# Investigation of Underground Gas Storage in a Partially Depleted Naturally Fractured Gas Reservoir

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**ABSTRACT:** *In this work, studies of underground gas storage (UGS) were performed on a partially depleted, naturally fractured gas reservoir through compositional simulation. Reservoir dynamic model was calibrated by history matching of about 20 years of researvoir production. Effects of fracture parameters, i.e. fracture shape factor, fracture permeability and porosity were studied. Results showed that distribution of fracture density affects flow and production of water, but not that of gas, through porous medium. However, due to high mobility of gas, the gas production and reservoir average pressure are insensitive to fracture shape factor. Also, it was found that uniform fracture permeability distribution enhances communication within reservoir and consequently more pressure support is obtained by water bearing of aquifer. Effect of aquifer on the reservoir performance was studied, and it was found that an active aquifer can reduce condensate drop out around the well bore. On the other hand, water invasion is an important issue which may kill the well. Results showed that use of horizontal wells is superior to vertical wells in order to avoid detrimental effects of active aquifer.*

**KEYWORDS:** *Underground gas storage, Naturally fractured reservoir, Fracture shape factor, Aquifer, Horizontal well.*

## INTRODUCTION

The demand for natural gas depends heavily on weather. Underground gas storage (UGS) is an economical means of balancing demand and supply of natural gas during year.

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Depleted gas and/or oil reservoirs are the best candidates for UGS. These reservoirs contain a cap rock with ensured prevention of gas/oil migration over geological time. Also, it takes advantages of existing wells, surface facilities, and pipeline systems which reduce investment costs. These reservoirs are cheapest to develop, operate and maintain compared to other candidates for gas storage.

A NFR is the one in which fractures have direct effect on fluid flow, reservoir anisotropy, hydrocarbon recovery and storage [1]. The most common model normally used for fracture characterization is dual-porosity and dual-permeability model introduced by *Warren & Root* [2], where the reservoir is considered as the rock matrix and fractures. Flow takes place through fractures and matrix act as fluid source. Fractures may have a positive or negative effect on oil or gas production. Wells in a fractured reservoir have higher deliverability, an important issue in UGS where high rate of injection and especially withdrawal is essential.

In NFR, horizontal wells intersect fractures and drain fractures and reservoir effectively. Horizontal wells can be employed effectively to reduce water conning, near well bore turbulence effect and number of wells, and increase rate of gas or oil production in tight reservoirs. In UGS cases, it is necessary to have a high injection and withdrawal rates during a relatively short time, use of horizontal wells can be very useful [3].

In this work, a partially depleted, naturally fractured gas reservoir was used to study for UGS. A compositional and dual- porosity model of the reservoir was constructed. After history matching, new wells were

defined to speed up the depletion phase. Then, injection/withdrawal (I/W) of gas was defined in the model and effects of fracture parameters, aquifer and horizontal wells were studied.

## NATURALLY FRACTURED RESERVOIRS

NFR contain two porosity systems, that of rock matrix ($\varphi_m$) and of fractures and vugs ($\varphi_f$) [4]:

$$\varphi_m = \frac{\text{Matrix void volume}}{\text{Matrix bulk volume}} \quad (1)$$

$$\varphi_f = \frac{\text{Fracture void volume}}{\text{Total bulk volume}} \quad (2)$$

The fracture parameters, namely fracture permeability ($K_f$), fracture storativity ($\omega$) and fracture conductivity ($\lambda$), can be obtained from welltest analysis. Average reservoir permeability can be estimated from Eq. (3);

$$K_{Average} = [162.6\, q.\mu_o.B_o]/[m.h] \quad (3)$$

The fracture permeability can be estimated from equation (4) [4]:

$$k_f = \frac{k^2}{k_m} \quad (4)$$

Fracture conductivity characterizes the ability of the matrix blocks to flow into fracture system[2]:

$$\lambda = \delta \frac{K_m}{K_f} r_w^2 \quad (5)$$

The shape factor ($\delta$) is related to fracture density. From *Warren & Root* theory [2]:

$$\delta = 4\left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2}\right) \quad (6)$$

A large shape factor implies smaller block size or higher density of fractures. By above equations, shape factor and average matrix block size are related to each other:

$$\delta = [\lambda.K_f]/[K_m.r_w{}^2] \quad (7)$$

$$L = r_w \sqrt{12\, K_m / (\lambda.K_f)} \quad (8)$$

Shape factor and matrix block size can be obtained using fracture conductivity from welltest, matrix permeability from core analysis, and knowing fracture permeability.

