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Geologic Thermal Energy Storage: Integrated Subsurface Characterization and Modeling to Decode Wellbore Operability Limits

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ABSTRACT

In Geologic Thermal Energy Storage (GeoTES) systems subsurface reservoir forms a thermal battery, storing heated or chilled brine using excess energy generated by wind or solar systems. Stored brine can then be produced for power generation or for district heating and cooling. High permeability sedimentary reservoirs can serve as long-duration and high-volume capacity storage batteries due to their high porosity and large extent. Long-term sustainability of GeoTES systems depends on the response of the rock formation to coupled Thermo-Hydro-Mechanical (THM) loads induced by injection and production operations. If operational parameters are not optimized, with data unique to reservoir formations, alteration of mechanical and flow parameters in the near wellbore behavior, can lead to reduced system output. These issues could include mechanical degradation, fines mobilization, flow channeling and permeability anomalies.

In this study we present an integrated subsurface characterization and modeling study to simulate THM behavior of a GeoTES system in shallow, high porosity sedimentary formations from the US Texas Gulf Coast. Our 2D/3D modeling approach incorporates THM coupled solutions to simulate flow through porous media while considering heat transfer and damage mechanics. We collect and use data from a planned demonstration site to characterize THM properties of target formations representative of a GeoTES system. We integrate operational parameters and formation characteristics within a suite of models and conduct sensitivity analysis. Results show that THM loading conditions can lead to near wellbore formation alteration. Operational parameters, unique to high porosity-weakly consolidated formations can be optimized to control near wellbore formation response to injection and minimizing potential formation integrity and injectivity issues. In this sense, integrated characterization and modeling workflows provide constraints on wellbore operability limits.

1. INTRODUCTION

Without long-duration energy storage (LDES), it is likely that much of the clean energy will in fact go to waste. This is evidenced by the significant curtailment of solar and wind generated power. ***For example, The California Independent System Operator (CAISO), the grid operator for most of the state, is increasingly curtailing solar- and wind-powered electricity generation as it balances supply and demand during the rapid growth of wind and solar power in California. In 2022, CAISO curtailed 2.4 million mega-watt hours (MWh) of utility-scale wind and solar output, a 63% increase from the amount of electricity curtailed in 2021***. As of September 2023, CAISO has curtailed more than 2.3 million MWh of wind and solar output. Geologic Thermal Energy Storage (GeoTES) has been proposed as a large-scale, long duration renewable energy storage method suitable for both short and long durations. This proposal targets optimization of GeoTES field operations to minimize and mitigate risks. Optimized GeoTES systems represent a flexible and in-demand energy storage asset class that, when paired with grid-scale intermittent renewable facilities, have the potential to disrupt current renewable energy markets and empower a rapid shift to net-zero. GeoTES concept has been proposed as a large-scale renewable energy storage method suitable for both short and long durations. GeoTES has the potential to compensate for the variable nature of renewable solar and wind power by allowing their excess energy to heat or cool shallow reservoir brine at the surface and inject it into a high porosity sedimentary reservoir. Stored brine can then be produced for power generation when necessary **(Figure 1)**. To date, no integrated characterization and predictive modeling workflow has been proposed to optimize GeoTES systems in sedimentary formations with a focus on near wellbore formation integrity and injectivity under Thermal-Hydraulic-Mechanical-Chemical (THMC) loading conditions. If operational parameters of GeoTES are not optimized with data unique to sedimentary formations and THMC cycling, near wellbore formation integrity and injectivity issues can lead to reduced efficiency and impact economic performance.

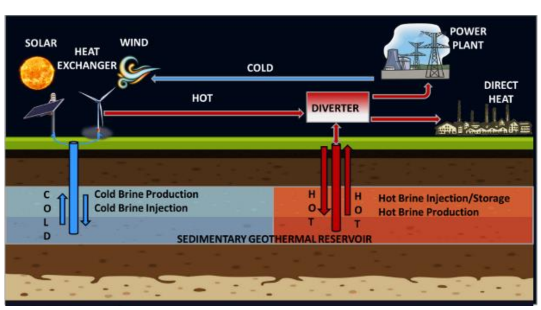


Figure 1: Geologic Thermal Energy Storage (GeoTES) Concept (Mutlu et al. 2023a)

A subsurface water saturated sedimentary reservoir is an ideal long-duration storage vessel due to its high porosity and large geographic extent. However, long-term sustainability of GeoTES operations (i.e., flow & mechanical integrity of the formation) depends on the response of the formation to coupled Thermo-Hydro-Mechanical-Chemical (THMC) loads induced by injection and production cycling. If operational parameters are not optimized, with data unique to sedimentary formations, near wellbore formation integrity issues can lead to reduced system output. These issues could cause wellbore instabilities, flow channeling, fines migration, injection/production problems, excessive horse-power requirements and even equipment breakdown. The term "coupled" indicates that each of the linked processes mutually affects the change of the others (**Figure 2**). Thus, it implies that the response of the formation to coupled loads cannot be characterized by measurements where each process is analyzed individually. GeoTES operations require a more comprehensive consideration of coupled processes. Quantifying the THMC behavior of sedimentary reservoirs via coupled thermal, hydraulic, mechanical and chemical processes becomes essential.

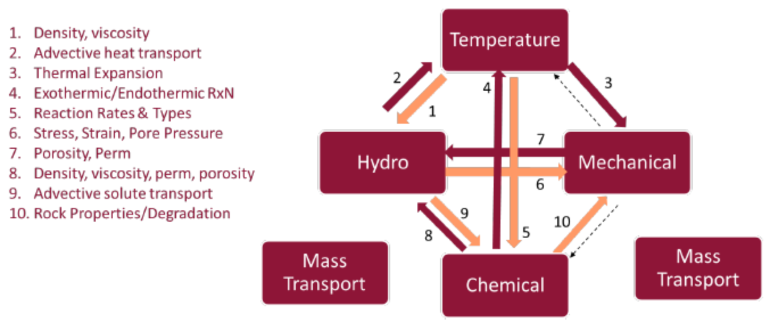


Figure 2: Coupled Processes

It is the premise of this study that, if the operational parameters, that are unique to THMC characteristics of the sedimentary reservoirs, are not optimized (e.g., injection and production rates, volume and temperature; duration and number of injection/production cycles), mechanical and flow integrity of the formation can be breached. This can cause fluctuations in injection and production rates or subsurface containment problems and eventually leading to reduced thermal output or energy storage capacities.

