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Application of Oilfield Geomechanics Techniques to Geologic Carbon Capture, Utilization, and Storage (CCUS) Projects

R. C. Alt, II, Baker Hughes, Fredericksburg, VA, USA

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Abstract

With increasing industry and government attention directed toward climate change mitigation, CO_2 injection wells are expected to play a vital role in America's emerging energy infrastructure and to make up an ever-increasing share of commercial wellbore geoscience activities. The Environmental Protection Agency (EPA) assigns CO_2 injection wells to a category distinct from oil and gas wells, asserts regulatory primacy, and imposes a specific set of regulatory guidelines that drive well planning procedures for what it defines as Class VI injectors. These permitting requirements for a Class VI injector are notably stricter than for a traditional hydrocarbon producing well, which also drives an expectation for greater precision in quantifying several geologic parameters during well planning. For geomechanics teams, this presents a valuable opportunity to develop customized models to optimize drilling and injection procedures, following in the footsteps of what has already been accomplished with horizontal drilling and hydraulic fracturing in the onshore unconventional space over the past two decades.

In this paper, we examine the application of oilfield geomechanics techniques, including pore pressure prediction, rock strength estimation, and wellbore stability analysis to assist in drilling and completion of CCUS wells. We walk through the workflow to build a robust 1-D geomechanical model, calibrated to available offset data utilizing field and wellbore scale geomechanical modeling platforms. Next, we identify best practices for drilling and completing CO_2 injectors. Finally, we apply the geomechanical modeling methodology to CCUS wells, focusing on four key operational risks that are exacerbated compared to similarly situated oil and gas wells: overpressure, borehole breakout, fault reactivation, and stress changes with depletion and injection. We conclude by considering future research opportunities in this field.

Introduction

Geomechanical modeling has long been a cornerstone of pre-drill well planning activities, particularly when undertaking pore fluid injection or extraction from a reservoir interval. The overarching goal is to define the stress field within the Earth at drilling depths, describe how the rock materials present at the drilling location would be expected to respond to these stresses, and apply those stresses along the planned wellbore (e.g. Alcalde 2021). This knowledge allows drilling teams to optimize their operations with reasonable mud windows and casing plans. Geomechanical modeling can be further applied to optimize hydraulic fractures during well completions or to assess the probable pattern of fluid flow and formation pressure change during injection or depletion operations. Techniques specific to unconventional reservoirs have been developed and refined over the past decade to describe the behavior of tight reservoirs, as well as the formation and propagation of induced hydraulic fractures when needed to optimize hydrocarbon production (e.g. Al Jassasi et al. 2023; Leem and Reyna 2014). This has also extended to the study of depletion. For example, a recent analysis applied microseismic monitoring to optimize infill well performance in the Bakken play by modeling fracture growth and frac hits between wells (Cipolla, Motiee, and Kechemir 2018). Now, we have the opportunity to extend these methods to optimize the design of carbon capture, utilization and storage (CCUS) wells.

The Geomechanical Modeling Workflow

The standard workflow for constructing a 1-D pre-drill geomechanical model is illustrated in Fig. 1. This geomechanical modeling and wellbore stability workflow requires determining several independent parameters from the available data: the magnitude of the vertical stress (S_v), the pore pressure (P_P), the magnitude of the horizontal stresses (S_{Hmax} and S_{hmin}), and the orientation of the maximum horizontal stress (S_{Hmax}), rock strength properties (most commonly estimated by unconfined compressive strength, cohesion, and the internal friction angle), and rock mechanical properties (most commonly estimated by Young's modulus and Poisson's ratio). Because modeling must be calibrated to ground truth observations, drilling events like kicks or lost circulation that would put an upper or lower bound on one of the geomechanical parameters at an offset well are the first line of evidence considered. These events are commonly recorded in daily drilling reports (DDRs) provided by the rig services company to the operator.

