following figures the results for FPR and FGIR in other scenarios are studied so that the optimum case could be figured out. In second scenario, FPR is generated and the result is as below.

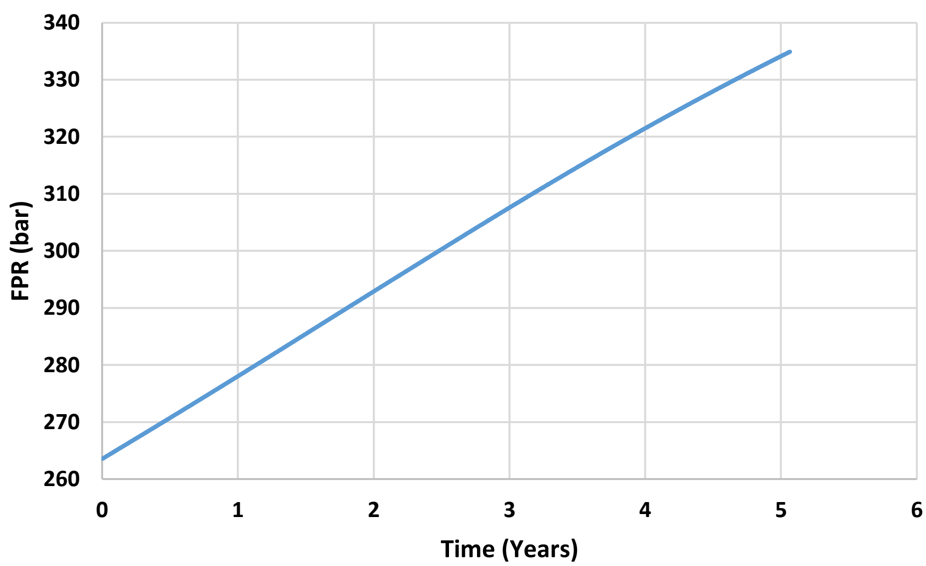

Figure 7. Field average pressure vs. time for 2nd scenario

As can be seen in figure 7 during preparation time, by injecting the cushion gas the field is pressurized with the average pressure of 300 bars.

Field gas injection rate versus time is also investigated to figure out how much gas is injected in this case.

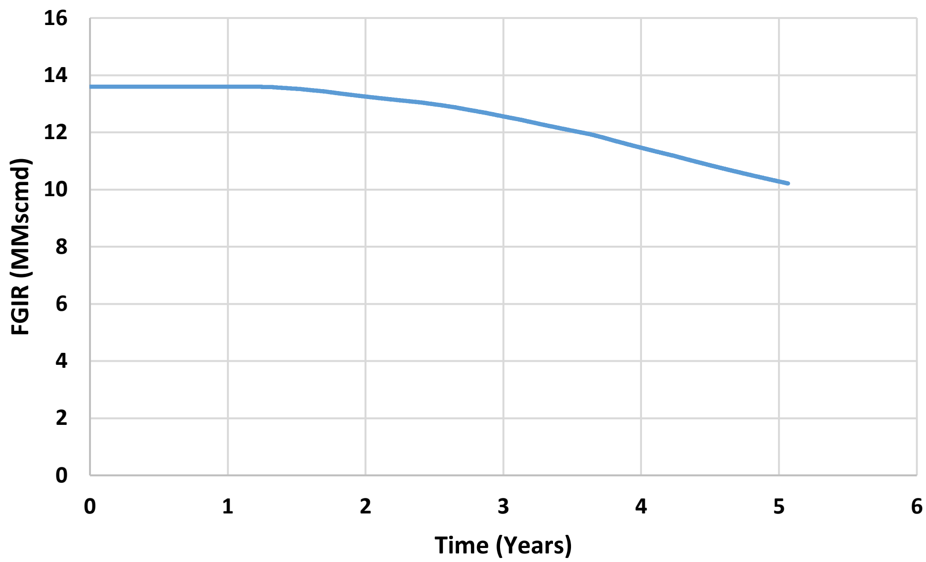

Figure 8. Field gas injection rate vs. time for 2nd scenario

As can be concluded from figure 8, field gas injection rate is averagely 12.5 Mscmd which makes each well has typically 0.7 Mscmd injection rate. The results for third scenario for FGIR and FPR are generated and these amounts are compared with other cases.

