SECTION 2 – PLUME MODEL

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2.1 Introduction

This section discusses key details of the plume model. The model characterizes the performance of CO_2 injection wells, the 3D spatial distribution of the CO_2 plume, and the associated pressure front over time. It incorporates hydrogeologic data with subsurface flow physics to model the significant physical processes that affect the plume and pressure front evolution. The distribution of the plume and pressure front defines the area of review (AOR) for the well, a corrective action plan if necessary, and the overall viability of the project.

While the following discussion specifically focuses on the [redacted] well, [redacted] This also helps to verify that the pressure of the reservoir remains below the fracture pressure gradient limits of the formation during combined injection operations.

The modeling software used to evaluate this project was Computer Modelling Group's GEM 2022.10 (GEM) simulator. Computer Modelling Group (CMG) has put together one of the most accurate and technically sound reservoir simulation software packages for conventional, unconventional, and secondary recovery. GEM uses equation-of-state (EOS) algorithms and some of the most advanced computational methods to evaluate compositional, chemical, and geochemical processes and characteristics, to produce highly accurate and reliable simulation models for carbon sequestration.

For the purposes of injection into a reservoir, CO_2 can be a relatively complex component in the supercritical phase as seen in downhole conditions. The GEM simulator utilizes the compositional methods described, along with equations specific to CO_2, to effectively model and simulate plume behavior within the injection intervals.

[redacted]

2.2 Model Inputs

2.2.1 Trapping Mechanisms

The CO_2 injected into the reservoir will take the form of a mobile CO_2-rich supercritical phase. In this phase, the CO_2 will displace reservoir fluids as it moves laterally and vertically into the reservoir.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Movement of the CO_2 phase does not continue indefinitely. As the CO_2 moves both vertically and horizontally, various trapping mechanisms immobilize the CO_2 within the reservoir. [redacted]

2.2.1.1 Upper Confining Zone

[redacted]

2.2.1.2 Residual Gas Trapping

While the CO_2 will remain in the supercritical phase within the storage interval ("reservoir"), the gas-liquid relative permeability relationships will govern fluid flow between the CO_2 and liquid phases present. [redacted]

[redacted] (Land C. S., 1971).

[redacted] (Land C. , 1968). [redacted]

[redacted] (Keelan, 1975). [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.2.1.3 Solubility Trapping in Brines

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.2.1.5 Structural Trapping

[redacted]

2.2.1.6 Geochemical Trapping

Mineral trapping can also occur due to the adsorption of CO_2 onto clay minerals. Once hysteresis and solubility trapping have been included in the model, geochemical formulae can be added through an internal geochemistry database to describe mineral trapping reactions. For aqueous reactions, the following formulae can be used:

$$CO_2(aq) + H_2O = H^+ + HCO_3^-$$
$$CO_3^{-2} + H^+ = HCO_3^-$$
$$OH^- + H^+ = H_2O$$

These three reactions are all common ionic reactions that can occur in the reservoir between water and/or CO_2. The following formulae show the mineral reactions that may be used within the model. Each of these is a common mineral that may be found in carbonates in an underground aquifer and cause the precipitation of carbon oxides in a solid state:

$$Anhydrite\ (CaSO_4) = Ca^{2+} + SO_4^{2-}$$
$$Calcite\ (CaCO_3) + H^+ = Ca^{2+} + HCO_3^-$$
$$Dolomite\ (CaMg(CO_3)_2) + 2H^+ = Ca^{2+} + 2(HCO_3^-) + Mg^{2+}$$
$$Illite\ (K_6Mg_{25}Al_{2.3}Si_{3.5}O_{10}(OH)_2) + 8H^+ = 2.3Al^{3+} + 5H_2O + 0.6K^+ + 0.25Mg^{2+} + 3.5SiO_2$$
$$Kaolinite\ \left(Al_2Si_2O_5(OH_4)\right) + 6H^+ = 5H_2O + 2Al^{3+} + 2SiO_2$$
$$K - Feldspar\ (KAlSi_3O_8) + 4H^+ = 2H_2O + Al^{3+} + 3SiO_2$$

While geochemical trapping can have a greater impact on carbon dioxide over hundreds or thousands of years, the short-term effects of these trapping mechanisms are relatively small, and fluid movement is predominated by hydrodynamic and solubility trapping. Inclusion of geochemical reactions and trapping mechanisms into the GEM simulator does create significant computational burden on the model runs. Because the impacts are not significant, the geochemical processes have not been included in the simulation cases.

2.2.1.7 Trapping Summary

After the containment zone overlying the reservoir, the significant mechanisms by which CO_2 is trapped in the storage interval [redacted]

[redacted]

2.2.2 Structural and Stratigraphic Elements

The model was built using the geologic data described in *Section 1 – Site Characterization*, which describes how the analysis of well logs, core data, and seismic data were used to generate structure maps and hydrogeology, and to define other rock properties. [redacted]

[redacted]

[redacted]

[redacted]

Vertical Permeability

Permeability normal to the bedding plane is usually lower than the permeability in the parallel direction. In most cases, "normal to the bedding plane" equates to vertical permeability, while the parallel-direction permeability corresponds to horizontal permeability. This contrast is caused by vertical heterogeneity over multiple scales, from very small (fractional inch) through many feet in range. By comparison, the scales of heterogeneity in the horizontal orientation will be significantly larger.