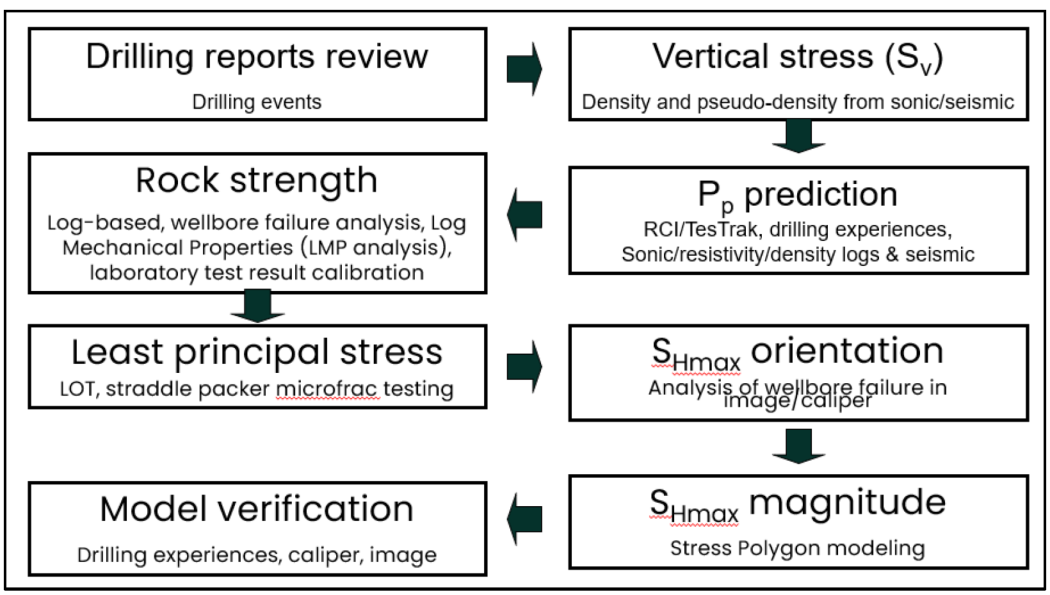

Figure 1—Example of a standardized 1-D geomechanical modeling workflow

Fig. 2 describes common sources of data used to estimate these parameters. Ideally, cores, MWD/LWD data, and wireline logs from nearby offset wells will be available, but information from relevant academic literature can also be incorporated. These parameters can sometimes be measured directly, as with the pore pressure of a sand or the fracture gradient of a shale with a leak-off test (LOT) or a diagnostic fracture injection test (DFIT), or the UCS and Poisson's ratio of a core sample. For example, because image logs are expensive to run and therefore relatively uncommon, the local S_{Hmax} orientation will often be determined by referencing the World Stress Map (Fuchs and Müller 2001). Notably, the magnitude of S_{Hmax} cannot be measured directly and must instead be constrained using geomechanical theory and known limits on frictional strength of the Earth's crust (Zoback et al. 2003). Depending on the relationship between the 3 principal stresses, the stress field at the drilling location can lead to one of three different faulting regimes. Whether regional stress field leads to normal faulting, strike-slip faulting, or reverse faulting, there is a limited range of values for S_{Hmax} compatible with the observed frictional strength of faults. A common method for constraining the plausible range of S_{Hmax} values at the drilling location is the stress polygon. An example is provided in Fig. 3. Furthermore, Fig. 4 illustrates the projection of geomechanical properties along a wellbore by depth using a common modeling software package.

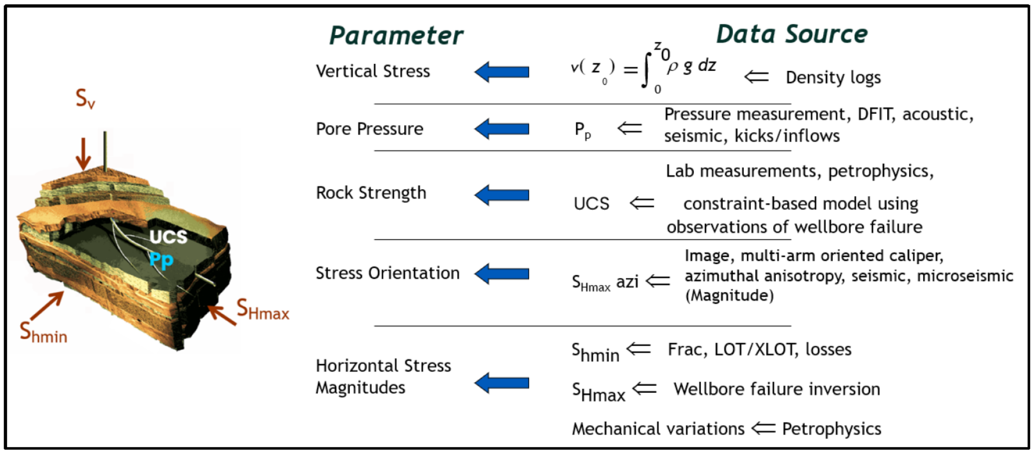

Figure 2—Standard data sources/inputs for a 1-D geomechanical model

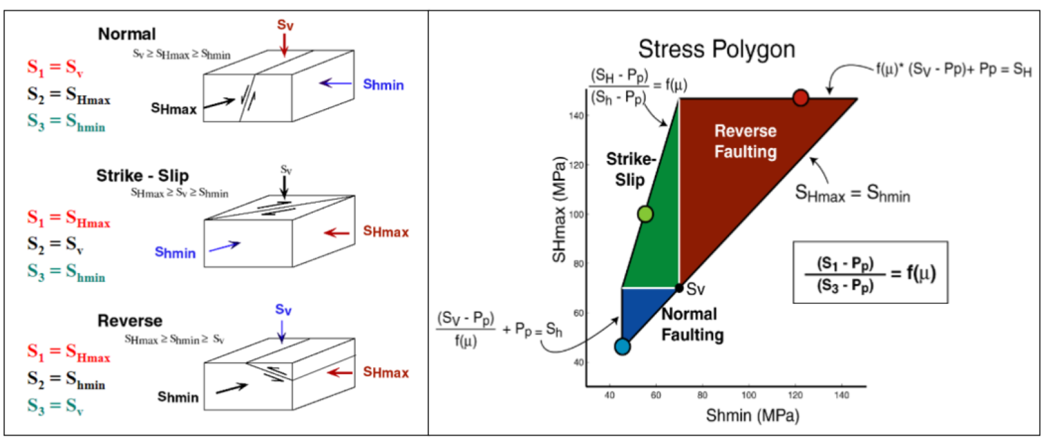

Figure 3—The 3 faulting regimes observed in the Earth's crust and how they are determined by the relative magnitudes of S_{hmin}, S_{Hmax}, and S_v (3a) and how the magnitude of S_{Hmax} can be constrained for each faulting regime using a Stress Polygon (3b). Stress states that would plot outside of the stress polygon at the depth of investigation can be ruled out because they are not physically compatible with the observed frictional strength of the Earth's crust.

