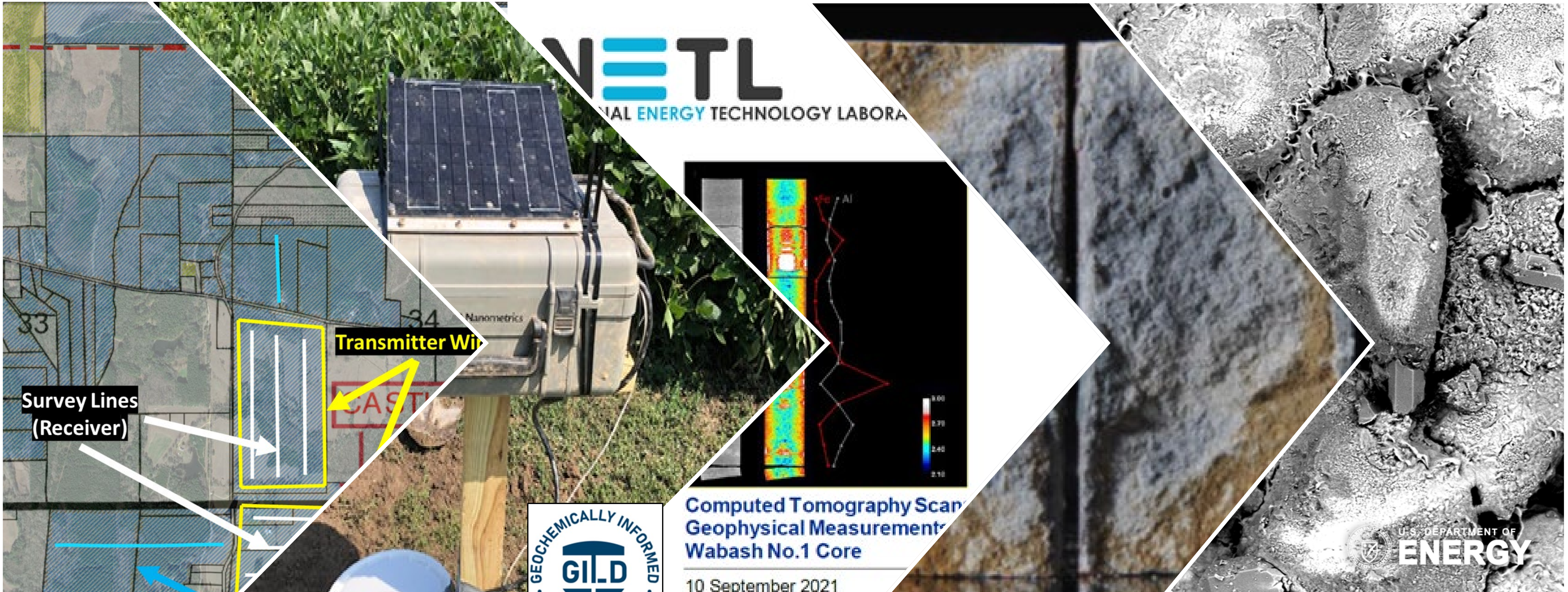
Low Risk Strategies for Geologic Carbon Storage (FWP-1022403)

Wei Xiong, Burt Thomas, Zineb Belarbi, *Dustin Crandall*
NETL RIC Wei.Xiong@netl.doe.gov

8/30/2023



Disclaimers

This project was funded by the United States Department of Energy, National Energy Technology Laboratory, in part, through site support contracts. Neither the United States Government nor any agency thereof, nor any of their employees, nor the support contractors, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

Actual research done by:

- Wei Xiong, Zineb Belarbi, and Burt Thomas from NETL RIC
- Ryan Klapperich and Merry Tesfu from the EERC

It's just my honor to present this update for them today.

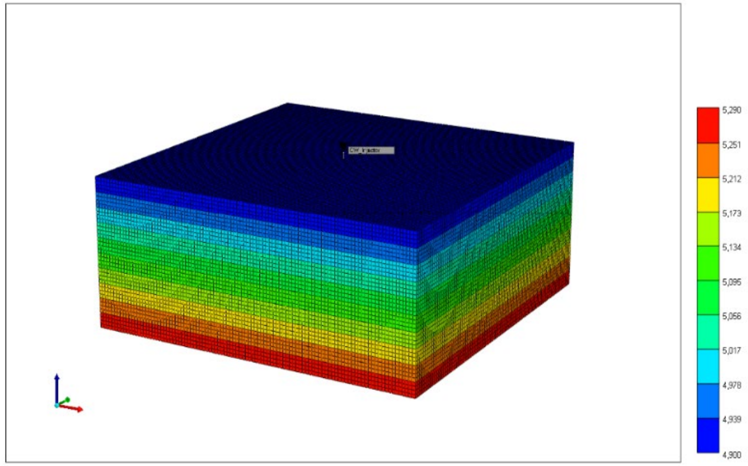
Summary

- Carbonated brine storage is a low-risk geologic CO_2 sequestration strategy.
  - The dissolved CO_2 concentration is affected by salinity, reservoir pressure and temperature. By selecting an appropriate CO_2 molality at the surface and subsurface, we can ensure minimal free-phase CO_2 in carbonated produced water for storage.
- Wellbore corrosion rate has been anticipated to be at an acceptable range to maintain operations for a carbonated brine injection.
  - Scale minerals can precipitate from carbonated produced water and further reduce corrosion rate. Adding CO_2 to produced water for injection is less likely to pose significant impacts on the existing wastewater disposal wells.
- CO_2 remained in liquid phase in long-term storage.
  - Small amount CO_2 converts to carbonate minerals in sandstone reservoir. CO_2 is safely stored via dissolution sequestration.

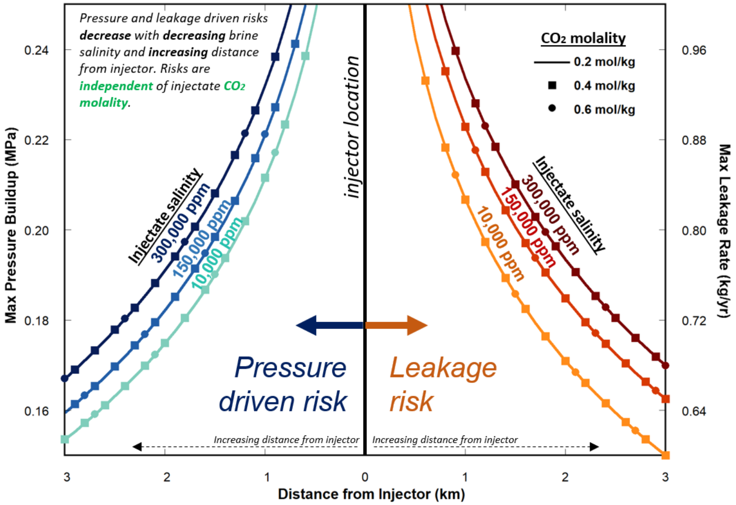
Project Summary

- **Project Summary:** Three year effort to develop a plan for carbonated brine injection, with an end goal of a path for pilot scale implementation.
- **Updates:** Reservoir modeling, wellbore materials compatibility and corrosion modeling, reactive transport modeling.

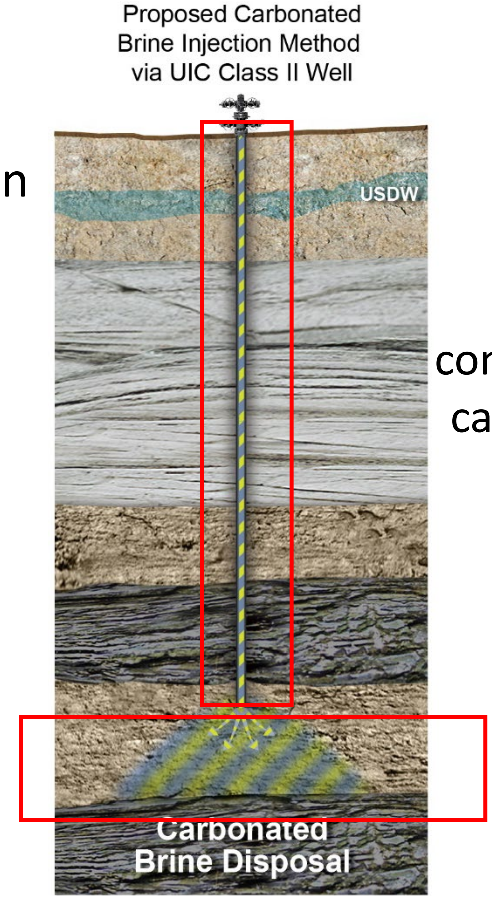
20 years of carbonated produced water injection, following long-term (100 years) of storage in a sandstone reservoir.



Reservoir modeling



Risk analysis



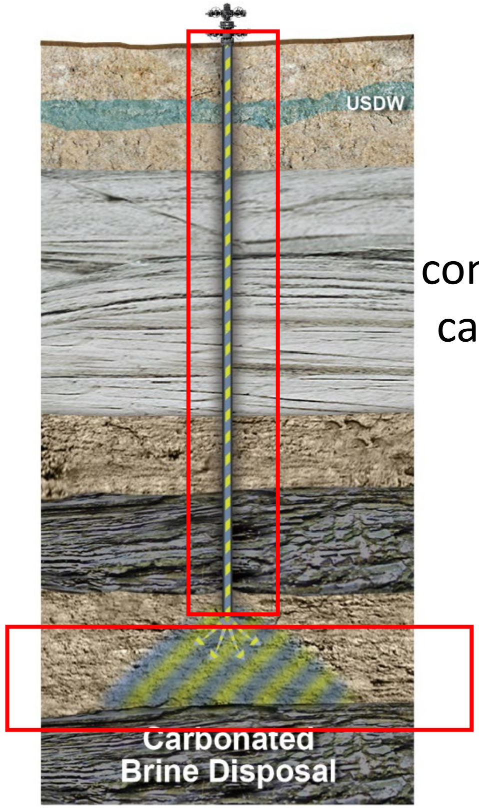
Wellbore compatibility with carbonated brine

CO_2 fate in reservoir

Outline

- Reservoir Flow Modeling
  - Model parameters determined from applicable past field operations.
- Wellbore corrosion modeling
  - Examination of corrosion rates and scaling anticipated for a range of brines, NGL wellbore materials and CO_2 saturations.
- Reactive Transport Modeling
  - Changes in system interrogated from CO_2 injection scenarios.

Proposed Carbonated Brine Injection Method via UIC Class II Well

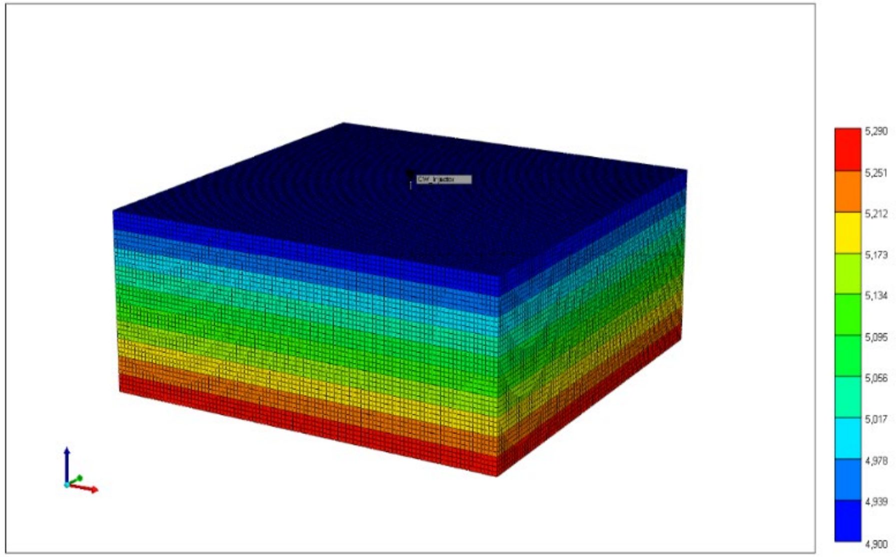


Wellbore compatibility with carbonated brine

CO_2 fate in reservoir

Reservoir Model Overview

- The simulation was built using Computer Modelling Group (CMG) GEM reservoir simulation software.
- Reservoir depth: 4,700 ft
- Reservoir thickness: 300 feet
- Simulation block widths in the I and J direction: 101*101
- Simulation cell size: 10*10-ft with a cell thickness of 10 ft (K).
- Number of layers: 40
  - Mowry Formation, 5 layers
  - Inyan Kara Formation, 30 layers
  - Swift Formation, 5 layers
- Input data: geologic and reservoir data
- For simplicity, model parameters are considered as homogeneous
- The reservoir was assumed to be 100% brine saturated
- Porosity and permeability data extracted from larger BEST model
  - Porosity 23%
  - Horizontal permeability is 284 md; vertical permeability 10% of the horizontal permeability



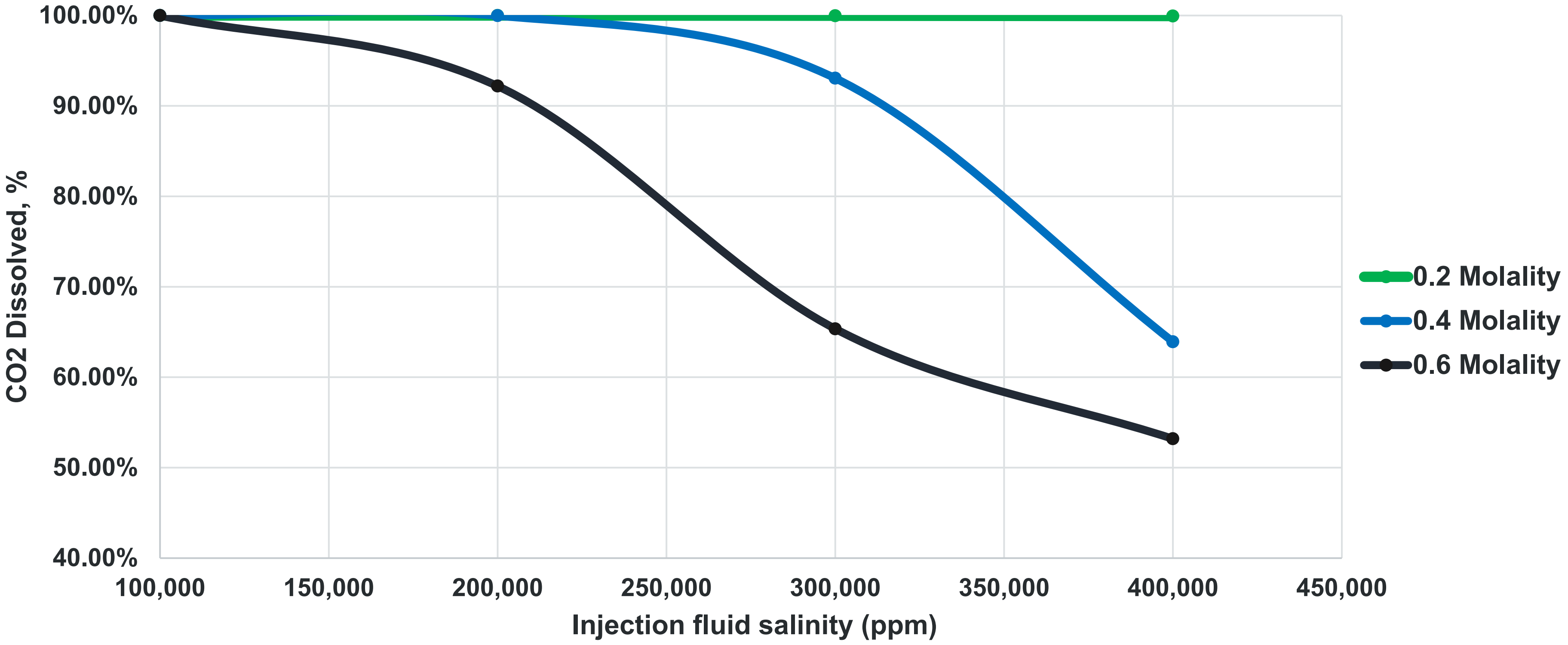
Simulation Input Parameters

Constant Parameters	
Injection Rate (bbl/day)	8,000
Years of Injection • Pre-injection • Post-injection	20 1 100
Reservoir Depth (ft)	4,700
Reservoir Pressure (Psi)	2,255 and 1,500
Reservoir Temperature (F)	165
Wellhead Temperature (F)	60