Fracture storativity is the fraction of fluid stored in the fracture system [2]:

$$\omega = \frac{(\varphi_f C_f)}{(\varphi_f C_f + \varphi_m C_m)} \quad (9)$$

Using definition of fracture storativity, the fracture porosity can be calculated as follows [4]:

$$\varphi_f = \varphi_m \frac{C_m}{C_f} \frac{\omega}{1-\omega} \quad (10)$$

Fracture compressibility might be different from matrix compressibility by an order of magnitude.

*Table 1: Initial reservoir fluid com.*

| Component | N2 | CO2 | C1 | C2 | C3 | IC4 | NC4 | IC5 | NC5 | C6 | C7+ |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Composition, mole % | 2.655 | 1.56 | 89.159 | 3.804 | 1.166 | 0.234 | 0.334 | 0.16 | 0.117 | 0.22 | 0.591 |

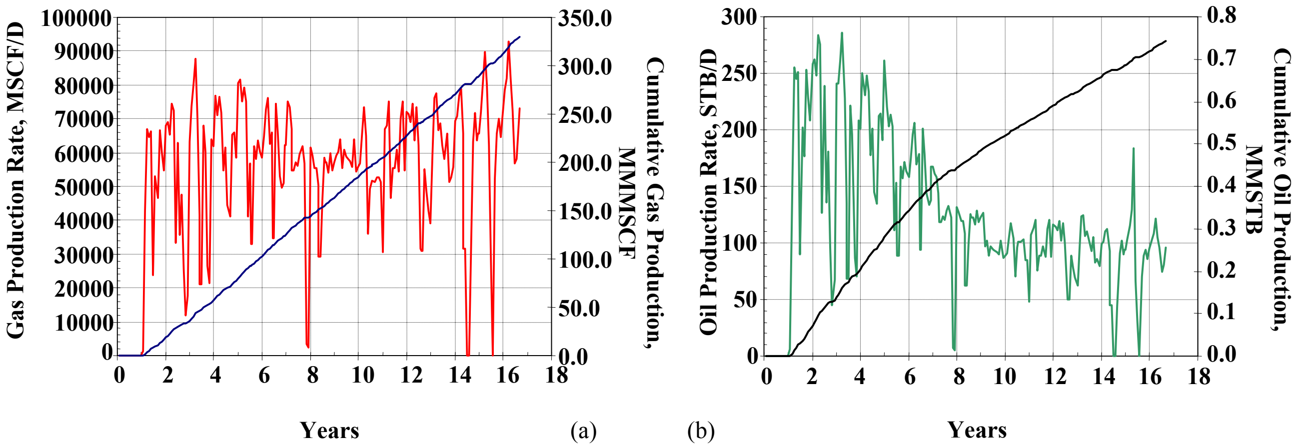


*Fig. 1: Daily and cumulative production history from reservoir (a: gas production; b: condensate production).*

**METHODOLOGY**

In this work, simulation study was conducted on an Iranian gas reservoir using compositional module of GeoQuest software, Eclipse 300, Version 2004 [5]. The reservoir was initially at 3130 psia and 171°F, and contained about 1 TCF original gas in place. It has produced for about 16 years with a single well. Fig. 1 illustrates the daily and cumulative production history from this reservoir.

A comprehensive fracture study revealed that the reservoir contains a network of fractures which contribute to production. The fracture density on top of structure where dip is high is higher than flanks. A dual porosity compositional model was then employed to simulate fluid flow in this reservoir. Average permeability of matrix and fractures is 0.72 and 93 md, respectively. Also, average porosity of matrix and fractures is 0.051 and 0.00085, respectively. The reservoir was discretized into 111×41×10 cells which first half of grids were allocated to matrix blocks and second half of grids to corresponding fractures.

