Instrumenting the Devine Site as a Field Laboratory for Hydrogen Injection: Characterization and Monitoring Feasibility Assessment

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Summary

The Devine Test Site is transitioning into a premier field laboratory for injection monitoring, offering extensive geophysical characterization, deep boreholes, and core material. With the planned addition of two new instrumented wells equipped with fiber-optic sensing and Electrical Resistivity Tomography (ERT), the site may serve as an ideal testing ground for validating monitoring technologies across various subsurface applications. As part of ongoing research, it is being prepared for a hydrogen injection test into an aquifer to evaluate monitoring strategies for this emerging storage option. Our study integrates ultra-dense seismic surveys, 3D VSP, and well instrumentation to establish a high-resolution baseline and refine monitoring design. Rock physics modeling confirms that hydrogen, as a light and highly mobile gas, induces measurable velocity reductions, supporting a time-limited monitoring program. Cross-well seismic simulations indicate detectable travel-time shifts, justifying a phased approach with frequent early-stage surveys. These efforts further solidify Devine's role in de-risking gas storage, positioning hydrogen storage in aquifers as a viable and cost-effective alternative to salt caverns.

Introduction

Geophysical monitoring is essential for tracking fluid injection in subsurface applications, including oil and gas production, underground gas storage, geological carbon storage (GCS), and hydrogen storage. As the energy transition accelerates, the demand for reliable monitoring technologies grows. Fluid injection alters subsurface conditions in complex ways, and geophysical methods provide critical insights into fluid movement, reservoir integrity, and containment. While hydrocarbon production and CO_2 injection monitoring is well established (Jonston, 2013; Ajayi et al., 2019; Jenkins et al., 2015) , hydrogen storage presents unique challenges due to its distinct physical and chemical properties.

Field experiments play a vital role in advancing monitoring strategies by refining detection techniques and establishing best practices. Given the limited real-world hydrogen injection tests, experimental programs are crucial for understanding hydrogen migration, reservoir interactions, and long-term stability (Pevzner et al., 2021; Beloborodov et al., 2024).

UT Austin's Devine test site provides an ideal opportinuty to test feasibility of characterisation and monitoring of hydrogen storage. This study outlines the characterization and monitoring efforts at the Devine site. By integrating geophysical surveys, advanced well instrumentation, and reservoir simulations, we assess monitoring technologies for tracking hydrogen migration in an aquifer setting. These efforts aim to de-risk hydrogen storage projects and enhance the safe and effective utilization of the subsurface for energy storage.

The Devine test site

The Devine test site is a major asset for UT Austin and the Bureau of Economic Geology (Hardage, 1999, 2004; Hosseini and Nicot 2016; Devine Test Site, BEG UT Austin), serving as a premier geophysical research facility for several decades (Figure 1a). Extensively used for seismic

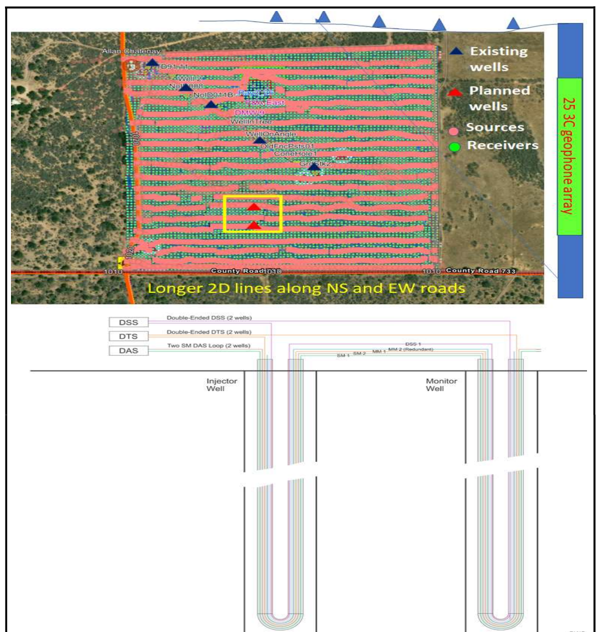

Figure 1: (a) Devine test site schematic with wells and UHD 3D+2D seismic and 3D VSP survey layout; (b) Fiber-optic design with continuous fiber linking both wells.

