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January 13, 2024

Integrated Fracture and Thermo-Hydro-Mechanical (THM) Simulators to Investigate Near-Wellbore Stress Changes in Underground Hydrogen Storage

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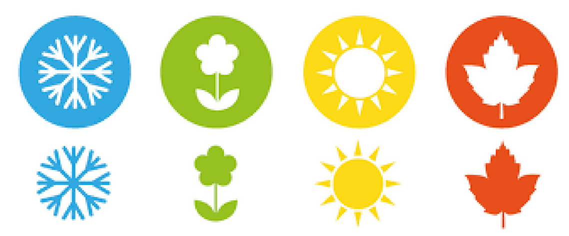
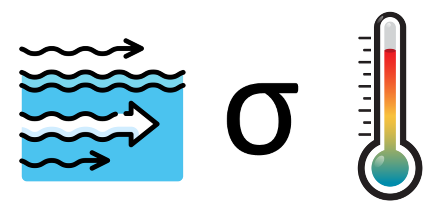
Introduction

Problem Statement:

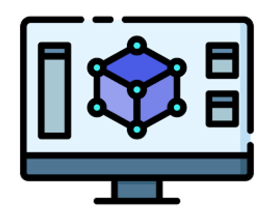
Renewable energy has seasonal dependency; Storing H_2 in aquifer can be the solution



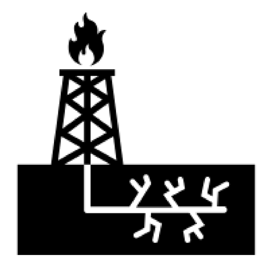
Most study on H_2 modeling considers hydrodynamics, few consider geomechanics, but none consider the thermal stresses



Reservoir Modeling is essential for safety of Underground Hydrogen Storage (UHS)



Common geomechanics software only show rock failure potential, without indicating where the hydrogen goes in case of fractures



Objectives:

1. Evaluate the impact of thermal stresses on cyclical UHS
2. Quantify the extent of rock failure or fracture in the near-wellbore region
3. Determine optimal injection controls to maintain storage integrity

Methodology: Numerical Simulation of Saline Aquifers

We used numerical simulator that integrates thermal, flow, geomechanics, and fracture processes. Initial pressure gradient is at 10 MPa/km, and geothermal gradient at 30C/km. The reservoir condition is 25MPa and 90C.

