Carbon Dioxide Injectivity in Brine Reservoirs Using Horizontal Wells

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Abstract

A simulation study of carbon dioxide injectivity in brine-saturated reservoirs was conducted to determine the feasibility of brinefield sequestration in the Ohio Valley. Reservoir and fluid properties similar to those found in Northern West Virginia and Eastern Ohio were used. All simulations were conducted with the equation of state compositional simulator UTCOMP.

Vertical wells provide insufficient injectivity. Horizontal injectors can greatly improve injectivity and storage capacity. In a layered, thicker reservoir the vertical position of the horizontal well is very important. Injectivity of 4000 tons per day (total output from a 250 MW power plant) can be achieved with horizontal wells in typical Ohio Valley sandstone formations.

Introduction

Deep saline aquifers of East Ohio and Northern West Virginia are attractive for CO_2 sequestration because of their storage capacity, existing geological characterization, and proximity to CO_2 emitting power plants (1). Moreover, the disposal of hazardous and non-hazardous waste in deep saline formations is a widely accepted practice, with over 400 injection wells disposing more than 75million cubic meters of industrial waste in the United States (2).

The first CO_2 sequestration field-test in a saline aquifer started in 1996 in the Sleipner West Field, in the North Sea. The operator, Statoil, started injecting CO_2 at a rate of 1 million tons of CO_2 /year in the Utsira sand. The Utsira sand reaches a maximum thickness of 300 m in the Sleipner area and is 800 m below the seabed. It has porosities ranging from 27-31% and a very large permeability of 3500mD (3).

Injectivity is a key variable for sequestration in a brine field. A reservoir pilot injectivity test is generally needed to provide a direct measurement of the reservoir injectivity. However, the results of a single well are not conclusive for the entire field. A single (pilot) well injectivity test can provide only limited, indirect information about a full field performance, because injectivity can vary considerable for different wells in the same reservoir and even for the same well under different operating conditions (4). Differences in permeabilities around the well, as well as local heterogeneities, combined with various operating practices are among the reasons that a specific well injectivity test may differ from the average reservoir injectivity.

Compositional simulation is a potentially attractive alternative for reservoir injectivity tests. A compositional simulator is capable of incorporating reservoir forces and processes in injectivity calculations, and can account for heterogeneity, dispersive mixing, capillary forces, viscous instability, phase behavior, and rock/fluid compressibility. Geostatistical techniques have advanced, making it possible to generate permeability fields that are consistent with measured core data and well logs. More rigorous modeling of heterogeneity combined with incorporation of physical mechanisms into the simulator may reduce the uncertainty in the interpretation of reservoir pilots and improve our ability to model injectivity and to extrapolate the results of a single well test to other operating conditions and locations in the field.

The efficiency of a carbon sequestration project depends also on operating conditions, type of injection wells (horizontal vs. vertical), length of horizontal injectors, reservoir properties, and fluid/fluid and fluid/rock interactions. In this work the primary motivation was to assess injectivity in low permeability brine saturated with anomalous fracture gradients as found in Northern West Virginia, by comparing vertical and horizontal injectors in various field configurations. A compositional simulator (UTCOMP), developed at University of Texas at Austin, which has been modified (2) for brine field sequestration, was used in this study (5).

Simulator Description

UTCOMP is an isothermal, three-dimensional, equation of state (EOS) compositional reservoir simulator. The formulation of UTCOMP is based on the volume-balanced approach with some modifications, which was detailed in the work of Chang (5). Four-phase flow behavior can be modeled using UTCOMP. These phases are numbered as (1) aqueous phase, (2) oil phase, (3) gas phase, and (4) a second, nonaqueous liquid. Water is allowed only in the aqueous phase and hydrocarbon components are allowed to be dissolved in the aqueous phase. The nonaqueous fluid properties are modeled using the Peng-Robinson (PR) EOS (6). Several relative permeability model options are available.

For the discretization of the component mass-balance equation, a higher-order finite-difference method, as well as the conventional one-point upstream weighting scheme, is used for numerical dispersion and grid orientation control.

Physical dispersion is modeled using the full dispersion tensor, and the elements of the dispersion tensor contain contributions from two sources: molecular diffusion and mechanical dispersion. Either constant bottomhole pressure or constant flow rate well conditions can be specified for either vertical or horizontal wells. Well rates and transmissibilities are treated explicitly. Constant or variable time stepping can be chosen.