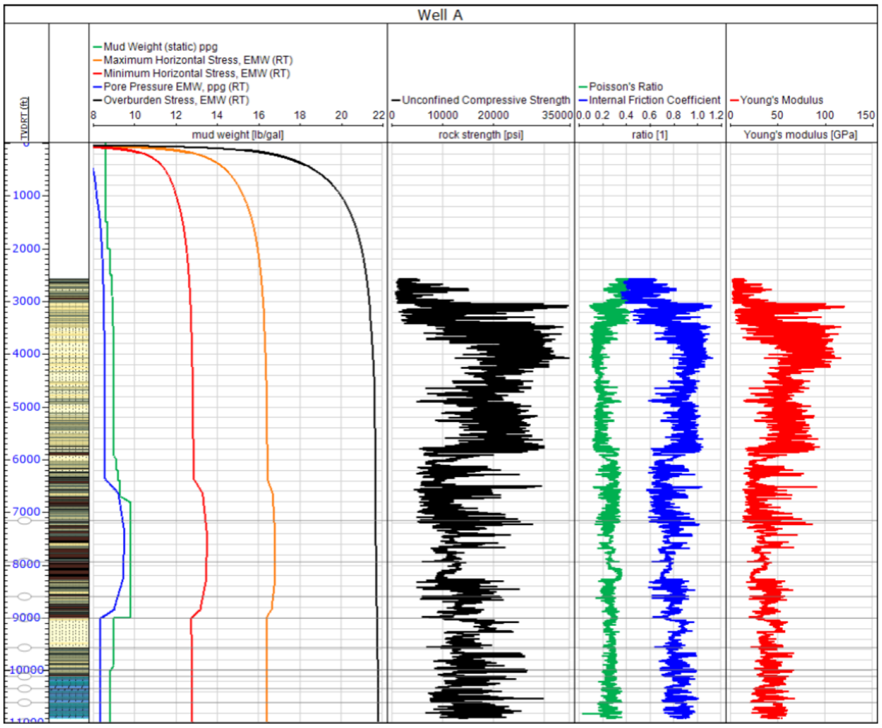

Figure 4—Example output of a 1-D geomechanical model with principal stresses, pore pressure, rock strength and rock mechanical properties projected along a hypothetical wellbore.

In addition to studies of the regional stress field and formation-scale properties like bulk rock strength and pore pressure, geomechanical modeling can also be used to describe behavior at the wellbore wall as the regional stress field acts on it (Alcalde 2021). Stress concentration effects around a hole have been well-documented and the wellbore wall deforms in a predictable pattern when exposed to anisotropic stress fields (Kirsch 1898; Zoback et al. 2003). Figs 5a and 5b describe the near-wellbore deformation expected from stress concentration around a vertical wellbore subjected to anisotropic horizontal stresses (that is, the magnitude of S_{Hmax} is meaningfully greater than the magnitude of S_{hmin}). Near-wellbore deformation gives many opportunities to constrain the stress field acting on the wellbore. The presence or absence of borehole breakouts or drilling-induced tensile fractures could also indicate an upper or lower bound on rock strength or one of the principal stresses. This information can then be used to estimate wellbore stability with a collapse pressure criterion that accounts for the planned wellbore trajectory and variation in rock properties by geological formation.

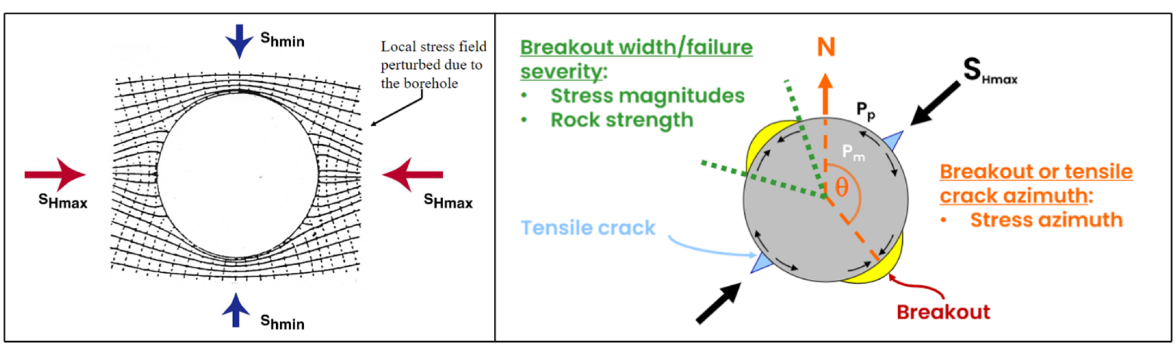

Figure 5—Example of local perturbation of the stress field by drilling a hole in a solid material (5a) and patterns of near-wellbore deformation in a vertical well under a given pore pressure (Pp), mud weight (Pm), and S_{Hmax} orientation (5b). The magnitude of S_{Hmax} is assumed to be meaningfully greater than the magnitude of S_{hmin} at this drilling location and depth to generate the noted breakouts and tensile cracks.

