Example Problem CO2-4

Contrasting Pressure- and Flow-Controlled CO_2 Injection Wells

Abstract: *The rate of CO_2 injection into saline reservoirs is often limited by the local fracture pressure gradient in the effort to meet regulatory requirements and to avoid fracturing the reservoir or caprock. This problem demonstrates the use of the coupled well model in STOMP-CO2, in which the user can specify both an injection rate and a maximum injection pressure. CO_2 is injected into a layered saline reservoir with layers of varying permeability and scenarios of pressure-controlled and flow-controlled CO_2 injection are investigated.*

Problem Description

This problem considers the injection of CO_2 under supercritical conditions ($scCO_2$) into a layered saline formation. The model contains 24 reservoir layers and 1 layer for the caprock. $scCO_2$ is injected at a specified constant rate over the entire thickness of the reservoir. Injection of CO_2 into the system is specified using the coupled well model, which allows the user to specify both an injection rate and a maximum injection pressure. This well model will solve for the injection pressure if the injection rate can be met without exceeding the maximum injection pressure. Otherwise, the well is considered to be pressure controlled and the injection rate becomes the unknown at the maximum injection pressure.

The grid is specified in cylindrical coordinates with the grid spacing beginning at 16.9257 ft and increasing by a factor of 1.3 to a horizontal extent of 10,000 ft (specified by 20 nodes). There are 25 layers in the vertical (z) direction representing 24 reservoir layers of variable thickness and 1 50-ft thick caprock layer representing a total thickness in the model of 630 ft. Figure 1 shows the grid for a 2D slice of the cylinder.

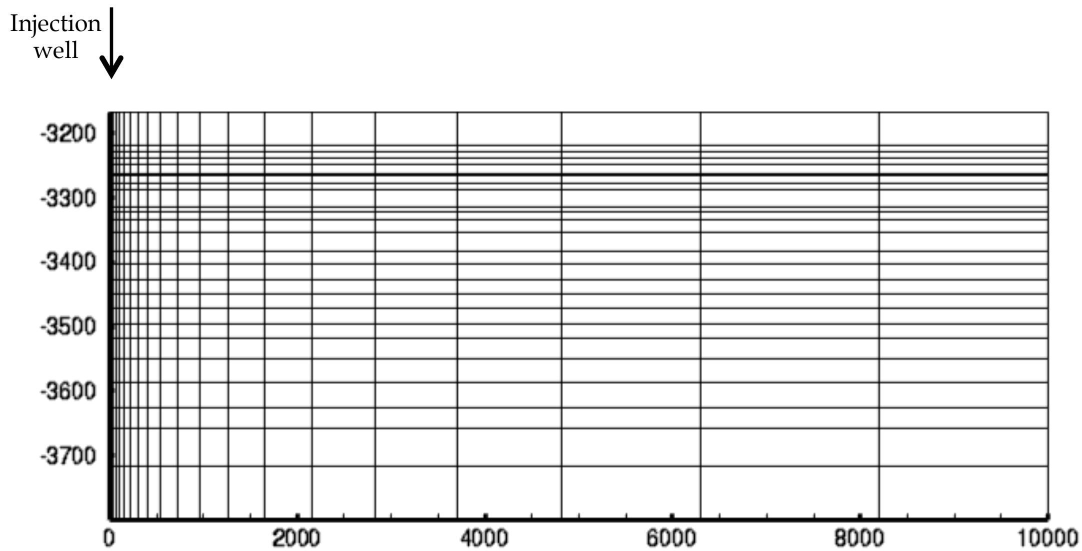

Figure 1. Grid for 2D (xz) slice of cylindrical domain

Hydrologic properties were assigned to each model layer to represent a reservoir that has been characterized with data from one well providing spatial variability in the vertical direction but lacking information to describe variability in the horizontal direction. The geophysical well log data is at a resolution of 0.5 ft. The model layers were defined by upscaling the well log data to 24 model layers representing zones with similar hydrogeologic properties deduced from the geophysical well logs. Figure 2 shows the vertical permeability distribution in the model. Note that the layers have variable thickness, representing the geologic interpretation of the well log data. The material properties for each reservoir layer are assigned in the *Mechanical Properties Card* and *Hydraulic Properties Card*.

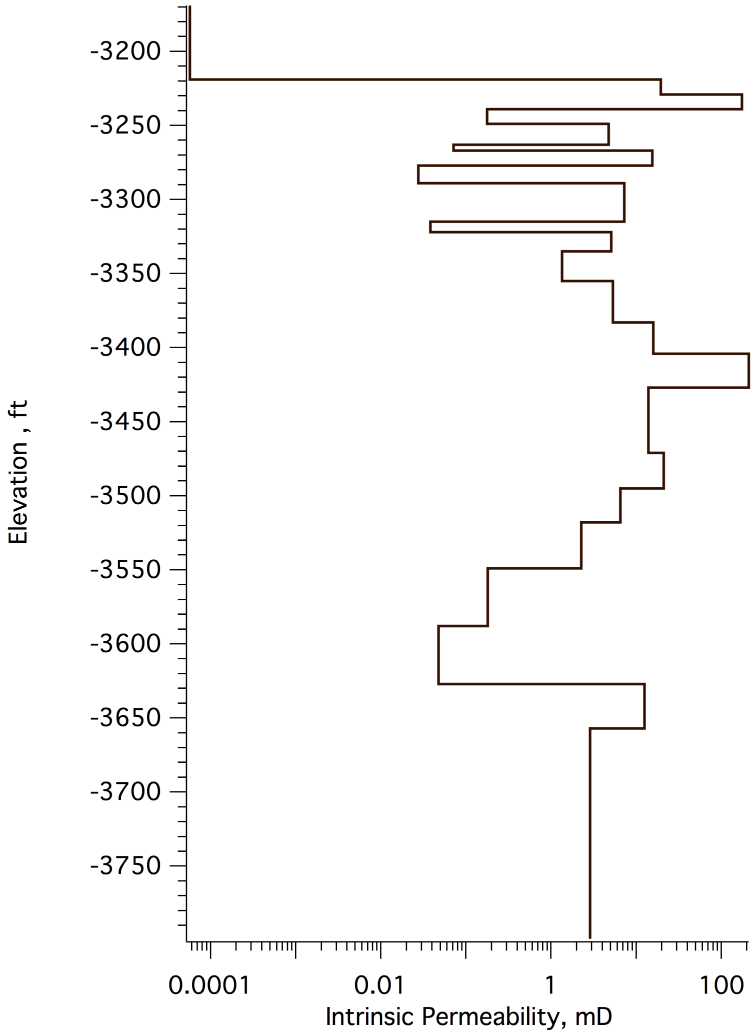

Figure 2. Vertical distribution of intrinsic permeability assigned to model layers

~Mechanical Properties Card
caprock,2650,kg/m^3,0.07,0.07,Compressibility,7.42E-10,1/psi,,,constant,1,1,
Reservoir24,2650,kg/m^3,0.13,0.13,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir23,2650,kg/m^3,0.18,0.18,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir22,2650,kg/m^3,0.09,0.09,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir21,2650,kg/m^3,0.10,0.10,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir20,2650,kg/m^3,0.08,0.08,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir19,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir18,2650,kg/m^3,0.09,0.09,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir17,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir16,2650,kg/m^3,0.08,0.08,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir15,2650,kg/m^3,0.10,0.10,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir14,2650,kg/m^3,0.08,0.08,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir13,2650,kg/m^3,0.10,0.10,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir12,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir11,2650,kg/m^3,0.19,0.19,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir10,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,

```
Reservoir9,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir8,2650,kg/m^3,0.13,0.13,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir7,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir6,2650,kg/m^3,0.09,0.09,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir5,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir4,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir3,2650,kg/m^3,0.15,0.15,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir2,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir1,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,

~Hydraulic Properties Card
caprock,5.70E-05,md,5.70E-05,md,5.70E-05,md,
Reservoir24,1.94E+01,md,1.94E+01,md,1.94E+01,md,
Reservoir23,1.75E+02,md,1.75E+02,md,1.75E+02,md,
Reservoir22,1.77E+00,md,1.77E+00,md,1.77E-01,md,
Reservoir21,4.72E+00,md,4.72E+00,md,4.72E+00,md,
Reservoir20,7.12E-01,md,7.12E-01,md,7.12E-02,md,
Reservoir19,1.55E+01,md,1.55E+01,md,1.55E+01,md,
Reservoir18,2.75E-01,md,2.75E-01,md,2.75E-02,md,
Reservoir17,7.26E+00,md,7.26E+00,md,7.26E+00,md,
Reservoir16,3.80E-01,md,3.80E-01,md,3.80E-02,md,
Reservoir15,5.09E+00,md,5.09E+00,md,5.09E+00,md,
Reservoir14,1.34E+00,md,1.34E+00,md,1.34E+00,md,
Reservoir13,5.33E+00,md,5.33E+00,md,5.33E+00,md,
Reservoir12,1.59E+01,md,1.59E+01,md,1.59E+01,md,
Reservoir11,2.10E+02,md,2.10E+02,md,2.10E+02,md,
Reservoir10,1.39E+01,md,1.39E+01,md,1.39E+01,md,
Reservoir9,1.39E+01,md,1.39E+01,md,1.39E+01,md,
Reservoir8,2.10E+01,md,2.10E+01,md,2.10E+01,md,
Reservoir7,6.51E+00,md,6.51E+00,md,6.51E+00,md,
Reservoir6,2.26E+00,md,2.26E+00,md,2.26E+00,md,
Reservoir5,1.80E-01,md,1.80E-01,md,1.80E-01,md,
Reservoir4,4.75E-02,md,4.75E-02,md,4.75E-02,md,
Reservoir3,1.25E+01,md,1.25E+01,md,1.25E+01,md,
Reservoir2,2.87E+00,md,2.87E+00,md,2.87E+00,md,
Reservoir1,2.87E+00,md,2.87E+00,md,2.87E+00,md,
```