Results of Predictive Injection Simulation

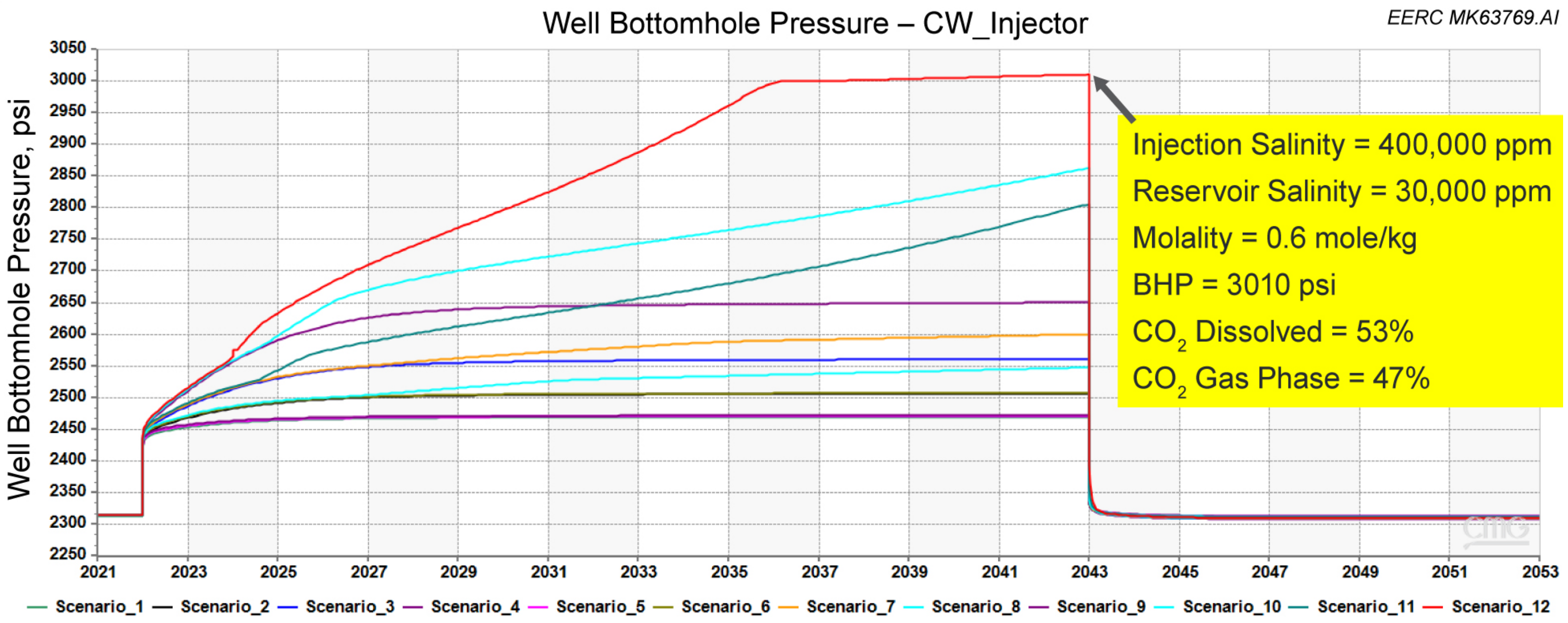
Scenario	Injection fluid salinity (ppm)	Reservoir fluid salinity (ppm)	Molality (mole/kg)	CO_2 Dissolved, %	CO_2 Gas Phase, %
1	100,000	10,000	0.2	99.99%	0.01%
2	200,000	10,000	0.2	99.99%	0.01%
3	300,000	10,000	0.2	99.97%	0.02%
4	400,000	10,000	0.2	99.94%	0.04%
5	100,000	20,000	0.4	99.99%	0.01%
6	200,000	20,000	0.4	99.98%	0.02%
7	300,000	20,000	0.4	93.06%	6.93%
8	400,000	20,000	0.4	63.92%	36.07%
9	100,000	30,000	0.6	99.99%	0.01%
10	200,000	30,000	0.6	92.19%	7.80%
11	300,000	30,000	0.6	65.35%	34.64%
12	400,000	30,000	0.6	53.19%	46.79%

Results: Dissolved CO_2 Profile



- Increases in salinity and molality may have higher impact on the dissolved CO_2.
- An increased water salinity may decrease the solubility of CO_2

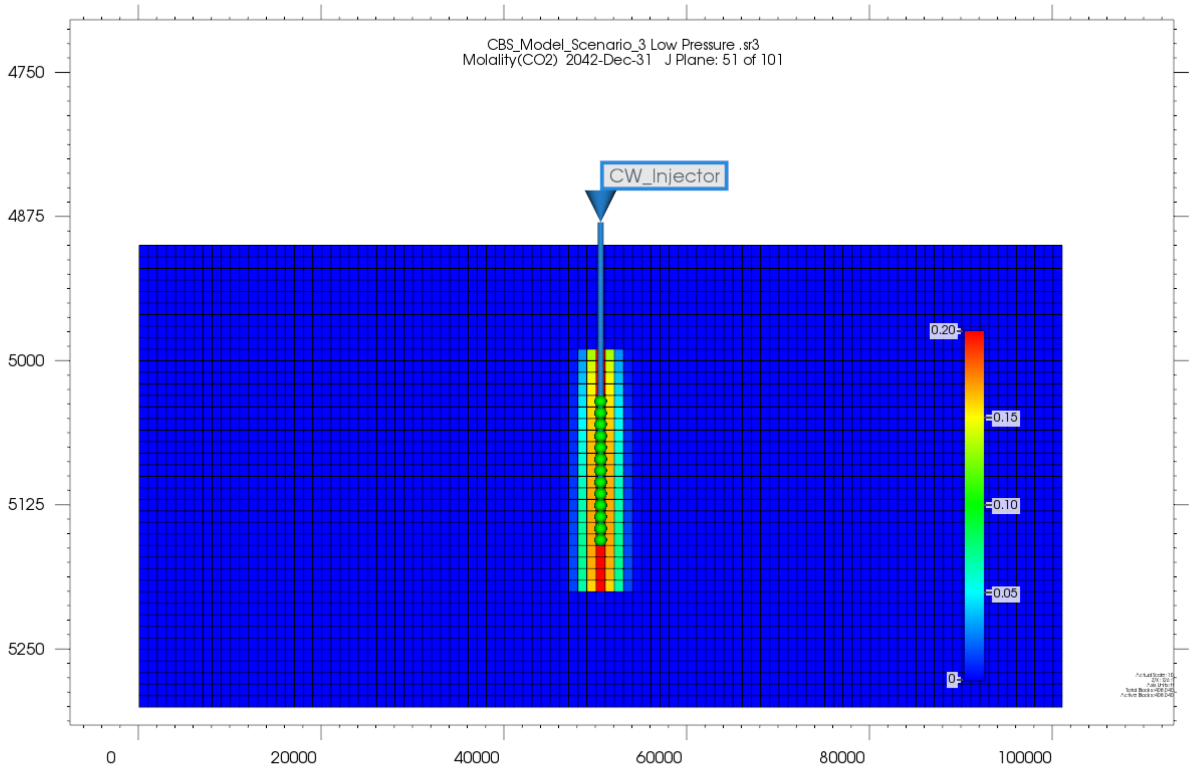
Bottom-hole Pressure Profile

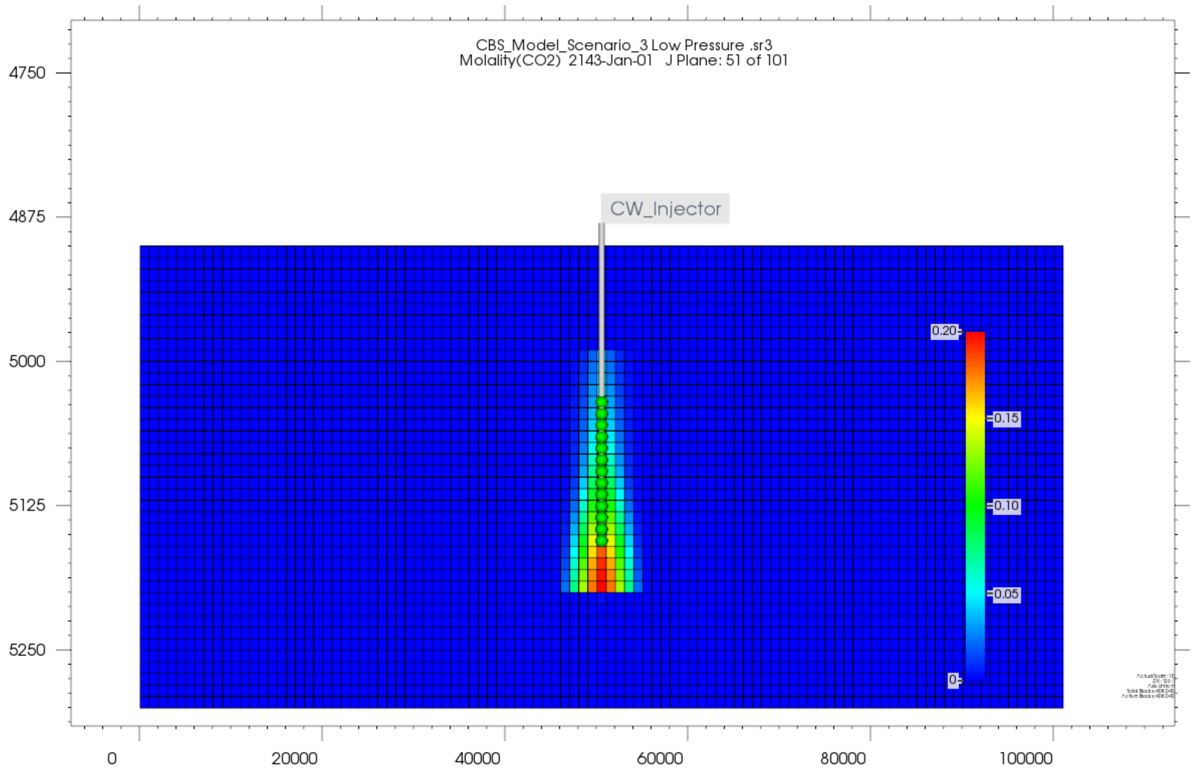


- Bottom-hole pressure increases as the injection salinity and molality rise

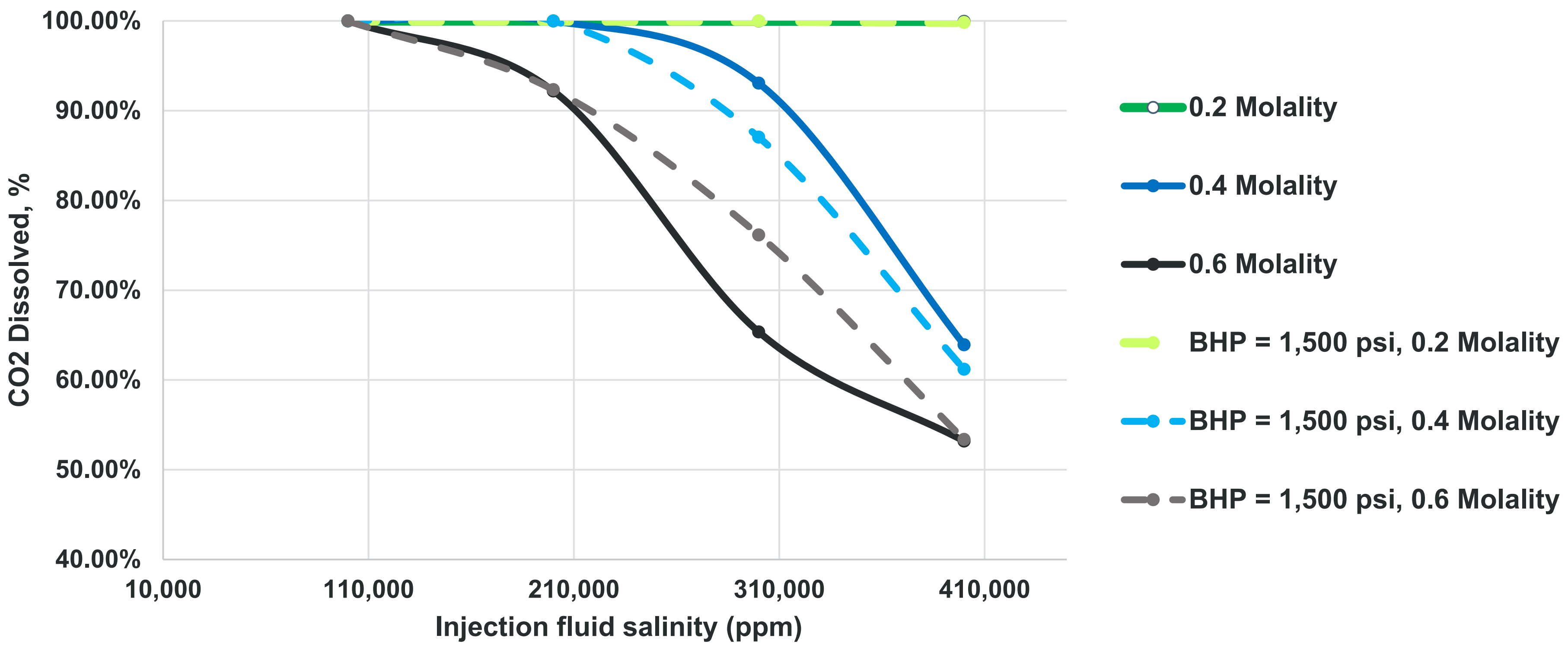
Molality Distribution Within The Reservoir Scenario 3

