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An assessment of the role of geophysics in future U.S. geologic carbon storage projects

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Abstract

Geologic carbon storage (GCS) is ramping up worldwide as a viable component of carbon capture, utilization, and storage (CCUS) projects aimed at reducing greenhouse pollution to limit climate change. GCS may be a growth opportunity for the application of geophysics in reservoir characterization and monitoring. Federal and state government financial incentives are the economic motivators of the CCUS business in the United States, and recent increases in these incentives have triggered a large number of U.S. Environmental Protection Agency Class VI permit applications to inject CO_2 for GCS. The applications indicate that almost all such projects propose using geophysical technology for monitoring. We assessed the GCS geophysical market in the United States based on an intensive analysis of recently filed Class VI permit applications. The analysis shows that reprocessing of existing seismic data will be the primary geophysical activity for reservoir characterization prior to CO_2 injection. For monitoring, verification, and recording of CO_2 injection, time-lapse vertical seismic profiling and 3D seismic imaging will be the dominant technologies followed by 2D time-lapse seismic imaging and some nonseismic methods. Passive seismic monitoring is planned for the majority of CCUS projects to reduce the risk of induced seismicity. If assumptions related to the United States meeting its current climate goals by 2050 are met, then geophysical activity will increase over the next 30 years. An estimate of the seismic crew count needed to support the projects suggests that the scale of GCS-related seismic acquisition by 2050 may reach the current level of onshore oil and gas geophysics crews in the United States. While the economic incentives of a regulation-driven market will press for the minimization of geophysical sensing in GCS, there is also the potential for growth in geophysical activity with the development of advanced processing and analysis tools, multiphysics data interpretation, and cost-effective continuous monitoring.

Introduction

Geologic carbon storage (GCS) has emerged as an important component of carbon capture, utilization, and storage (CCUS) to reduce greenhouse gas emissions from power generation and other industries that traditionally release CO_2 directly into the atmosphere (IPCC, 2014). For this reason, most published scenarios reaching net-zero addition of greenhouse gases to the atmosphere rely in small part on some form of GCS. For example, the International Energy Agency's (IEA's) Net-Zero Emissions by 2050 Scenario, which results from techno-economic modeling of the portion of the global economy that emits greenhouse gases, has 7.6 gigatonnes (Gt) of CO_2 captured in 2050. Of this amount, about 95%, or about 7.2 Gt, is sequestered through GCS (IEA, 2021). In four of five scenarios in the Net-Zero America study published by Princeton University, 1 to 1.7 Gt are captured in the United States in 2050 (Larson et al., 2021). The U.S. plan to reach net-zero emissions indicates 0.4 to 1.3 Gt from CCUS in 2050 across seven scenarios, according to Suter et al. (2022).

To ensure the safe subsurface confinement of CO_2 and conformance with current U.S. Environmental Protection Agency (EPA) Class VI injection well permitting regulations, a proper assessment of proposed storage sites as well as their proposed monitoring solutions are needed to assure that the injected supercritical CO_2 is behaving as expected without posing societal and environmental risks. Geophysical techniques provide one of the cornerstones in effective site characterization and monitoring. The use of geophysical methods for monitoring of CO_2 injection at depth has been demonstrated extensively through various studies. Typically, time-lapse seismic technology is used for characterizing temporal-spatial changes in the reservoir with the injection of CO_2, and several past GCS projects have demonstrated the successful use of time-lapse seismic monitoring techniques. Examples include those conducted at:

- The Sleipner and Snøhvit CCUS projects in saline reservoirs offshore Norway (Furre and Eiken [2014] and Grude and Landro [2019], respectively);
- Onshore projects enhancing oil recovery by injecting CO_2 (CO_2-EOR) in the United States at the Bell Creek oil field in Montana (Hamling et al., 2017), the Postel Field in Oklahoma, and Delhi Field in Louisiana (Davis et al., 2019), and the Cranfield site in Mississippi (Ditkof et al., 2013);
- Onshore saline reservoir storage at the Aquistore site in Canada (Roach et al., 2017) and the Illinois Basin – Decatur Project (IBDP) in Illinois (Bauer et al., 2019).