The Brooks Corey Model with the Webb extension is specified in the *Saturation Function Card*. The option to include the CO_2 gas entrapment model is also specified in the *Saturation Function Card.* A fundamental assumption for the gas entrapment model in STOMP-CO2 is that the aqueous phase is the wetting phase relative to the gas phase. Gas entrapment is assumed to occur only when the aqueous phase is on an imbibition path (i.e., increasing aqueous saturation). Gas saturation can be free or trapped:

$$s_g = 1 - s_l = s_{gf} + s_{gt} \tag{1}$$

where the trapped gas is assumed to be in the form of aqueous occluded ganglia and immobile. A complete theoretical model for scanning path hysteresis and non-wetting fluid entrapment was developed by Parker and Lenhard (1987). The entrapment model used in STOMP-CO2 is formulated after the simplifications of the Parker and Lenhard model published by Kaluarachchi and Parker (1992). The potential effective trapped gas saturation varies between zero and the effective maximum trapped gas saturation as a function of the historical minimum value of the apparent aqueous saturation. When the gas entrapment model is active, the effective aqueous saturations are replaced with the apparent aqueous saturations, which makes the apparent aqueous saturations a function of the capillary pressure. The entrapment model requires one additional input parameter in the *Saturation Function Card*; the actual maximum trapped gas saturation. In this example the maximum trapped gas saturation is assigned a value of 0.2.

```
~Saturation Function Card
caprock,Brooks and Corey w/ Webb w/Entrapment,10,m,0.8311,0.0597,0.2,
Reservoir24,Brooks and Corey w/ Webb w/Entrapment,1.2,m,0.8311,0.0597,0.2,
Reservoir23,Brooks and Corey w/ Webb w/Entrapment,0.5,m,0.6215,0.0810,0.2,
Reservoir22,Brooks and Corey w/ Webb w/Entrapment,3.6,m,0.8311,0.0597,0.2,
Reservoir21,Brooks and Corey w/ Webb w/Entrapment,2.0,m,0.8311,0.0597,0.2,
Reservoir20,Brooks and Corey w/ Webb w/Entrapment,5.0,m,0.8311,0.0597,0.2,
Reservoir19,Brooks and Corey w/ Webb w/Entrapment,1.3,m,0.8311,0.0597,0.2,
Reservoir18,Brooks and Corey w/ Webb w/Entrapment,6.9,m,0.8311,0.0597,0.2,
Reservoir17,Brooks and Corey w/ Webb w/Entrapment,1.7,m,0.8311,0.0597,0.2,
Reservoir16,Brooks and Corey w/ Webb w/Entrapment,6.2,m,0.8311,0.0597,0.2,
Reservoir15,Brooks and Corey w/ Webb w/Entrapment,1.9,m,0.8311,0.0597,0.2,
Reservoir14,Brooks and Corey w/ Webb w/Entrapment,3.1,m,0.8311,0.0597,0.2,
Reservoir13,Brooks and Corey w/ Webb w/Entrapment,1.9,m,0.8311,0.0597,0.2,
Reservoir12,Brooks and Corey w/ Webb w/Entrapment,1.2,m,0.8311,0.0597,0.2,
Reservoir11,Brooks and Corey w/ Webb w/Entrapment,0.4,m,1.1663,0.0708,0.2,
Reservoir10,Brooks and Corey w/ Webb w/Entrapment,1.3,m,0.8311,0.0597,0.2,
Reservoir9,Brooks and Corey w/ Webb w/Entrapment,1.3,m,0.8311,0.0597,0.2,
Reservoir8,Brooks and Corey w/ Webb w/Entrapment,1.1,m,0.8311,0.0597,0.2,
Reservoir7,Brooks and Corey w/ Webb w/Entrapment,1.7,m,0.8311,0.0597,0.2,
Reservoir6,Brooks and Corey w/ Webb w/Entrapment,2.6,m,0.8311,0.0597,0.2,
Reservoir5,Brooks and Corey w/ Webb w/Entrapment,6.5,m,0.8311,0.0597,0.2,
Reservoir4,Brooks and Corey w/ Webb w/Entrapment,10.7,m,0.8311,0.0597,0.2,
Reservoir3,Brooks and Corey w/ Webb w/Entrapment,1.4,m,0.8311,0.0597,0.2,
Reservoir2,Brooks and Corey w/ Webb w/Entrapment,2.3,m,0.8311,0.0597,0.2,
Reservoir1,Brooks and Corey w/ Webb w/Entrapment,2.3,m,0.8311,0.0597,0.2,
```

The hydrologic system is initialized under hydrostatic conditions with a reference pressure of 1790.25 psi at an elevation of -3415 ft. These initial conditions are then held throughout the simulation along the right vertical boundary surface (i.e., STOMP-CO2 east boundary). Zero flux boundary surfaces are assumed for the upper horizontal caprock (i.e., STOMP-CO2 top boundary), lower horizontal basement rock (i.e., STOMP-CO2 bottom boundary). The initial temperature is specified at 103° F at an elevation of -2711 ft with a vertical thermal gradient of 110° F per 100 ft (or -0.011 °F per ft). Note that the gradient is specified as a negative value because positive is in the upward direction within the STOMP domain and the temperature gradient is negative upward. The salinity is specified as the salt mass fraction with a value of .0475 at a reference elevation of -2711 ft with no vertical salinity gradient. The *Initial Conditions Card* is shown below:

```
~Initial Conditions Card
Hydrostatic,1790.25,psi,-3415,ft,103,F,-2711,ft,-0.011,F/ft,0.0475,-2711,ft,0,1/ft,
```

The CO_2 injection parameters are specified in the *Coupled Well Card*. For a cylindrical coordinate system the well coordinates must be specified at the model origin (x=0, y=0 in this case). The vertical screened interval is the entire thickness of the reservoir (-3219 ft to -3799 ft). The maximum injected mass is set to a large number so that the CO_2 will continue to be injected over the entire injection period regardless of the amount of mass injected during that time. The injection period is 2 years with a specified constant rate of 1.0 MMT/yr and a maximum pressure constraint of 2378.5 psi. The maximum injection pressure is determined by taking 90% of the fracture initiation pressure, and is specified at the top of the injection well (at an elevation of -3219 in this case). The total simulation time is 10 years.

```
~Coupled Well Card,
1,
CO2 Injection Well,Water Relative Saturation,1.0,1.0,1.0,10000,MMT,
1,
0,ft,0,ft,-3219,ft,0,ft,0,ft,-3799,ft,4.5,in,0.0,screened,
2,
0,yr,1.0,MMT/yr,2378.5,psi,0.0,
2,yr,1.0,MMT/yr,2378.5,psi,0.0,
```