Dissolved CO_2 moves downward



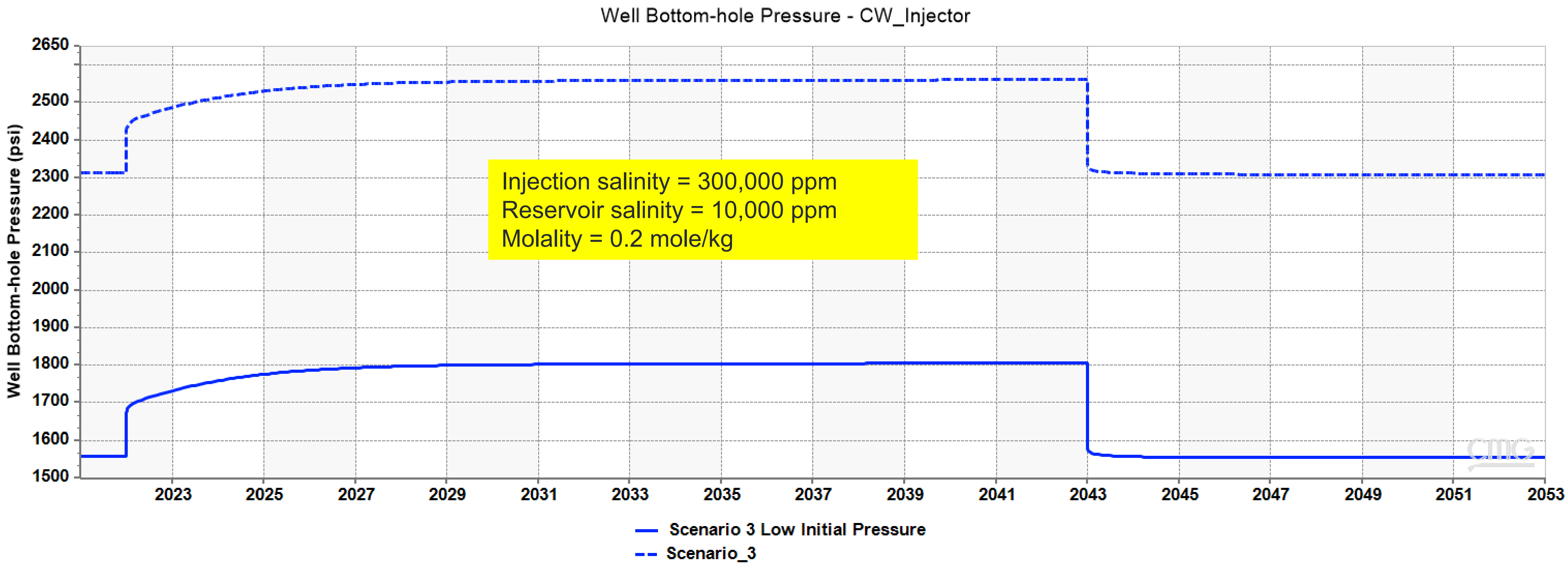


Additional Scenarios: Bottom-hole Pressure = 2,255 psi and 1,500 psi



- The relationship between pressure and the solubility of CO_2 in brine is complex and depends on a variety of factors. However, 0.2 molality may represent the best balance of volume of CO_2 injected and volume of CO_2 remaining in solution

Bottom-hole Pressure Profile



Reservoir Model Summary

NATIONAL ENERGY TECHNOLOGY LABORATORY

- Recommended CO_2 molality for all scenarios: 0.2 mol/kg.

- This concentration can increase if the injection fluid salinity is lower.
  - Salinity < 200,000 ppm, CO_2 molality = 0.4 mol/kg.
  - Salinity <100,000 ppm, CO_2 molality = 0.6 mol/kg.

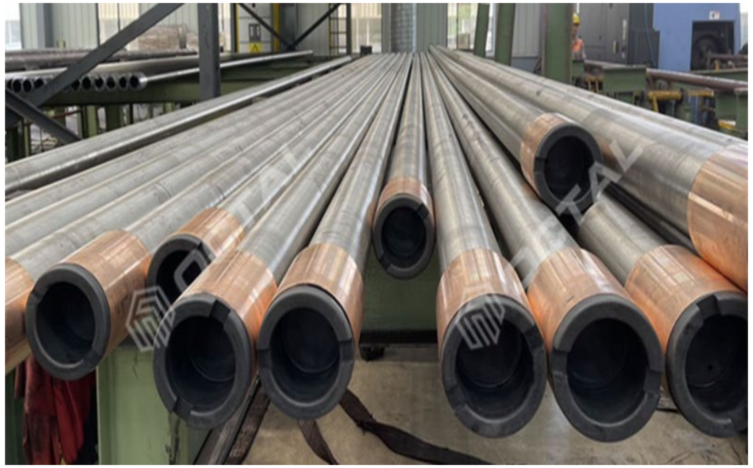
- This dissolution molality range will ensure no free-phase CO_2 in the carbonated brine.

Wellbore Corrosion Model

Wellbore materials and corrosion issue in class II well: NGL wells

➢ ***Corrosion***

- **Tubular materials and long string** made of Carbon steel L80 (API 5CT). Internally coated.
  - API 5CT L80 casing and tubing include grades L80-1, L80 9Cr (Cr 8%-10%), L80 13Cr (Cr 12%-14%)
  - Uncoated carbon steel L80-1 is susceptible to CO_2 corrosion
  - Corrosion resistant alloy (CRA) casing L80 9Cr (Cr 8%-10%)& L80 13Cr (Cr 12%-14%) are susceptible to localized corrosion due to metallurgical structure, chloride concentration, temperature, pH, Presence of other species such as scaling ions, organic acids, and CO_2 and H_2S gases.



API 5CT L80 13Cr Casing

Carbonated Brine Chemistry

Produced water data (Excel) input to OLI.

- USGS produced water (15000 dataset)-North Dakota-McKenzie County-Bakken formation
- Remove data with above +-5% charge imbalance. Use averaged data.

  - ➢ Chemical Composition of produced water- **No added CO_2** , Steam amount = 1L. Temperature 25° C, **1 atm**

Total Dissolved	Total Diss	Total	mg/L	
TIC	TIC		mol C/L	Average
Density			g/mL	1.17
PH	pH			5.94
K+1	Potassium		mg/L of K+	4483.17
Na+1	Sodium		mg/L of Na+	75341.45
Ba+2	Barium		mg/L of Ba2+	34.40
Ca+2	Calcium		mg/L of Ca2+	16674.76
Fe+2	Iron II		mg/L of Fe2+ (If specified, else all Total assigned to Fe2+)	124.71
Mg+2	Magnesium		mg/L of Mg2+	1091.15
Cr+3	Chromium III		mg/L of Cr3+	0.69
Cl-1	Chloride		mg/L of Cl-	152006.21
HCO3-1 as C	Bicarbonate		mmol/L of C	32.78
NO3-1	Nitrate		mg/L of NO3-	151.96
SO4-2	Sulfate		mg/L of SO42-	613.46

- ➢ Chemical Composition of produced water **with 0.2 mole/kg (8800 mg/L)CO_2**. Steam amount = 1L. Temperature 25° C, **6.415 atm**
- ➢ Chemical Composition of produced water **with 0.6 mole/kg (26400 mg/L) CO_2**. Steam amount = 1L. Temperature 25° C, **20 atm**

Scaling Tendency

Brine Analysis

Scaling Tendency Definition

The Scaling Tendency (ST) is the ratio of the Ion Activity Product (IAP) to the solubility product constant (K_{sp}).

$$Scale\ Tendency = S_{mineral} \cong \frac{C}{C_0} = \frac{IAP}{K_{sp}}$$

Where

C = measured concentration

C_0 = concentration at equilibrium

IAP = ion activity product

K_{sp} = Thermodynamic Solubility Product Constant

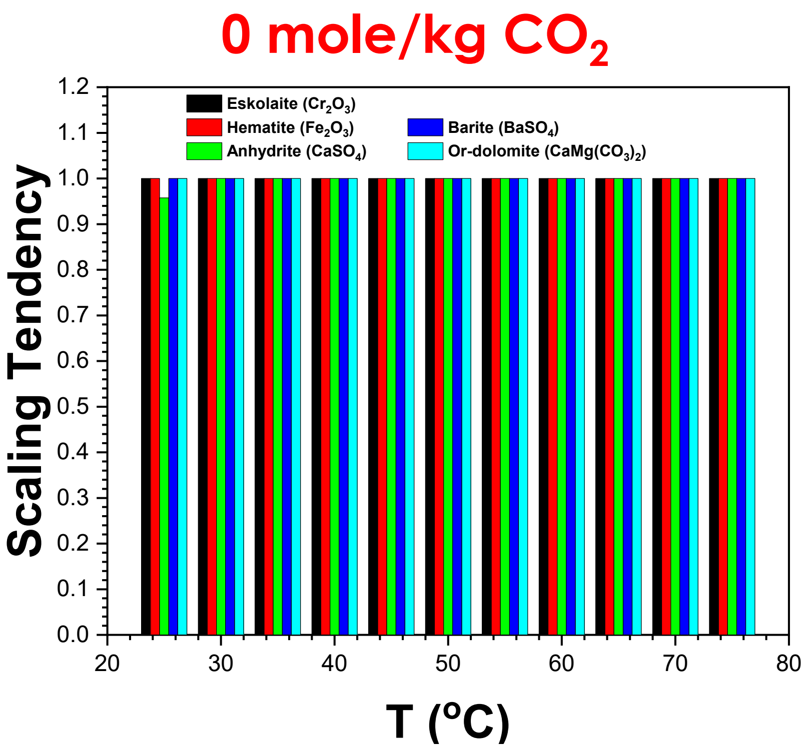
Thus,

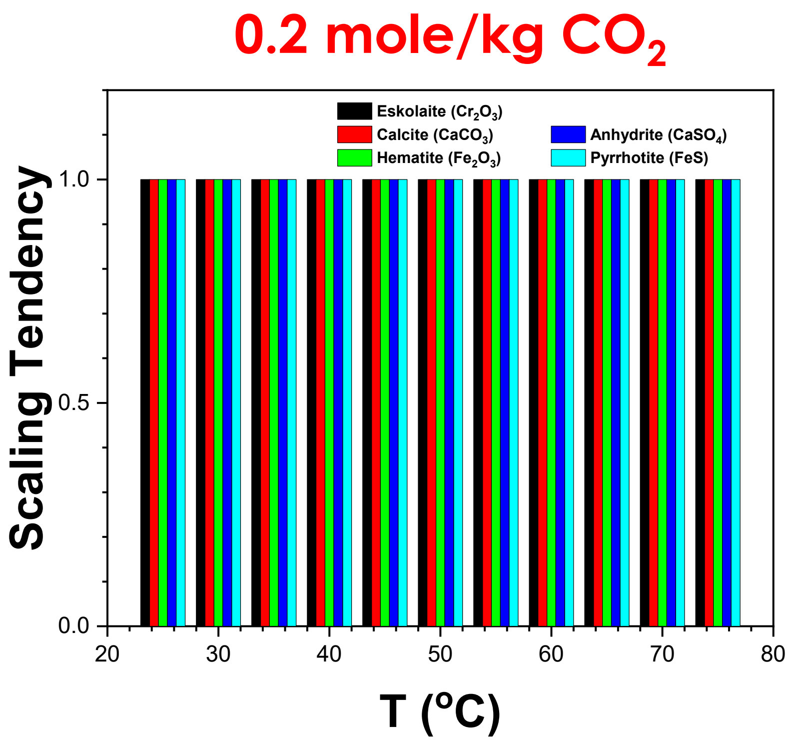
- **ST < 1** Indicates sub-saturation, and the solid is not expected to form
- **ST = 1** Indicates saturation, and the solid is in equilibrium with water
- **ST > 1** Indicates supersaturation, and solids will form

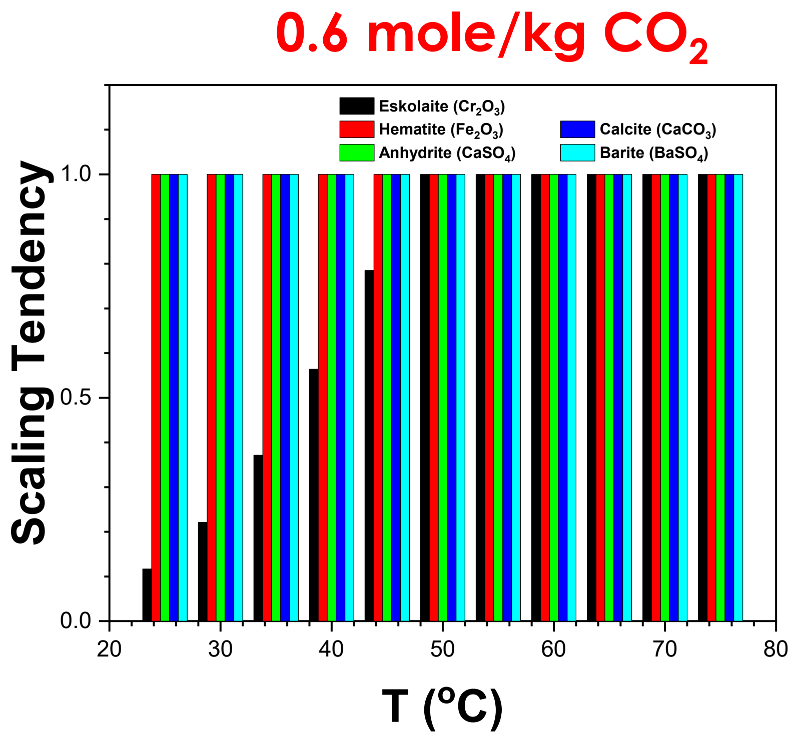
Scaling Tendency

OLI simulation used to predict scaling tendency.