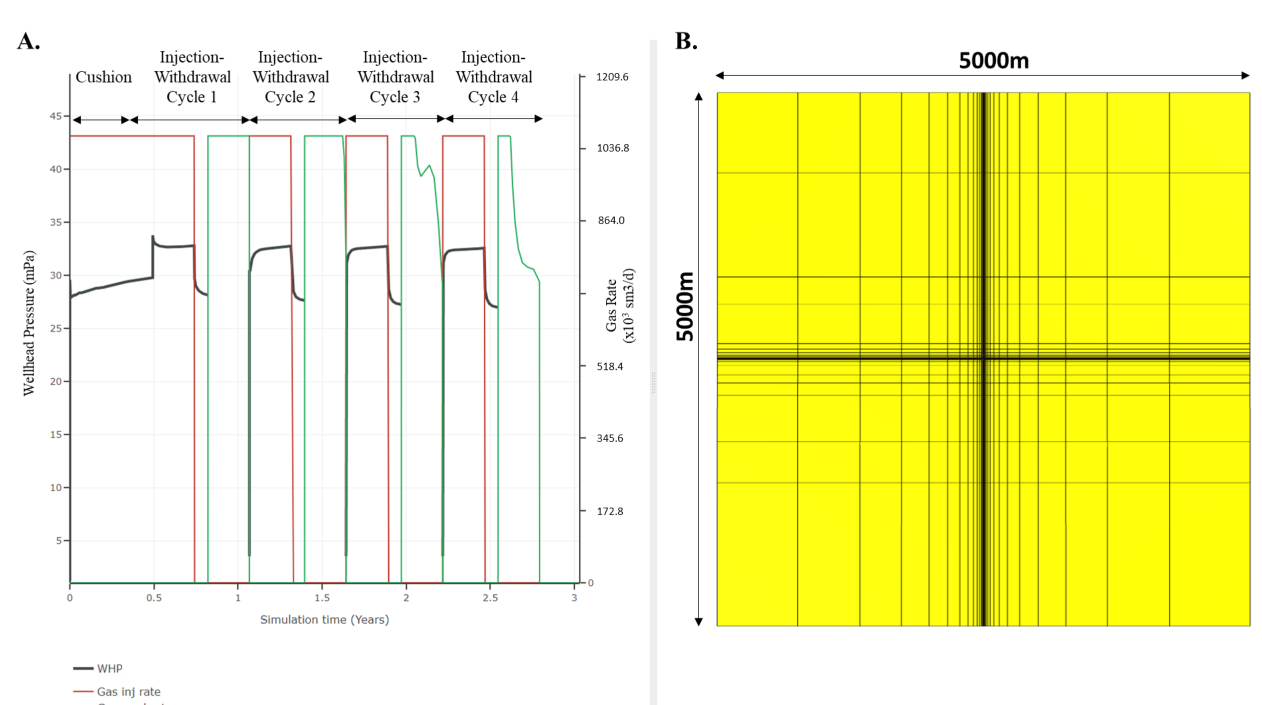


Figure 1 – (A) Injection and withdrawal control (rate and BHP) of the model, and (B) top view of saline aquifer model showing dimension and grid refinement

Base Case & Sensitivity

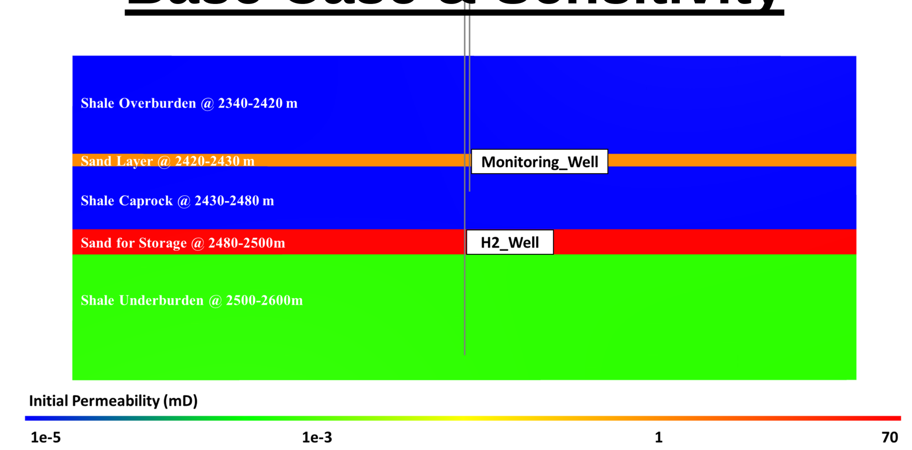


Figure 2 – Cross-section view (x-axis) of the model, showing the layering and well placement.

Parameter	Base Case	Sensitivity Study
Injection Rate, m3/s	12	6-18
Injection Temperature, C	25	5-90
Wellhead Pressure, MPa	33	26, 33, 36
Permeability, mD	70	0.7-700
Porosity	0.2	0.1-0.25
Fracture Gradient, MPa/km	16.1	13-19
Poisson's ratio	0.23	0.20-0.26
Compressibility, 1/MPa	1e-4	1E-5 – 3E-4
Young Modulus, MPa	10000	5000-10000

Table 1 – Base values and sensitivity parameters used in the simulation. Not all results from this sensitivity analysis will be shown