Although injection, production and storage of cold and hot fluids in geothermal applications are not entirely new, one of the unique features of GeoTES systems is the injection of hot/cold fluids into high porosity, high permeability, water saturated sedimentary formations where coupled THM loads are directly induced on relatively weak and unconsolidated formations. Historically, the majority of the GeoTES system studies have involved identifying optimum characteristics of the sedimentary reservoirs and operational parameters. However, these studies were conducted in a decoupled manner. That is, the main focus of these studies stayed primarily on the flow aspects (i.e., only thermo-hydro coupling) with the intent to maximize thermal power output (e.g., Green et al. 2021) while mechanical coupling (i.e., formation failure) is not considered.

There are only a few studies conducted on THM coupled characterization of GeoTES systems with the intent to understand and mitigate near wellbore formation integrity issues. Miller and Delin (1994) studied cyclic injection, production and storage of heated water in sandstone reservoirs. They suggested that fines migration during production/injection cycles could lead to flow impediment, where fines repack a distance away from the wellbore and effectively reduce the porosity and permeability of the formation. However no systematic characterization and modeling was performed to quantify mechanics of fines migration and trigger conditions. As part of the GeoTES project (Phase-I), McLing et al. (2022) investigated coupled THMC impact on porosity and permeability of GeoTES well pairs, however, failure of rock was not included in the coupling equations. McLing et al. (2022) suggested that thermal expansion/contraction, effective stress and pore pressure changes and mineral precipitation can have an impact on near wellbore reservoir porosity and permeability. To date, no integrated geomechanics characterization and modeling workflow has been proposed with a focus on near wellbore flow and mechanical integrity issues in GeoTES systems.

To date, no integrated characterization and modeling workflow has been proposed with a focus on near wellbore formation integrity issues in GeoTES systems. There is no integrated commercial product that can consider THMC characteristics of the formation, model progressive damage in formation (under in-situ conditions) and optimize operational parameters to avoid potential near wellbore formation integrity issues in GeoTES. To improve our understanding of GeoTES systems the subsurface and evaluate the role of coupled THMC loading conditions on operations, we have undertaken this study, to build and apply a physics-based workflow adaptable to GeoTES systems. This workflow has resulted in proof-of-concept models that demonstrate near wellbore processes can be quantified and used to optimize GeoTES performance. Workflow and proof of concepts are implemented by:

- Collecting site specific GeoTES data from a planned test site in South Texas
- Integrating site specific data with fast-running analytical and high-fidelity numerical models
- Finalizing the modeling approaches for subsurface simulations
- Running sensitivities to quantify near wellbore damage and wellbore operability limits for a range of plausible scenarios

The primary objective of this study is to optimize GeoTES systems in sedimentary formations and to avoid near wellbore formation integrity issues. The help achieve this goal the work presented in this paper focuses on the development and commercialization of an integrated characterization workflow and coupled modeling software to help optimize GeoTES operations. The workflow integrates key formation characteristics within the framework of coupled analytical and numerical models. Model results identify the impact of formation and operational parameters on near wellbore formation integrity and wellbore operability limits. Based on the model results, we then demonstrate the feasibility of optimizing operational parameters to minimize potential formation damage and to maximize thermal output.

2. SUBSURFACE CONSIDERATIONS FOR GEOTES SYSTEMS

There are several subsurface design challenges associated with the analysis of GeoTES systems. First of all, efficiency and safety of the GeoTES operations (i.e., flow and mechanical integrity of the subsurface) depend on the response of the wellbore and sedimentary formations to **coupled THMC loads** induced by production and injection **(see Figure 2).** For instance, thermal loading would not only induce a thermal gradient within the formation but will also affect the mechanical, flow, and chemical fields. In a 2-way coupled system, injection and flow would change the pore pressure and effective stresses in the near wellbore region. Conversely, alteration of effective stresses in the mechanical field would then change porosity and permeability distribution in the flow field (which in turn impacts fluid flow and heat convection). Thus, it implies that the response of the formation to coupled loads cannot be characterized by measurements where each process is analyzed individually. GeoTES operations require a more comprehensive consideration of coupled processes (Mutlu et al. 2023b). Quantifying the THMC behavior of sedimentary reservoirs via coupled thermal, hydraulic, mechanical and chemical processes becomes essential.

Second, **mechanical degradation of the formation** can lead to generation of fines, flow channeling and fines migration (i.e., physical movement of fine rock grains within the formation) and needs to be addressed in GeoTES system design. If excessive formation degradation and alteration occurs along the near wellbore region, the critical velocity required for mobilization of fines can be reduced significantly. During production/injection cycles, flow velocity can exceed this reduced threshold velocity, leading to fines mobilization and increasing the risk of pore plugging. Resulting **permeability reduction** can lead to injectivity or producibility issues. **Figure 3** illustrates this phenomenon where contours (cold colors-tensile failure and hot colors-shear failure) indicate damage patterns around a horizontal wellbore. Critical velocity to mobilize produced fines decreases as intensity of the near wellbore damage increases. Fines (during production) can then migrate towards the wellbore and plug sand screens or pore throats.

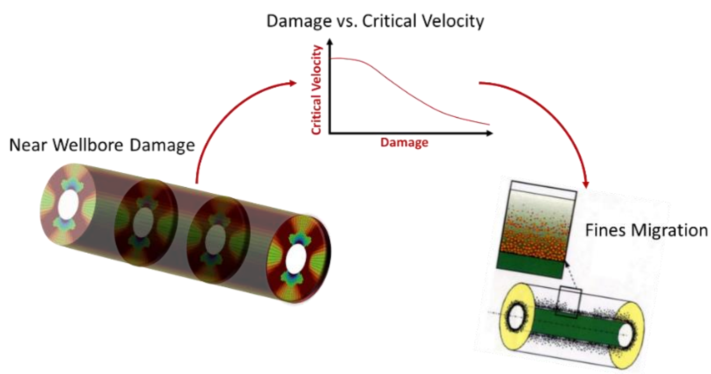


Figure 3: Near Wellbore Damage and Fines Migration

Finally, another technical challenge is the lack of **testing set-ups that allow coupled measurements under THMC conditions**. These measurements should quantify THM properties, damage-permeability, stress-permeability, mechanical degradation correlations and are used as input in coupled numerical models. Coupled laboratory experiments focused on GeoTES should be considered and can close a potential characterization gap while improving the accuracy of advanced numerical models. **Figure 4** illustrates such a set-up where samples can be tested under in-situ THMC loading conditions with reactive brines to quantify stress/damage dependent permeability relationships and mechanical degradation of rocks as a function of fluid chemistry. To be more specific these near wellbore tests quantify:

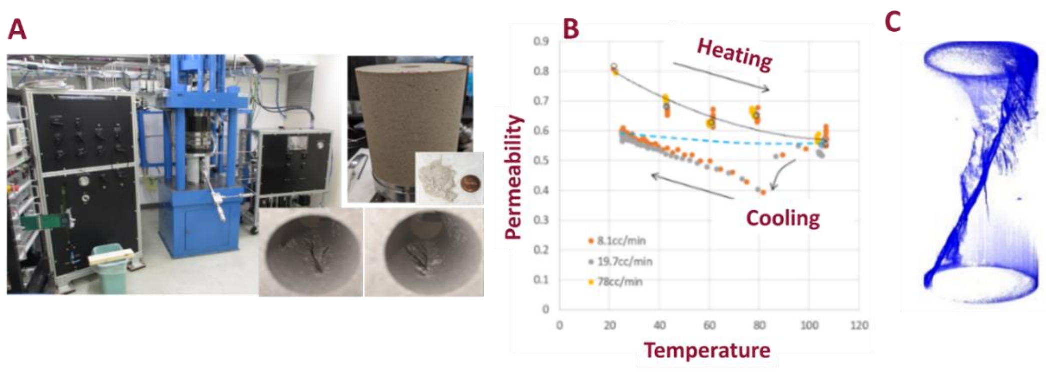


Figure 4: (A) Thick Wall Cylinder Tests, (B) Permeability as a Function of Temperature, (C) Damage Imaging

- Extent of damage as a function of stress, temperature, pressure, fluid chemistry, and injection rate
- Permeability as a function of stress, temperature, pressure, fluid chemistry and injection rate
- Collected fines as a function of stress, temperature, pressure and injection rate
- CT and boroscope images of near wellbore failure and damage patterns
- Petrophysical observations of evidence for chemical reactions and their significance to geomechanics and flow.

In this study we establish an integrated characterization and modeling workflow and take into consideration key subsurface challenges as summarized above. We decode wellbore operability limits for GeoTES systems by investigating a range of plausible subsurface scenarios and quantifying the impact of key parameters on near wellbore damage. We integrate characterization data from a GeoTES field site with models and demonstrate that quantification of subsurface processes can be used to identify operational limits and minimize risks. Our ultimate objective is to integrate these results and workflow within the framework of a commercial project.

3. MODELING APPROACH

Analytical and numerical THM formulation implemented in GeoTES framework follows (Zhou and Ghassemi (2009), Tran (2010), Lee and Ghassemi (2011), Mutlu et al. 2023a and 2023b), and governed by coupled equations that include the constitutive, transport and damage laws. The constitutive equations of thermo-poroelasticity have been developed by McTigue (1986) and Palciauskas and Domenico (1982). Using the geomechanics sign convention, the constitutive equations are:

$$\dot{\sigma}_{ij} = 2G\dot{\varepsilon}_{ij} + \left(K - \frac{2G}{3}\right)\dot{\varepsilon}_{kk}\delta_{ij} + \alpha\dot{p}\delta_{ij} + \gamma_1\dot{T}\delta_{ij} \tag{1}$$

$$\dot{\zeta} = -\alpha\dot{\varepsilon}_{ii} + \beta\dot{p} - \gamma_2\dot{T} \tag{2}$$

where σ_{ij} and ε_{ij} are the total stress and strain tensors, p and T are the pore pressure and temperature respectively. α is the Biot coefficient, ζ is the variation of fluid contents, K is bulk modulus, and G is the shear modulus; γ_1, γ_2 and β are given by:

$$\beta = \frac{\alpha-\varphi}{K_s} + \frac{\varphi}{K_f} \tag{3}$$

$$\gamma_1 = K\alpha_m \tag{4}$$

$$\gamma_2 = \alpha\alpha_m + \left(\alpha_f - \alpha_m\right)\varphi \tag{5}$$

where φ is the porosity, α_f and α_m the thermal expansion coefficients of solid and fluid, respectively.

Fluid flow in porous rock is governed by Darcy's law, and heat conduction obeys Fourier's law, so that:

$$J^f = -\rho_f\frac{k}{\eta}\nabla p \tag{6}$$

$$J^T = -k^T\nabla T \tag{7}$$

where ρ_f is fluid mass density, k and η the permeability and viscosity, respectively, k^T the thermal conductivity.

The equation of equilibrium and continuity for the fluid mass are given by:

$$\sigma_{ij,j} = 0 \tag{8}$$

$$\frac{\partial\zeta}{\partial t} = -\frac{1}{\rho_f}\nabla J^f \tag{9}$$

By substituting the constitutive equations into the balance laws given by Eqn. (8), (9), we obtain the field equations for the rock deformation and fluid flow, namely Eqn. (10) and Eqn. (11). The conservation of energy with Fourier's law yields the field equation for the temperature distribution:

$$\left(K + \frac{G}{3}\right)\nabla(\nabla\cdot u) + G\nabla^2 u + m(\alpha\nabla p + \gamma_1\nabla T) = 0 \tag{10}$$

$$-\alpha(\nabla\cdot\dot{u}) + \beta\dot{p} - \frac{k}{\eta}\nabla^2 p - \gamma_2\dot{T} = 0 \tag{11}$$

$$\dot{T} + v(\nabla T) - c^T\nabla^2 T = 0 \tag{12}$$

where u is the displacement, c^T is the thermal diffusivity, $m = [1,\ 1,\ 0]^T$ for 2D problems and $m = [1,\ 1,\ 1,\ 0,\ 0,\ 0]^T$ for 3D cases.