Brine solution is contact with Super 13Cr stainless steel

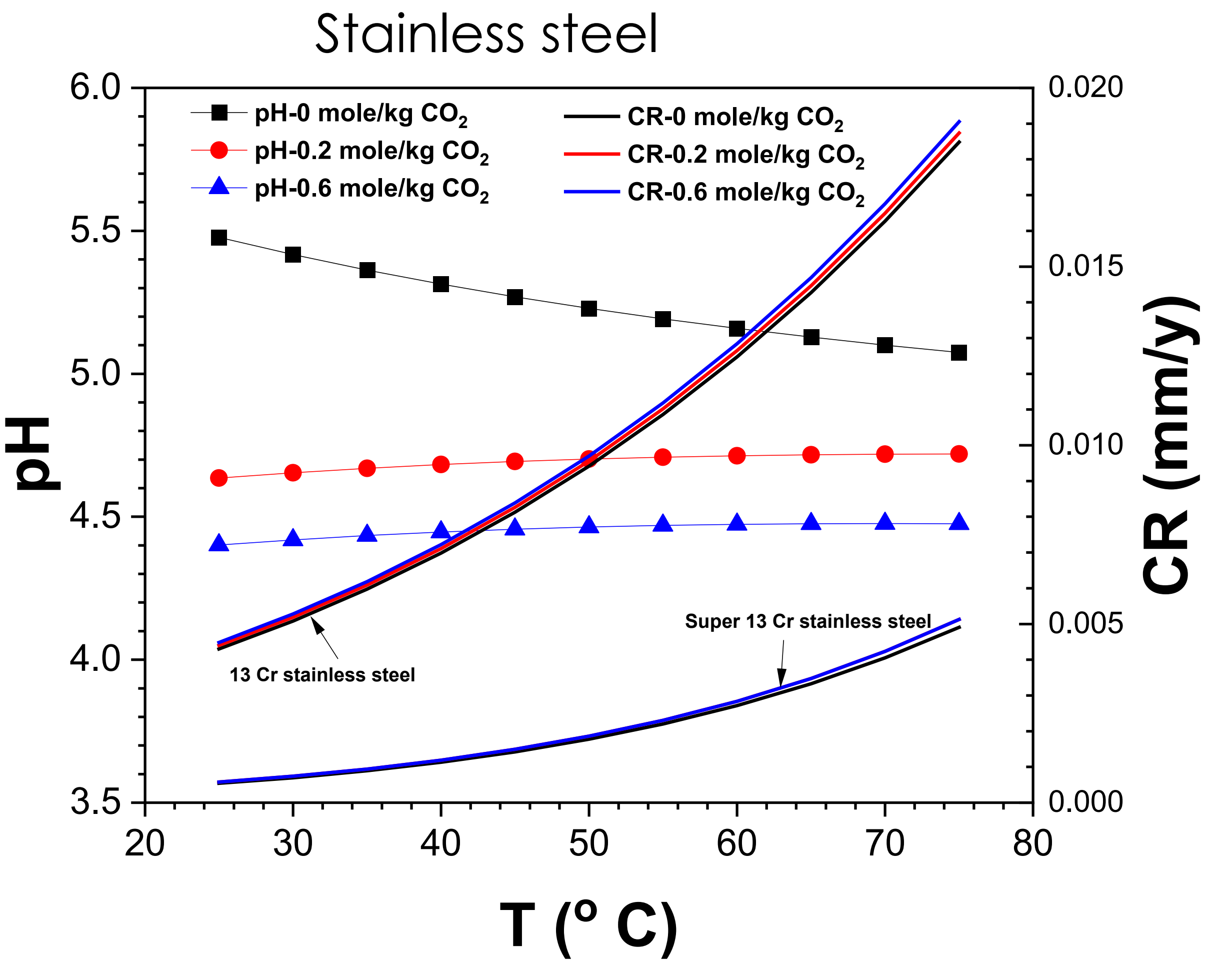






Wellbore Corrosion Rate

OLI simulation to predict corrosion rates and calculate pH



Wellbore corrosion model summary:

- Acceptable corrosion rates for carbonated brine injection (<0.02 mm/y)
- Scale minerals (which is not considered in the corrosion model) can further reduce corrosion rate.

Reactive Transport Model

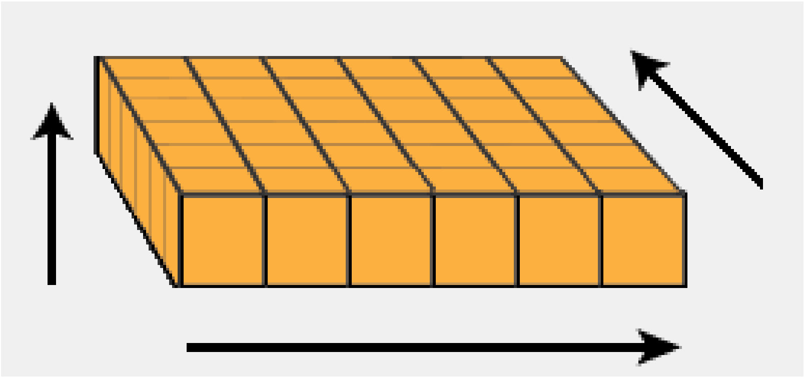
NATIONAL ENERGY TECHNOLOGY LABORATORY

2D Reactive Transport Model for Rock-Fluid Geochemical Interactions

- Reservoir: 300m x 300m x 100m
- Well location: x,y = 150m, 150m, well fluid discharge rate = 1280 m^3/day (8000 bbl/day)
- Reservoir boundary is set to be open on both sides, without fluid velocity/discharge
- Longitudinal dispersivity = 100 cm, transverse dispersivity = 10 cm
- Diffusion coefficient = 1e-6 cm2/s
- Nodes number: 29 x 29

closed

Open
No fluid discharge



Open

Injection point in the middle of the domain

closed

Rock-Fluid System

NATIONAL ENERGY TECHNOLOGY LABORATORY

Formation	Concentration	Injection water	Concentration
Quartz	70.5 volume %	SiO2(aq)	
Muscovite	2.7 volume %	Al+++	
Siderite	3.8 volume %	Fe++	124.71 mg/L
Mg++	57 mg/L	Mg++	1091.15 mg/L
pH	6.1	pH	5.94
Ca++	259 mg/L	Ca++	16674.76 mg/L
Na+	7114 mg/L	Na+	75341.45 mg/L
K+	408 mg/L	K+	4483.17 mg/L
Cl-	10600 mg/L	Cl-	152006.21 mg/L
SO4--	1000 mg/L	SO4--	613.46 mg/L
HCO3-	1086 mg/L	HCO3- as C	0.2 molal
Ba++		Ba++	34.40 mg/L
NO3-		NO3-	151.96 mg/L

Temperature = 74 $^\circ$C

Chu, Min H. Study of the geothermal production potential in the Williston Basin, North Dakota. No. DOE/ID/12736-2. North Dakota Univ., Grand Forks, ND (United States). Energy and Environmental Research Center, 1991.

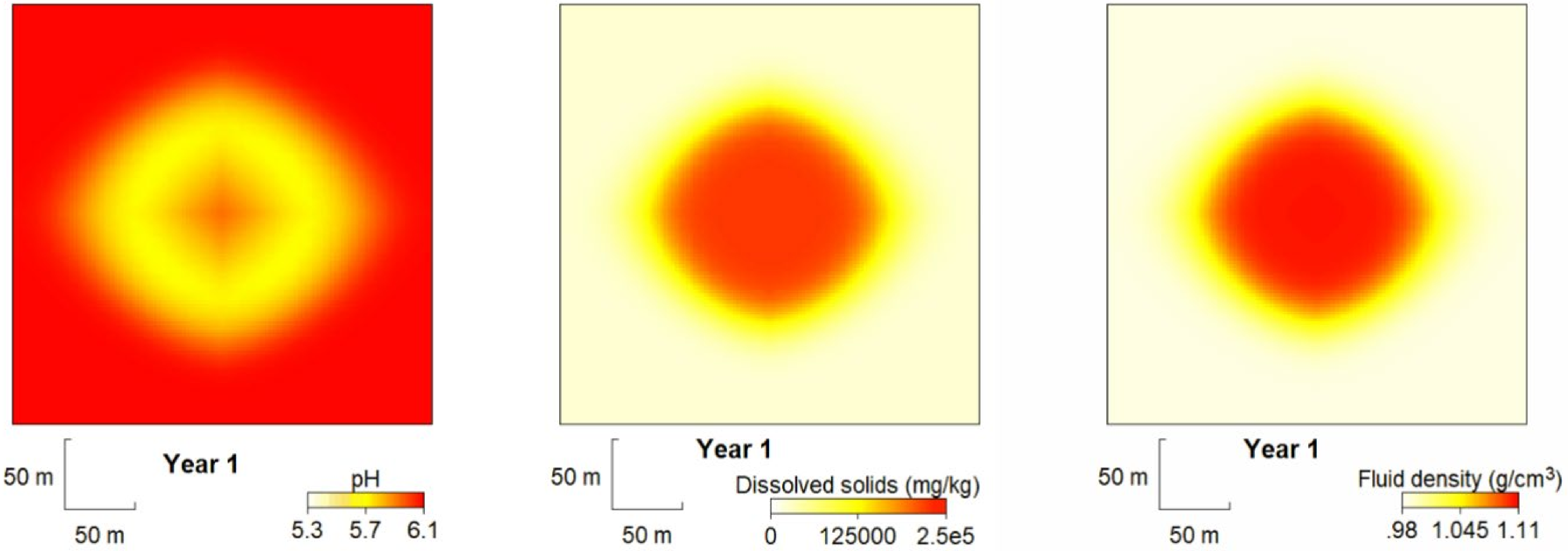
Mineral kinetics

NATIONAL ENERGY TECHNOLOGY LABORATORY

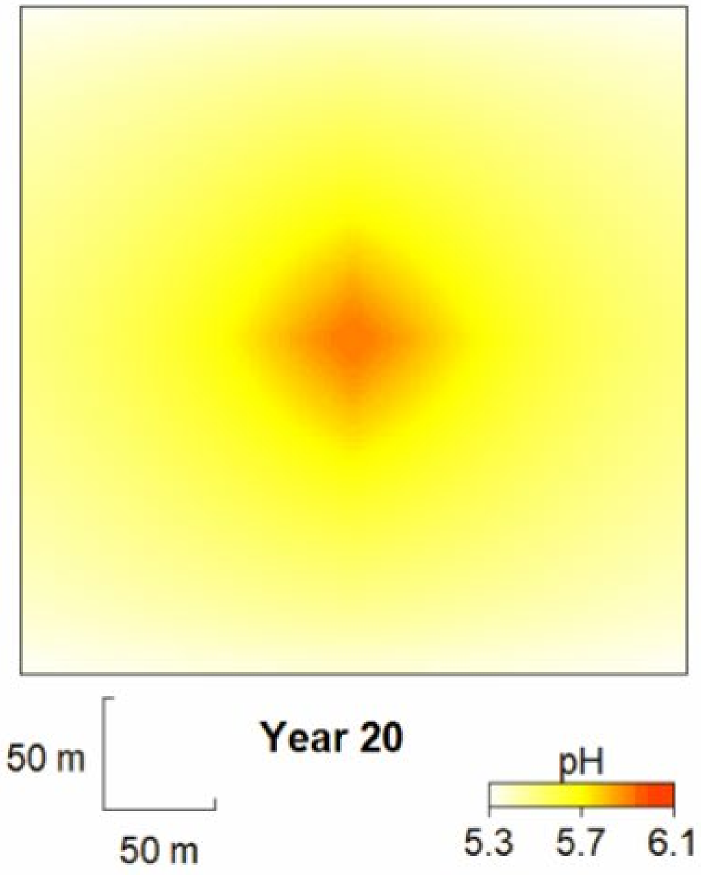
Primary

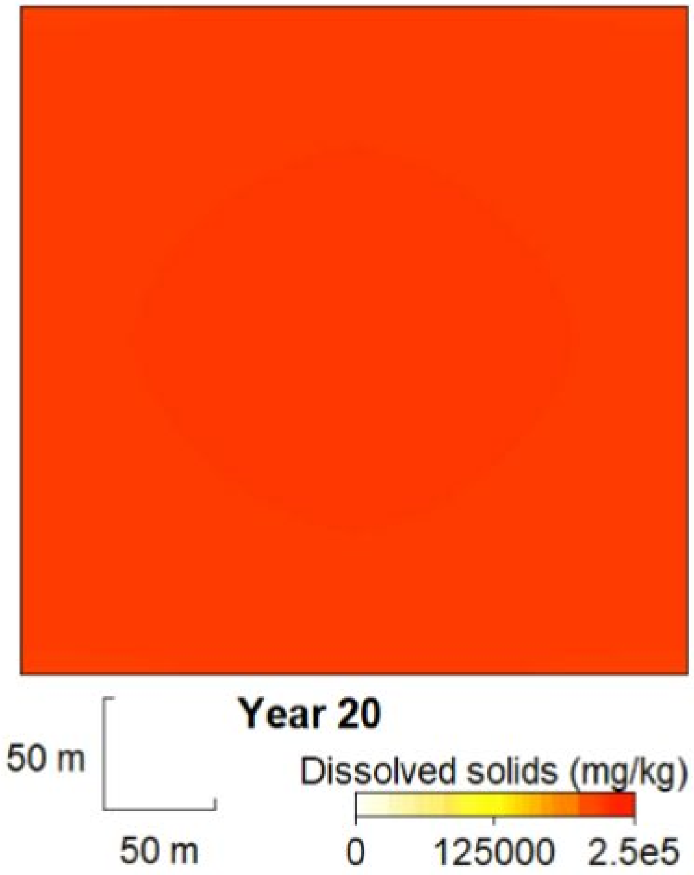
Minerals	k (mol/cm2 s)	E (J/mol)	SA (cm2/g)	nucleus (cm2/cm3)	Reference
Quartz	1.00E-16	87500	1000		Rimstidt and Barnes 1980
Muscovite	2.00E-16	64000	1000		Nagy 1995
Siderite	2.00E-11	55000	1000		set to dolomite
Barite	1.26E-12	30800	1000	1000	Palandri and Kharaka 2004
Calcite	1.58E-10	63000	1000	1000	Plummer et al. 1978
Dolomite	2.00E-11	55000	1000	1000	Busenberg and Plummer, 1982
Witherite	4.47E-12	41900	1000	1000	set to strontianite, Sonderegger et al., 1976
Kaolinite	3.98E-16	64000	1000	1000	Sverdrup, 1990
Dawsonite	1.00E-11	62800	1000	1000	Palandri and Kharaka 2004
Magnesite	4.57E-14	23500	1000	1000	Palandri and Kharaka 2005
Aragonite	1.58E-10	63000	1000	1000	set to calcite
Huntite	2.00E-11	55000	1000	1000	set to dolomite
Monohydrocalcite	1.58E-10	63000	1000	1000	set to calcite
Maximum Microcline	1.26E-15	58000	1000	1000	set to K-feldspar
K-feldspar	1.26E-15	58000	1000	1000	Helgeson et al., 1984

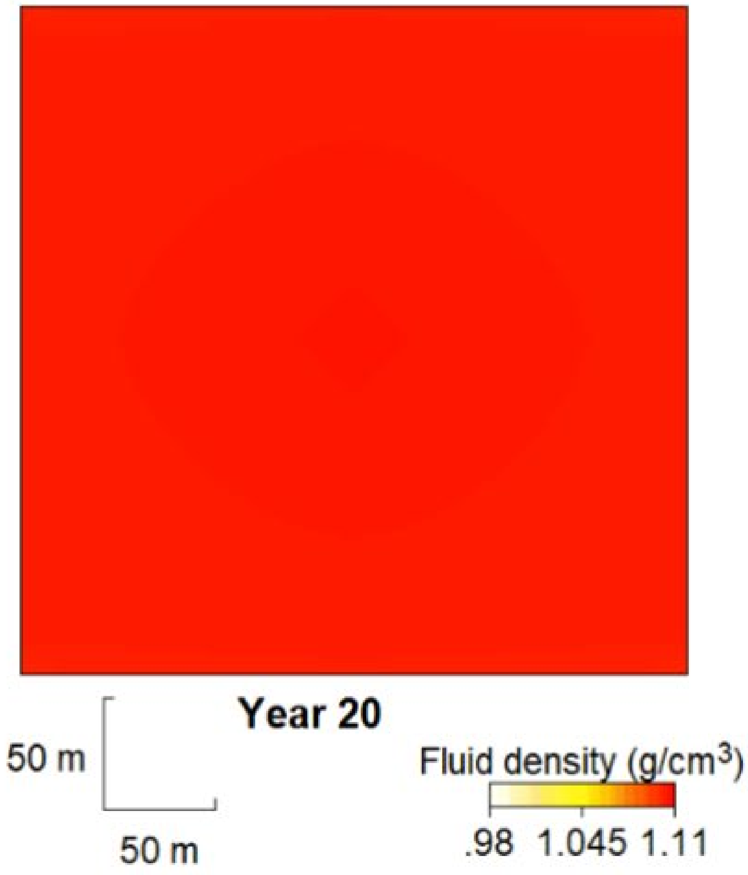
Injection Period (year 0-20)
System Parameters