and borehole experiments, the site features five deep boreholes reaching up to 3,000 feet. However, these wells were drilled as geophysical test holes—they are not perforated and have never been used for injection experiments. Past injection studies at the site were limited to ultra-shallow depths (~100 meters) conducted by the AEC Consortium (AEC, BEG UT Austin), but no gas injection has ever been performed in deeper formations.

Devine Site Hydrogen Injection Monitoring

Hydrogen Injection Test Objectives

The upcoming hydrogen injection experiment at the Devine site aims to advance the understanding of hydrogen behavior in the subsurface and improve monitoring capabilities. Several tons of hydrogen will be injected into the Olmos Sandstone at a depth of ~1,600 ft, with no planned withdrawal. This formation is a poorly cemented sandstone with no structural trap, relying only on capillary trapping and a small dip to the north. The test is designed to achieve the following key objectives:

- Refine flow and diffusion parameters to better predict hydrogen migration.
- Evaluate monitoring tools for tracking hydrogen movement and storage integrity.
- Investigate leakage tendencies and assess the effectiveness of leakage detection technologies.
- Study microbial interactions and their impact on hydrogen stability, geochemistry, and bioactivity.
- Assess geomechanical effects, including potential changes in rock properties due to hydrogen exposure.

Characterization Efforts and Geophysical Surveys

To support the injection test, comprehensive site characterization was conducted, integrating laboratory analysis and field-scale geophysical surveys. The reservoir sandstones range from arkoses to litharenites, with porosity estimated at ~31% and permeability near 100 mD based on five core samples from the target zone. Core analysis and laboratory testing further refine key reservoir properties, including a vertical-to-horizontal permeability ratio (Kv/Kh ≈ 0.5), providing critical constraints on expected hydrogen migration.

At the field scale, a high-resolution seismic survey was performed to enhance subsurface imaging and guide monitoring design as explained by Bakulin et al (2023). The ultra-dense 3D nodal seismic survey, with a 7.5 × 7.5 m receiver grid and 7.5 × 30 m source spacing, captured detailed structural and stratigraphic features (Figure 1a). A 3D VSP survey was also conducted in Well #9, utilizing 25 three-component borehole sensors to further refine the velocity model and assess borehole seismic monitoring potential.

Instrumentation and Simulation-Driven Well Placement

The monitoring well placement is guided by reservoir simulations, assessing hydrogen migration under different scenarios. A series of numerical simulations were conducted to evaluate plume behavior, with Figure 2 presenting an example where 2,000 kg of H_2 is injected into the Olmos Sandstone. These results indicate that closely spaced monitoring wells (15-30m from the injector) provide optimal coverage for tracking plume evolution. The final spacing will be refined as additional simulations and injection volume estimates are updated. The instrumentation program relies on fiber-optic sensing and Electrical Resistivity Tomography (ERT) behind the casing in both wells (Figure 1b). A single fiber-optic cable runs through both closely spaced injector and monitoring well, with some fiber loops forming a closed circuit to enhance measurement continuity.. The primary monitoring strategy focuses on borehole-based techniques for direct detection of H_2 and is planned for a duration of 8 to 18 months.

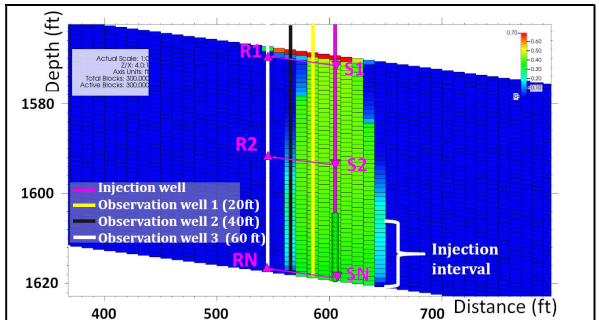

Figure 2: H_2 saturation cross-section one year after injection, showing observation wells and cross-well survey layout.