Geomechanics of CCUS projects

In the case of CCUS wells, several distinguishing factors drive unique well designs. As expected, the precision needed in quantifying these parameters is higher when planning Class VI CO_2 injection wells. The economics of CO_2 sequestration projects are fundamentally different from a traditional hydrocarbon-producing development, often relying on federal and state level subsidies and tax credits per unit of CO_2 injected into geological storage. CCUS well planning activity in the US has notably increased following the increase in the Section 45Q tax credit in the Inflation Reduction Act of 2022 (Boschee 2022). The viability of a CCUS project often depends on access to a host of interlocking tax credits and other governmental incentives. This includes optimization for Class VI well permitting requirements, which are notably stricter than for traditional hydrocarbon producing or wastewater injection wells (EPA 2012). In the vast majority of states, the permitting process is handled directly through the EPA in contrast to state and tribal regulatory primacy that has been commonplace for decades when dealing with Class II hydrocarbon producing wells (e.g. Wasicek 1983). Currently, only Wyoming and North Dakota have Class VI well primacy, while planned CCUS developments are concentrated along the Gulf Coast (EPA 2023; Rassenfoss 2023). Class VI wells are associated with higher injection rates and therefore higher pressures than more commonplace Class II wells. Injection also continues for an extended time period, longer than would be typical for an EOR operation. CO_2 is also corrosive to standard drilling and completions equipment, so well designs must be adjusted to account for this (EPA 2012).

As illustrated in Fig. 6, well planning must account for requirements intended to protect the Underground Source of Drinking Water (USDW) from contamination with injected CO_2 through several different geological processes. Because CO_2 emissions into the atmosphere from industrial processes are routine, regulation in this domain focuses on the protection of groundwater. Note that the low density of Carbon dioxide in comparison to average reservoir fluids means that it will tend to rise to the top of the injection target formation over time (EPA 2012). Fluid might then escape from the target injection zone by hydraulic fracturing of the caprock, by slip on faults that extend upwards toward the USDW, by matrix flow (which can be mitigated by selecting an injection target isolated by particularly low permeability caprock), or through the annular space due to well integrity issues. In this situation, the well itself can be a migration pathway for injected CO_2 to escape the target formation. For this reason, cement must be confirmed to extend to the surface for each hole section of a Class VI well (EPA 2012). Furthermore, the hole section that penetrates the injection target interval must be cemented with specialized CO_2 resistant cement. With these considerations in mind, the acceptable ranges for mud windows and wellbore stability criteria are narrower for CCUS wells than for traditional oil and gas wells, enhancing the value added by pre-drill geomechanical modeling during well planning. For example, a loss event that could be controlled relatively easily with lost circulation material when drilling an oil and gas production well might unknowingly fracture the caprock of a CCUS project or initiate fluid communication outside of the injection target zone. Caliper logs are also mandatory to confirm a sufficiently circular wellbore, in every hole section from the surface hole to the injection interval.

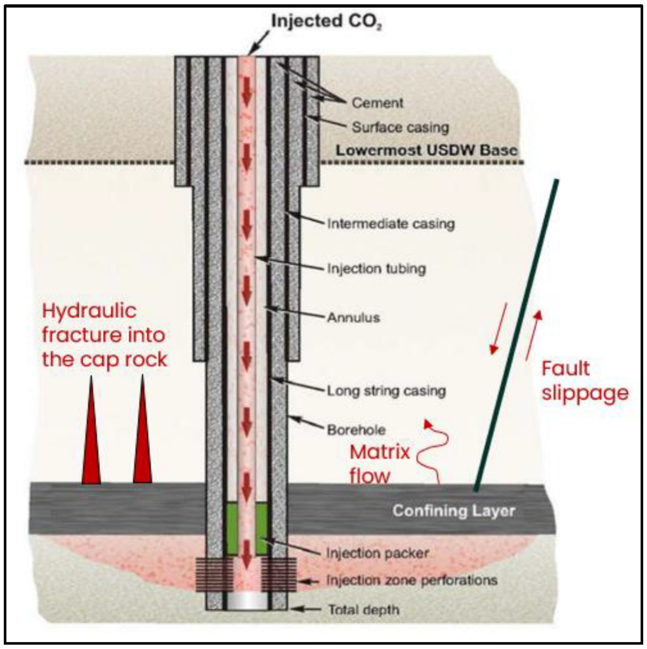

Figure 6—Diagram illustrating several geomechanical risks associated with Class VI CO_2 injection wells, including hydraulic fracturing into the cap rock, matrix flow upward out of the confining layer, and inducing slip on faults extending to the USDW (after EPA 2012s).