Time-lapse vertical seismic profile (VSP) surveys have been reported for:

- Onshore CO_2-EOR monitoring at the SACROC site in west Texas (Yang et al., 2014), the Cranfield site (Daley et al., 2014), and the Aneth Field in Utah (Zhang and Huang, 2022);

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- Onshore saline reservoir storage at the IBDP site (Bauer et al., 2019), Aquistore (White, 2019), and the CO2CRC Otway Project (Yurikov et al., 2021).

Other notable geophysical methods have also been applied, such as:

- Electromagnetic (EM) techniques offshore at Sleipner (Park et al., 2017) and onshore for CO_2-EOR at the West Hastings Field in Texas (MacLennan, 2022);
- Electrical resistivity tomography (ERT) at Cranfield (Carrigan et al., 2013) and Ketzin, Germany (Bergmann et al., 2022);
- Continuous gravity monitoring at Sleipner (Alnes et al., 2008) and the Farnsworth Field in Texas (Sugihara et al., 2014).

With the rapid growth in proposed CCUS projects in the past few years, aligned with the pressing need to reduce greenhouse gas emissions, new challenges emerge in the realm of geophysical characterization and monitoring. In this paper, we provide an assessment of the future of geophysics in the United States as applied to this newly emerging business of GCS. Note that subsurface storage requires permitting of injection wells under EPA Class VI regulations that in turn fall under the Safe Drinking Water Act. This discussion is limited to the United States because other countries have their own carbon reduction incentives and geologic sequestration regulatory requirements, and providing a worldwide assessment in the same way that we have done for the United States alone would be unfeasible. Therefore, with this manuscript we aim to provide a summary of the proposed geophysical characterization and monitoring techniques in current public Class VI applications as of October 2023, establish statistics on various geophysical methods as they have been proposed for use to date, and discuss the potential for future trends in the field of geophysical monitoring taking into consideration the analysis of current applications.

Our assessment assumes that the United States will meet its stated goal of net-zero greenhouse pollution emitted in 2050, that the various financial incentives currently available to businesses for projects in the United States will be sufficient to attain that goal, and that no significant changes to characterization and monitoring requirements in Class VI regulations will occur. Additionally, data limitation can bias the analysis, given the share of Class VI applications that are not available to the public, including in part due to redactions of confidential business information. This assessment should be interpreted as a potential for growth in the applied geophysics industry and not as a prediction of the future geophysical market.

U.S. financial incentives for CCUS

Federal incentives. Within the United States, the growth in CCUS and, more importantly for this paper, GCS operations will be funded via credits provided in Internal Revenue Code Section 45Q (see Carbon Capture Coalition [2022a] for more details). With the passage of the Inflation Reduction Act of 2022 in the United States, the incentives driving development of CCUS have been greatly increased over previous values. The 45Q tax credits are now US\$85/million-metric tonne (MMt) for GCS in saline reservoirs and \$60/MMt for EOR processes. The incentive is even greater for direct air capture (DAC) facilities with a tax credit of \$180/MMt for GCS in saline reservoirs and \$130/Mt for EOR. And along with these enhanced credits, the minimum yearly storage thresholds have been lowered with DAC facilities only needing to prove safe storage of 1000 MMt/yr, industrial facilities of 12,500 MMt/yr, and electric generation 18,750 MMt/yr. Note that these tax incentives can be obtained for any CCUS project that starts construction before 1 January 2033.

State incentives. Individual states are also providing financial support for CCUS projects. An example of state-led initiatives is California's low-carbon fuel standard (LCFS) credit market, with a credit being permission to emit one tonne of CO_2. California's current target is carbon intensity of energy used for transportation in the state to decline roughly linearly by about 19% from 2015 to 2030 (California Code of Regulations § 95484) and remain at that intensity afterward (California Air Resources Board, 2018). While the target regards only energy used for transportation in the state, it applies to that energy no matter where in the world it is generated. The program also allows projects capturing CO_2 from the atmosphere anywhere in the world and sequestering it to generate credits.