Monitoring Program Summary

The hydrogen injection test will integrate a multi-scale monitoring framework, combining borehole-based, geophysical, and geochemical techniques. The monitoring program includes:

- Borehole-based monitoring: Repeat time-lapse logs and fiber-optic sensing (DAS, DTS, DSS) in both the injector and monitoring wells.
- Seismic monitoring: 4D DAS VSP, permanent seismic sources, and high-resolution cross-well seismic with DAS for plume tracking.
- Leakage detection: Surface H2 sensing.
- Geochemical and microbial assessments through downhole water sampling.
- Geomechanical monitoring: strain monitoring and laboratory core studies.
- Novel technologies: The site provides an integrated framework to test emerging technologies such as shallow strain measurements, permanent source/receiver systems, and advanced fiber-optic sensing.

These efforts aim to establish best practices for hydrogen storage monitoring, providing critical insights into containment strategies and long-term storage feasibility.

Rock Physics Modeling

Gassmann's equations are used to model the impact of hydrogen saturation on sandstone elastic properties. The sandstone is moderately consolidated, providing the basis for modeling elastic property changes with hydrogen saturation. The baseline case, validated against acoustic logs at full water saturation, yields a saturated density of 2.17 g/cc, a compressional wave velocity (Vp) of 2620 m/s, and a shear wave velocity (Vs) of 1156 m/s. A low grain bulk modulus (Kgrain) of 35 GPa was estimated, consistent with XRD analysis showing clay minerals primarily concentrated within grains rather than in interparticle pore spaces, preserving permeability. The composition includes smectite (~12.5%), illite/mica (~2.2%), and mixed-layer illite/smectite (~1.5%). Modeling predicts the greatest velocity drop of ~370 m/s at ~8% hydrogen saturation, followed by a slower, more gradual increase toward full hydrogen saturation. This behavior results in more subdued Vp variations between 20% and 80% hydrogen saturation, impacting geophysical detectability within typical sweep ranges. The reservoir model assumes a residual hydrogen saturation of ~5%.

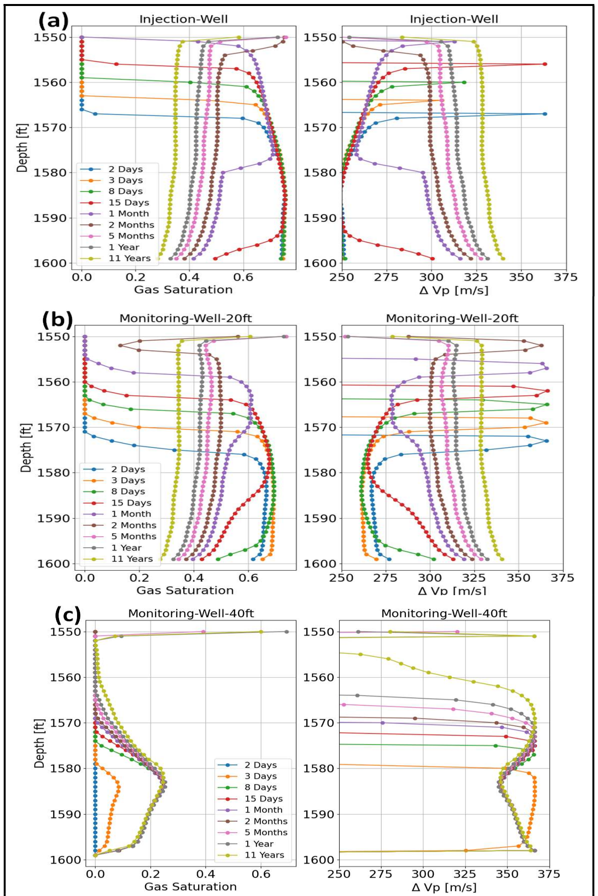

Figure 3: Cross-sections of saturation and ΔVp changes (base vs. monitor) along the injection well (a) and observation wells at 20 ft (b) and 40 ft (c) in the dip direction.