In Eqn. (12), we consider ***convective heat transfer*** because of cooling-heating effects which is from the fluid velocity in damaged phase. This fluid velocity is coupled with pore pressure variations in Darcy's law, $v = -\frac{k}{\eta}\nabla p$. In this formulation, ***constitutive and transport laws are coupled with formation integrity*** such that permeability and mechanical properties evolve as a function of stress and damage induced via coupled THM loading conditions (**Figure 5: Left**). Full coupling between THM fields, damage propagation and alteration of mechanical/flow properties provide an uplift over fast-running analytical solutions. For example, permeability and porosity are linked to material damage and evolves over time (Tang et al. (2002), Wang and Park (2002)). As material degrades (reduction in stiffness), stresses are transferred to neighboring/intact material regions and can lead to progressive failure within the framework of coupled THM loading conditions (**Figure 5: Right**)

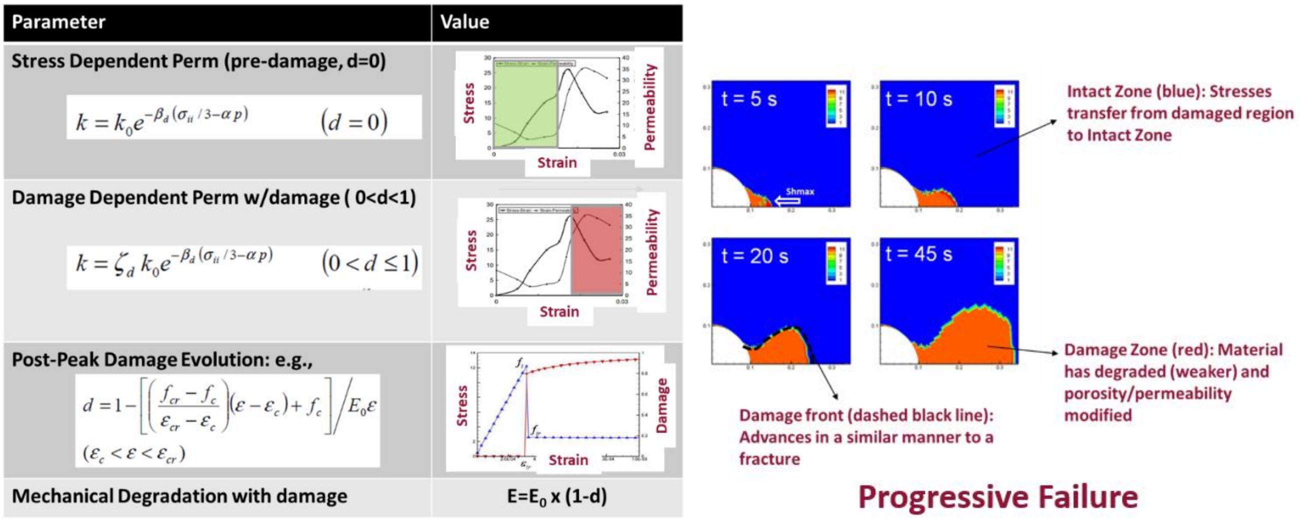


Figure 5: Left: Constitutive Laws for Damage and Mechanical Degradation, Right: Damage Induced Progressive Failure

Numerical models adapt eight-node quadrilateral or hexahedral mesh elements for the displacements u , pore pressure p , and temperature T to improve numerical resolution of deformation and formation failure. The following variables are approximated using Galerkin's method for u , p , and T.

$$u = N_u \tilde{u} \tag{13}$$

$$p = N_p \tilde{p} \tag{14}$$

$$T = N_T \tilde{T} \tag{15}$$

where the shape functions for the displacement, pore pressure and temperature are Nu , Np , and N_T, respectively and nodal variables for displacements, pore pressure and temperature are $\tilde{u}$, $\tilde{p}$, and $\tilde{T}$ respectively. Numerical formulation is then obtained by substituting Eqns. (13)-(15) to the field Eqn. (10)-(12). For discretization of the time domain, the Crank-Nicolson type approximation is applied. In convective heat transfer computation, Streamline-Upwind/Petrov-Galerkin (SUPG) method is used to avoid numerical oscillations (Heinrich and Pepper 1999).

4. FIELD APPLICATION

In our analysis, we focused on horizontal GeoTES wellbores to be drilled in shallow, high porosity sedimentary formations of the Gulf Coast region near Navasota in Grimes County, Texas. The target interval was selected as the Yegua formation, the uppermost formation in the Middle Eocene Upper Claiborne Group. It consists of a water carrying sandstone aquifer that lies approximately between 3600 ft to 3950 ft (1100 m to 1200 m). The Yegua formation is comprised of clean sands, interbedded sands and some silt-clay deposited in settings ranging from fluvial to marginal marine to shallow marine environments. The Yegua is identified as the stratigraphically lowest location where sandstone predominates over shale (Thompson, 1966) and varies from 400 ft (121 m) to over 1,000 feet (305 m) in thickness at the outcrop, being thinnest in East Texas (Barnes, 1992). The Yegua aquifer is extensive, paralleling the Gulf Coast shoreline and lies from 70 to 120 miles inland of the present-day coast (Knox et al. 2007). It is a narrow band ranging from 15 to 40 miles wide (Preston, 2006) extending almost 500 miles long within Texas from the Mexican border to the Louisiana border and including parts of 35 counties (Preston, 2006).

4.1 Field Data

Data included a combination of site-specific and analog log data:

- Mud logs, Thermal Gradients, Triaxial test data, Combo Logs (i.e., compensated neutron density, porosity, sonic logs)
- Drilling data (i.e., mud weights, leak off tests, lost circulation records)
- Chemical composition of the geothermal brine and target formation rocks

Field data was combined with site specific data from literature and published calibration points (e.g., Chen et al. 2018, Chen et al. 2023) to derive key formation properties such as overburden stress, rock strength, fracture gradients, permeability and as published. **Figure 6**

(Mutlu et al. 2023b), shows a collage of figures as they relate to the field site location, data collection and characterization: Team visiting NOV's site, Site Location, Depositional Column Yegua, Mud Logs & Target interval (~ 3,800 ft TVD).