Steps in the simulation study of UGS were described elsewhere [10]. The IRAP RMS 7.5.1 software [6] was used to construct a geological model. Also, the *Peng-Robinson* EOS [7] was used and tuned to predict the phase behavior of reservoir fluid. Tables 1 and 2 show the initial and lumped reservoir fluid and injection gas compositions, respectively. Fig. 2 illustrates phase envelope of reservoir fluid. Three wells (one existing and 2 new wells) were used for I/W. Each cycle took 6 months for injection and 5 months for withdrawal. The injection period in each year was from April 15th to October 15th, and production period was from November 1st to March 31st of next year.

**RESULTS & DISCUSSION**

A total of 6 different scenarios were run to investigate effects of fracture parameters, well direction (horizontal vs. vertical), and aquifer on the performance of UGS. Table 3 summarizes these scenarios

**FRACTURE NETWORK AND RESERVOIR HETEROGENEITY**

***A. Shape Factor***

Fig. 3 shows distribution of sigma in layer 13. The top of reservoir has a higher shape factor. This seems to be reasonable, as the higher dip of layers increases the likelihood of fracturing in the reservoir rock. Based on the real model, distribution of fracture shape factor was taken non-uniform throughout the reservoir. However, as we are dealing with a gas reservoir, using a uniform shape factor throughout the model might be reasonable.

*Table 2:Lumped reservoir fluid composition and Composition of injection gas.*

| Lumped Component | C1-N2 | C2-CO2 | C3-NC4 | IC5-NC5 | FC6 | C7-C11 | C13+ |
|---|---|---|---|---|---|---|---|
| Reservoir Fluid Composition, mole % | 91.814 | 5.364 | 1.734 | 0.277 | 0.22 | 0.525 | 0.066 |
| Injection Fluid Composition, mole% | 97.5 | 2.46 | 0.04 | 0 | 0 | 0 | 0 |