Time-Shift Response for Cross-Well Surveys

With the comprehensive monitoring program outlined above, we now focus on assessing the feasibility of repeat cross-well seismic using DAS to detect small travel-time shifts associated with hydrogen migration. This study specifically evaluates the expected ΔT (travel-time) changes, leveraging simulations of hydrogen plume evolution and using rock physics model above. Other monitoring approaches are being evaluated separately and will be reported elsewhere.

Figure 3 illustrates the evolution of the hydrogen plume over time, showing gas saturation and corresponding velocity reduction (ΔVp) at different intervals, ranging from three days to one year. Hydrogen is injected into the lower third of the target aquifer (Figure 3a), where it rises due to buoyancy, reaching the top of the reservoir within one month in the injector well. By this time, hydrogen saturation decreases from ~70% to 50%, dropping further to ~40% at one year due to diffusion and redistribution. A similar pattern is observed in the 20 ft monitoring well, where the hydrogen front reaches the bottom portion within two days with an initial saturation of ~70% (Figure 3b). It rises through the reservoir, gradually diffusing to ~40% saturation after one year. At 40 ft, the monitoring well detects hydrogen arrival at ~3 days, but with a lower initial saturation of ~7% (Figure 3c). Over time, saturation increases to ~20% at the bottom of the reservoir while remaining largely unchanged over time, with slow vertical expansion higher up at low saturation below 10%.

Figure 4 provides a horizontal view of plume migration. Near the injection interval (not shown), hydrogen spreads

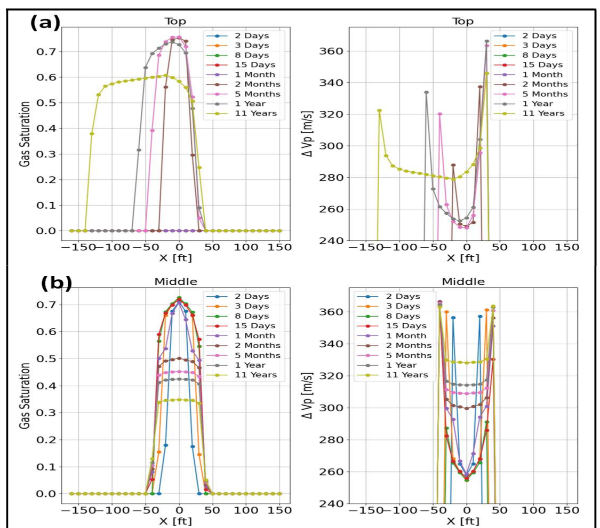

Figure 4: Horizontal profiles of H_2 saturation and ΔVp along the dip direction at different depths: (a) top ~5 ft below caprock, (b) middle ~25 ft below caprock.

rapidly within two days, reaching ~90 ft in width while maintaining ~70% saturation. The lateral extent remains stable, but saturation gradually declines below 50% within two weeks and ~30% at one year as hydrogen redistributes upward. The mid-reservoir section (Figure 4b) shows a similar trend, though upward migration takes several days before the plume stabilizes at its full ~90 ft lateral extent. At the top of the reservoir, plume arrival occurs at around two months, followed by asymmetric up-dip migration up to ~70 ft away from the injector forming the tongue of the plume (Figure 4a). However, this section represents only the topmost cell beneath the caprock, where the hydrogen tongue remains very thin (Figure 2).