A variable-width cross-section option is also available, which accommodates the simulation of two-dimensional reservoir cross sections with radial flow near injection and production wells and any arbitrary two-dimensional geometry between wells using either pressure or rate-specified boundary conditions.

To perform horizontal wellbore calculations, modification were made to allow the representation of wells parallel to either x or y-axis. For horizontal well calculations the simulator assumes negligible pressure drops along the well (7).

UTCOMP was further modified for CO_2 sequestration. A correlation for the PR EOS parameter for water was added to the code; it computes the water vapor pressure within 1%. Also, the density of the aqueous phase is computed by the PR EOS. The critical volume of water has been adjusted to fit the viscosity of water at high pressure and temperature. Finally, a binary interaction coefficient between water and CO_2 for the PR EOS has been added to the base input file (2).

Project Background

The National Energy technology Laboratory is studying the feasibility of sequestering CO_2 in brine saturated formations located in the vicinity of CO_2 producing power plants in West Virginia, Ohio and elsewhere. Therefore, the simulations described in this paper are for a generic brine field sequestration project with formation properties similar to those found in this region. Due to the low permeability encountered in some of these formations horizontal wells may be needed to increase the injectivity (8). In this paper injectivity is defined as the CO_2 injection rate at a specified pressure, lower than the fracture pressure. Thus, all simulations were performed using constant injection pressure.

Three-dimensional simulations (3-D) were performed using a variable grid, 6800x6800ft pattern with either a vertical, or one or two horizontal injector wells in the middle of the pattern. If two injectors were used, they formed a “plus” sign within the square of the pattern. A constant pressure boundary surrounded the pattern. The completion of the wells and the physical properties of the reservoir can be seen in Table 1. The horizontal injection well length was varied between 1400ft and 3000ft. Because of the symmetry of the pattern, all runs were performed on a quarter of the pattern. A 30x30x10 grid was used to do these runs, representing a 3400x3400x200-ft reservoir. The injection pressure was determined based on fracturing pressure gradients found in Northern West Virginia formations (9).

Table 1. 3-D base case description.

Pattern Dimensions (x, y, z)	6800, 6800, 200 ft
Number of Grid Blocks	30x30x10
Initial Pressure	2200 or 3700 psi
Initial Water Saturation	1.0
Injection Pressure	3300 or 5400 psi
Injection Time	5 years
Total Time	5 or 15 years
Aquifer Temperature	140 or 220°F
Porosity	0.11
Average Permeability	10 to 50 mD
Depth	5500 and 9000 feet
Relative Permeability Model	Corey
Residual Water Saturation	0.2
Residual Gas Saturation	0.1
Water endpoint relative permeability	1.0
Gas endpoint relative permeability	0.9
Water relative permeability exponent	3.25
Gas relative permeability exponent	2.9

Simulation Results and Discussions

The simulator was very helpful in understanding the process of CO_2 injection using vertical injectors and horizontal injectors of various lengths in different configurations and placed at different depths in the formation. Comparisons with real, field injectivity cannot be made at this time, because no wells have been drilled.

Initially, runs were performed using vertical injectors completed along the formation thickness. Reduced injectivities have been observed for the interval of permeabilities and thickness considered. Thus, horizontal injectors were seen as a way to improve CO_2 injection rate.
Figure 1 shows the injectivity for one, 1400-ft horizontal injector placed at various depths and fracture gradients of 0.6 psi/ft in a homogeneous formation with a thickness of 200 ft and a permeability of 10mD. The injectivities in the figure are average injectivities for the period of time between the start of injection and the time when the CO_2 front reaches the constant pressure boundary. The results show that a horizontal injector placed at the middle depth offers the best injectivity. However, due to gravity override, typical for CO_2 injection in a homogeneous formation, we chose layer six, just under the middle depth, for the simulations represented in Figures 2-4.
Next, horizontal injector lengths of 1400 to 3500 ft were considered. Figure 2 shows that injectivities are increase linearly with injector length. Simulations predict that even in a relatively low permeability formation with an average thickness of 200ft, thousands of tons of CO_2 can be disposed. For example at a depth of 9000 ft, one horizontal well with a length of 3500 ft would suffice the disposal capabilities of a small powerplant (250 MW), producing 1.5 million tons of CO_2 per year. For formations with higher permeabilities, higher injection rates are possible, as can be seen in Figure 3. It can be also concluded that for a homogeneous reservoir, permeability can be considered a scalable reservoir property. For the heterogeneous formation case, the same may not apply. Moreover, it has been shown that heterogeneous formations exhibit lower injectivities (10).