For the case of 11 injection wells while producing with 4 wells FPR is generated as below.

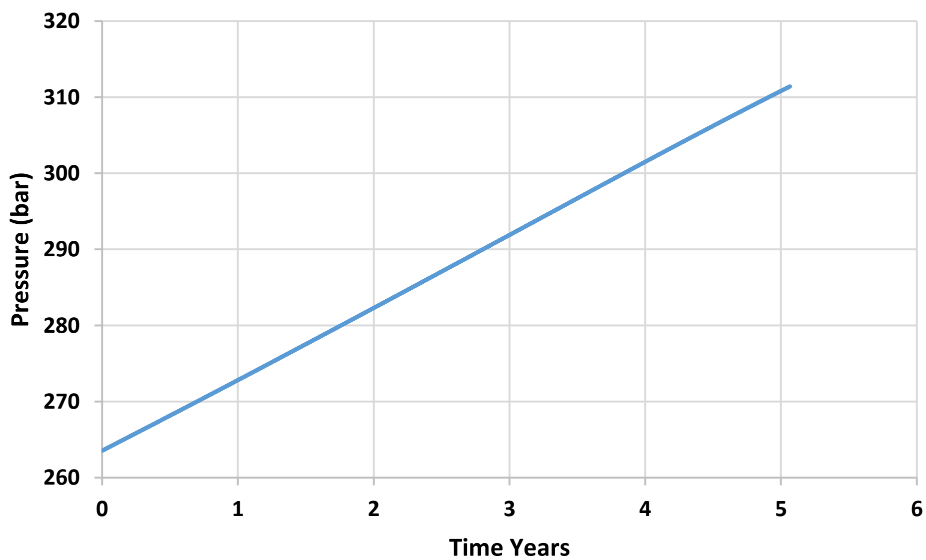

Figure 9. Field average pressure vs. time for 3rd scenario

As can be seen in figure 9, field pressure is increased from 260 bars to 310 bars. The field pressure is averagely 285 bars.

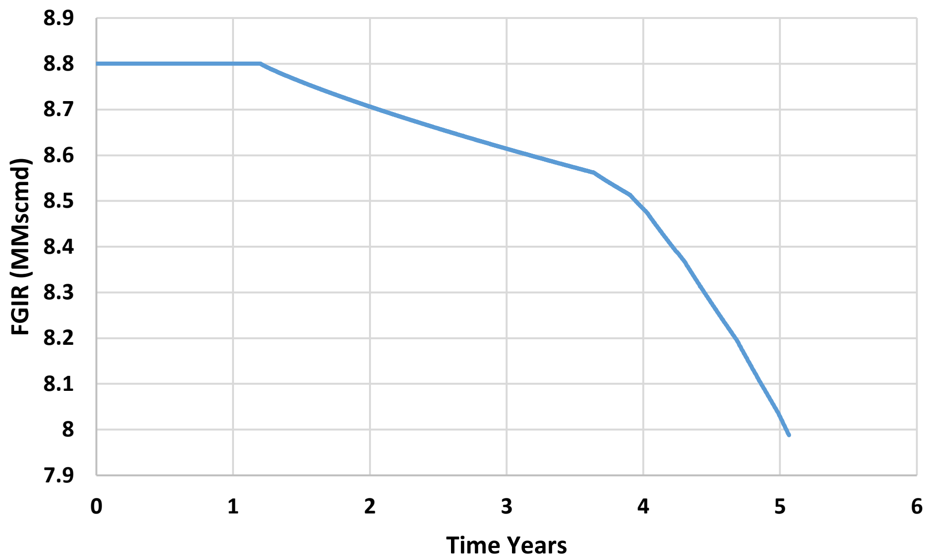

Figure 10. Field gas injection rate vs. time for 3rd scenario

For this case, FGIR is also generated and as can be seen in figure 10, the average rate is 8.4 MMscmd. For the last case which was with 9 injection wells, FPR and FGIR is generated and as can be seen in figures 11, 12 FPR is averagely 280 and the field rate is approximately 7.2 MMscmd.