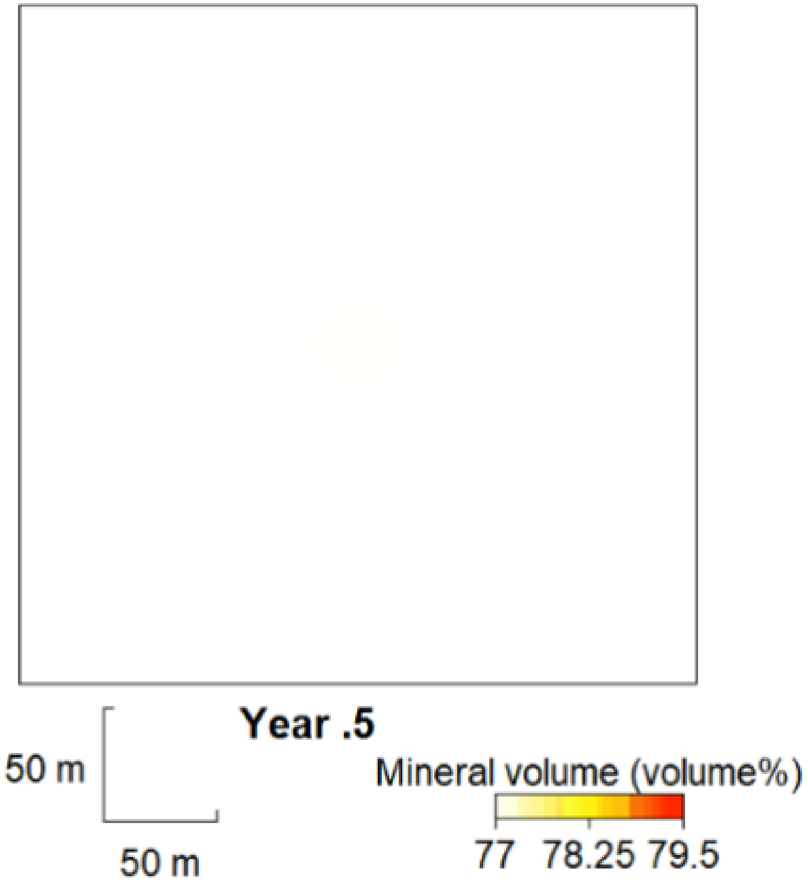
Injection Period (year 0-20)
System Parameters

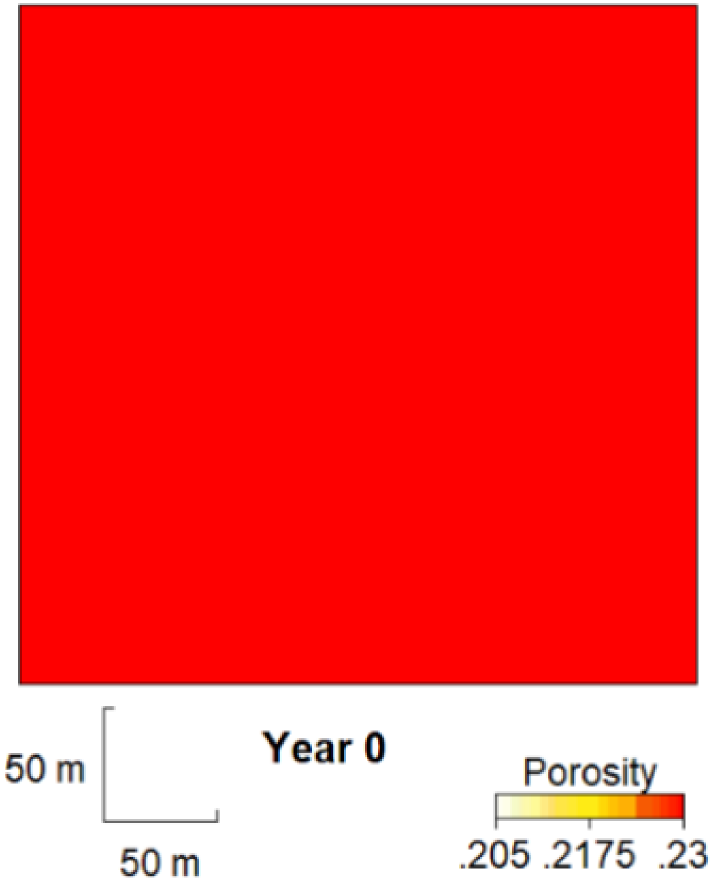




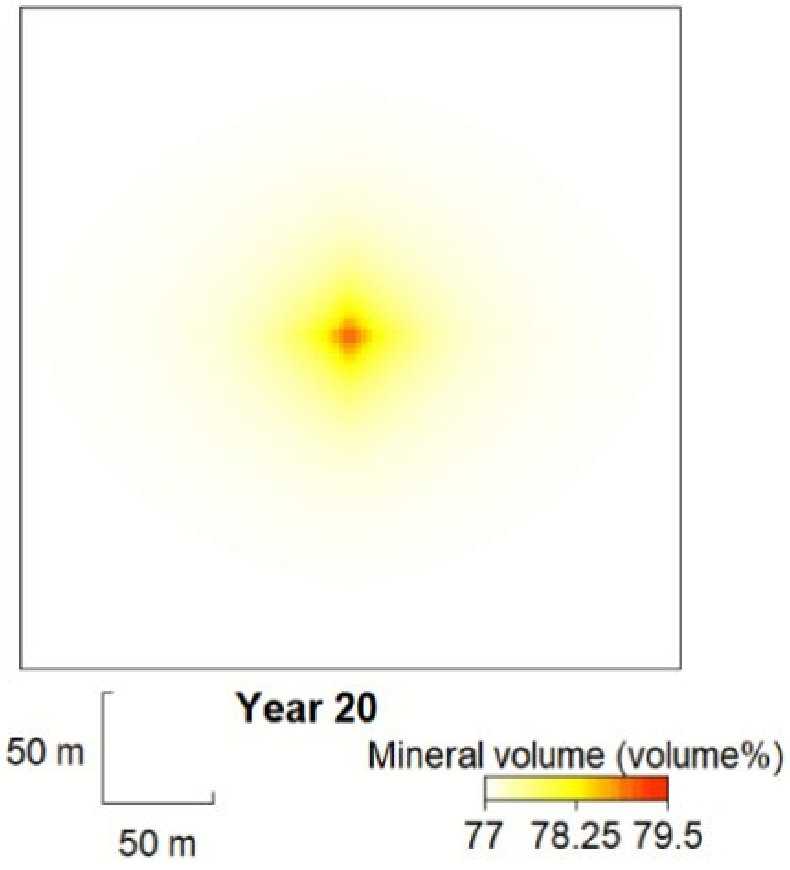


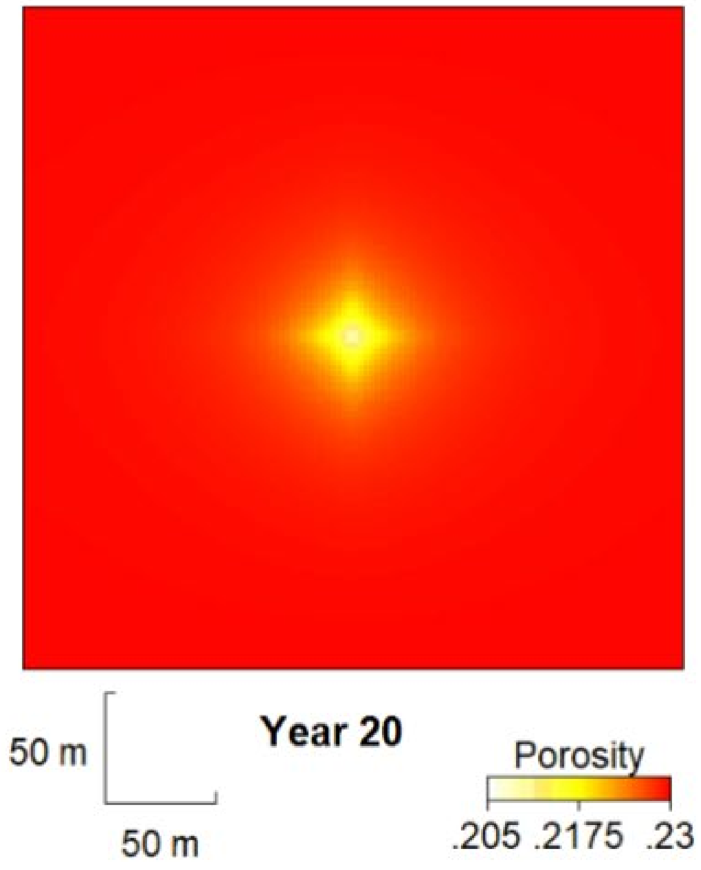
Injection Period (year 0-20)
System Parameters



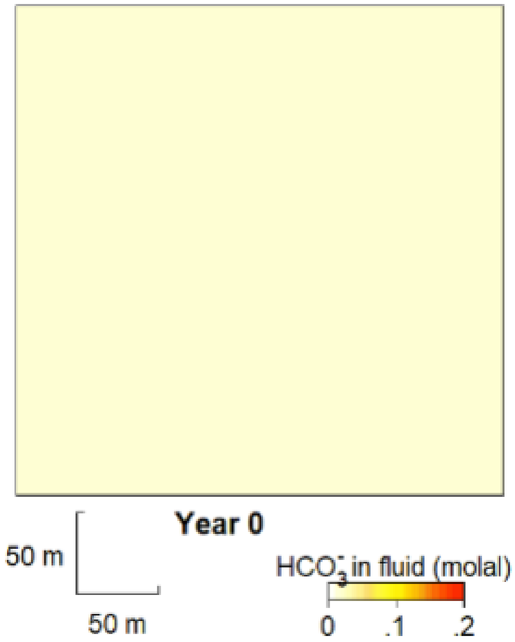


Injection Period (year 0-20)
System Parameters

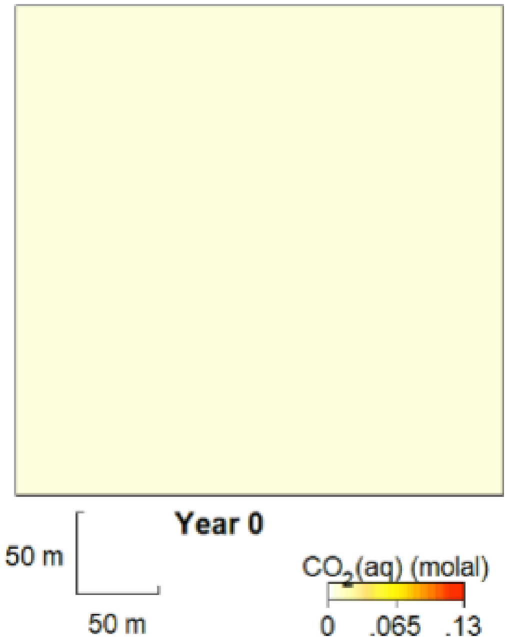




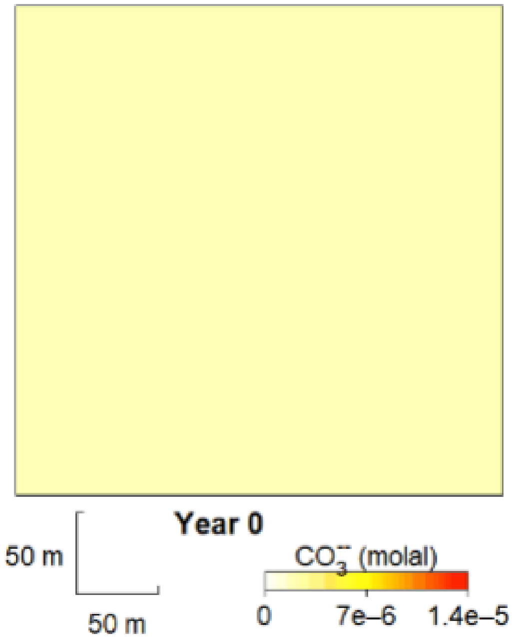
Injection Period (year 0-20) Dissolved Carbon



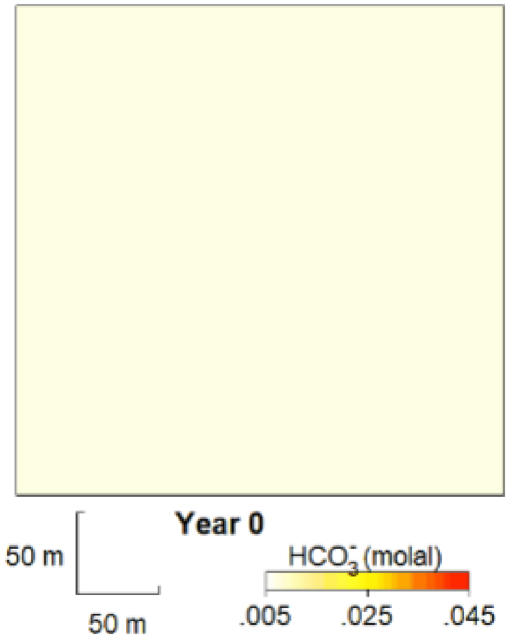
Total Aqueous C



CO_2 (aq)