The value of the fracture gradient is of extreme importance for determination of permissible rates and pressures for the injection of CO_2. It was observed that fracture gradients in Northern West Virginia have an anomalous behavior. Fracture gradients as high as 1.1psi/ft were measured by service companies (8). Consequently, simulations were performed for higher-pressure gradients, as illustrated in Figure 4. It can be seen that much higher injection rates for CO_2 can be projected if measurements indicate that the formation has a higher fracturing pressure.

Since the focus of this work is on CO_2 injectivity in low permeability and thin formations, runs were performed with perpendicular horizontal injectors forming a “plus” sign in the middle of the pattern. The injectivity of these two injectors of various lengths was compared to that of one injector, in a thin, 10-ft formation with an absolute permeability of 10mD. Evidently, the use of two injectors increases the injectivity as it is shown in Figure 5. However, in the field, economic considerations can dictate the length and configurations of horizontal injectors.

Figure 6 and Figure 7 show contours of CO_2 saturation for one injector and two perpendicular injectors, for a quart of the pattern at different times during the CO_2 injection. It can be seen that the two injector produce a more uniform, symmetric front. This allows a better areal displacement of the brine.

Conclusions

Horizontal well can significantly increase CO_2 injectivity in brine formations of lower permeability. Injection rates can be increased 4-5 times over that for a vertical for realistic injector lengths with no increase in injection pressure. For deeper formations, or Northern West Virginia formations with higher than normal fracture gradients even higher injection rates can be achieved.

Using two perpendicular injectors in the center of the pattern adds additional injectivity and produces a better areal sweep efficiency.

In thicker formations, the placement of the horizontal injectors must be considered for maximum injectivity and conformance (areal and vertical sweep).

The results show that CO_2 injection rates of 4000 tons/day, corresponding to the emissions of a small power plant can be achieved using a proper length for horizontal injectors, even in low permeability, homogeneous formations, such as those considered in this study.

These simulations did not include the effects of reservoir heterogeneity and well stimulation that can have a very large effect on the rate of CO_2 injected. Other effects that can alter injectivity and have not been simulated include relative permeability and CO_2 reaction with formation minerals and brine.

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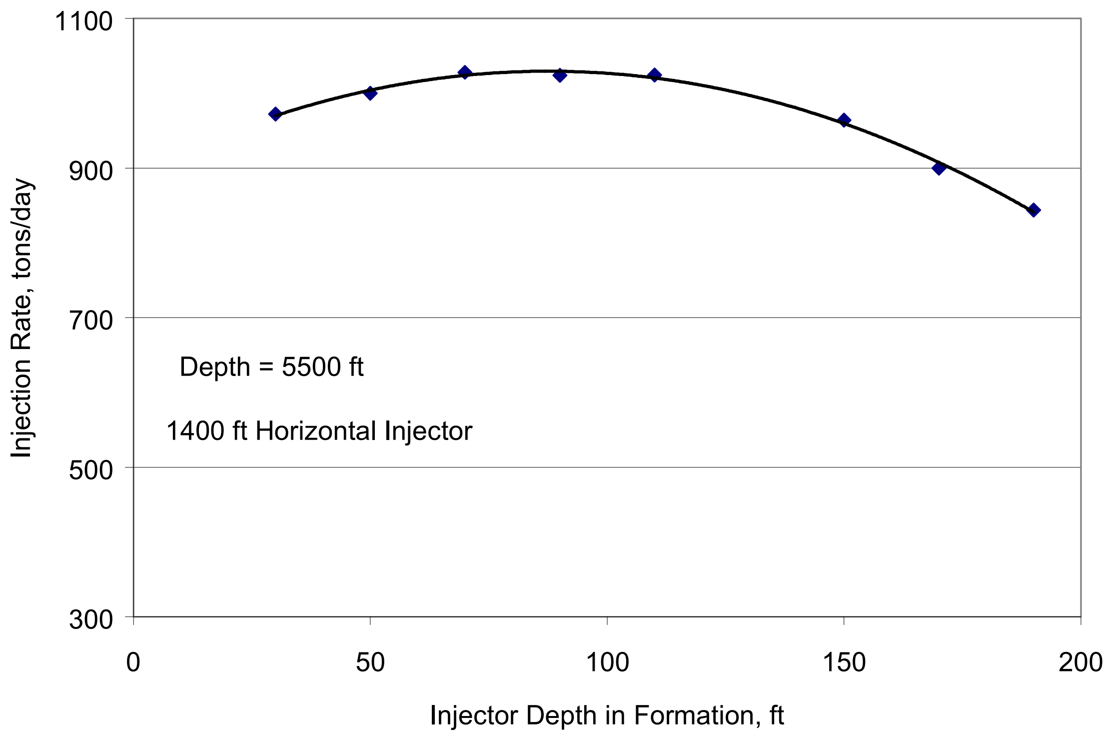

Figure 1. CO_2 injectivity vs. horizontal well position in the formation.