In addition to the typical reference node output requested such as gas saturation and pressure, the total integrated CO_2 mass in the domain is requested along with the integrated mass for each of the phases (*Integrated CO2 Mass, Integrated CO2 Aqueous Mass, Integrated CO2 Gas Mass,* and *Integrated Trapped CO2 Gas*). The injection rate and pressure at the well and the integrated mass injected at the well are also requested (*Coupled-Well Press, Coupled-Well CO2 Mass Rate, Coupled-Well CO2 Mass Integral*).

```
~Output Options Card
6,
1,1,11,
10,1,11,
20,1,11,
1,1,24,
10,1,24,
20,1,24,
1,1,yr,ft,deg,6,7,7,
18,
Gas Saturation,,
Integrated CO2 Mass,MMT,
Integrated CO2 Aqueous Mass,MMT,
Integrated CO2 Gas Mass,MMT,
Integrated Trapped CO2 Gas,MMT,
Trapped Gas Saturation,,
Aqueous Relative Permeability,,
Salt Aqueous Mass Fraction,,
CO2 Aqueous Mass Fraction,,
Gas Density,kg/m^3,
Aqueous Density,kg/m^3,
Gas Pressure,psi,
Aqueous Pressure,psi,
Diffusive Porosity,,
Coupled-Well Press,1,psi,
Coupled-Well CO2 Mass Rate,1,MMT/yr,
Coupled-Well CO2 Mass Integral,1,MMT,
CO2 Gas Mass Fraction,,
2,
0,yr,
10@0.5,yr,
19,
Rock/Soil Type,,
Gas Saturation,,
Salt Saturation,,
Salt Aqueous Mass Fraction,,
CO2 Aqueous Mass Fraction,,
Gas Pressure,psi,
Aqueous Pressure,psi,
Trapped Gas Saturation,,
Vertically Integrated Gas CO2 Mass per Area,MT/ft^2,
Vertically Integrated Gas CO2 Mass,MT,
Vertically Integrated CO2 Mass per Area,MT/ft^2,
Vertically Integrated CO2 Mass,MT,
CO2 Gas Mass Fraction,,
x intrinsic permeability,mD,
z intrinsic permeability,mD,
znc gas vol flux,m/yr,
znc aqueous vol,m/yr,
znc salt flux,MT/m^2 yr,
z-direction node centroid,ft,
```

The plot file output requested includes the *Vertically Integrated Mass* and the *Vertically Integrated Mass per Area* for total CO_2 and for CO_2 in the gas phase. These values can be used to help determine the Area of Review (AoR), which is required in the permit applications for UIC Class VI Injection Wells. Generally, most of the CO_2 injected for sequestration exists in the subsurface in the supercritical phase, assuming appropriate reservoir pressure and temperature. Some of the CO_2 dissolves in the aqueous phase.

Therefore, defining the AoR based on the amount of mass instead of the extent of the plume defined by the gas saturation better represents the location of the CO_2 plume. To accurately delineate the plume size, the vertically integrated mass per unit area (VIMPA) of CO_2 is calculated as follows:

$$VIM_{i,j} = \sum_{k} \frac{M_{i,j,k}}{A_{i,j,k}} \tag{1}$$

where: M = the total CO_2 mass in a cell
A = the horizontal cross-sectional area of a cell,
i and j = cell indices in the horizontal directions and
k = the index in the vertical direction.

The VIMPA may be calculated for the separate-phase (gas) CO_2, the dissolved CO_2, or the total (gas and dissolved) CO_2 for the entire vertical depth or for a specific layer or layers (e.g., the reservoir, caprock).

The VIMPA distributes nonuniformly in the horizontal plane. Generally, the VIMPA is larger near the injection well and decreases gradually away from the well. The plume size defined by the area that contains all of the CO_2 mass can be very large, while in fact, most of the mass may reside in a subregion of that area. Therefore, the extent of the plume can be defined as the contour line of VIMPA, within which a certain percentage (such as 95% or 99%) of the CO_2 mass is contained.

Figures 3 and 4 show the gas saturation for years 2 and 10 respectively for the full domain. The lateral migration of the plume is less than 3000 ft illustrating that the 10,000-ft domain boundary is sufficiently far from the injection well. Figures 5 and 6 show the gas saturation in the area near the well at 2 and 10 years to illustrate the plume development due to buoyancy. The pressure buildup after 2 years of injection is shown in Figure 7. This is calculated by subtracting the pressure at 2 years minus the initial pressure (pressure at year 0). It can be seen that the pressure effects are much more far-reaching than the presence of CO_2 in the reservoir. Figure 8 shows the vertically integrated mass of the CO_2 plume after 2 years of injection, providing a way to characterize where the bulk of the CO_2 mass exists in the reservoir.

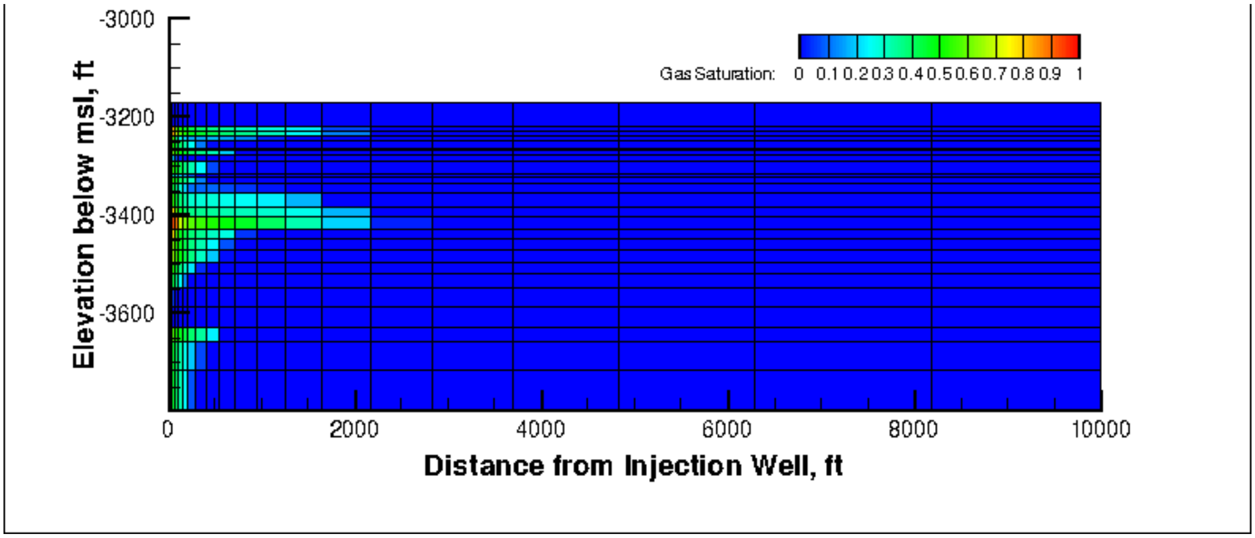

Figure 3. Gas saturation after 2 years of injection

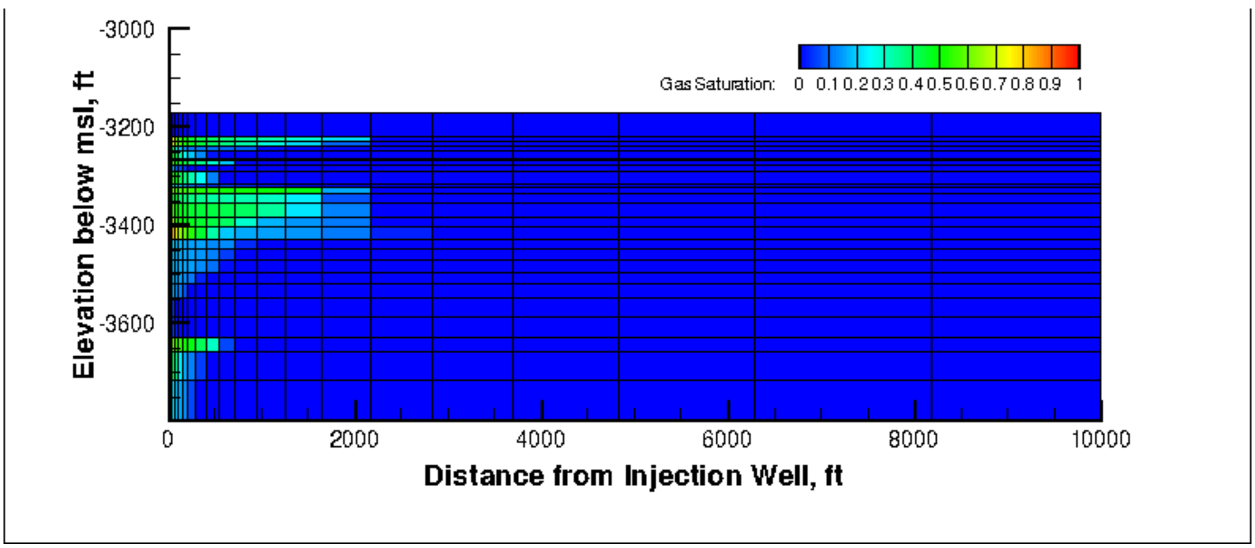

Figure 4. Gas saturation after 10 years of simulation time (2 year of injection and 8 years post-injection)