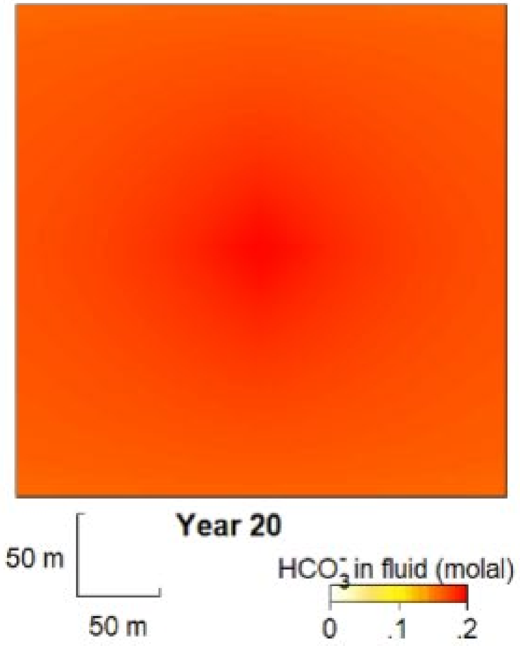
CO_3^{2-}



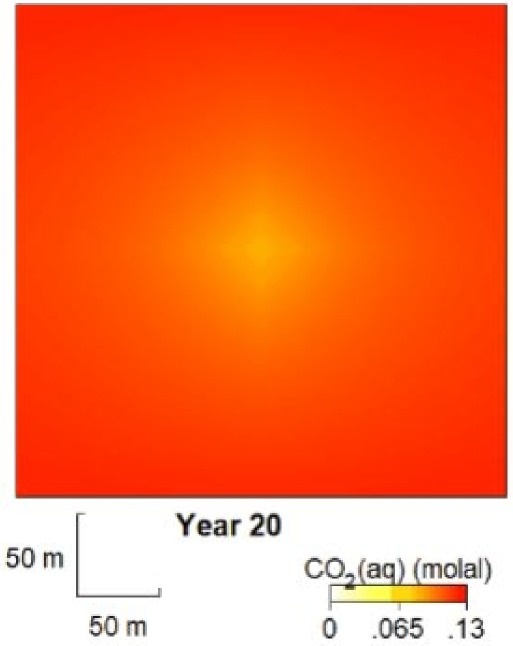
HCO_3^-

Injection Period (year 0-20) Dissolved Carbon

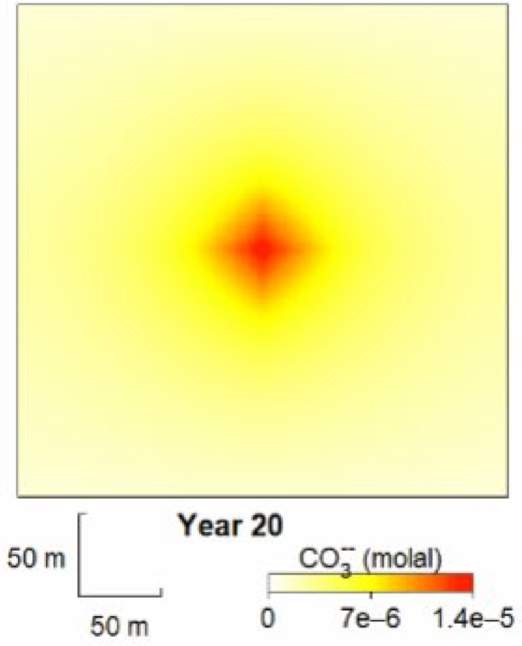
NATIONAL ENERGY TECHNOLOGY LABORATORY



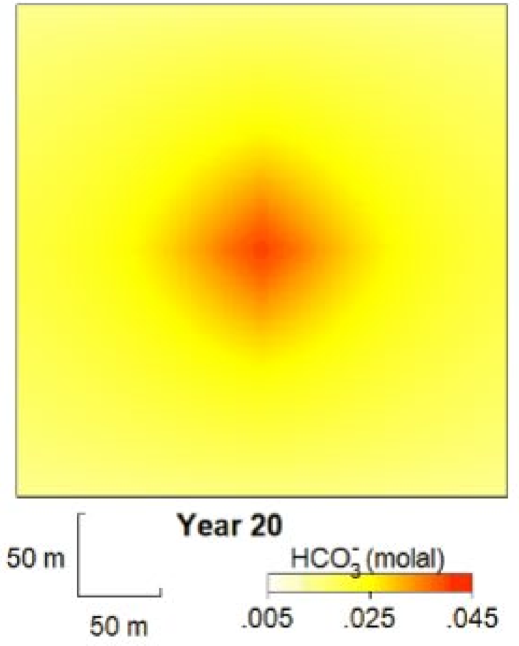
Total Aqueous C



CO_2 (aq)



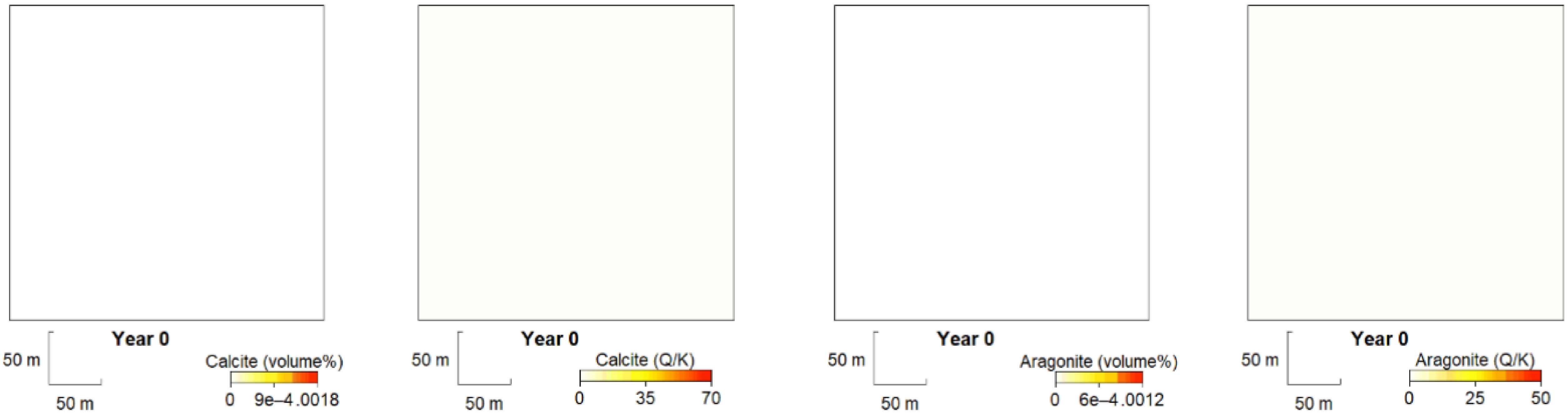
CO_3^{2-}



HCO_3^-

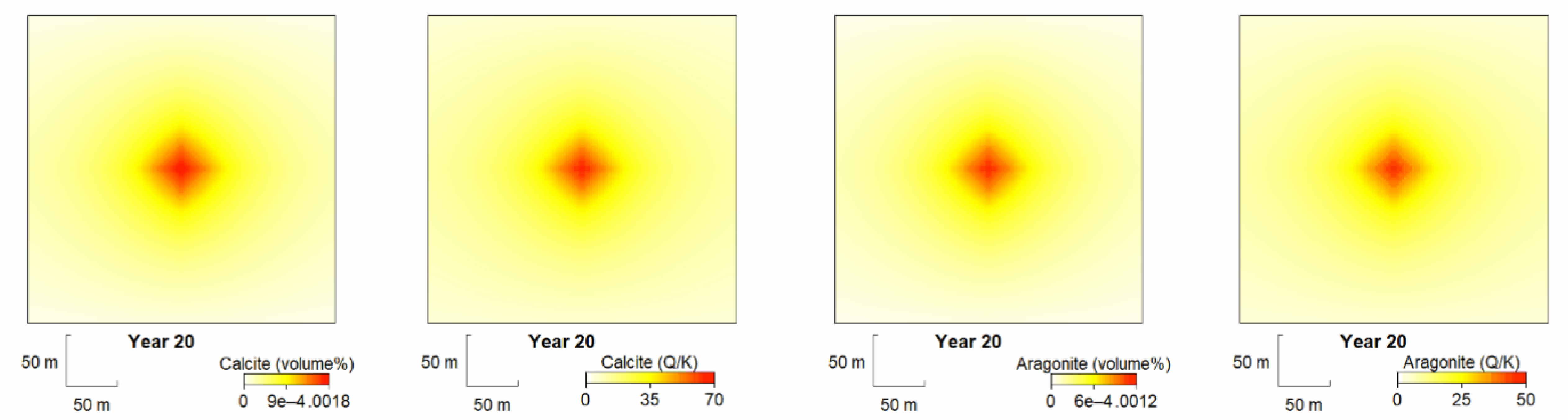
Injection Period (year 0-20)
Secondary Minerals-Carbonate Example

NATIONAL ENERGY TECHNOLOGY LABORATORY



Calcite and aragonite $CaCO_3$

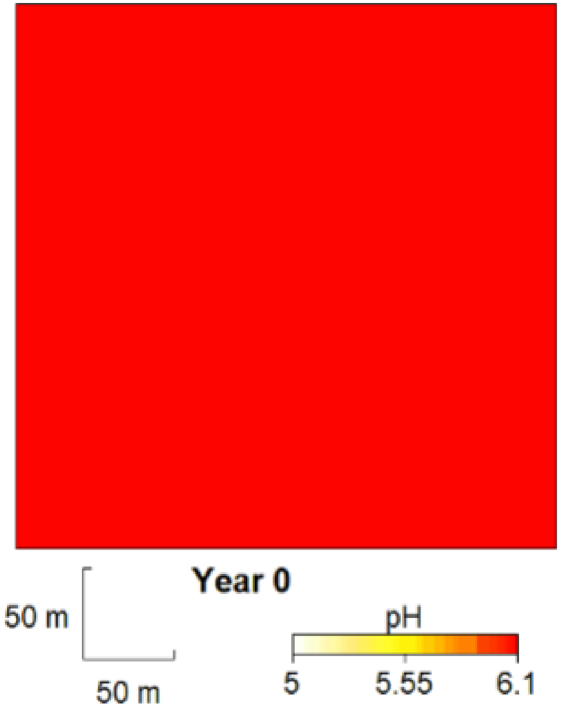
Injection Period (year 0-20)
Secondary Minerals-Carbonate Example