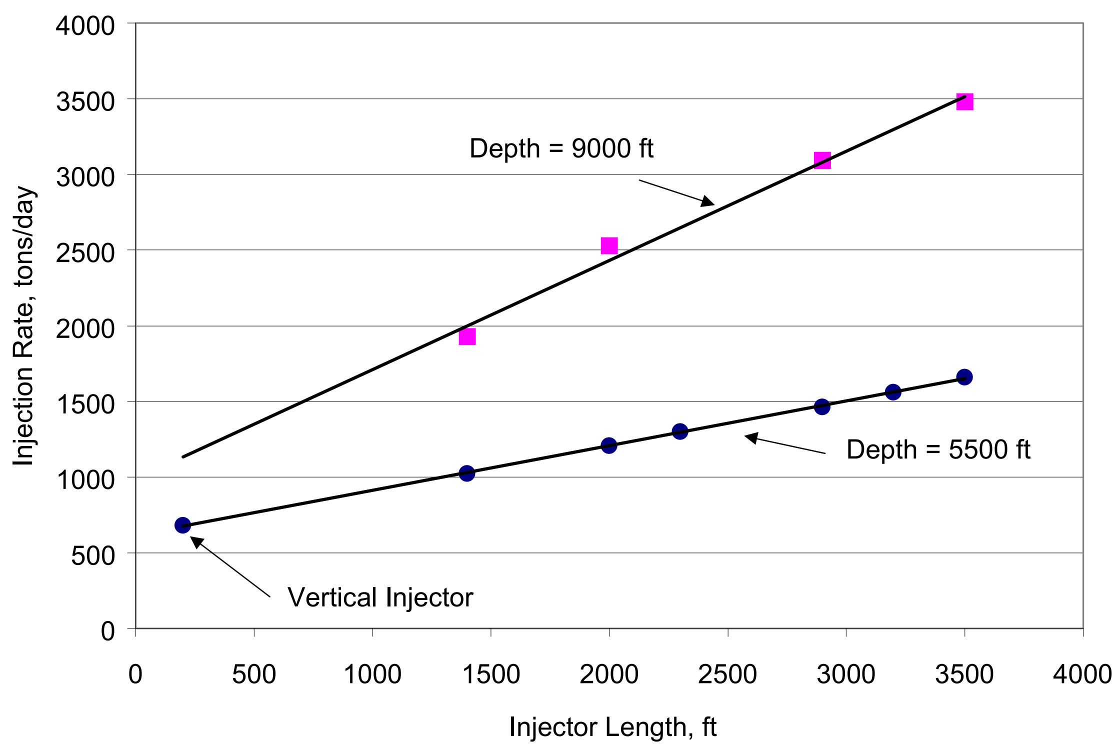

Figure 2. CO_2 injection rate vs. horizontal injector length.