Geomechanical investigations of specific geologic CO_2 sequestration sites have already been undertaken in many parts of the US and internationally. Studies of the Illinois Basin as a potential CCUS reservoir were performed as early as 2004 (Frailey et al.). A recent study of the Rock Springs Uplift site in Wyoming, USA gathered cores and conducted triaxial tests at three different confining stresses to characterize rock strength in the Weber Sandstone and Madison Limestone, potential CCUS injection formations (Ng et al. 2019). Elsewhere, a mechanical earth model (MEM) has been constructed for the CO2-WAG field in Farnsworth, Texas, USA, where a mature waterflood is being converted into a CCUS development which also involved extensive core collection and testing combined with estimation of pore pressure and the three principal stresses (McMillan et al. 2019). Reservoir permeability was also analyzed extensively. These are just a few of the many specific geomechanical studies that have been undertaken in recent years to prepare for the development of CCUS projects and responsible exploitation of geologically compelling injection zones.

Specific Operational Applications

Next, we consider four specific risks that must be addressed in CCUS well design and how each of these risks can be mitigated with a robust pre-drill geomechanical model:

Overpressured zones encountered in high-permeability formations above the planned injection interval can compromise drilling operations with influxes, kicks, and even blowouts. Even within a shale caprock, the presence of a local permeable streak could also lead to high pressure drilling events. Many of the conditions leading to overpressured zones in the Earth are also associated with physical and chemical processes that lead to the formation of hydrocarbon deposits, so this is a frequent geologic hazard in the oilfield. This carries over to CCUS wells because it is often most efficient to drill them near major oil and gas developments where local geology has been well constrained. As mentioned earlier, many of the CO_2 injection targets themselves are former hydrocarbon reservoirs. Overpressure must be clearly identified and isolated from the injection zone with casing (e.g. Hoetz and Nijhuis 2019; Dodds et al. 2001). Several common overpressure generation mechanisms are described in Fig. 7. Hard overpressure in the overburden must be isolated from the caprock and injection target when planning a Class VI CO_2 injection well in order to ensure a wide enough drilling window to comply with EPA regulations. Additionally, significant overpressure within an injection target formation would compromise the economic viability and safety of the project because the pore space that could be filled with injected CO_2 would be greatly limited.

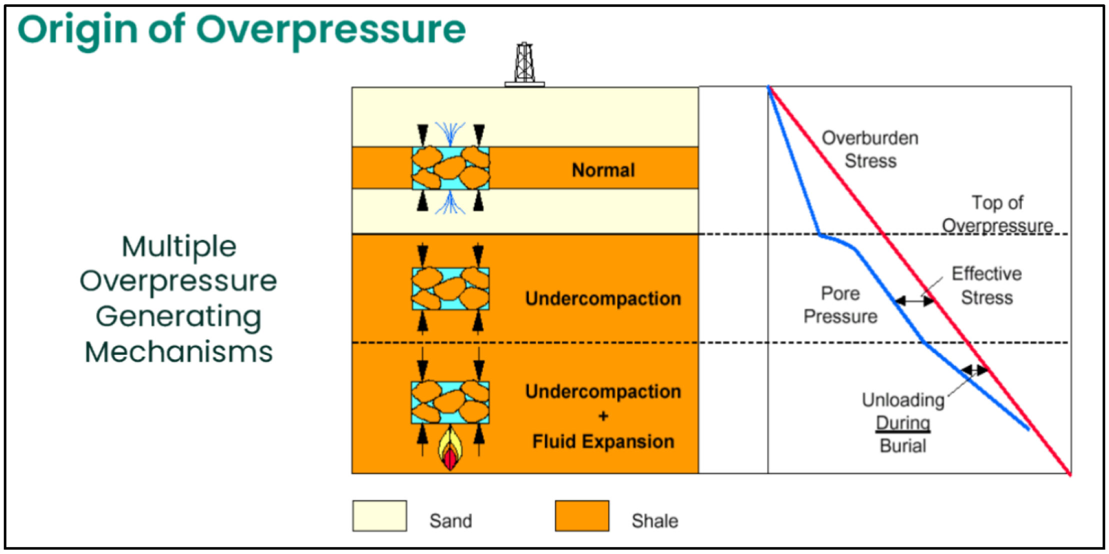

Figure 7—Common scenarios for overpressure generation at drilling depths (after Bowers 2001).