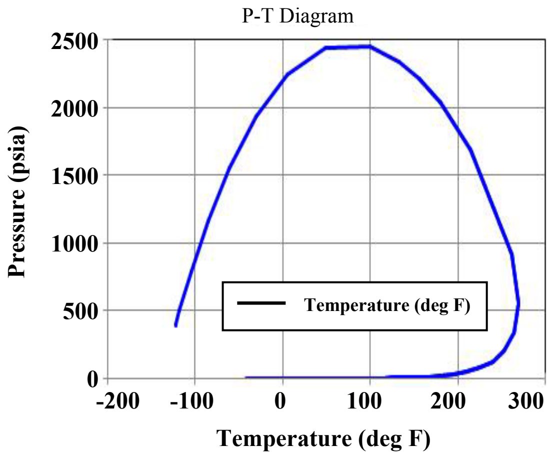


*Fig. 2: Phase envelope of reservoir fluid*

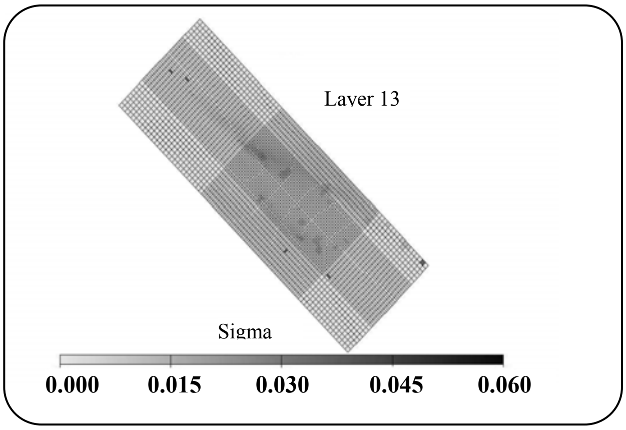


*Fig. 3: Distribution of sigma in Layer 13*

This has the advantage of decreasing simulation run time. To compare the effect of shape factor, 2 models were defined. In the first model (Run 015), sigma distribution map based on fracture study was used; in second model (Run 012), a uniform sigma value (0.01, which corresponds to a block dimension of 3.5 meters in all directions) was used throughout reservoir. Figs. 4 and 5 compare gas and water production rate in these two models, respectively. According to Fig. 4, the gas production is insensitive to sigma. The same result was obtained for and reservoir average pressure. The high mobility of gas makes it easy to flow through fracture network to well bore. Generally, shape factor is more important in oil reservoirs than gas reservoir [8]. On the other hand, due to lower mobility, water production from reservoir may be affected by the distribution of fracture density. Higher water production in model 015, shown in Fig. 5 confirms this idea. Higher density of fractures around wells in case 015 causes breakthrough of water, while the uniform case 012 produced no water. In other words, shape factor affects movement of water through porous medium as a fluid with lower mobility more than gas. As there is no aquifer defined in these 2 models, the produced water origin is from connate water.

***B. Fracture Permeability***

Fig. 6 shows distribution of fracture permeability in layer 13. To test the effect of fracture permeability on the reservoir performance for UGS, a case (Run 018) was run with uniform fracture permeability of 90 md, which is the mean value of fracture permeability in the model, and the results were compared with Run 015. Figs. 7-10 show the reservoir gas production, average pressure, and GOR and water production rate, respectively.

According to Fig. 7, there is a minor difference in gas production rate and both models can produce with the anticipated target rate. But, Fig. 8 shows a considerable difference in reservoir average pressure (FPR), especially in injection-withdrawal cycles.

In uniform fracture permeability case (018), the FPR is higher. The idealistic uniform fracture permeability distribution enhances communication within reservoir and consequently more pressure support is obtained by water bearing cells.

As can be seen in Fig. 6, many water bearing cells below gas-water contact have low fracture permeability that makes them less effective in pressure maintenance of reservoir. In the case with a uniform permeability of fracture for these cells, they can effectively contribute in pressure maintenance. In addition, higher average pressure

***Table 3: Summary of different scenarios in this work.***

| Case | Sigma | Analytical Aquifer | Horizontal Wells | Fracture Permeability |
|---|---|---|---|---|
| 011 | constant 0.01 | Yes | No | Map |
| 012 | constant 0.01 | No | No | Map |
| 015 | Map | No | No | Map |
| 015a | Map | Yes | No | Map |
| 017 | Map | Yes | Yes | Map |
| 018 | Map | No | No | constant 90 md |

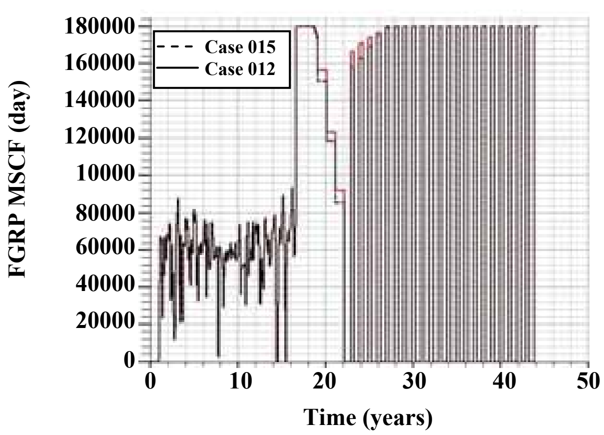


***Fig. 4: Comparison of gas production rate for models 012 and 015.***

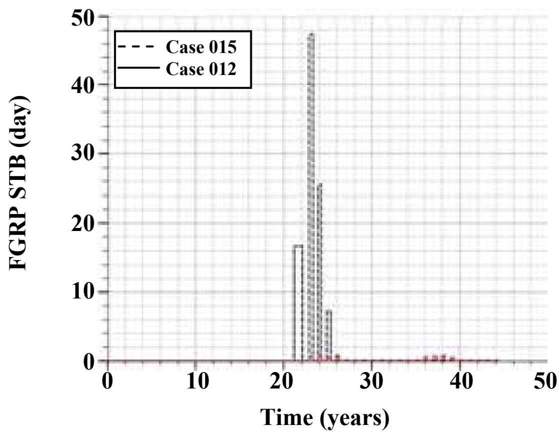


***Fig. 5: Comparison of water production for models 012 and 015.***

causes less GOR, which is reflected in Fig. 9. Also, higher water production shown in Fig. 10 indicates that water flow from water bearing cells is faster.