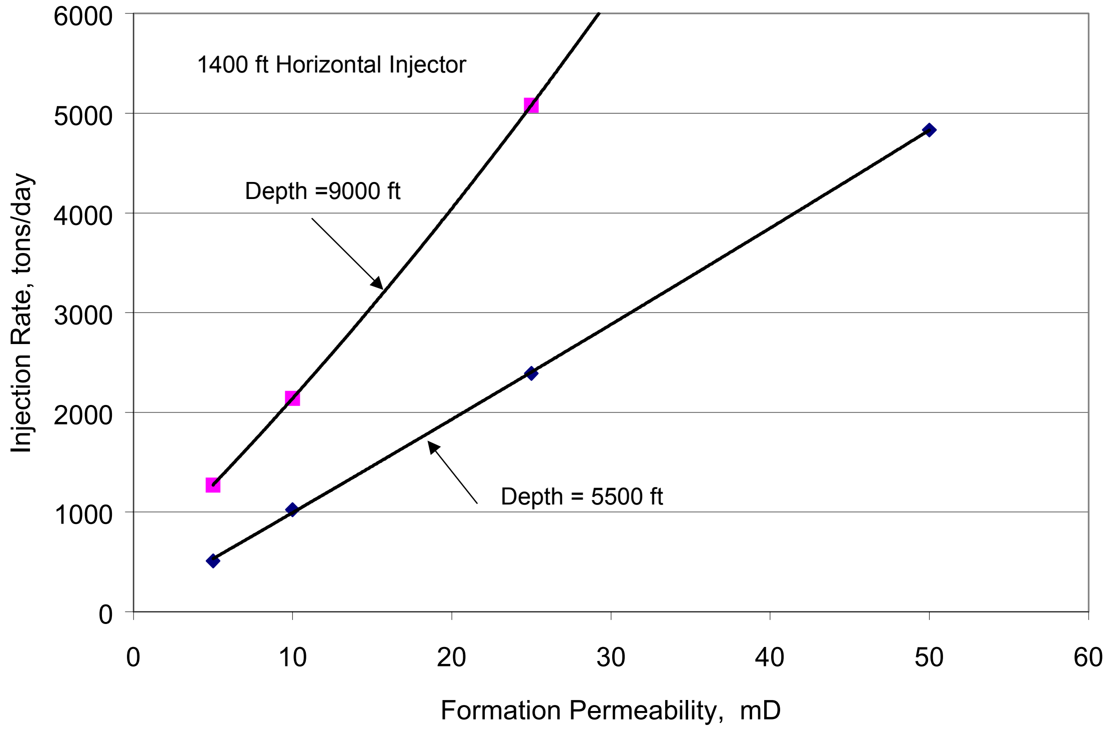

Figure 3. Influence of reservoir permeability on injection rate.

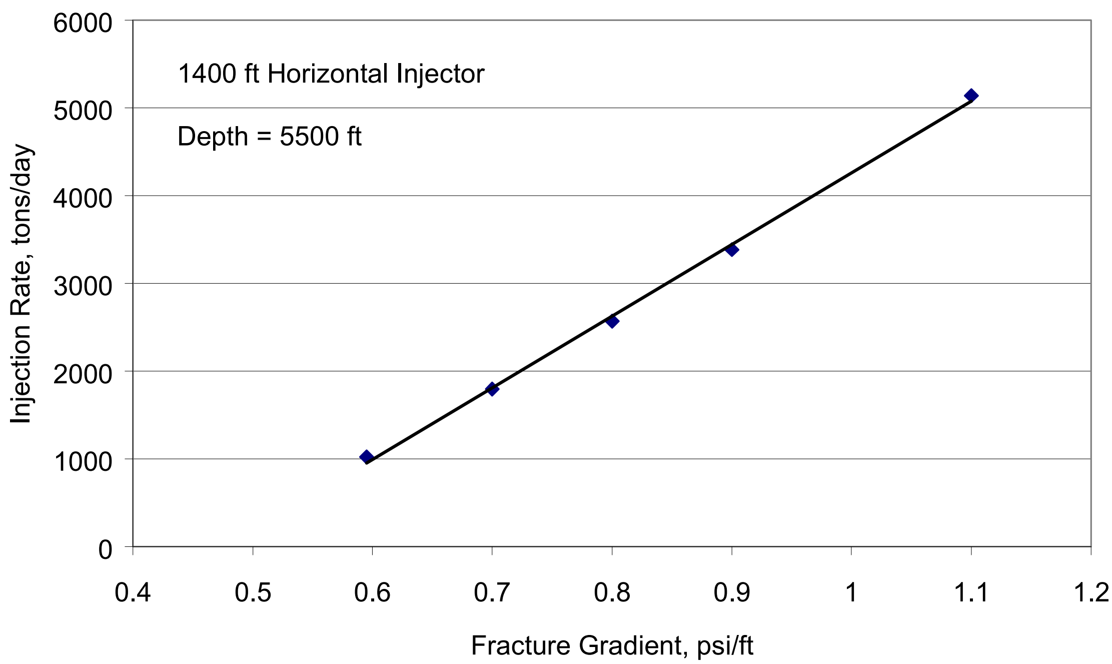

Figure 4. CO_2 injection rate vs. fracture pressure gradient.