Caprock integrity is of critical importance during injection and must be confirmed through pre-drill geomechanical analysis and ideally monitored during and after injection with a microseismic array to estimate the extent of fault slip from pressure perturbation. For this reason, microseismic monitoring is a legal requirement for CO_2 injection wells (Printz et al. 2022; EPA 2012). The propagation of pressure waves associated with the injected CO_2 out of the injection target zone along faults and fractures would likely trigger induced earthquakes on a scale this equipment could pick up. Because critically stressed faults are ubiquitous in the Earth's crust, rock formations are always expected to be closer to shear failure than pure tensile failure at typical CO_2 injection depths (Townend and Zoback 2000). Crucially, those fractures which are prone to slip are also the most hydraulically conductive. Fig. 8 provides an example of a critically stressed analysis for a population of fractures using the Mohr-Coulomb method to calculate how close each fracture is to shear failure. Note that this shear failure should register as an earthquake on a sufficiently sensitive microseismic array, which gives an opportunity to detect deformation of the caprock and fluid migration early in an injection program. Fault reactivation that could initiate fluid communication with the Underground Source of Drinking Water (USDW) must be carefully avoided. For this reason, meaningful fluid losses during any stages of operations are a compliance risk that must be assessed before drilling and injection. It is also a best practice to monitor caprock integrity continuously during CO_2 injection operations. Cement integrity must also be closely monitored to confirm that cement has set properly and gone to surface. Cement bond logs are of critical importance to ensure compliance with applicable regulations. Finally, the faulting regime at the injection site must be well determined from pre-drill modeling. Probable active faults should be identified and studied on seismic surveys. Because injection takes place in the reservoir interval, the greatest concern would be for hydraulically active faults that extend from the injection target formation into and potentially beyond the cap rock. These faults will most likely slip first due to the increase in pore pressure. Faults in the cap-rock that are not in communication with the reservoir can also slip due to deformation arising from the injection process but these occurrences are quite infrequent compared to those associated with depletion. Ideally, injection pressure should be kept below the reservoir fault reactivation threshold.

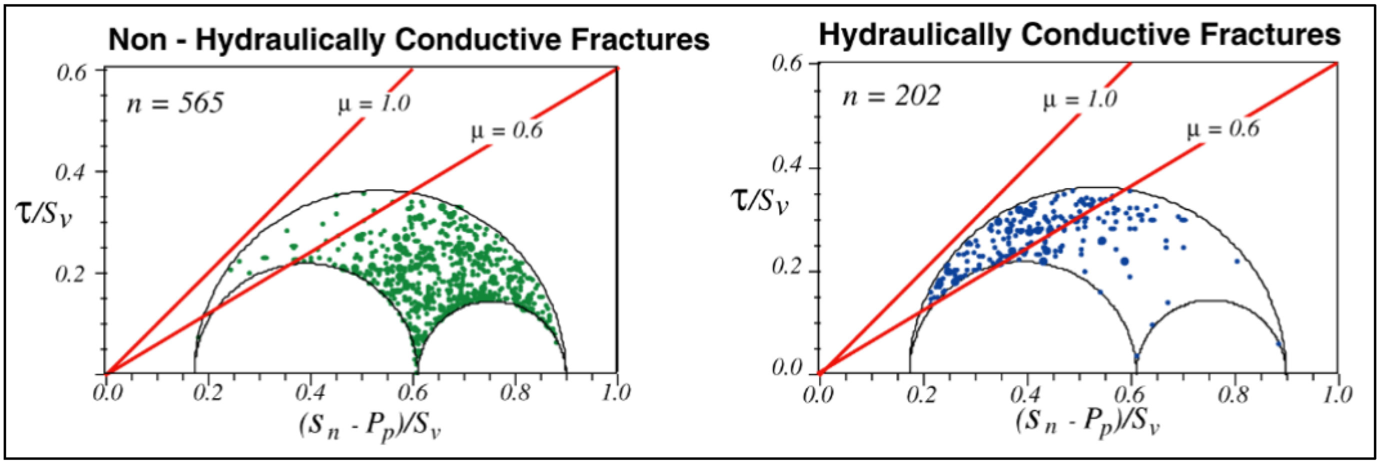

Figure 8—Example of the identification of critically stressed fractures using a Mohr-Coulomb stress diagram. For each fracture, the effective normal stress expressed as a fraction of overburden (S_n – P_p/S_v) is plotted on the horizontal axis and the shear stress expressed as a fraction of overburden (τ/ S_v) is plotted on the vertical axis. The red lines represent upper and lower bound scenarios for the coefficient of sliding friction (μ). The population of non-conductive fractures analyzed on the left includes very few which are critically stressed, while the population of conductive fractures analyzed on the right includes many which are critically stressed.

Borehole breakout tolerance is lower than industry standards for a comparable hydrocarbon producing well. As previously noted in Fig. 5b, borehole breakout leads to a non-cylindrical wellbore that could become geometrically incompatible with planned casing and completions tools. When corrective action is not taken, the accumulation of rock material spalling into the hole from breakouts of significant size can also impair drilling and completions operations, and in extreme cases, the hole can be lost due to packoff leading to stuck pipe (Zoback et al. 2003; Blanton and Teufel 1985; Cheatham 1984). The phenomenon is explored in more detail in Fig. 9, where the Mohr-Coulomb analysis originally applied to a population of faults in Fig. 8 is extended to consider failure conditions at different locations along the wellbore wall under the influence of stress concentration. The stability of the wellbore wall is governed by the difference between the hoop stress ($\sigma_{\theta\theta}$), which varies with orientation along the wellbore wall, and the radial stress (σ_{rr}), which acts equally in all directions and therefore is not dependent on orientation along the wellbore wall. The tendency for borehole breakout will be highest when $\sigma_{\theta\theta}$ is at its peak (which will be along the azimuth of S_{hmin} in a vertical wellbore with anisotropic horizontal stresses). It is possible to increase the radial stress by increasing mud weight in the wellbore and so mitigate the presence and severity of borehole breakouts. This moves the wellbore wall further away from failure in a given stress state. Estimating breakout width in advance of drilling is a core function of geomechanical modeling.