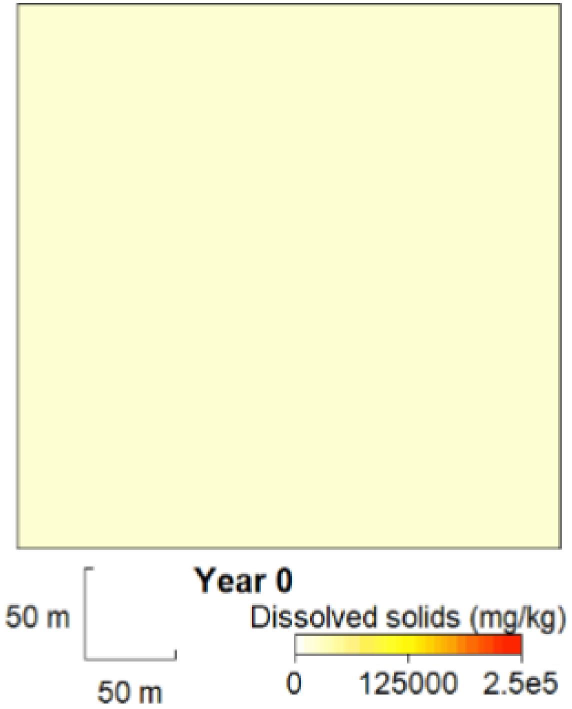


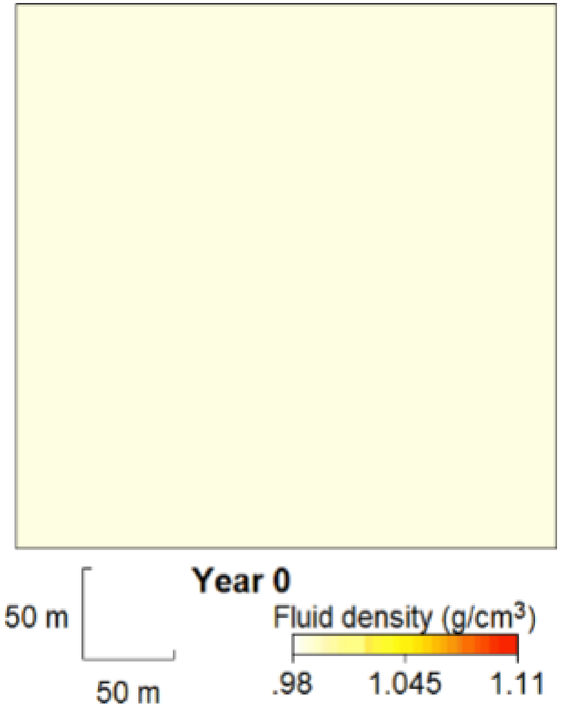
Calcite and aragonite $CaCO_3$

Shut-in Period (Year 0-120, Injection Stops at Year 20) System Parameters

NATIONAL ENERGY TECHNOLOGY LABORATORY

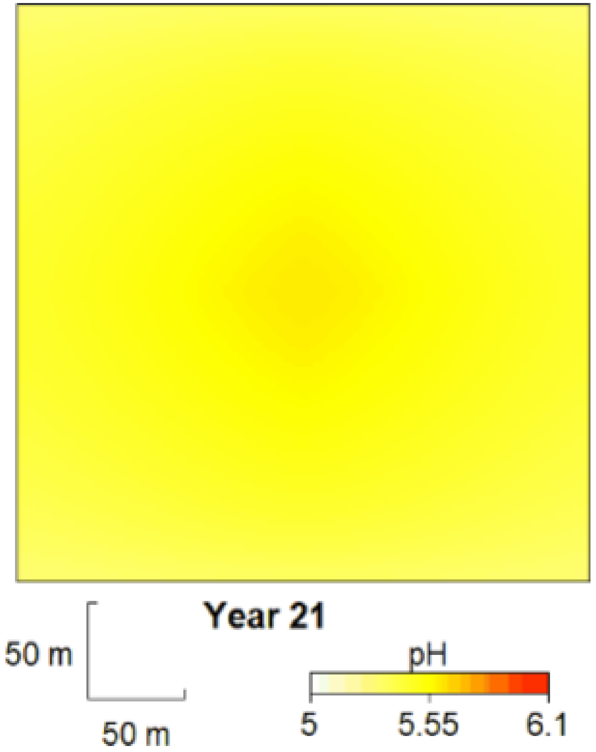


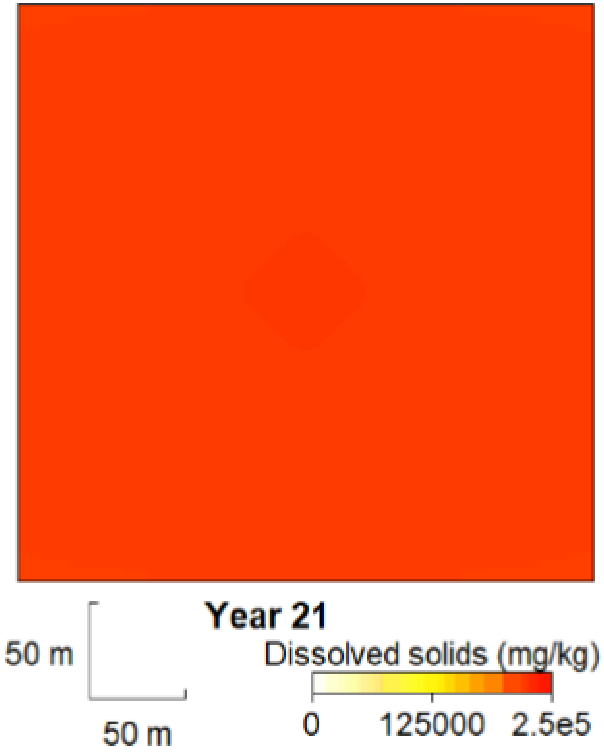


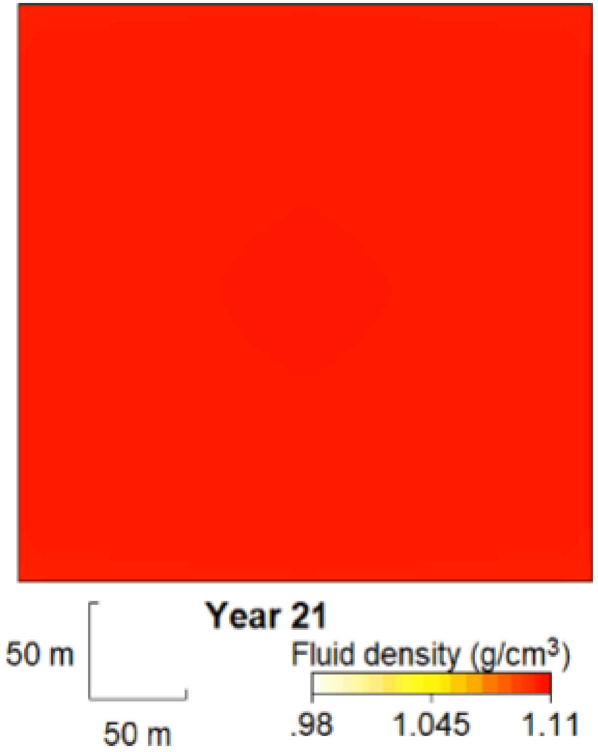


pH keeps decreasing

Shut-in Period (Year 0-120, Injection Stops at Year 20)
System Parameters

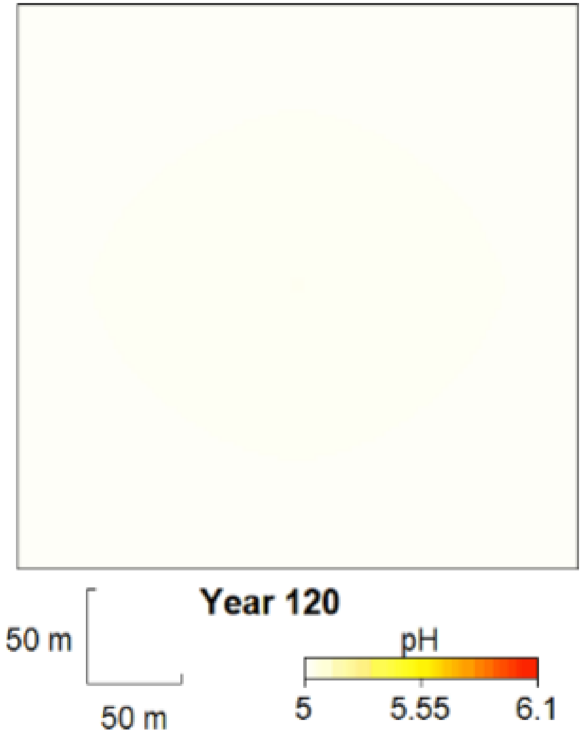


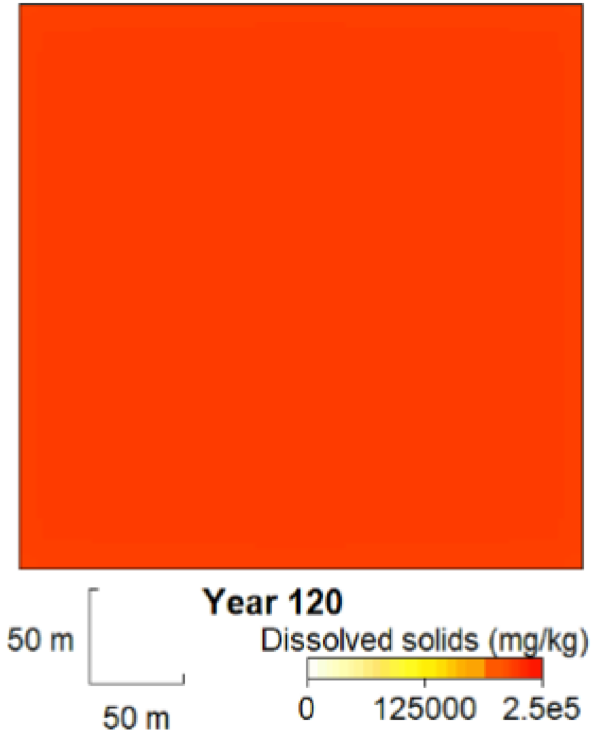


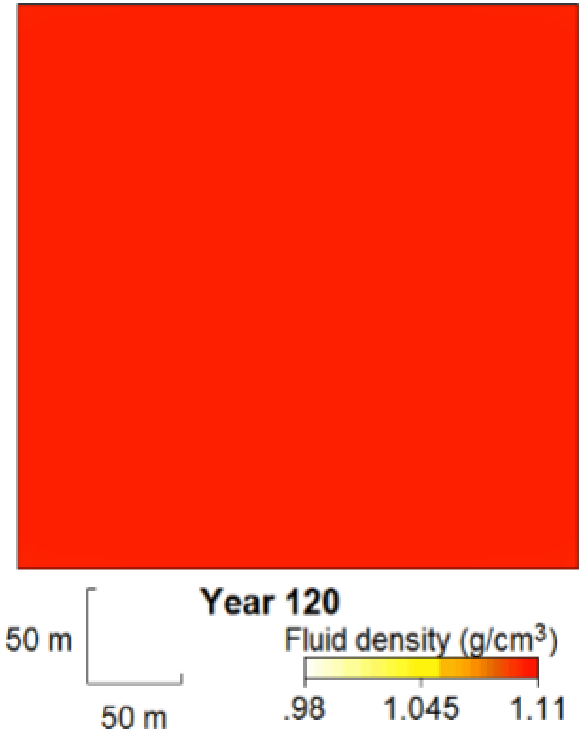


pH keeps decreasing

Shut-in Period (Year 0-120, Injection Stops at Year 20) System Parameters

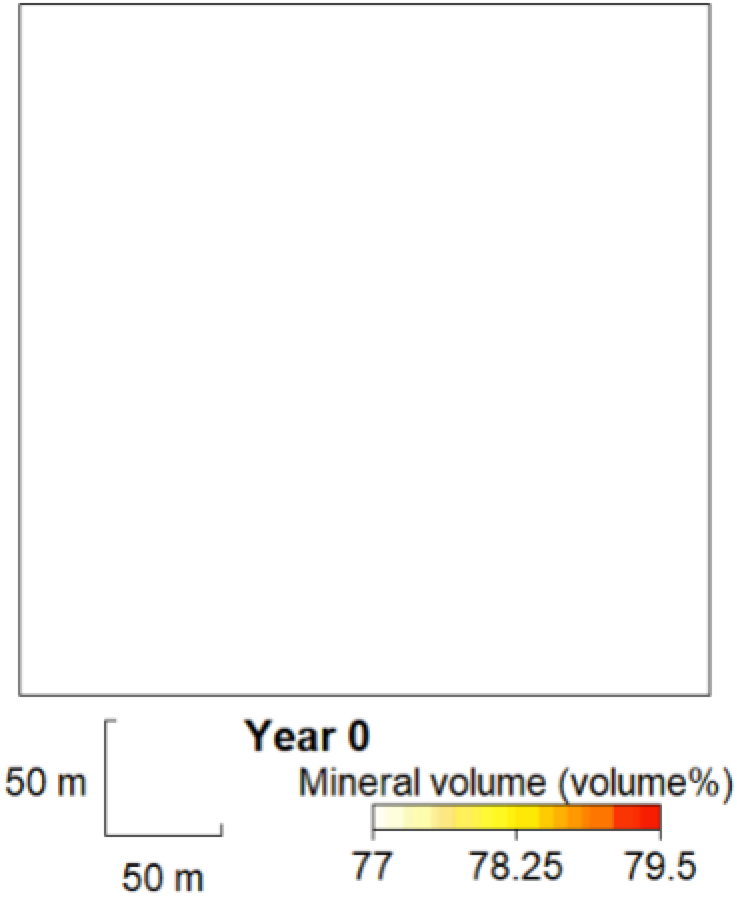


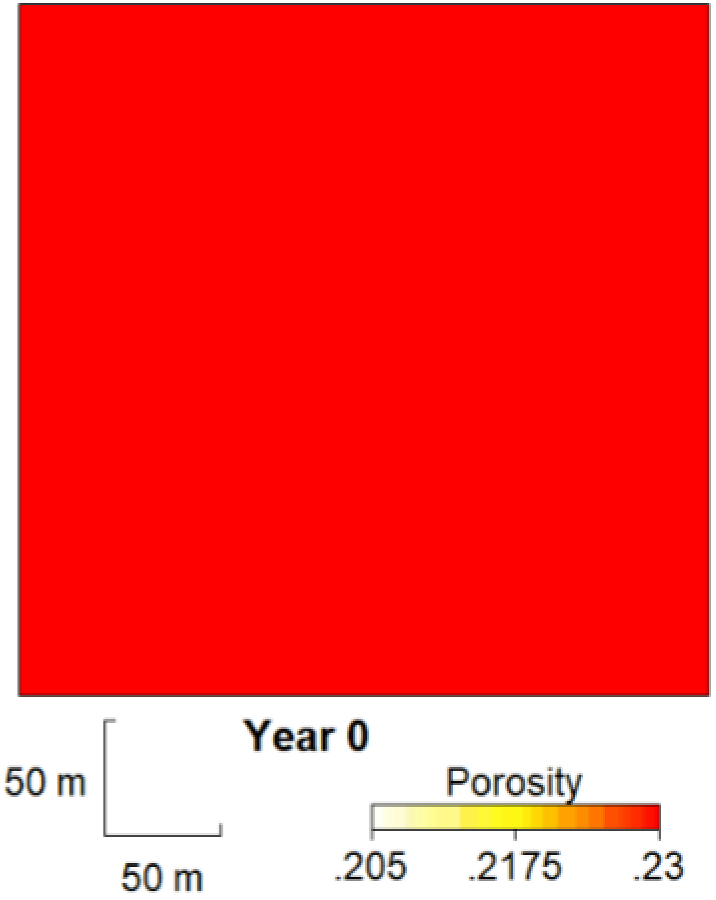




pH keeps decreasing

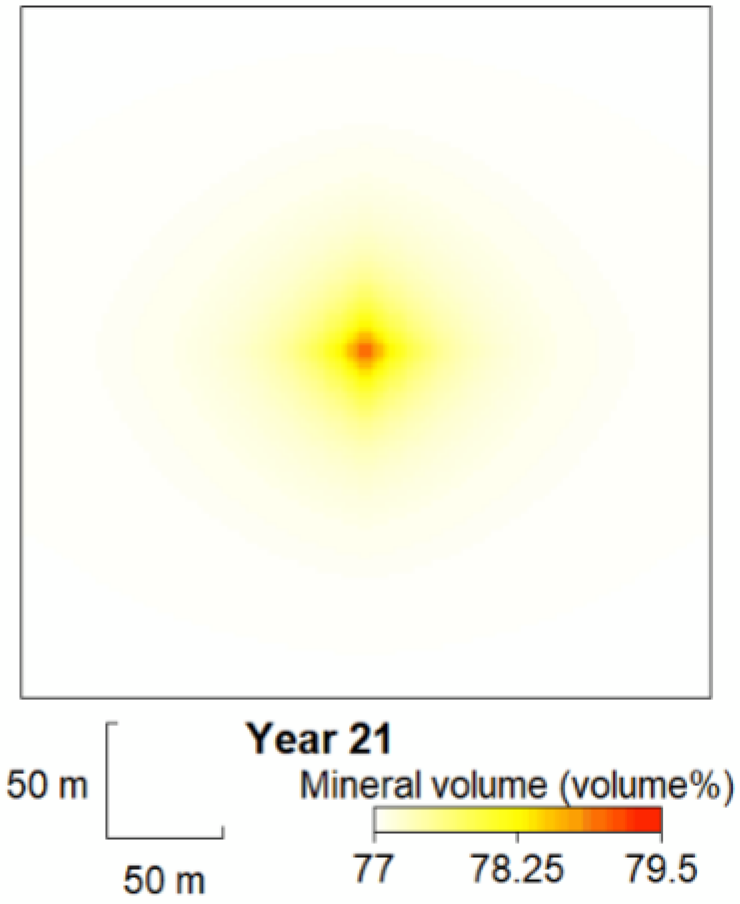
Shut-in Period (Year 0-120, Injection Stops at Year 20)
System Parameters