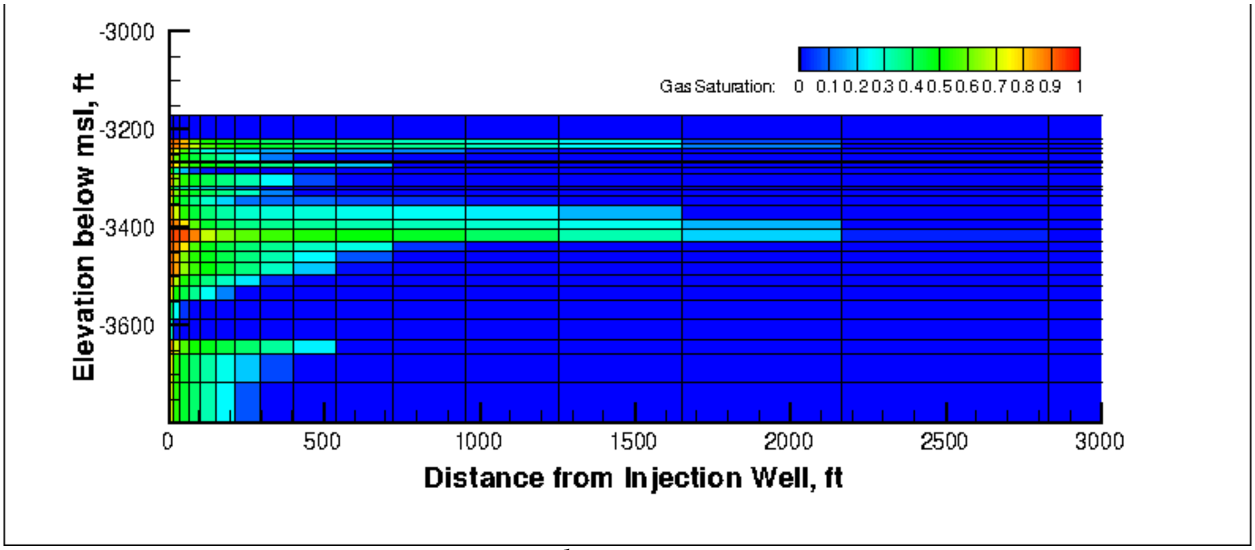

Figure 5. Gas saturation in the near field after 2 years of injection

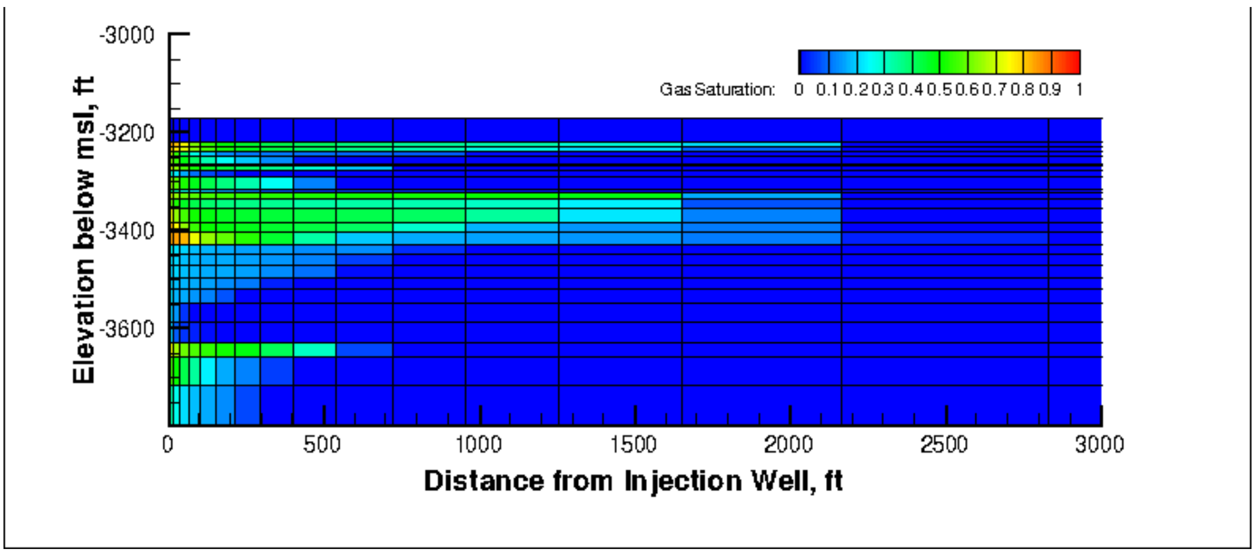

Figure 6. Gas saturation in the near field after 10 years of simulation time (2 year of injection and 8 years post-injection)

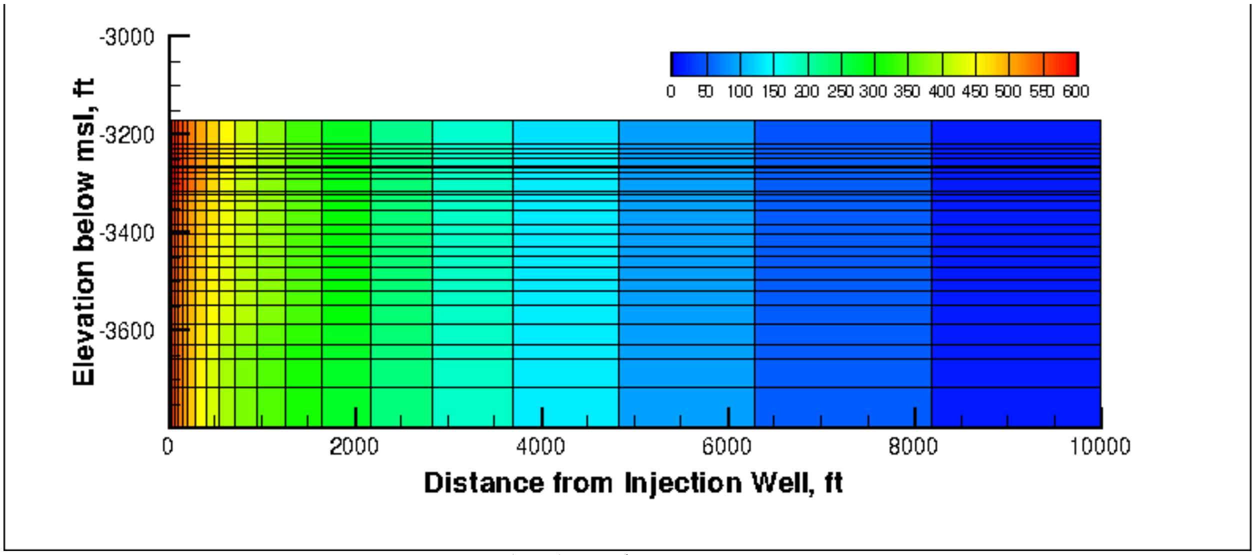

Figure 7. Pressure buildup (psi) in the reservoir after 2 years of injection

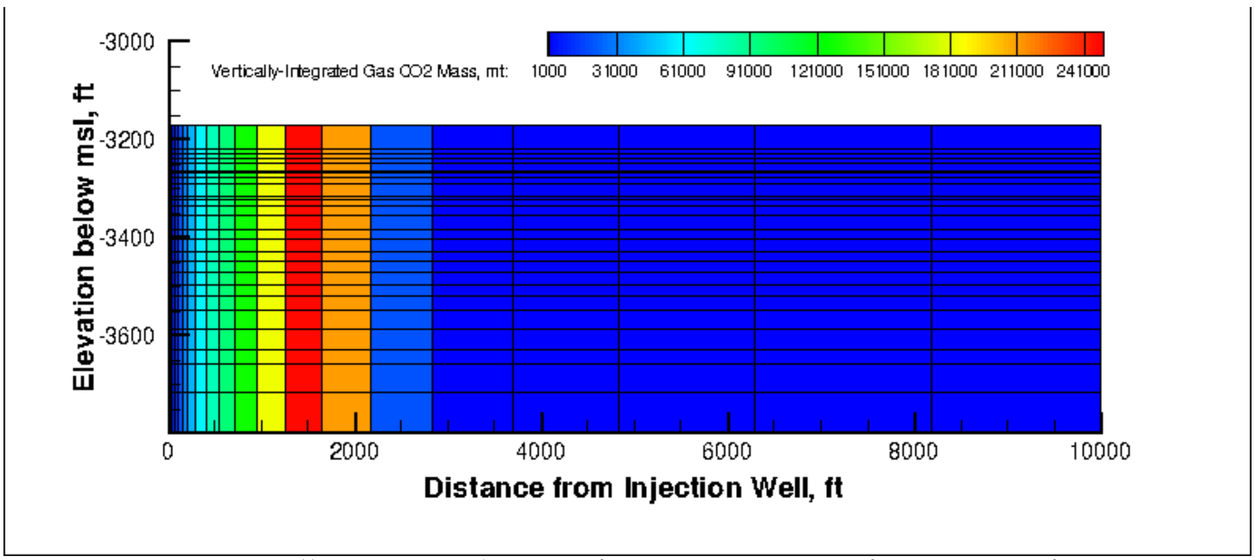

Figure 8. Vertically integrated mass of CO_2 in reservoir after 2 years of injection.