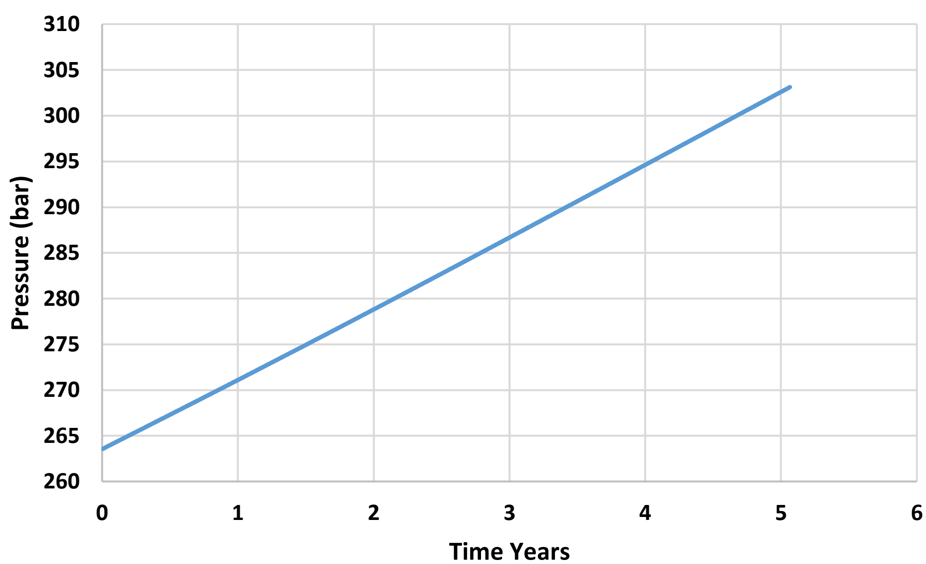

Figure 11. Field average pressure vs. time for 4th scenario

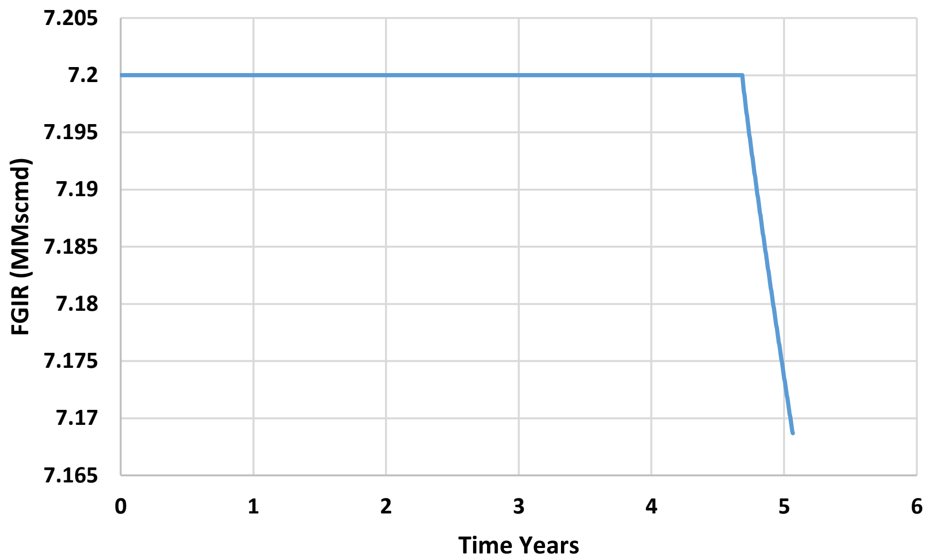

Figure 12. Field gas injection rate vs. time for **4th scenario**

Figure 13 shows the impact of the number of wells on the average FGIR for each case. The average rate for the case in which there are 19 injection wells is more than others. It is obvious since with more injection wells, more gas can be injected. As can be seen from Figure 13, the fewer the number of wells yields the less average gas injection rate.