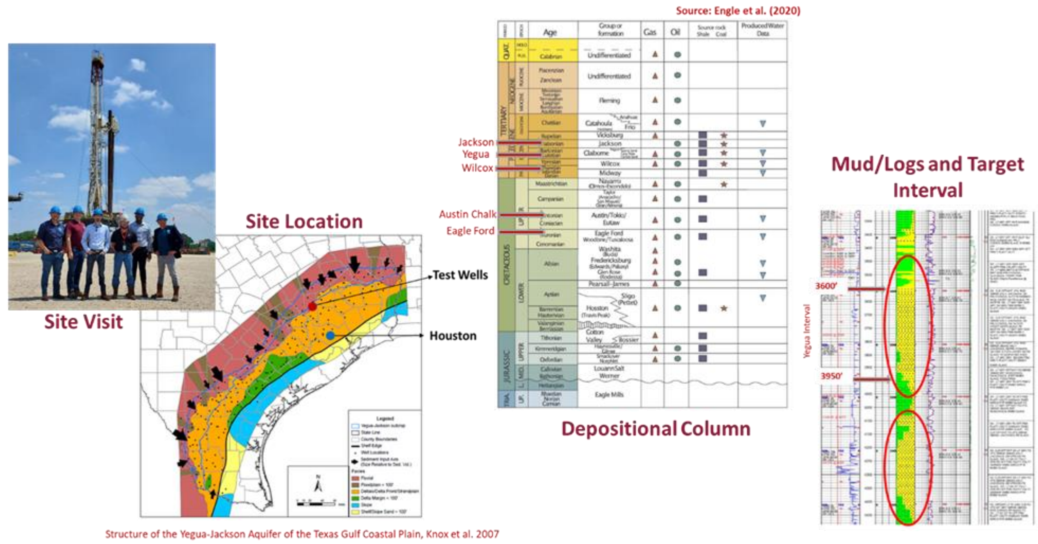
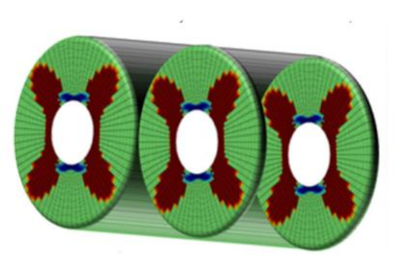


Figure 6: Site Visit, Location, Depositional Column and Mud Logs/Target Intervals (Mutlu et al. 2023b)

Table 1 summarizes some of the input data used in the simulations. These preliminary analyses consider **horizontal wellbores** drilled in a normal stress regime where Sv>Shmin=Shmax and with stress/pressure gradients: Sv=1.0 psi/ft, Shmin=Shmax (0.625 - 0.7 psi/ft), Pore Pressure= 0.46 psi/ft. Core and log data, indicate a relatively weak formation with an unconfined compressive strength (UCS) less than 1,000 psi, porosity=30% and permeability around 1,000 mD. Given the data table in **Figure 7** and from a formation integrity/stability point of view, this field is likely to present a worst-case scenario. To explore the scaling potential of a GeoTES system at the planned demonstration site in Texas, brine chemistry from an offset well was also used as input **(see Table 1)**. Note that advanced numerical models require input that defines the evolutionary behavior of formation in the near wellbore region. This includes parameters that relate stress and strains to the evolution of material damage and porosity-permeability in the near wellbore region (**see Figure 5**).



Wellbore Deviation	Horizontal
(Thermal Conductivity, Rock)	2 W/m K
(Thermal Conductivity, Fluid)	0.685 W/m K
(Thermal Diffusivity Fluid)	0.174 mm^2/sec
(Thermal Diffusivity Rock)	1.127 mm^2/sec
(Specific Heat Capacity Fluid)	4.3 J/gk
(Specific Heat Capacity Rock)	0.71 J/gK
(Thermal Expansion Fluid)	2.10E-04 K^-1
(Thermal Expansion Rock)	1.10E-05 K^-1
(Cold Injection_R)	150 F
(Cold Injection_I)	41 F
(Hot Injection_R)	150 F
(Hot Injection_I)	320 F
(Sv)	3724 psi
(Shmin)	Low=2375 psi High= 2660 psi
(Shmax)	Low=2375 psi High= 2660 psi
(PP)	1748 psi
(UCS)	970 psi
(Tensile Strength)	100 psi
(Porosity), perm (md)	0.31 , 1000 mD
(PR)	0.41
E	1 GPa
(Internal Friction Angle)	25
(Skempton's B)	0.92
(Fluid Viscosity & Fluid Density)	0.1864 cP; 0.918 g/cm^3

Figure 7: Left: Horizontal Wellbore Configuration, Right: Field Data

Table 1: Brine Chemistry from off-set wellbores

	SiO2 (ppm)	Ca (ppm)	Mg (ppm)	Na (ppm)	K (ppm)	HCO3 (ppm)	CO3 (ppm)	SO4 (ppm)	Cl (ppm)	NO3 (ppm)	TDS (ppm)	Hardness/CaCO3	% Na
Offset A	46	77	7.1	327	327	164		293	348	2.2	1180	221	76
Offset B	42	17	1.8	470	470	522	28	1.2	435	7.5	1250	50	95

4.2 Field Models

Figure 8 summarizes the emerging THM behavior induced by cold-hot injection into the weakly consolidated high porosity/permeability formation using input data as described in **Figure 7** and weakly coupled analytical models (Mutlu et al. 2023a and 2023b). 2D analytical models represent a cross section of an open hole assuming a perfectly horizontal wellbore oriented in the direction of Shmin (minimum horizontal stress). Early into **injection (Figure 8A and 8B)** the near wellbore region shows shear (hot colors) and tensile (cold colors) damage extending from the wellbore following a diagonal pattern. Tensile failure is well pronounced for the cold injection case and more diffuse for the hot injection. This is expected since thermal contraction tends to reduce compressive tangential stresses around the wellbore, promoting tensile failure.

We consider two horizontal stress states for further analysis (i) low (Shmin=Shmax= 2375 psi) and (ii) high (Shmin=Shmax= 2660 psi) while keeping Sv the same in all analyses. Approximately 11 days of injection (i.e., injecting only 75 psi below the fracture gradient at higher injection rates) into the weakly consolidated sands of the target formation extends the near wellbore shear failure into the far-field **(Figure 8C)** for cold injection (41 F) following a diagonal pattern. Extent of tensile failure is limited relative to shear failure. Finally, a sensitivity study around the magnitude of horizontal stress and injection temperature indicates that a reduction in stress anisotropy (higher horizontal stresses) and higher temperatures (320 F) might stabilize the damage front even when the wellbore is operated at relatively high injection pressures **(Figure 8D)**. As a summary, analytical models suggest that higher injection pressures, lower temperatures and lower horizontal stress state promote relatively extensive damage zone around open-hole horizontal wellbores (also see Mutlu et al. 2023b).