Exercises

1. (Basic) Run the simulation. Plot the integrated mass with time and the injection pressure and injection rate at the well with time. Determine whether the injection well is behaving in a pressure-controlled or rate-controlled manner. Plot the gas saturation at 2 years and 10 years and compare with Figures 3-6.

2. (Basic) Create a new simulation folder and copy all files from exercise 1 into the new location. Change the maximum injection pressure to 5000 psi and rerun the simulation. Determine the injection pressure that corresponds to the injection rate of 1 MMT/yr. Compare this value to the maximum specified pressure in exercise 1 (2378.5 psi). Plot the gas saturation at 2 years and 10 years and compare the plume to that from exercise 1.
3. (Moderate) Change the maximum injection pressure back to 2378.5 psi. Modify the permeability of one or more layers in the reservoir to create a rate-controlled injection scenario that honors the maximum injection pressure.
4. (Difficult) Determine the extent of the CO_2 plume using the vertically integrated mass and the vertically integrated mass per area. Compare this to the plume radius based on the gas saturation. Plot the pressure buildup at the end of the injection period and using 44.1 psi (3 bar) as the critical pressure, determine which extent is greater.

Input File

```
~Simulation Title Card
1,
STOMP Example Problem CO2-4,
Signe White,
Pacific Northwest National Laboratory,
01 July 2012,
13:30,
2,
Reference Case with radial symmetry (cylindrical coordinate system) based on
25 lithologic layers including caprock.

~Solution Control Card
Normal,
STOMP-CO2,
1,
0,yr,10,year,1000,s,0.5,yr,1.25,16,1.e-06,1,s,0.2,
1000000,
Variable Aqueous Diffusion,
Variable Gas Diffusion,
0,

#
~Grid Card
Cylindrical,
20,1,25,
0.0000,ft,16.9257,ft,38.9291,ft,67.5335,ft,104.7192,ft,
153.0607,ft,215.9046,ft,297.6016,ft,403.8078,ft,541.8759,ft,
721.3643,ft,954.6993,ft,1258.0347,ft,1652.3708,ft,2165.0078,ft,
```

```
2831.4358,ft,3697.7922,ft,4824.0556,ft,6288.1980,ft,8191.5830,ft,
10000,ft,
0.0,deg,360.0,deg,
-3799,ft,-3717,ft,-3657,ft,-3627,ft,-3588,ft,
-3549,ft,-3518,ft,-3495,ft,-3471,ft,-3449,ft,
-3427,ft,-3404,ft,-3383,ft,-3355,ft,-3335,ft,
-3322,ft,-3315,ft,-3289,ft,-3277,ft,-3267,ft,
-3263,ft,-3249,ft,-3239,ft,-3229,ft,-3219,ft,
-3169,ft,

~Rock/Soil Zonation Card
25,
caprock,1,20,1,20,25,25,
Reservoir24,1,20,1,20,24,24,
Reservoir23,1,20,1,20,23,23,
Reservoir22,1,20,1,20,22,22,
Reservoir21,1,20,1,20,21,21,
Reservoir20,1,20,1,20,20,20,
Reservoir19,1,20,1,20,19,19,
Reservoir18,1,20,1,20,18,18,
Reservoir17,1,20,1,20,17,17,
Reservoir16,1,20,1,20,16,16,
Reservoir15,1,20,1,20,15,15,
Reservoir14,1,20,1,20,14,14,
Reservoir13,1,20,1,20,13,13,
Reservoir12,1,20,1,20,12,12,
Reservoir11,1,20,1,20,11,11,
Reservoir10,1,20,1,20,10,10,
Reservoir9,1,20,1,20,9,9,
Reservoir8,1,20,1,20,8,8,
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Reservoir6,1,20,1,20,6,6,
Reservoir5,1,20,1,20,5,5,
Reservoir4,1,20,1,20,4,4,
Reservoir3,1,20,1,20,3,3,
Reservoir2,1,20,1,20,2,2,
Reservoir1,1,20,1,20,1,1,
#
~Mechanical Properties Card
caprock,2650,kg/m^3,0.07,0.07,Compressibility,7.42E-10,1/psi,,,constant,1,1,
Reservoir24,2650,kg/m^3,0.13,0.13,Compressibility,3.71E-10,1/psi,,,constant,1,1,
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Reservoir18,2650,kg/m^3,0.09,0.09,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir17,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir16,2650,kg/m^3,0.08,0.08,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir15,2650,kg/m^3,0.10,0.10,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir14,2650,kg/m^3,0.08,0.08,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir13,2650,kg/m^3,0.10,0.10,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir12,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
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Reservoir9,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir8,2650,kg/m^3,0.13,0.13,Compressibility,3.71E-10,1/psi,,,constant,1,1,
Reservoir7,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,
```

```
Reservoir6,2650,kg/m^3,0.09,0.09,Compressibility,3.71E-10,1/psi,,,constant,1,1,
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Reservoir4,2650,kg/m^3,0.12,0.12,Compressibility,3.71E-10,1/psi,,,constant,1,1,
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Reservoir1,2650,kg/m^3,0.11,0.11,Compressibility,3.71E-10,1/psi,,,constant,1,1,

~Hydraulic Properties Card
caprock,5.70E-05,md,5.70E-05,md,5.70E-05,md,
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Reservoir23,1.75E+02,md,1.75E+02,md,1.75E+02,md,
Reservoir22,1.77E+00,md,1.77E+00,md,1.77E-01,md,
Reservoir21,4.72E+00,md,4.72E+00,md,4.72E+00,md,
Reservoir20,7.12E-01,md,7.12E-01,md,7.12E-02,md,
Reservoir19,1.55E+01,md,1.55E+01,md,1.55E+01,md,
Reservoir18,2.75E-01,md,2.75E-01,md,2.75E-02,md,
Reservoir17,7.26E+00,md,7.26E+00,md,7.26E+00,md,
Reservoir16,3.80E-01,md,3.80E-01,md,3.80E-02,md,
Reservoir15,5.09E+00,md,5.09E+00,md,5.09E+00,md,
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Reservoir13,5.33E+00,md,5.33E+00,md,5.33E+00,md,
Reservoir12,1.59E+01,md,1.59E+01,md,1.59E+01,md,
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Reservoir9,1.39E+01,md,1.39E+01,md,1.39E+01,md,
Reservoir8,2.10E+01,md,2.10E+01,md,2.10E+01,md,
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Reservoir6,2.26E+00,md,2.26E+00,md,2.26E+00,md,
Reservoir5,1.80E-01,md,1.80E-01,md,1.80E-01,md,
Reservoir4,4.75E-02,md,4.75E-02,md,4.75E-02,md,
Reservoir3,1.25E+01,md,1.25E+01,md,1.25E+01,md,
Reservoir2,2.87E+00,md,2.87E+00,md,2.87E+00,md,
Reservoir1,2.87E+00,md,2.87E+00,md,2.87E+00,md,
#
~Saturation Function Card
caprock,Brooks and Corey w/ Webb w/Entrapment,10,m,0.8311,0.0597,0.2,
Reservoir24,Brooks and Corey w/ Webb w/Entrapment,1.2,m,0.8311,0.0597,0.2,