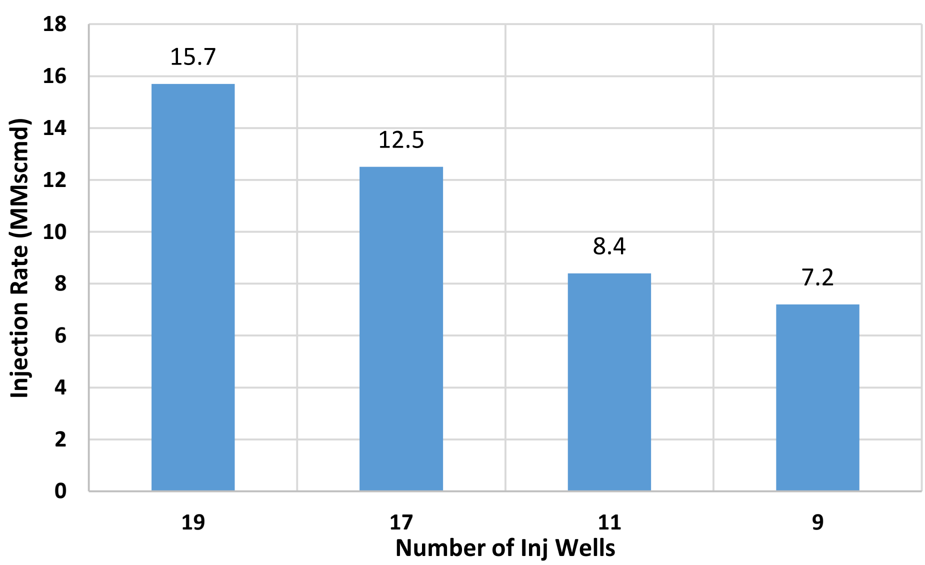

Figure 13. Field gas injection rate vs. number of injection wells.

As can be seen from Figure 14 and 15, FGIR and field average pressure for different scenarios are compared and it can be seen that the second scenario is the optimum case as adequate gas is injected without experiencing a sudden decrease in rate during the preparation time. However, the first case is not acceptable, since after some time the rate decreases and it cannot be kept constant during long time. The lowest injection rates (i.e. scenario #4) causes the lowest field pressure increase which may be the best case due to lower caprock failure risk. But to achieve highest possible efficiency, highest safe injection rate may be chosen which leads us to the second scenario.