In 2018, California's program adopted a protocol for transportation energy providers to use carbon capture and sequestration onshore to lower the carbon intensity of their product. The sequestration component of this protocol regards injecting CO_2 that would otherwise be emitted as a separate phase into geologic reservoirs. Eligible reservoirs are onshore brine aquifers, depleted hydrocarbon, and oil for the purpose of enhancing production (EOR). Credits are generated with approved life cycle accounting for each, including that of CO_2 produced back during EOR.

Federal grants and research. Additional governmental financial incentives for the private sector to invest have been provided recently by the Infrastructure Investment and Jobs Act or Bipartisan Infrastructure Law (BIL), which was signed into law by U.S. President Joe Biden on 15 November 2021. The BIL provides \$12.1B over 5 years, which from a carbon storage perspective includes the following programs and associated funding (Carbon Capture Coalition, 2022b):

- Carbon Capture Demonstration Projects (\$2.54 billion);
- Carbon Capture Technology Program for Front-End Engineering and Design studies (\$100 million);
- Carbon Storage Validation and Testing and Carbon Storage Assurance Facility Enterprise (CarbonSAFE) programs (\$2.5 billion);
- Regional Direct Air Capture Hubs (\$3.5 billion).

These funding programs are run primarily through the U.S. Department of Energy (DOE) Office of Fossil Energy and Carbon Management, which along with the DOE's Office of Basic Energy Sciences has been funding research and development (R&D) projects associated with CCUS and, more specifically to this paper, R&D associated with geophysical site characterization and monitoring, since the late 1990s. It must be noted that the National Science

Foundation and the United States Geological Survey are other governmental entities that have supported CCUS research, but not with the same funding levels as those provided by the DOE.

Much of the DOE's R&D effort has been provided via traditional university and DOE national laboratory research. As part of this R&D effort, the DOE has established three major programs to further the safe sequestration of CO_2:

- The Regional Initiative to Accelerate CCUS Deployment (NETL, n.d.-a) which was established in 2019 as an evolution of the Regional Carbon Sequestration Partnerships (NETL, n.d.-b);
- The National Risk Assessment Partnership (NRAP) (NETL, n.d.-c), which provides a coordinated research effort between five DOE national laboratories to develop computational tools and workflows that quantitatively assess risks and potential liabilities associated with GCS and address critical stakeholder questions in support of commercial GCS deployment;
- The SMART Initiative (NETL, n.d.-d), which aims to develop and deploy physics-informed machine learning algorithms and workflows with the goal of improving efficiency and effectiveness of field-scale carbon storage operations.

The DOE also targets funding for small businesses through its Small Business Innovative Research (SBIR) program. There have been many recent SBIR funding opportunity announcements that have included topics related to CCUS.

Applying geophysical practices to GCS projects

Geophysics used for site characterization. Among GCS projects in the contiguous United States, geophysics is initially used in two steps: (1) regional assessment and screening and (2) site appraisal and characterization (Branston and Sameh, 2023). During the assessment and screening process, it is most common to use legacy geophysical data and avoid the cost of new acquisition. As described in more detail to follow, most current and proposed future GCS saline reservoir projects exist in geologic basins that are also known for hosting oil and gas reservoirs, thus legacy geophysical data are often available. However, to use the data effectively, there are times when some or all of these data need reprocessing with modern techniques in order to have consistent structural and stratigraphic imaging across multiple vintages of acquired data. Reprocessing ensures that high-value sites are identified in the screening process.

In the site appraisal and characterization step, some legacy gravity, magnetic, and seismic data may be purchased and/or reprocessed, and EM data may be acquired. If legacy data are not available, it is most common to collect, process, and interpret new 2D or 3D seismic data for characterization. This supports the need to understand the suitability of the site for GCS, supports the preinjection reservoir model that will be used as a digital twin, and establishes the baseline for time-lapse acquisition of geophysical data for monitoring during injection.