Reservoir23,Brooks and Corey w/ Webb w/Entrapment,0.5,m,0.6215,0.0810,0.2,
Reservoir22,Brooks and Corey w/ Webb w/Entrapment,3.6,m,0.8311,0.0597,0.2,
Reservoir21,Brooks and Corey w/ Webb w/Entrapment,2.0,m,0.8311,0.0597,0.2,
Reservoir20,Brooks and Corey w/ Webb w/Entrapment,5.0,m,0.8311,0.0597,0.2,
Reservoir19,Brooks and Corey w/ Webb w/Entrapment,1.3,m,0.8311,0.0597,0.2,
Reservoir18,Brooks and Corey w/ Webb w/Entrapment,6.9,m,0.8311,0.0597,0.2,
Reservoir17,Brooks and Corey w/ Webb w/Entrapment,1.7,m,0.8311,0.0597,0.2,
Reservoir16,Brooks and Corey w/ Webb w/Entrapment,6.2,m,0.8311,0.0597,0.2,
Reservoir15,Brooks and Corey w/ Webb w/Entrapment,1.9,m,0.8311,0.0597,0.2,
Reservoir14,Brooks and Corey w/ Webb w/Entrapment,3.1,m,0.8311,0.0597,0.2,
Reservoir13,Brooks and Corey w/ Webb w/Entrapment,1.9,m,0.8311,0.0597,0.2,
Reservoir12,Brooks and Corey w/ Webb w/Entrapment,1.2,m,0.8311,0.0597,0.2,
Reservoir11,Brooks and Corey w/ Webb w/Entrapment,0.4,m,1.1663,0.0708,0.2,
Reservoir10,Brooks and Corey w/ Webb w/Entrapment,1.3,m,0.8311,0.0597,0.2,
Reservoir9,Brooks and Corey w/ Webb w/Entrapment,1.3,m,0.8311,0.0597,0.2,
Reservoir8,Brooks and Corey w/ Webb w/Entrapment,1.1,m,0.8311,0.0597,0.2,
Reservoir7,Brooks and Corey w/ Webb w/Entrapment,1.7,m,0.8311,0.0597,0.2,
Reservoir6,Brooks and Corey w/ Webb w/Entrapment,2.6,m,0.8311,0.0597,0.2,
Reservoir5,Brooks and Corey w/ Webb w/Entrapment,6.5,m,0.8311,0.0597,0.2,
Reservoir4,Brooks and Corey w/ Webb w/Entrapment,10.7,m,0.8311,0.0597,0.2,
Reservoir3,Brooks and Corey w/ Webb w/Entrapment,1.4,m,0.8311,0.0597,0.2,
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Reservoir2,Brooks and Corey w/ Webb w/Entrapment,2.3,m,0.8311,0.0597,0.2,
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#
~Aqueous Relative Permeability Card
caprock,Burdine,,
Reservoir24,Burdine,,
Reservoir23,Burdine,,
Reservoir22,Burdine,,
Reservoir21,Burdine,,
Reservoir20,Burdine,,
Reservoir19,Burdine,,
Reservoir18,Burdine,,
Reservoir17,Burdine,,
Reservoir16,Burdine,,
Reservoir15,Burdine,,
Reservoir14,Burdine,,
Reservoir13,Burdine,,
Reservoir12,Burdine,,
Reservoir11,Burdine,,
Reservoir10,Burdine,,
Reservoir9,Burdine,,
Reservoir8,Burdine,,
Reservoir7,Burdine,,
Reservoir6,Burdine,,
Reservoir5,Burdine,,
Reservoir4,Burdine,,
Reservoir3,Burdine,,
Reservoir2,Burdine,,
Reservoir1,Burdine,,
#
~Gas Relative Permeability Card
caprock,Burdine,,
Reservoir24,Burdine,,
Reservoir23,Burdine,,
Reservoir22,Burdine,,
Reservoir21,Burdine,,
Reservoir20,Burdine,,
Reservoir19,Burdine,,
Reservoir18,Burdine,,
Reservoir17,Burdine,,
Reservoir16,Burdine,,
Reservoir15,Burdine,,
Reservoir14,Burdine,,
Reservoir13,Burdine,,
Reservoir12,Burdine,,
Reservoir11,Burdine,,
Reservoir10,Burdine,,
Reservoir9,Burdine,,
Reservoir8,Burdine,,
Reservoir7,Burdine,,
Reservoir6,Burdine,,
Reservoir5,Burdine,,
Reservoir4,Burdine,,
Reservoir3,Burdine,,
Reservoir2,Burdine,,
Reservoir1,Burdine,,
#
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~Salt Transport Card
caprock,0.0,ft,0.0,ft,
Reservoir24,0.0,ft,0.0,ft,
Reservoir23,0.0,ft,0.0,ft,
Reservoir22,0.0,ft,0.0,ft,
Reservoir21,0.0,ft,0.0,ft,
Reservoir20,0.0,ft,0.0,ft,
Reservoir19,0.0,ft,0.0,ft,
Reservoir18,0.0,ft,0.0,ft,
Reservoir17,0.0,ft,0.0,ft,
Reservoir16,0.0,ft,0.0,ft,
Reservoir15,0.0,ft,0.0,ft,
Reservoir14,0.0,ft,0.0,ft,
Reservoir13,0.0,ft,0.0,ft,
Reservoir12,0.0,ft,0.0,ft,
Reservoir11,0.0,ft,0.0,ft,
Reservoir10,0.0,ft,0.0,ft,
Reservoir9,0.0,ft,0.0,ft,
Reservoir8,0.0,ft,0.0,ft,
Reservoir7,0.0,ft,0.0,ft,
Reservoir6,0.0,ft,0.0,ft,
Reservoir5,0.0,ft,0.0,ft,
Reservoir4,0.0,ft,0.0,ft,
Reservoir3,0.0,ft,0.0,ft,
Reservoir2,0.0,ft,0.0,ft,
Reservoir1,0.0,ft,0.0,ft,
#
~Initial Conditions Card
Hydrostatic,1790.25,psi,-3415,ft,103,F,-2711,ft,-0.011,F/ft,0.0475,-2711,ft,0,1/ft,

~Boundary Conditions Card
1,
East,Aqu Initial Condition,Gas Zero Flux,Initial Condition,
20,20,1,1,1,25,1,
0,s,,,,,,,,,
#
~Coupled Well Card,
1,
CO2 Injection Well,Water Relative Saturation,1.0,1.0,1.0,100000,MMT,
1,
0,ft,0,ft,-3219,ft,0,ft,0,ft,-3799,ft,4.5,in,0.0,screened,
2,
0,yr,1.0,MMT/yr,2378.5,psi,0.0,
2,yr,1.0,MMT/yr,2378.5,psi,0.0,
#
~Output Options Card
6,
1,1,11,
10,1,11,
20,1,11,
1,1,24,
10,1,24,
20,1,24,
1,1,yr,ft,deg,6,7,7,
18,
Gas Saturation,,
Integrated CO2 Mass,MMT,
Integrated CO2 Aqueous Mass,MMT,
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Integrated CO2 Gas Mass,MMT,
Integrated Trapped CO2 Gas,MMT,
Trapped Gas Saturation,,
Aqueous Relative Permeability,,
Salt Aqueous Mass Fraction,,
CO2 Aqueous Mass Fraction,,
Gas Density,kg/m^3,
Aqueous Density,kg/m^3,
Gas Pressure,psi,
Aqueous Pressure,psi,
Diffusive Porosity,,
Coupled-Well Press,1,psi,
Coupled-Well CO2 Mass Rate,1,MMT/yr,
Coupled-Well CO2 Mass Integral,1,MMT,
CO2 Gas Mass Fraction,,
2,
0,yr,
10@0.5,yr,
20,
Rock/Soil Type,,
Gas Saturation,,
Salt Saturation,,
Salt Aqueous Mass Fraction,,
CO2 Aqueous Mass Fraction,,
Gas Pressure,psi,
Aqueous Pressure,psi,
Temperature,F,
Trapped Gas Saturation,,
Vertically Integrated Gas CO2 Mass per Area,MT/ft^2,
Vertically Integrated Gas CO2 Mass,MT,
Vertically Integrated CO2 Mass per Area,MT/ft^2,
Vertically Integrated CO2 Mass,MT,
CO2 Gas Mass Fraction,,
x intrinsic permeability,mD,
z intrinsic permeability,mD,
znc gas vol flux,m/yr,
znc aqueous vol,m/yr,
znc salt flux,MT/m^2 yr,
z-direction node centroid,ft,
#
```

Solutions to Selected Exercises

Exercise 1

Figure 9 shows the integrated mass with respect to time. The total mass that should have been injected if the 1 MMT/yr rate for 2 years was honored is 2 MMT. However, it can be seen from this plot that the injection rate must not have been sustained over the injection period because the total mass present in the domain is only 1.5 MMT. This can also be seen in Figures 10 and 11, where the injection pressure equals the maximum pressure specified and the injection rate clearly is not maintained during injection.