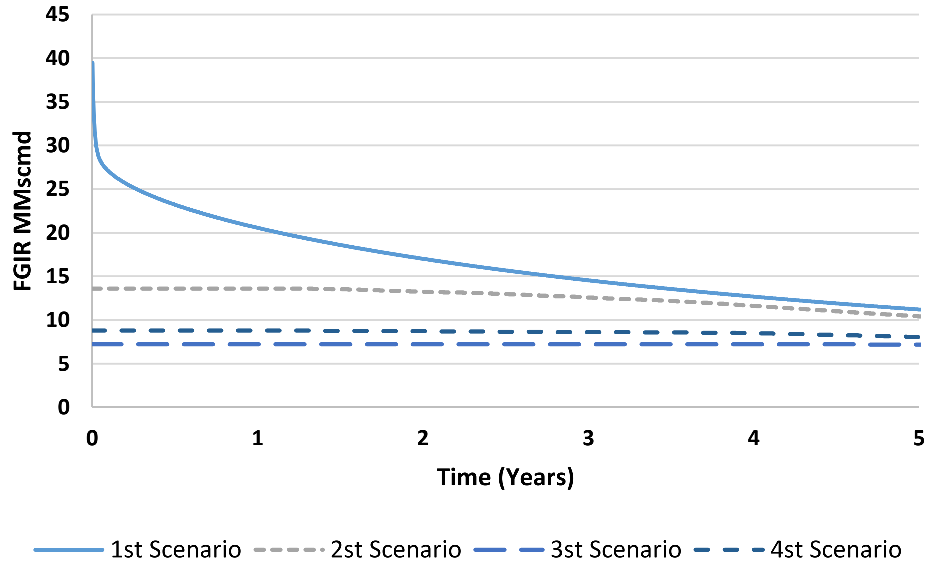

***Figure 14*. Field gas injection rate vs. time for each scenario.**

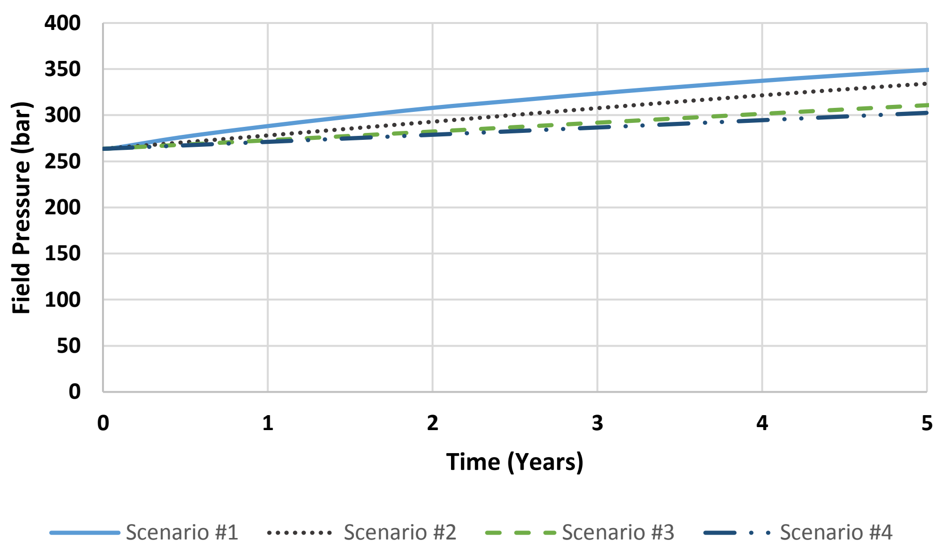

Figure 15. Field average pressure for different scenarios

Figure 16 shows the previous plot in a different way. It clearly shows the impact of the number of wells on the average rate and helps one to find the optimum number of wells for the field. As can be seen the optimum number of wells is approximately 17 wells that is the 2nd scenario as with lower number of wells (i.e. lower cost), the acceptable amount of gas is injected with a constant rate.

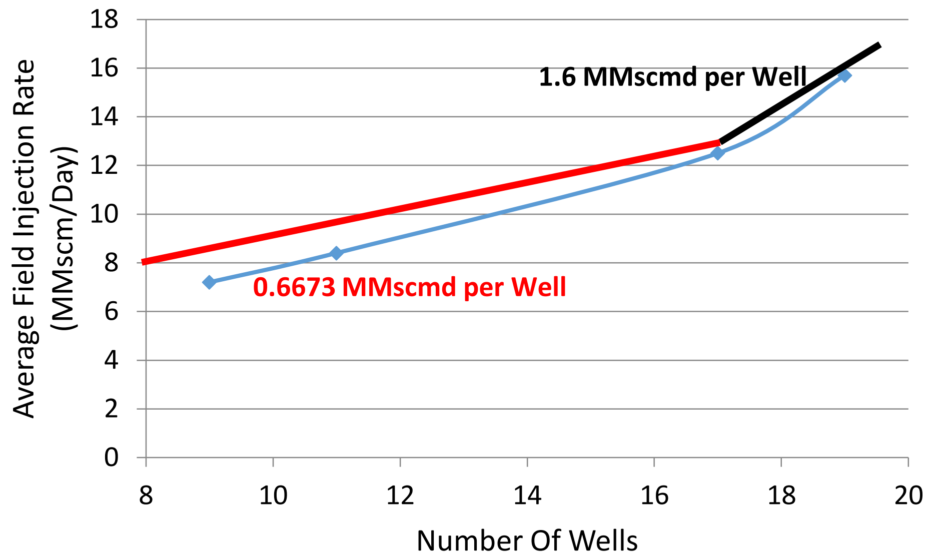

Figure 15*6 *Average field injection rate vs. number of wells for finding the optimum number of wells.

4. Conclusion

It can be figured out that the number of wells could lead to different average rates and field pressure. By considering different factors, the optimum number of wells can be investigated as the number by which high and constant rate is injected with respect to BHP pressure, preparation time and costs of wells. It can be seen in the chart discussed above that there is a sudden change in the slope of plots making the optimum number of wells easier to be found. It could also be seen in FGIR figure that the case in which the rate is constant and is not decreased rapidly is the optimum case since a large amount of gas is injected with constant rate. Paying attention to this subject not only will help us inject as much gas as possible to prepare the field in appropriate target time, but also will greatly and economically reduce costs.

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