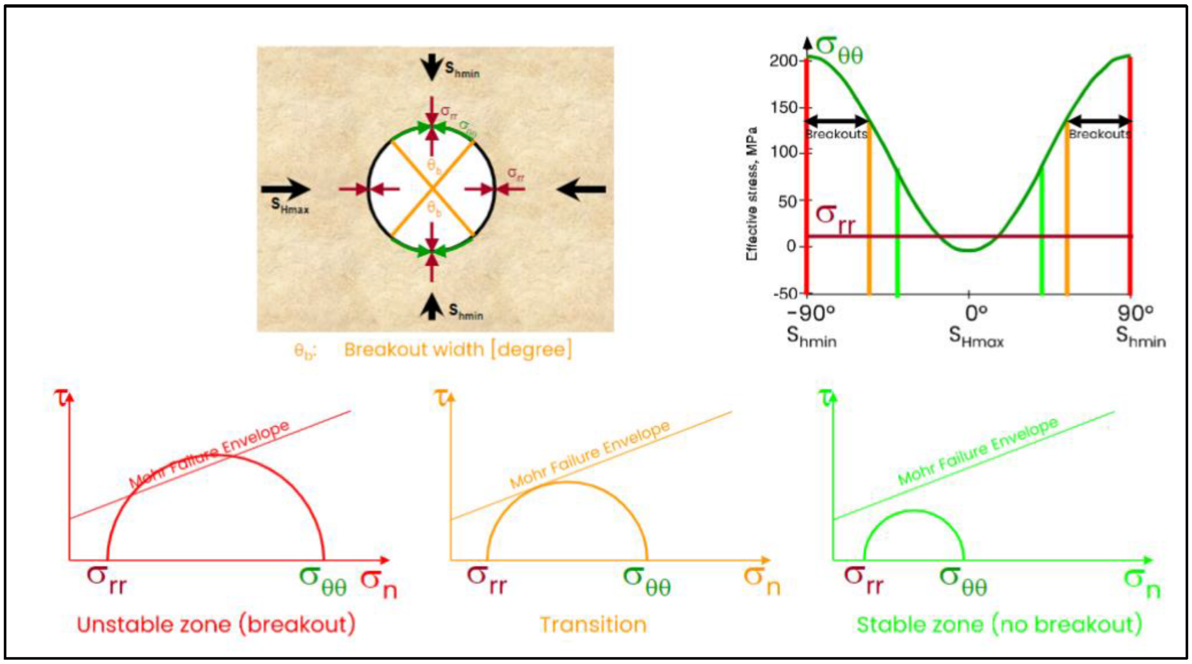

Figure 9—Applying the Mohr-Coulomb Failure Criterion with hoop stress ($\sigma_{\theta\theta}$) and radial stress (σ_{rr}) to understand rock failure due to stress concentration at the wellbore wall.

In a CO_2 sequestration well, there will likely be more casings to run and the consequences of wellbore rugosity for the development are more severe, because a well could fall out of compliance with the EPA Class VI guidelines due to well barrier problems. For this reason, caliper logs are critically important component of wireline logging programs for CCUS wells. Caliper logging allows for the rapid identification of out-of-gauge hole in advance of casing runs and well completion activities. Furthermore, time-dependent wellbore deformation is often a more serious concern with CO_2 injection wells than similarly situated hydrocarbon-producing wells because wireline logging programs will generally need to be longer and more extensive than industry standards for hydrocarbon-producing wells. The open hole will often be left exposed for several additional days. Geomechanical modeling can mitigate this risk by constraining the operational mud window more narrowly and identifying the optimal mud additives to mitigate changes in hole stability over time.

Shales with swelling tendencies can also be a significant risk to wellbore stability, particularly when the open hole must be exposed for longer and more extensive wireline logging than is typical for hydrocarbon wells. Within North America, regulatory regimes and governmental incentives have significantly favored carbon sequestration developments along the Gulf Coast, where this geologic phenomenon is particularly common and well-documented (e.g. Gilmore and Sanclemente 1989). As of early 2023, 15 of 28 planned CO_2 sequestration developments in the US were located in Louisiana (Rassenfoss 2023). When drilling in smectite-rich Gulf Coast sediments, swelling stress/pressure can develop to very high levels, leading to wellbore collapse in a stress state that would otherwise appear to be stable. This can be addressed by altering mud chemistry and modeling alternative mud formulations in advance.