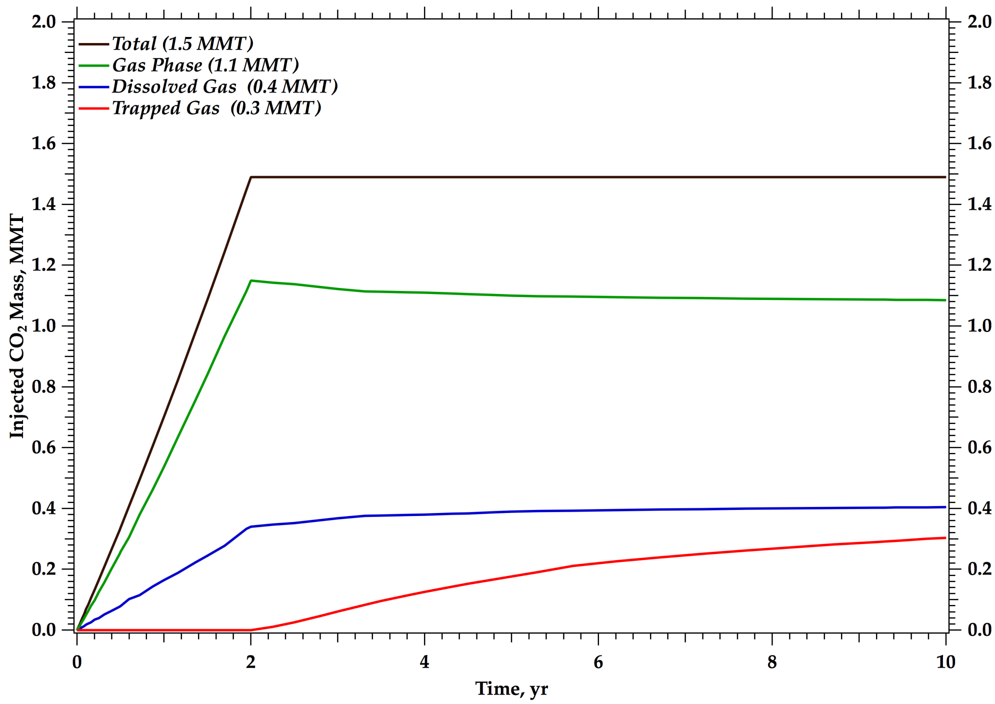

Figure 9. Integrated Mass of CO_2 vs. time

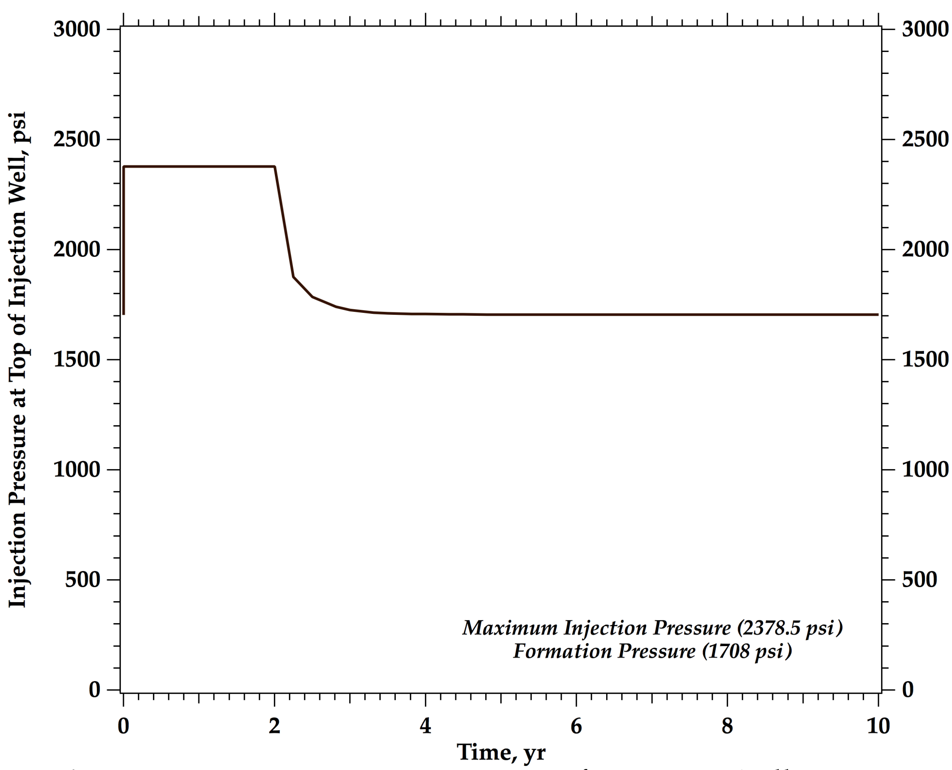

Figure 10. Injection Pressure at Top of Injection Well vs. time

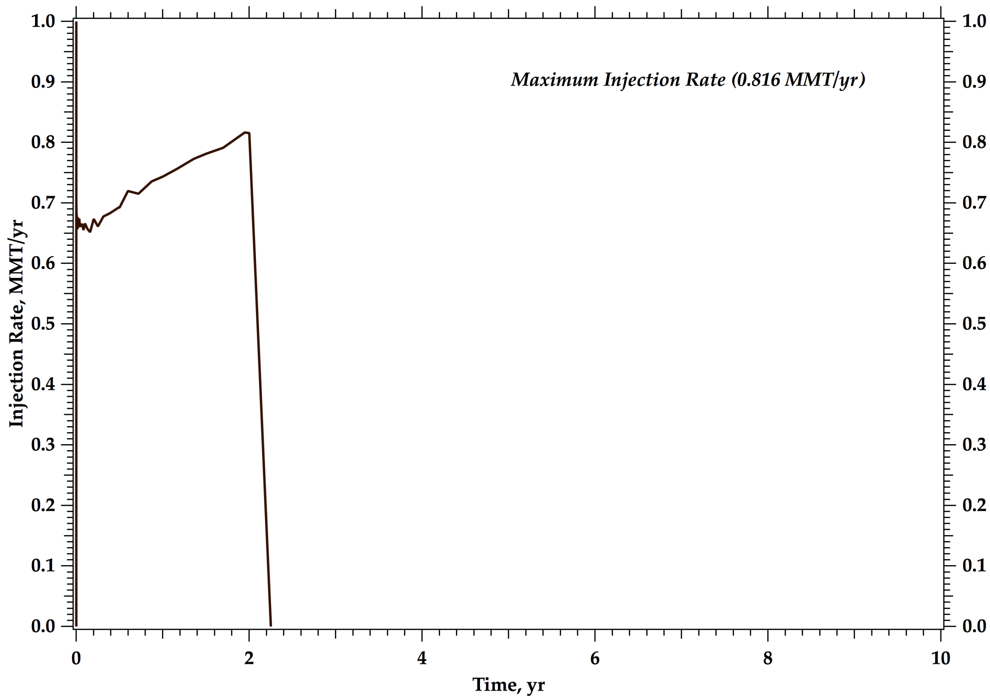

Figure 11. CO_2 Injection Rate vs. time

Exercise 2

Figure 12 shows the integrated mass with respect to time. In this case, the entire 2 MMT is injected. Figure 13 shows the injection pressure with respect to time. The maximum injection pressure corresponding to an injection rate of 1 MMT/yr is 2675.2 psi. This increase in the injection pressure of nearly 300 psi shows only a small change in the plume size as seen when comparing Figure 14 with Figure 3 and Figure 15 with Figure 4.