Results & Discussions

Case 1: Isothermal Case

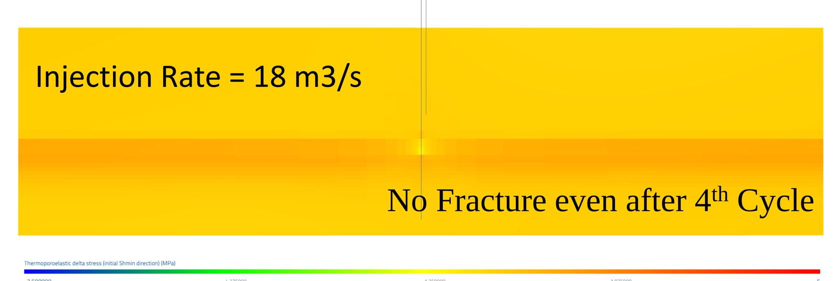


Figure 3 – Isothermal model did not find any rock failure in base reservoir condition but high injection rate.

Case 2: Thermo-Hydro-Mechanical + Fracture Case

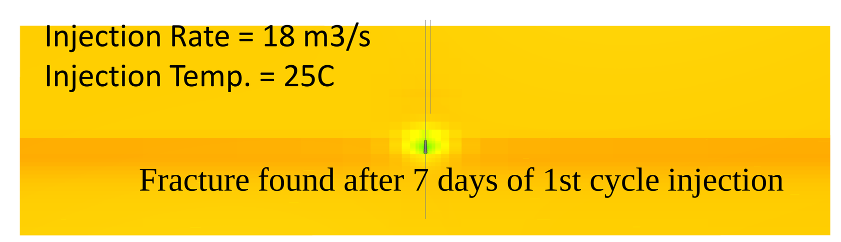


Figure 4 – Small fracture found around the wellbore, indicating the importance of thermal integration

Case 3: Findings in Low Permeability Reservoir

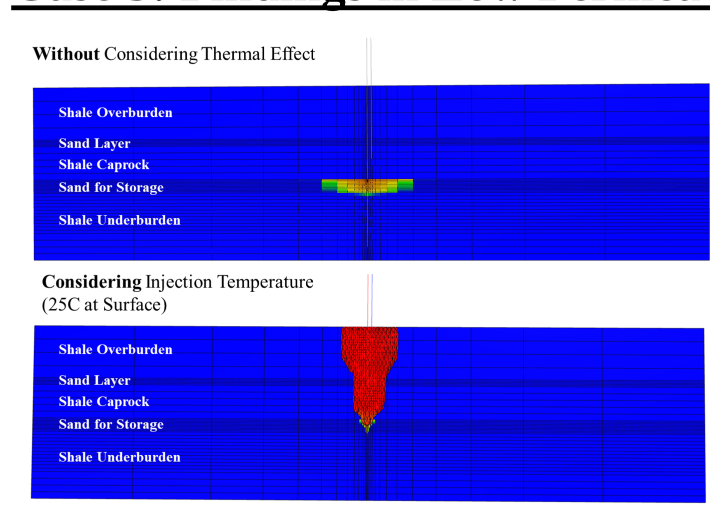


Figure 6 – Very small fracture is predicted in isothermal model, and H_2 is contained in storage layer after 4-cycle

Figure 7 – In thermal model, Fracture is generated after 2-days of injection. H_2 tries to escape upwards.