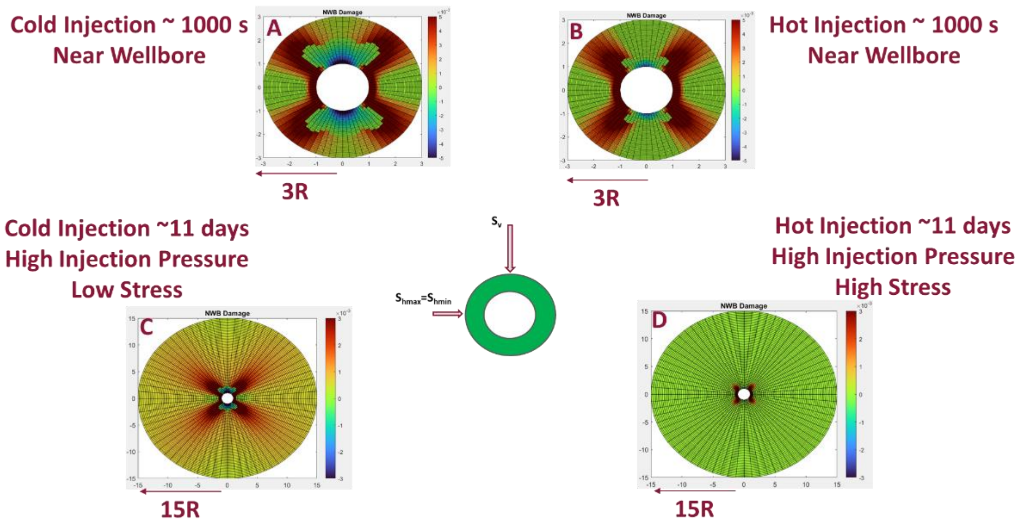


Figure 8: Analytical Models: Damage Patterns (R: Radius)

Although analytical THM models provide insight into near wellbore processes and wellbore operability limits for GeoTES systems in sedimentary reservoirs, they build on several critical assumptions that limit their uncalibrated use. These limitations are:

- Heat transfer is dominated by conduction rather than convection
- Evolution and propagation of formation failure is not considered: i.e., progressive failure is not included
- Mechanical and flow properties remain constant: i.e., not a function of stress and failure

To address these limitations, we developed and performed 2D/3D numerical simulations that adapt the Finite Element Modelling (FEM) framework (Zhou and Ghassemi (2009), Lee and Ghassemi (2011)) to honor the full coupling between THM fields and to simulate damage initiation and propagation in the near wellbore region. Numerical Implementation followed Zhou and Ghassemi (2009), Lee and Ghassemi (2011), Mutlu et al. 2023(b). In these simulations both the conductive and convective heat transfer were considered in the thermo-poro-elastic formulation coupled with damage mechanics. As injection continues, temperature and pressure gradients are realized within the formation. If the stress state and material properties dictate that it should, material degrades, and stresses drop from peak to residual in zones where failure/damage is realized **(Figure 9)**. As shown in **Figure 9** (a quarter symmetric 2D numerical model), damage is confined within the near wellbore region (even with further injection), while thermal and pressure front moves farther away from the wellbore. It is important to note that, in most cases presented in this study, damage initiates and stabilizes early into the injection. However, material degradation and stress relief within the damaged zones can act as a precursor to potential progressive fines migration as injection-production cycles continue. That is, with each additional injection and production cycle, damage front can progressively move away from the wellbore in the long term.

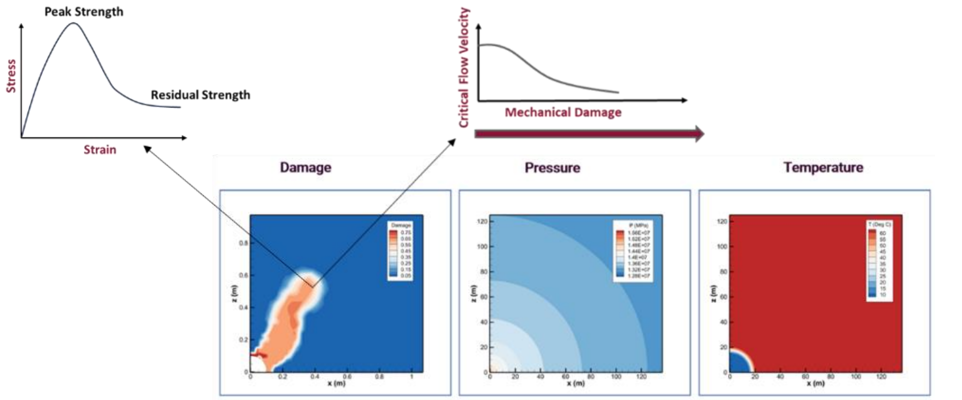


Figure 9: Evolution of Damage, Fluid Pressure and Temperature

4.2.1 Numerical Sensitivity Analysis

Guided by the analytical screening **(Figure 8)**, and preliminary numerical models **(Figure 9)**, we designed a range of THM case studies and modeled using high-fidelity numerical approach (**see Section 3**) that honors THM coupling with damage propagation. These models are designed to (i) quantify near wellbore damage (ii) decode wellbore operability limits.

A total of 8 different cases are considered in these simulations covering low vs. high stress state(s), injection pressure(s) and injection temperature(s). In all cases we assume horizontal wellbores, isotropic horizontal stresses (Shmin = Shmax) and an initial reservoir temperature of 150 F. For each stress state (low vs. high) we consider two different injection temperatures (41 F versus 320 F) and injection pressures. A low injection pressure corresponds to a case where pressure is 300 psi below the corresponding Shmin while a high injection pressure corresponds to a case only 75 psi below the in-situ Shmin.