Depletion and Injection can lead to profound changes in effective stress of the target formation over the course of a field development campaign (e.g. Orlic and Wassing 2013; Orlic and Wassing 2012). Analytical methods have also been applied to estimate the stress path of a CCUS reservoir and consider the risk of induced seismicity (Burghardt 2017). Other researchers have recognized the importance of surveillance monitoring to track injection and depletion using fiber-optic cabling (Oppert et al. 2022). Depletion increases the effective stress of the formation over time while injection decreases it. Severely depleted intervals will often have subhydrostatic pore pressure gradients and correspondingly low fracture gradients. In the context of CCUS wells, this is a common concern because injection wells often intentionally target low pressure, highly permeable zones for ease of operations and governmental incentives often favor the development of CO_2 injection projects targeting formerly oil-producing formations. In some fields, the explicit conversion of former oil and gas wells into CCUS injection wells is being pursued (Koning et al. 2023). Depending on local regulations, this can be attractive both because it saves resources and because it could increase the odds of preserving caprock integrity. In theory, fewer total penetrations of the caprock would be needed compared to drilling a full set of new wells.

However, a depleted interval can be a major constraint on well design, as the fracture gradient can locally be dramatically lower than overlying or underlying formations, as can be seen in Fig. 10. By contrast, injection can raise pressures over time, elevating the risk of induced seismicity (e.g. Lima et al., 2017). An accurate understanding of the reservoir stress path is fundamental to mitigate depletion and injection concerns and describe the stress changes the target formation can handle within operational constraints. A well-constructed geomechanical model will identify a reasonable range of scenarios for depletion in advance of drilling and completions operations.

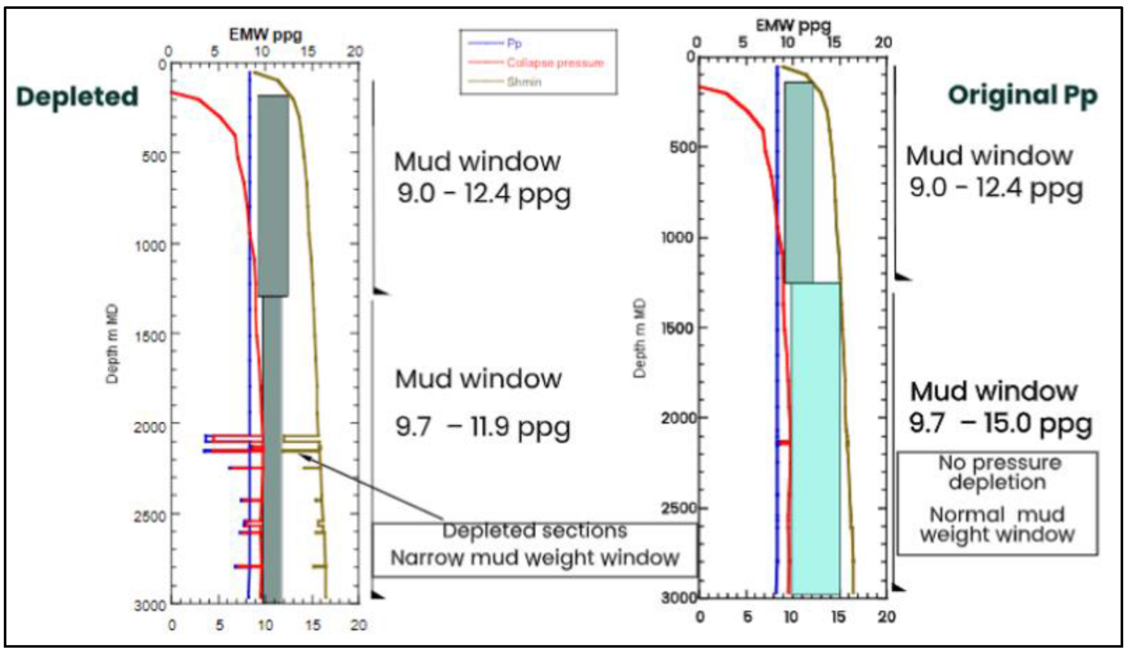

Figure 10—Illustration of depleted intervals as an operational constraint on well planning. The upper bound on the safe mud window must be reduced substantially to avoid loss of circulation in a depleted interval.

Conclusions

The development of CO_2 injection wells presents an important new economic opportunity for the energy industry and an important opportunity for society to eliminate greenhouse gas emissions that would otherwise warm the global climate. Recent efforts to enhance the tax treatment of these investments have led to rapid growth and experimentation to customize drilling and completions techniques. Thoughtful use of geomechanical modeling plays a vital role in optimizing these operations to meet the more specific regulatory standards the EPA imposes for Class VI CO_2 injectors.

In this paper, we have walked through a standardized methodology for 1-D geomechanical modeling and then applied it to the unique context of CCUS wells, considering four specific operational risks that are enhanced when dealing with CCUS projects: overpressure, caprock integrity, borehole breakout tolerance, and stress changes with depletion and injection. The opportunity to apply and adjust geomechanical workflows to improve drilling and completions outcomes and regulatory compliance for CCUS wells is clear, just as it was with tight shale wells a decade ago. Opportunities for future research include applying hydraulic fracture growth modeling techniques from onshore unconventionals to optimize well placement and the overall injection efficiency while minimizing total operational expenses over the life of the project. This can be explored in more granular detail once we have a sufficient population of parent and child CO_2 injection wells to compare. Another attractive possibility would be the development of novel casing materials that could withstand shear stresses and corrosion over a longer injection timescale. Finally, there could be an opportunity to develop specialized microseismic arrays calibrated specifically to CO_2 injection conditions.

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