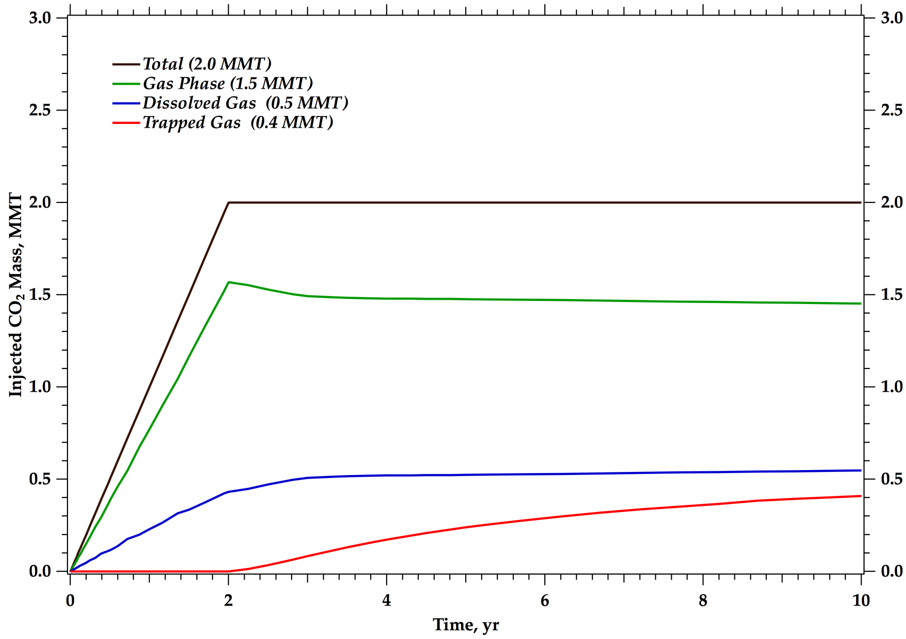

Figure 12. Integrated Mass of CO_2 vs. time

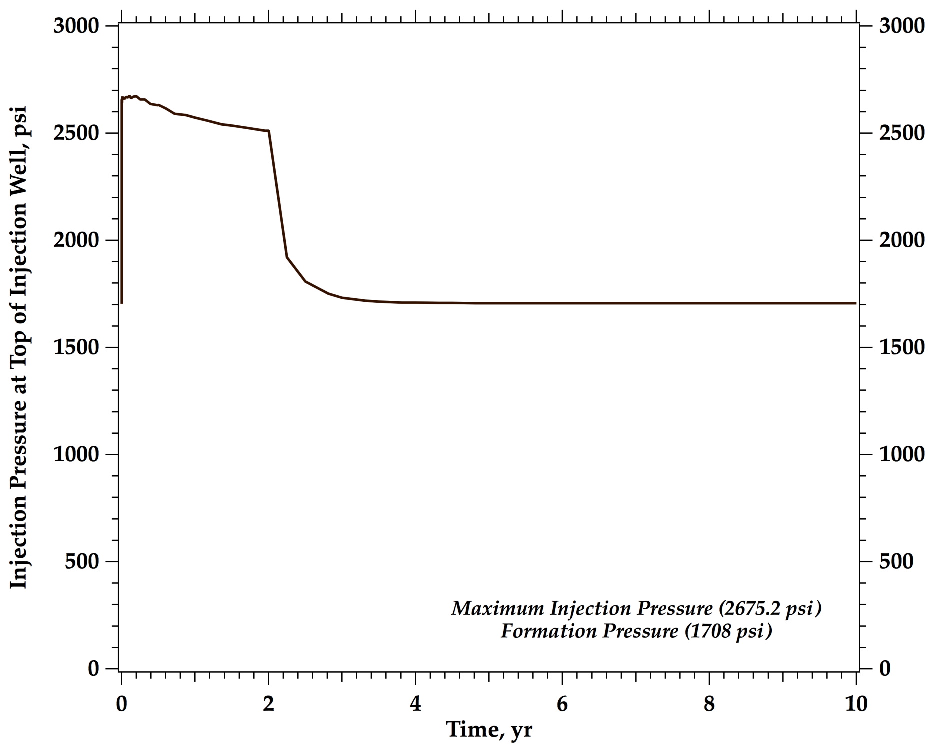

Figure 13. CO_2 Injection Pressure at Top of Injection Well vs. time

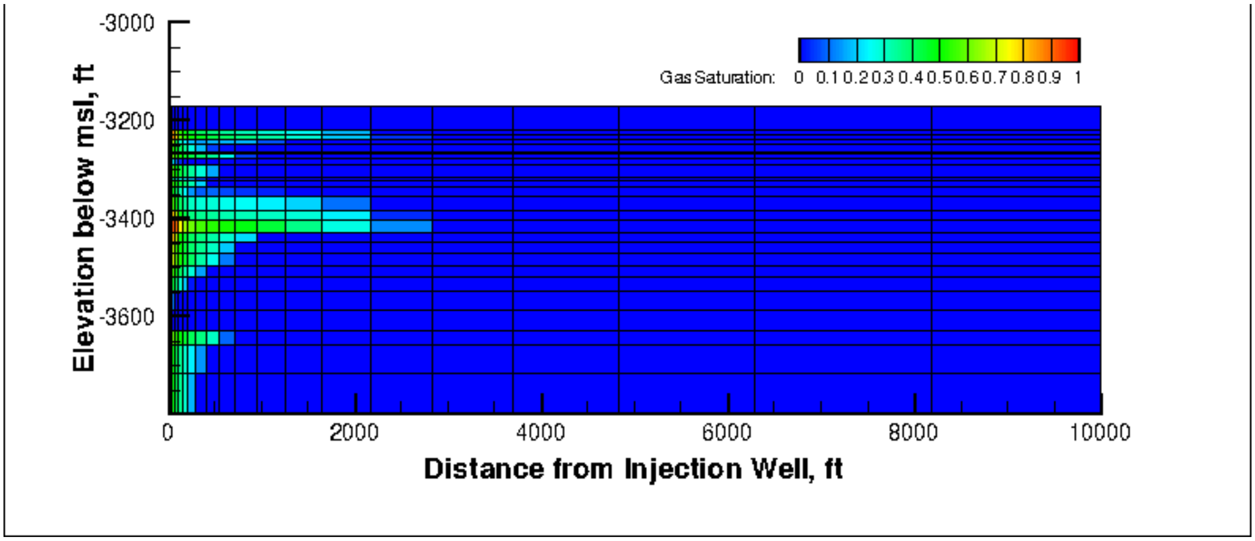

Figure 14. Gas saturation after 2 years of injection

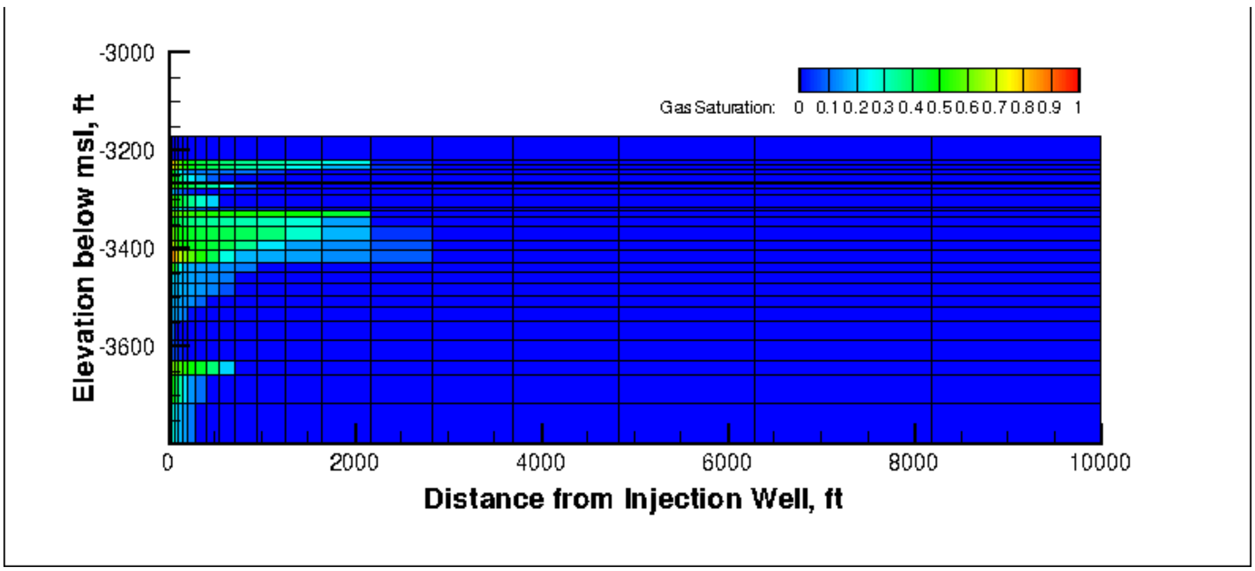

Figure 15. Gas saturation after 10 years of simulation time (2 years of injection and 8 years post-injection)