Table 2: Summary of all cases used in 2D/3D numerical simulations

Case #	Stress State Low/High	P, injection MPa	T, injection Deg F	T, reservoir Deg F
Case 1	Low Shmin	2075 psi	41 F	150 F
Case 2	Low Shmin	2075 psi	320 F	150 F
Case 3	Low Shmin	2300 psi	41 F	150 F
Case 4	Low Shmin	2300 psi	320 F	150 F
Case 5	High Shmin	2360 psi	41 F	150 F
Case 6	High Shmin	2360 psi	320 F	150 F
Case 7	High Shmin	2585 psi	41 F	150 F
Case 8	High Shmin	2585 psi	320 F	150 F

Low Stress	
Shmin = Shmax =	2375 psi

High Stress	
Shmin = Shmax =	2660 psi

Figure 10 shows a collage of case studies that simulate up to 2 days of injection. Hot (red) colors are used as a damage proxy and mark regions of failed rock. Within these failed regions, material has completely degraded and stresses are transferred to neighboring intact regions (cyan-background color). According to Figure 10, stress state has a significant impact on the resulting damage patterns. For lower horizontal stresses (Case(s) 1 thru 4) damage zone is relatively extensive compared to cases simulated under higher isotropic in-situ stresses (Cases(s) 5 thru 8).

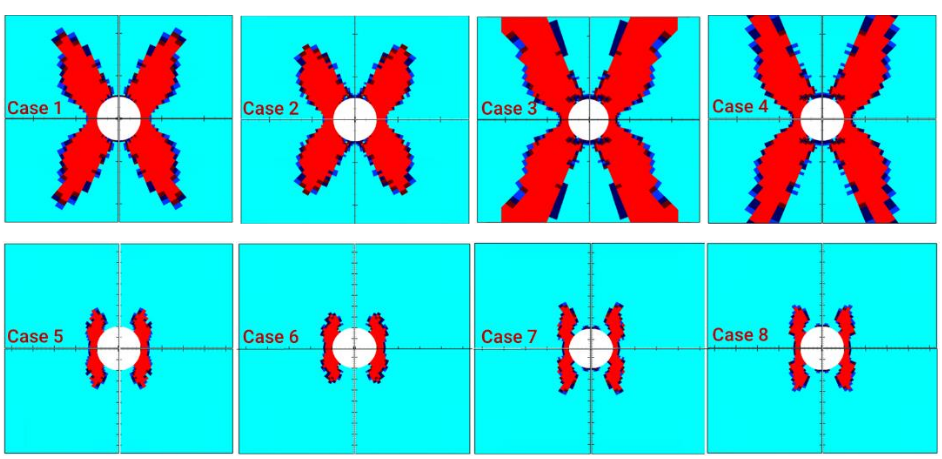


Figure 10: Summary of Results

Another important observation is that, colder thermal front increases the extent of damage around the wellbore. This is evident from comparison(s) between Case-1 (cold) vs. Case-2 (hot) and Case-3 (cold) vs. Case-4 (hot) where for each compared pair injection pressure and stress state remain the same. Further to this, injection pressure (i.e., or rate) has a significant impact on the extent of the damage front. For example, a comparison between Case-1 (high injection pressure) vs. Case-3 (low injection pressure) and Case-2 (high injection pressure) vs. Case-4 (low injection pressure) show that higher injection pressures result in more extensive damage around the wellbore where for each compared pair stress state and temperature remain the same.

Damage is realized early into simulations in most of the cases as shown in **Figure 10,** even when the injection pressure is well beyond in-situ fracture gradient. Among the cases presented in Figure 10, Case-3 presents the highest risk, (i.e., in terms of flow channeling and fines migration), where wellbore is loaded with colder brine, at higher injection pressures and under low/isotropic stress regime. In this case, damage propagates in shear mode and large areas can fail simultaneously: potentially leading to complete loss of formation integrity in a way that would impact subsequent injection-production cycles.

5. KEY FINDINGS

- Near wellbore formation alteration and associated damage can occur at injection pressures below the in-situ fracture gradient. This alteration is realized predominantly in shear and occurs early during injection

- Damage localizes within a relatively thick band and continues to propagate away from the wellbore in a diagonal pattern as shown in both the analytical and numerical simulations

- The majority of the cases investigated in this study, indicates development of a damage front that stabilizes early into injection. However, lower horizontal stress regimes (or higher vertical-horizontal stress anisotropy), chilled geofluids and higher injection rates can trigger unstable damage propagation and flow channeling: in particular considering the cyclic nature of the operations

- Site-specific formation properties (i.e., in particular considering the strength of the formation), suggest that these simulations represent worst case scenario for GeoTES where damage will initiate early into injection and rapidly

- Given that damage initiates early into injection and near wellbore: injection strategies, with a focus on engineering near wellbore temperature and injection gradients (i.e., with data unique to the target reservoir), have the potential to optimize operations and maximize system output while minimizing formation damage

- Complete loss of formation strength within the damaged zones creates a risk for fines mobilization during injection and production. This risk can be minimized by customizing injection temperature and pressure/flow rate with data unique to the formation of interest or by using screens.

- Perforation and completion architecture can play an important role in minimizing near wellbore damage patterns. For example, number, size and spacing of the perforations can alter near wellbore damage and flow channeling: as it impacts near wellbore stress field, flow rate and velocities. Perforation and completion design should be a part of the optimization process

- Advanced modeling techniques as used in this project are only accessible to specialist users. Democratization and commercialization of such software would allow a larger user base to benefit from risk assessments and optimization techniques guided by modeling

6. FUTURE WORK

Understanding geochemical effects on reservoir brine under cyclical heating and cooling is critical to successful operation of a Geological Thermal Energy Storage (GeoTES) system. Scale and corrosion issues have been identified as root cause failures in multiple aquifer thermal energy storage (ATES) systems in Europe(McLing et al. (2022)) and represent a significant challenge for many geothermal energy generation facilities worldwide. Geochemical-related parameters include both the brine chemistry and brine-rock interaction within the storage reservoir. In-situ brine always contains various dissolved constituents and as temperature and pressure are changed, the solubilities of these naturally-occurring minerals also change. For example: as temperature increases, the solubility or tendency to dissolve can increase, as is the case for SiO_2 (quartz). Conversely, if a brine containing high concentrations of calcium and carbonate ions are heated, the mineral Calcite ($CaCO_3$) will tend to precipitate due to its retrograde solubility relationship with temperature. Changes in pressure can also control whether a certain mineral will dissolve or precipitate, primarily due to gas effects. Further, the pH of a brine has a strong effect on chemical reaction kinetics and is directly influenced by increases or decreases in various dissolved constituents (e.g., bicarbonate, HCO_3).