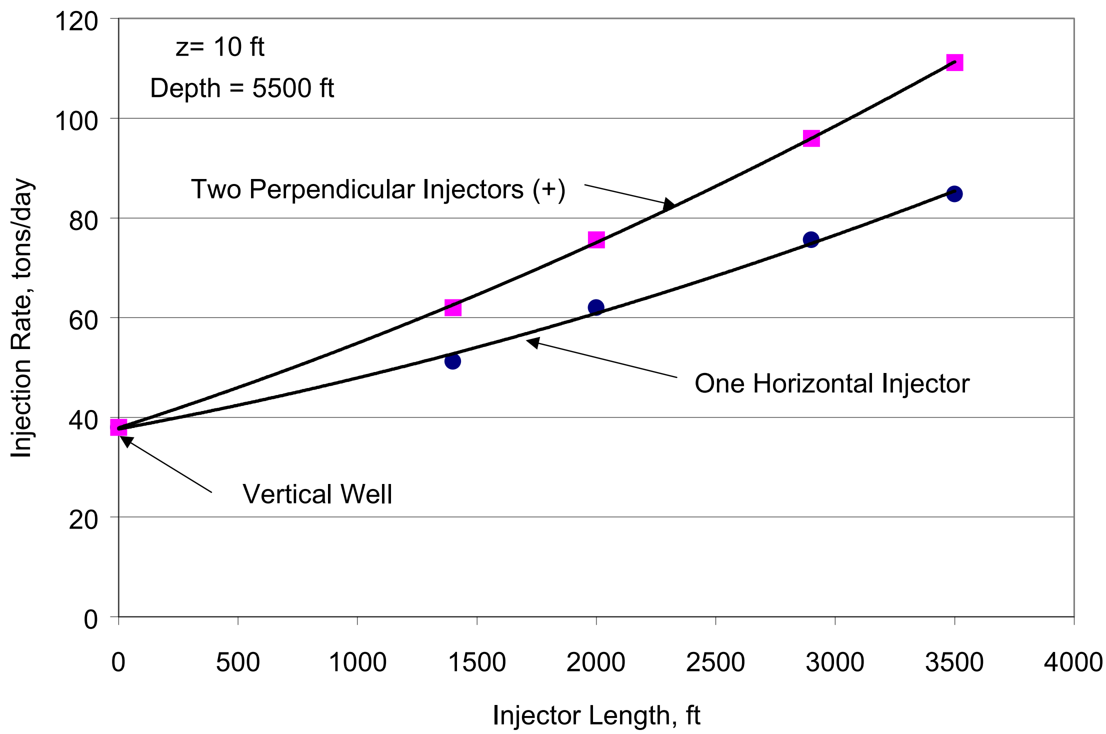

Figure 5. Injectivity comparison: one horizontal injector vs. two perpendicular injectors (forming a plus sign).

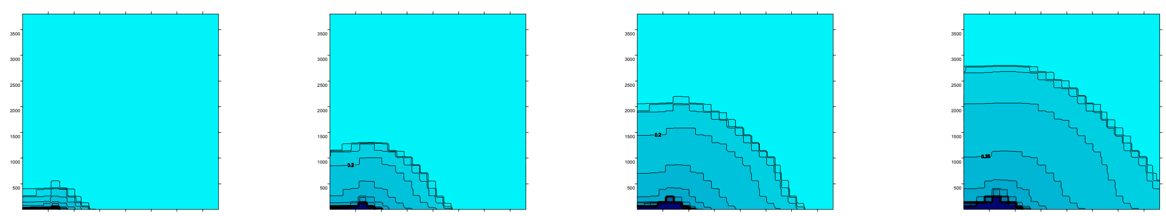

Figure 6. CO_2 injection fronts for quarter of pattern for one horizontal injector at 1, 5, 10 and 15 years.

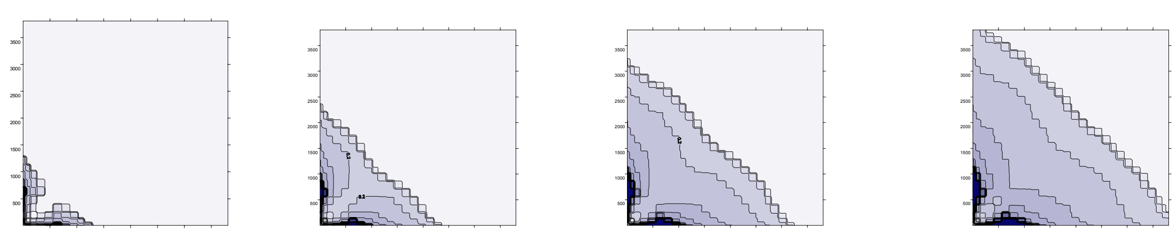

Figure 7. CO_2 injection fronts for a quarter of pattern for two perpendicular, 700ft injectors at 1, 5, 10 and 15 years.