Armed with this understanding, we can now interpret the simulated cross-well travel-time differences over various time steps (Figure 5), with wave propagation oriented along bedding using the injector and monitoring well 3 (Figure 2, 60 ft/18.3 m apart). If the maximum velocity reduction (-370 m/s) were to occur across each reservoir cell, we would expect a travel-time decrease of approximately 0.95 ms for a plume extending 50 ft (15 m) away from the injector (Figure 2). Across the injection interval, travel-time shifts increase from ~0.4 ms on day 1 to ~0.7 ms at 1 month, then gradually plateauing at ~0.75 ms at 1 year. This is slightly less than the maximum expected change, as not all cells experience the peak velocity reduction. For instance, Figure 4b shows the lowest saturation reaching ~43%, corresponding to a ~310 m/s velocity decrease. The lateral

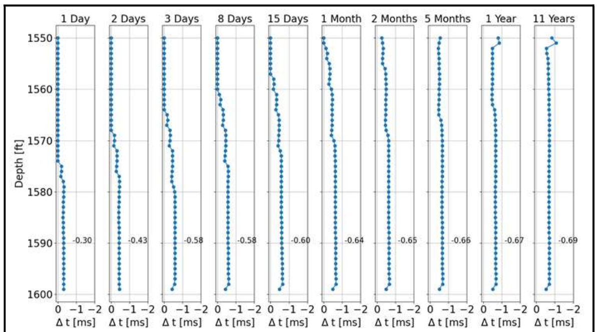

Figure 5: Travel-time changes (base vs. monitor) for the cross-well survey using the injector and Well 3 (60 ft), based on the acquisition geometry from Figure 2.

extent of the hydrogen plume remains nearly unchanged at ~90 ft (27 m), while saturation gradually declines over time due to upward migration. The vertical expansion of the plume is also evident in the lateral travel-time shifts. The plume reaches the top of the reservoir at ~2 months, where ΔT just below the caprock reaches 0.3 ms, eventually increasing to ~1 ms at 1 year in the updip tongue (Figure 2).

The monitoring system must ensure high repeatability and spatial resolution to detect small travel-time variations. Permanent sources and receivers offer the most stable measurements, but high-resolution wireline sources are a viable alternative. Our simulations support a phased monitoring approach, with daily surveys during early hydrogen migration, tapering to weekly, bi-monthly, and then every few months as the plume stabilizes. Previous studies (Zhang et al., 2012; Ajo-Franklin et al., 2013) and recent trials with DAS and high-frequency sources (Beloborodov et al., 2024) confirm the feasibility of detecting small travel-time shifts, reinforcing the potential of cross-well seismic for gas storage monitoring.

Conclusions

The Devine Test Site is transitioning from a world-class static geophysical laboratory into a shared field lab for injection monitoring, integrating advanced seismic imaging, borehole instrumentation, and reservoir simulations. Recent ultra-dense 3D seismic surveys combined with 3D VSP have significantly improved our understanding, providing a robust framework for tracking fluid migration and optimizing monitoring strategies. The upcoming hydrogen injection test aims to further demonstrate the site's capability to assess storage integrity and monitoring feasibility in aquifers, an emerging alternative to salt caverns.

As part of ongoing development, two new closely spaced instrumented wells (injector and monitor) will be drilled, each equipped with fiber-optic DAS, DTS, DSSS, and Electrical Resistivity Tomography arrays behind casing. These enhancements will enable detailed tracking of hydrogen propagation in the aquifer, addressing critical questions about simulation validity, geochemical interactions, and geomechanical effects, ultimately refining the ability to monitor hydrogen migration and potential leakage.

Our feasibility assessment of cross-well seismic monitoring confirms that detectable travel-time shifts justify a phased approach with frequent early-stage surveys, capturing rapid changes while limiting the monitoring program to about 12 months. Moving forward, we will explore alternative injection scenarios with varying hydrogen volumes to assess plume expansion, improving detectability and optimizing storage design. These efforts reinforce the Devine Test Site's role as a shared industry laboratory for advancing injection monitoring technologies across hydrogen, CO_2, and other subsurface storage applications.

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