***C. Fracture Porosity***

A model with constant fracture porosity (case 020) was run and compared with case 015. The constant porosity value was selected so that the initial gas in place in fractures was kept unchanged. As just 4.5% of original gas in place was stored in the fractures, the main act of fractures is to enhance total permeability and communication between matrix blocks rather than reservoir storativity. The results of these cases are not very different.

## ANALYTICAL AQUIFER EFFECT

The *Carter-Tracy* analytical aquifer model [9] was set in the dynamic model. Properties of analytical aquifer are given in Table 4. Active aquifer can reduce ultimate recovery of a gas reservoir, and impose problems in UGS process like reducing reservoir volume in successive I/W cycles, increasing compressor power, and reducing relative permeability to gas [10].

To study the effect of aquifer on UGS performance, two models (case 011 and case 012) were run and their results were compared. Case 011 has an analytical aquifer which its properties are given in Table 4, and case 012 does not have an aquifer. The results show that reservoir average pressure, GOR and water production are very different in two models. In case 011, pressure increases continuously in successive I/W periods. However, in case 012, the rate of pressure increase is much less, as can be seen in Fig. 11. Maintaining reservoir at higher pressure during successive I/W cycles by the act of an active aquifer leads to less condensate drop out in reservoir. As a result, the gas-oil ratio will be lower. Fig. 12 compares condensate saturation near the well bore for cases 011 and 012. It is clear from this figure that an active aquifer can reduce condensate drop out around the well bore. Such a high water cut kills