To explore the scaling potential of the same GeoTES system, brine chemistry from an offset well was used as input **(see Table 1)** to hydrogeochemical modeling software called PHREEQC (Parkhurst and Appelo (2013)), developed by The US Geological Survey. In the model, an aqueous solution with measured concentrations of the major chemical constituents from the nearby well was heated from 50 C to 100 C and pressurized to 100 bar to simulate heating and injection of the brine for hot thermal storage in a reservoir at ~3000 ft depth. The relative changes in concentrations of various minerals are shown in **Figure 11-Left**, plotted against temperature and depth. Temperature and pressure (i.e. depth) are incrementally increased from 50 C to 150 C and 11 bar to 100 bar. Some minerals are initially present and decrease in concentration as temperature increases (e.g., quartz and pyrite) and other minerals precipitate and increase in concentration as temperature increases (e.g., calcite and talc). The scaling potential can be further investigated by modeling the saturation index (SI) of each mineral which is defined as the amount of mineral precipitation required to re-establish the chemical equilibrium of the brine **(Figure 11- Right)**. Here, SI value at or above zero indicates that a mineral is oversaturated within the aqueous solution and therefore has a tendency to precipitate. Using the same input data as above, **Figure 11- Right** shows that Calcite and Talc are initially present as dissolved minerals at 50 C and are then predicted to precipitate as temperature increases to ~75 C (Calcite) and ~100 C (Talc). Anhydrite approaches oversaturation by 150 C but remains in solution. By 180 C, Anhydrite is predicted to precipitate and contribute to system scaling (not shown).

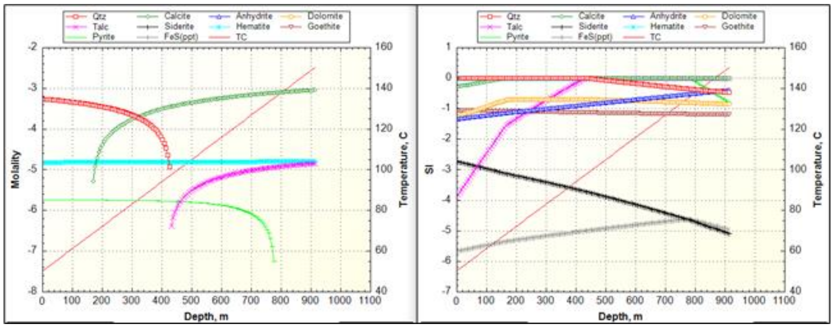


Figure 11: (Left): Concentrations of scale-forming minerals for a brine heated from 50-150 C and pressurized from 11 bar to 100 bar (PHREEQC model output). (Right): Saturation index of scale-forming minerals for a brine heated from 50 C to 150 C and pressurized from 11 bar to 100 bar (PHREEQC model output).

This initial qualitative examination of the scale and corrosion risk at the site shows potential for scale formation within a GeoTES system having a similar brine chemistry as the observed offset well data. Although, small changes in brine or rock chemistry can have a significant effect on predicted scale or corrosion outcomes and this analysis using offset data only provides a scoping-level view of potential results. While offset data can be sufficient for initial examination of any given location, they are typically inadequate to ascertain geochemical effects to the degree necessary for detailed operational optimization and scale or corrosion mitigation plans for a commercial GeoTES facility. It is therefore critical to use site-specific data to constrain these risks. Modeling and prediction of these often complex chemical interactions between all of the aforementioned geochemical parameters is paramount to successful demonstration and commercialization of GeoTES technologies. Therefore, integration of additional geochemical modeling and analyses into the coupled-THM system should be a critical part of any future work.

Results presented in this paper are based on 2D quarter symmetric analysis of an open hole cross-section of a horizontal wellbore where damage is constrained within the plane analysis (no out of plane deformation is considered) and follows a transverse itinerary. However, near wellbore damage initiation and propagation in weakly consolidated rocks is truly a 3D phenomenon. Depending on wellbore trajectory and completion design (e.g., perforation architecture): damage initiation, propagation and coalescence could lead to complex patterns. For example, a set of preliminary 3D models, that honor individual perforations, show longitudinal damage propagation along the wellbore during injection **(Figure 12)**. This is an important observation suggesting preferential flow channeling that can potentially connect multiple zones along the horizontal and warrants further 3D studies.

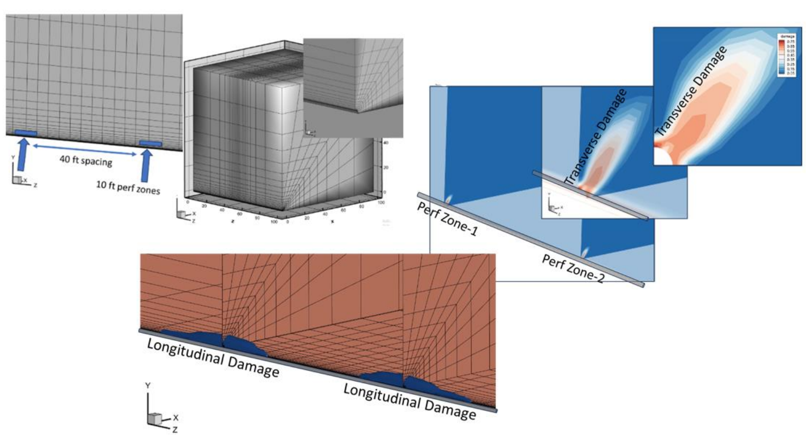


Figure 12: 3D Damage Patterns Along a Horizontal Wellbore: Transverse and Longitudinal Damage

Numerical models require advanced input parameters and constitutive laws to accurately define deformation, flow and damage behavior of the subsurface formations (see Section(s) 2 and 3). These include THMC properties, damage-permeability, stress-permeability, mechanical degradation and among other input parameters required by the coupled physics formulation. These parameters can significantly impact model predictions. THMC coupled laboratory experiments focused on GeoTES systems should be considered to constrain input parameters and to close a potential characterization gap.

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