[redacted]

[redacted]

2.2.3 Relative Permeability and Capillary Pressure

Relative permeability curves were generated using the industry standard power law model based on the approach developed by Corey (Corey, 1954). In this model, the relative permeability for the respective water and supercritical gas phases are based on the normalized saturation, scaled between the end points of mobility for a respective phase, and raised to an exponent value (termed the "Corey exponent"). Relationships for water and gas relative permeabilities can be expressed with the following equation. The gas relative permeability applies to the supercritical CO_2 phase.

$$k_{rw} = k_{rwcg} \left[\frac{(S_w - S_{wc})}{(1 - S_{wc} - S_{gc})} \right]^{nw}$$

And

$$k_{rg} = k_{rgrl} \left[\frac{(S_g - S_{gc})}{(1 - S_{wc} - S_{gc})} \right]^{ng}$$

With variables defined as follows:

k_{rw}, k_{rg} = Relative permeability to water and gas phases, respectively

k_{rwcg} = Water relative permeability endpoint, k_{rw} at critical gas saturation

k_{rgrl} = Gas relative permeability endpoint, k_{rc} at irreducible water saturation

S_w, S_g = Water and gas saturations, respectively

S_{wc} = Irreducible saturation of water

S_{gc} = Critical saturation of gas

nw, ng = Corey exponents for water and gas curves, respectively

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[redacted]

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[redacted]

[redacted]

[redacted]

When considering a relative permeability relationship, it is important to look at the data in the context of reservoir conditions, using in situ fluid properties by the generation of a fractional flow curve. Absent gravity effects, the fractional flow of CO_2 versus saturation is calculated using the relationship:

$$f_g = \frac{1}{1 + \frac{\mu_g}{\mu_w}\frac{k_{rw}}{k_{rg}}}$$

Where f_g represents the volume fraction of the gas (supercritical CO_2), μ_g and μ_w represent the in situ viscosity for the CO_2 and brine, and k_{rw} and k_{rg} represent the relative permeability for the brine and CO_2 at the saturations evaluated. [redacted]

[redacted] (Buckley & Leverett, 1942) (Welge, 1952). [redacted]

[redacted]

[redacted]

[redacted]

2.2.3.1 Capillary Pressure Relations

[redacted] Low permeabilities together with associated high capillary entry pressures will combine to prevent flow through the confining interval. [redacted]

[redacted]

2.2.4 Initial Conditions

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2.2.5 Injection Rate

[redacted]

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[redacted]

2.2.6 Injected Fluids Composition

[redacted]

[redacted]

2.2.7 Completion Plan

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2.3 Model Orientation and Gridding Parameters

2.3.1 Spatial Conditions

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2.3.2 Boundary Conditions

Boundary Definition

The top and base of the model were set up as no-flow boundaries to vertical flow, these being the upper and lower confining zones, respectively. Each of the lateral edges of the model has been connected to one or more numerical aquifers, using the Fetkovich water influx calculation option (Fetkovich, 1971) to characterize connections between the modeled area and surrounding region. The use of Fetkovich-type numerical aquifers allows for the definition of aquifers having finite connectivity to the reservoir model. [redacted]

[redacted]

[redacted]

[redacted] (Leibrock, Hiltz, & and Huzarevich, 1951). [redacted]

[redacted] (Craft & Hawkins, 1959).

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2.3.3 Model Time Frame

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2.4 CO_2 Plume Model Results

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2.4.1 Critical Pressure Front

The second component to defining the AOR is the determination of the extent of the critical pressure front. The worst-case scenario for moving reservoir fluids to the Underground Source of Drinking Water (USDW) would be through an improperly plugged and abandoned wellbore or subsurface feature that is open in the base of the USDW and at the top of the injection interval. This resultant pressure is referred to as the critical pressure. The methodology for finding critical pressure was sourced from Environmental Protection Agency (EPA) Method 1 guidance, for calculations based on displacing fluid initially present in the borehole in the hydrostatic case.

[redacted] (McCain, 1991).

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2.5 Area of Review Delineation

Title 16 of the Texas Administrative Code (TAC) **§5.203(d)(1)** [Title 40, U.S. Code of Federal Regulations (40 CFR) **§146.84(b)**] requires that an AOR be delineated for a Class VI carbon sequestration well application. The EPA defines the AOR as the greater of either the maximum extent of the separate-phase plume (pore occupancy plume) or the pressure front where the pressure buildup is of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW. Both parts of this definition were analyzed to define the Orchard #1 AOR.

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