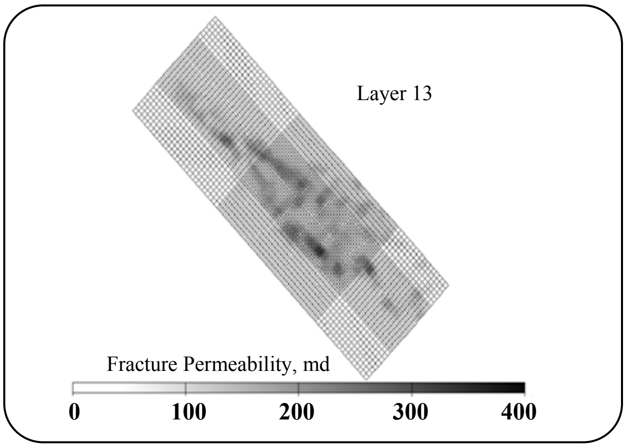


*Fig. 6: Distribution of fracture permeability in different layer 13.*

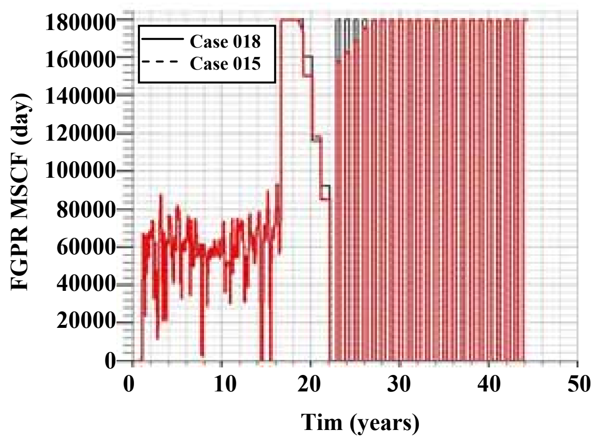


*Fig. 7: Comparison of reservoir gas production for models 0.15 and 0.18.*

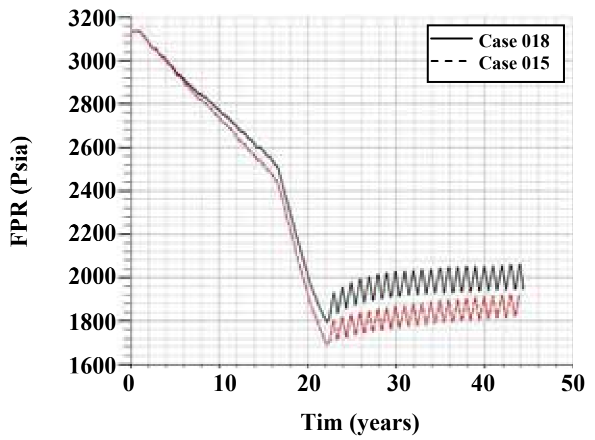


*Fig. 8: Comparison of reservoir average pressure for models 0.15 and 0.18.*

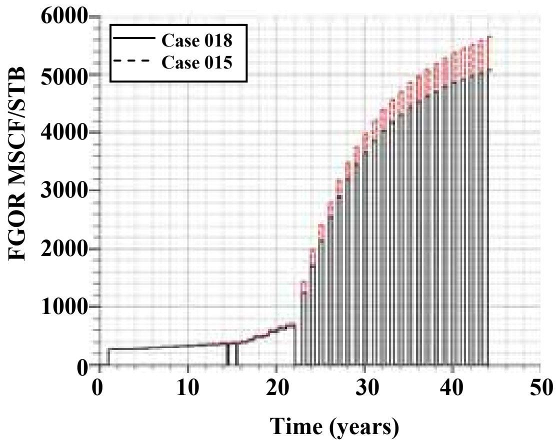


*Fig. 9: Comparison of GOR for models 015 and 018.*

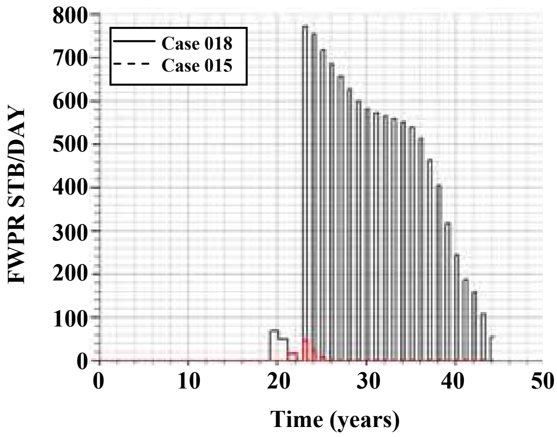


*Fig. 10: Comparison of water production rate for models 015 and 018.*

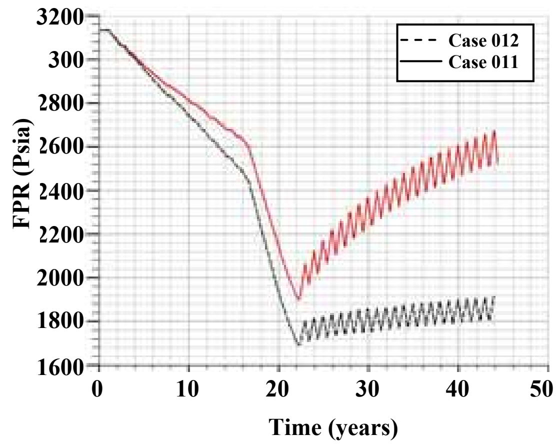


*Fig. 11: Comparison of reservoir average pressure for models 011 and 012.*

***Table 4: Properties of analytical aquifer.***

| Permeability, md | Porosity, fraction | Water & Rock Compressibility, 1/psi | Inner Radius,ft | Thickness,ft | Angle, Degree |
|---|---|---|---|---|---|
| 5 | 0.05 | 0.0000035 | 50000 | 1000 | 360 |