Case 4: Cases Where it is Safe for Both Model

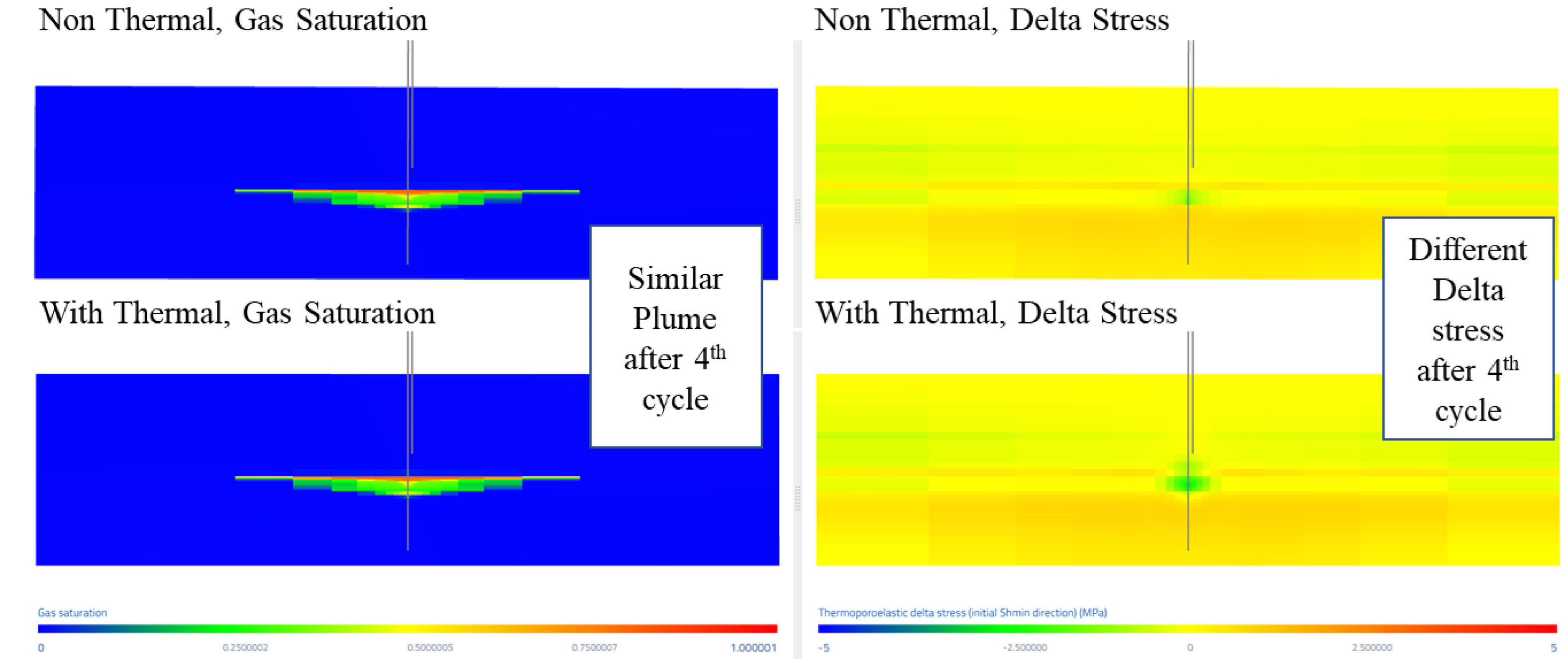


Figure 8 – Although the gas saturation looks the same, the thermal model reveals that higher delta stress occurred in S_{hmin} direction. This indicates increasing number of cycles further increase the thermoporoelastic stress change.

Conclusion

Coupled THM and fracture simulation identify UHS risks in saline aquifers, providing novel insights towards hydrogen injection performance:

1. The study predicts that an increase in the number of injection and extraction cycles may heighten UHS integrity risks due to changes in thermoporoelastic stresses.
   - Higher fracture risks are associated with conditions of low permeability, low fracture gradients, low compressibility, and low Poisson's ratio.
2. The model predicts the extent of fractures in near-wellbore region, and suggests that the gas can escape storage formation if fracturing occurs.
3. Lower temperature difference (<65C) and lower rate of H_2 injection (<18 sm3/d) would reduce the risks of fracturing in UHS.

Acknowledgement

We would like to express gratitude to ResFrac Corporation for their support on software, training, and guidance towards the creation of this research.

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