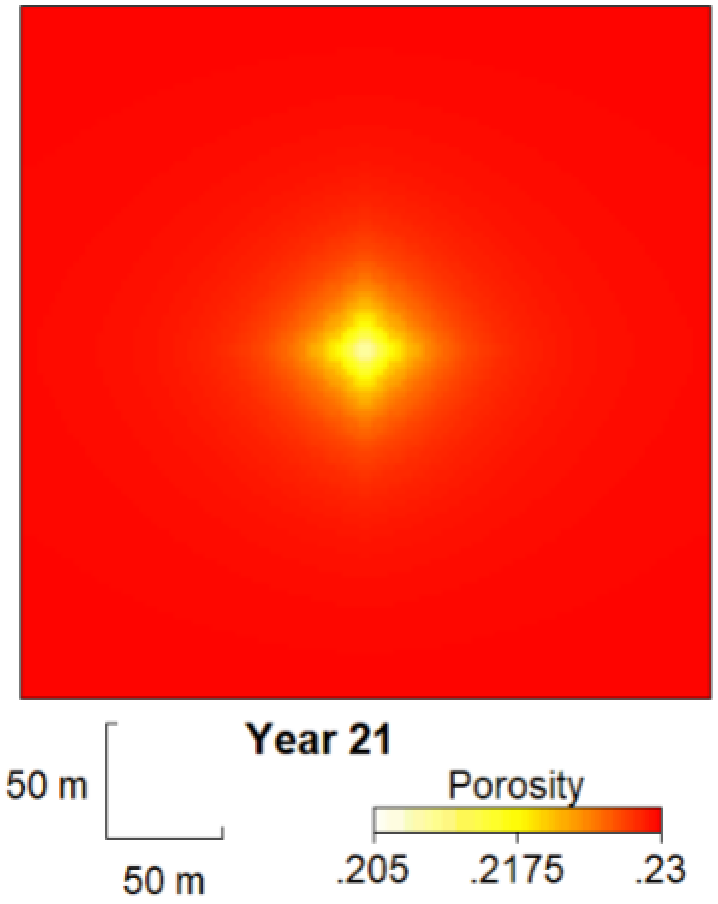




Shut-in Period (Year 0-120, Injection Stops at Year 20)
System Parameters

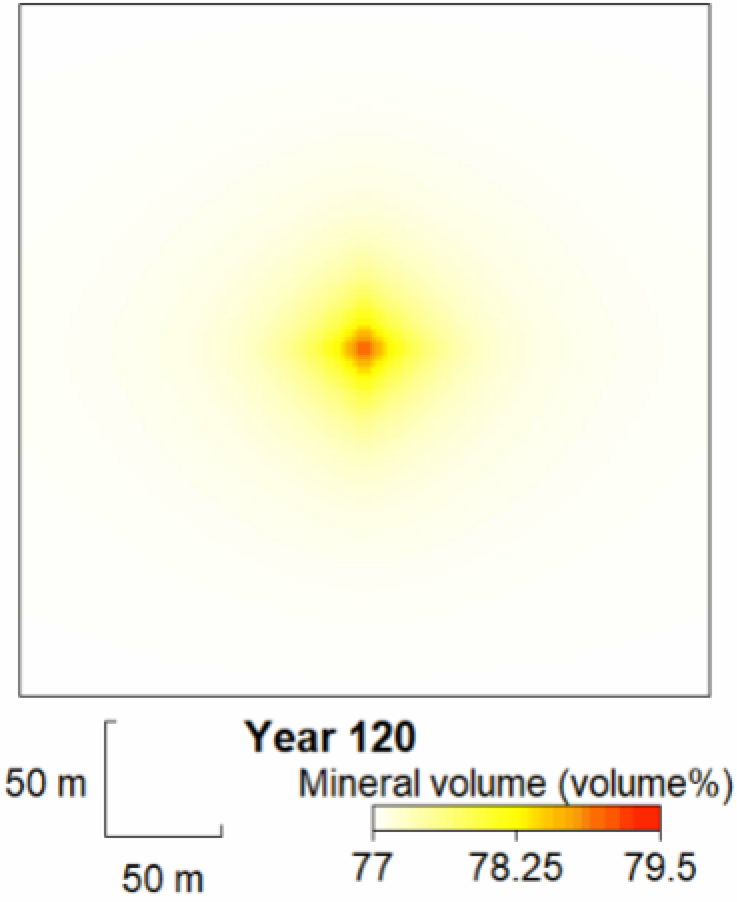
NATIONAL ENERGY TECHNOLOGY LABORATORY

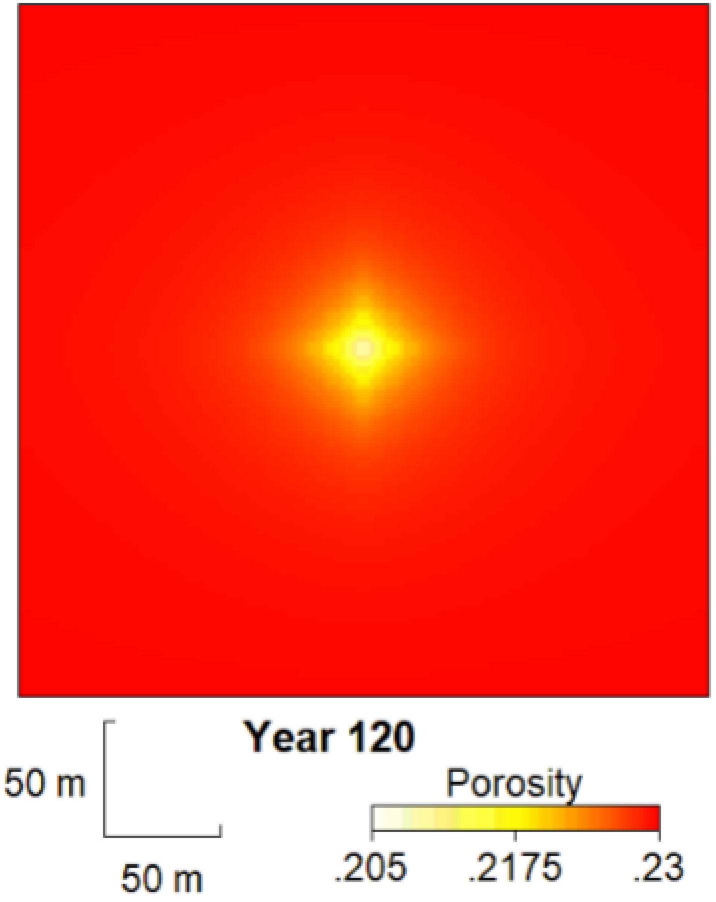




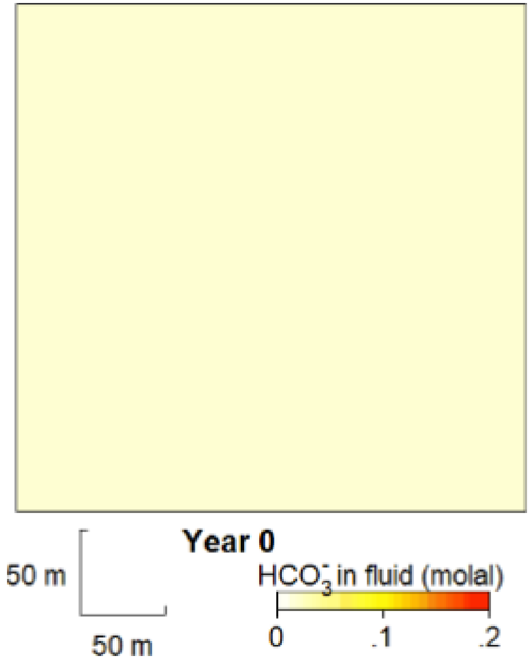
Shut-in Period (Year 0-120, Injection Stops at Year 20)
System Parameters

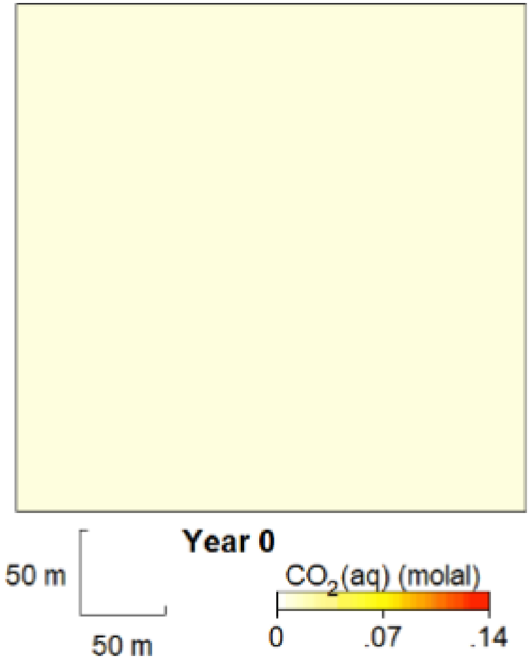
NATIONAL ENERGY TECHNOLOGY LABORATORY

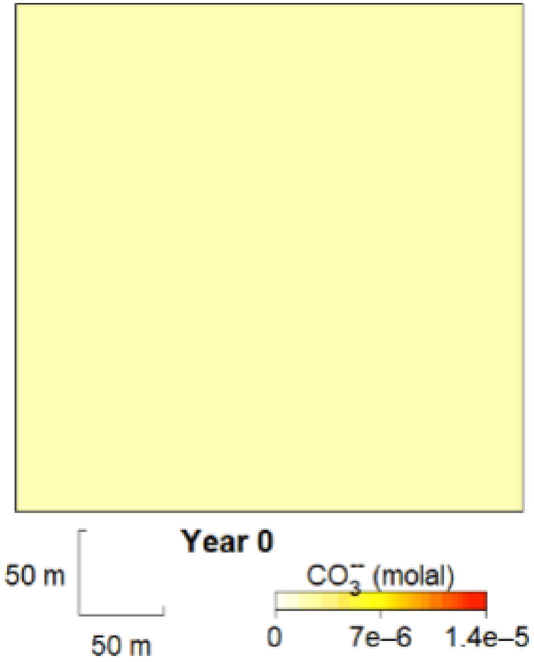


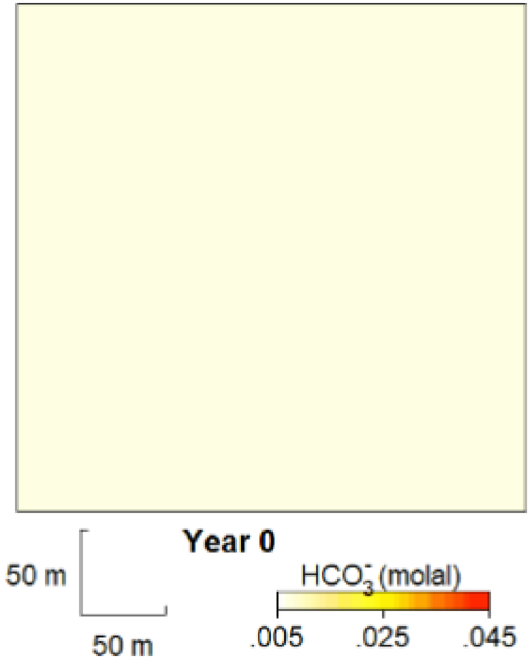


Shut-in Period (Year 0-120, Injection Stops at Year 20)
Dissolved Carbon









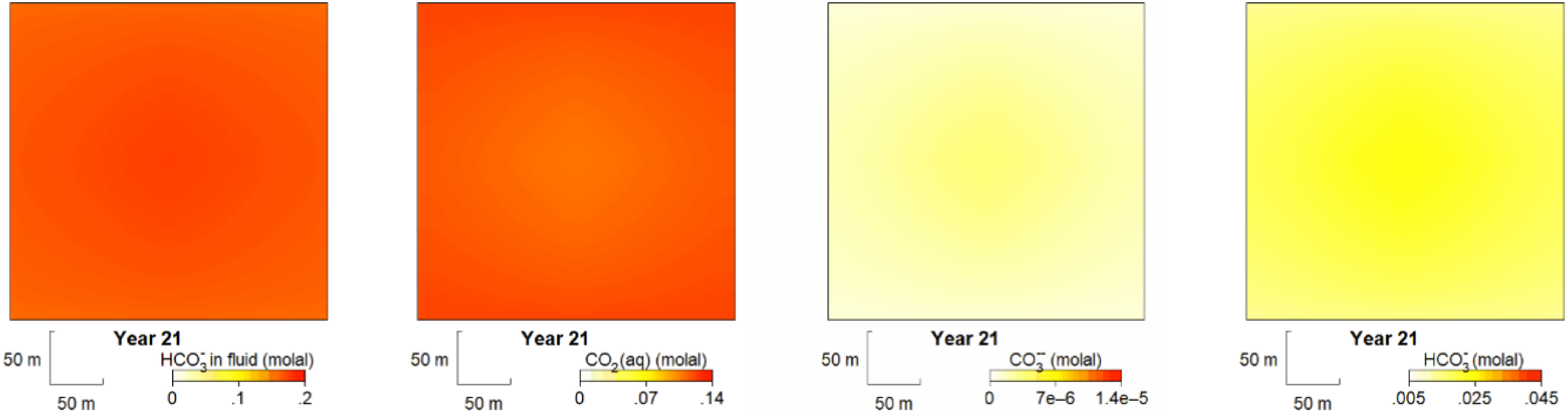
Total Aqueous C

CO_2 (aq)

CO_3^{2-}

HCO_3^-

Shut-in Period (Year 0-120, Injection Stops at Year 20) Dissolved Carbon



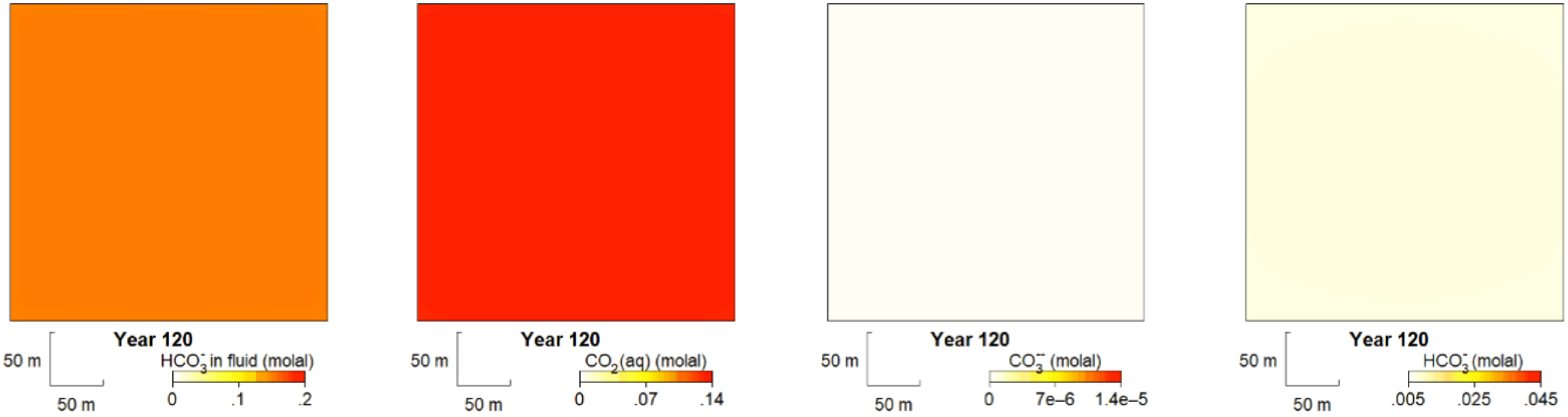
Total Aqueous C

CO_2 (aq)

CO_3^{2-}

HCO_3^-

Shut-in Period (Year 0-120, Injection Stops at Year 20) Dissolved Carbon



Total Aqueous C

CO_2 (aq)

CO_3^{2-}

HCO_3^-

CO_2 Fate in Reservoir-20 Years of Injection and Long-term Storage

- Most rock-fluid interactions are limited in a certain region where the carbonated water is injected.

- pH decreased outside this region due to dissolved CO_2(aq), which is the major phase of the sequestered carbonated water. Most CO_2(aq) remained its phase during long-term storage.

- Mineral precipitation in reservoir is unlikely to block flow pathways for injection.
- Secondary precipitates mostly composed of carbonate minerals (Ca, Mg, Ba) and some barite.

- Limited stored CO_2 is sequestered as carbonate minerals. CO_2 long-term storage is still solubility sequestration.

Summary

- Carbonated brine storage is a low-risk geologic CO_2 sequestration strategy.
  - The dissolved CO_2 concentration is affected by salinity, reservoir pressure and temperature. By selecting an appropriate CO_2 molality at the surface and subsurface, we can ensure minimal free-phase CO_2 in carbonated produced water for storage.
- Wellbore corrosion rate can be anticipate to be at an acceptable range to maintain operations for a carbonated brine injection.
  - Scale minerals can precipitate from carbonated produced water and further reduce corrosion rate. Adding CO_2 to produced water for injection is less likely to pose significant impacts on the existing wastewater disposal wells.
- CO_2 remained in liquid phase in long-term storage.
  - Small amount CO_2 converts to carbonate minerals in sandstone reservoir. CO_2 is safely stored via dissolution sequestration.

Next Steps: Pilot-Scale Implementation

- Future research needs
  - Specific pilot site characterization and analysis?
  - Experimental test for wellbore corrosion?

- Technical challenges
  - Site selection and permits
  - Wellbore dissolution technology
  - Mixing scenarios
  - Injection operations