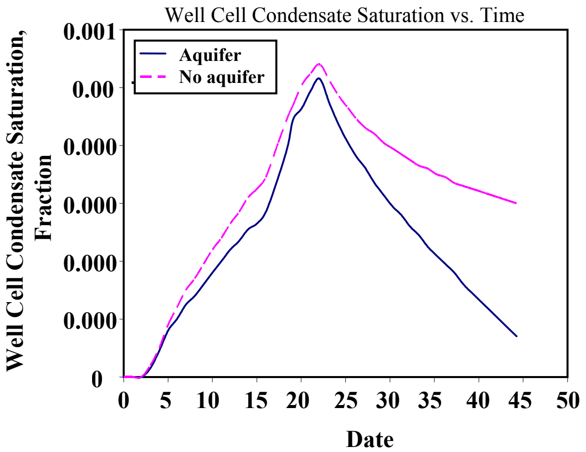


***Fig. 12: Condensate saturation near the well block for cases 011 and 012.***

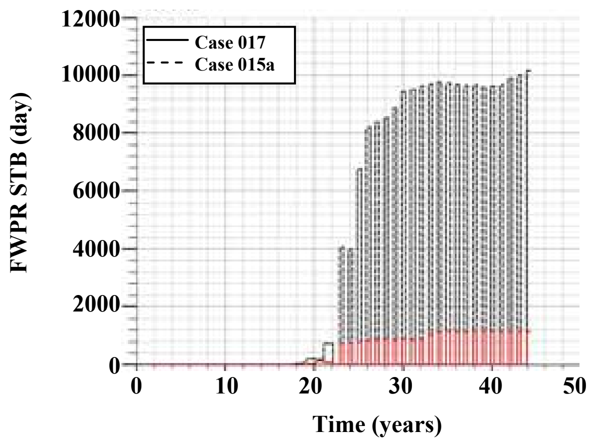


***Fig. 13: Water production in reservoir with vertical wells (case 015a) and horizontal wells (case 017)Table 1-Initial reservoir fluid composition.***

the well due to water invasion. One of the solutions is to use horizontal well instead of vertical wells, discussed in the next section.

## HORIZONTAL WELLS

As mentioned before, horizontal wells can intersect more fractures and provide more area for gas injection/withdrawal, as well as reducing the risk of high water cut and conning problem during UGS. Two cases were run to study and observe the role of horizontal wells and compare reservoir performance with vertical wells (case 015a) and horizontal wells (case 017), completed near the crest of reservoir. Water production in these cases are plotted and compared in Fig. 13. According to this figure, water production reduced considerably in the case 017 with horizontal wells. So, for this reservoir, use of horizontal wells is superior to vertical wells.

## CONCLUSIONS

Water production from reservoir is affected by the distribution of fracture density; Fracture shape factor affects movement of water through porous medium, but not for gas; Active aquifer can reduce condensate drop out around the well bore; Use of horizontal wells is superior to vertical wells in this case.

## Abbreviations

| | |
|---|---|
| EOS | Equation of State |
| FPR | Field Pressure |
| GOR | Gas Oil Ratio |
| I/W | Injection/ Withdrawal |
| NFR | Naturally Fractured Reservoir |
| UGS | Underground Gas Storage |

## Nomenclature

| | |
|---|---|
| $B_o$ | Oil formation volume factor, bbl/STB |
| $C_m$ | Compressibility of matrix, 1/psi |
| $C_f$ | Compressibility of fracture, 1/psi |
| K | Average reservoir permeability from welltest analysis, md |
| $K_m$ | Average matrix permeability from core analysis, md |
| $K_f$ | Fracture permeability, md |
| L | Matrix block size, ft |
| h | Producing thickness, ft |
| m | Slope of pressure build-up data versus log of time in Horner plot, dimensionless |
| q | Flow rate, STB/d |
| $r_w$ | Well bore radius, ft |
| $\lambda$ | Fracture conductivity, dimensionless |

| | |
|---|---|
| $\mu_o$ | Oil viscosity, cp |
| $\varphi_f$ | fracture porosity, dimensionless |
| $\varphi_m$ | Matrix porosity, dimensionless |
| $\delta$ | Shape factor, 1/ft$^2$ |
| $\omega$ | Fracture storativity, dimensionless |

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