As a final task of the characterization phase, the geophysical interpretations are integrated with geology to produce a static reservoir model. This model includes geologic structure and characterization of the storage units' porosity and connectivity. It also identifies seals, fractures, and faults. Geophysics is then integrated with engineering and geomechanical data for dynamic modeling. Dynamic modeling includes projected injection rates, predicted plume location, and saturation. It also evaluates leakage and seismicity risk, and establishes the injection monitoring plan.

Geophysical methods proposed for monitoring. During the CO_2 injection phase, monitoring intends to verify three important aspects. The first is startup assurance during injection, which aims to ensure that the CO_2 is being safely injected in the right zone and that there are no potential leakage pathways that can compromise the safe containment. The second aspect is verification via dynamic monitoring (Le Calvez et al., 2021). Passive seismic monitoring, the third aspect, is essential to ensure that hazardous induced seismicity does not become a risk in terms of generating damaging earthquake activity.

During initial CO_2 injection, several important nongeophysical tools are used to provide assurance. These include surface gas monitoring and continuous measurements of in-well pressure and temperature. Geophysical logs, such as pulsed-neutron logs for saturation estimation and sometimes sonic logs, are also commonly used for verification. However, such methods provide measurements at a specific point location and lack the lateral resolution for aerial monitoring.

Surface geophysical techniques can be employed for indirect measurements away from the borehole. For example, interferometric synthetic aperture radar can be used to detect ground movement in the presence of CO_2 leakage (Vasco et al., 2010). Microgravity surveys can also be used to constrain the position of the injected CO_2 plume (Alnes et al., 2008). However, seismic methods such as 2D and 3D surface seismic surveys and VSP acquisition are the most common indirect measurement techniques because they usually provide the necessary lateral and vertical resolution for CO_2 detection.

After initial injection and assurance, GCS projects enter a long-term phase of verification via dynamic monitoring. Note that current EPA requirements require a site to be monitored for 50 years after injection stops, while California requires monitoring for 100 years after termination of the injection process. In this phase, monitoring measurements are made at appropriate time intervals, and the subsurface digital twin is calibrated, updated, and used for prediction and project management. Behavior of the CO_2 plume, including its location and saturation, is an important aspect of monitoring. Another critical aspect of monitoring is the early detection of evidence of CO_2 and/or brine leakage into upper zones. This can be particularly risky when dealing with legacy wellbores, when there are unmapped nearby faults, or when the seal has been compromised. Note that although slow CO_2 leakage into upper zones may not seem that impactful given the time scales we are considering here, the leakage of saline brines potentially can affect potable groundwater quality.

Observations and statistics from current EPA applications

Data analyzed in this section were collected from publicly available EPA Class VI permit applications. These data were gathered from websites for those EPA regions posting applications (regions 5 and 9) and of the relevant regulatory agency in those states, North Dakota and Wyoming, that oversee Class VI permitting. North Dakota and Wyoming are said to have "primacy," which is when a state gains authority from the EPA to regulate a class of underground injection control wells. Applications to EPA regions 4 and 6 were collected through Freedom of Information Act (FOIA) request responses available from the EPA's former FOIA website. Additionally, applicant and project name, project location by state and county, and number of injection wells were gathered from the 13 October 2023 version of the EPA's Class VI permit tracker (EPA, 2023), although it will have been updated relative to the version we utilized. These data are available in supplemental information file SI-1. The analysis of current Class VI applications offers insights into current trends in terms of geophysical characterization and monitoring in future CCUS projects.

We identified 60 projects with active permit applications or approved and operating projects as of 13 October 2023. These included projects from the EPA's project tracker and those in the primacy states of North Dakota and Wyoming. Class VI permit applications often have data redacted, as some information is proprietary. As a result, data were not available for every parameter analyzed for each project.

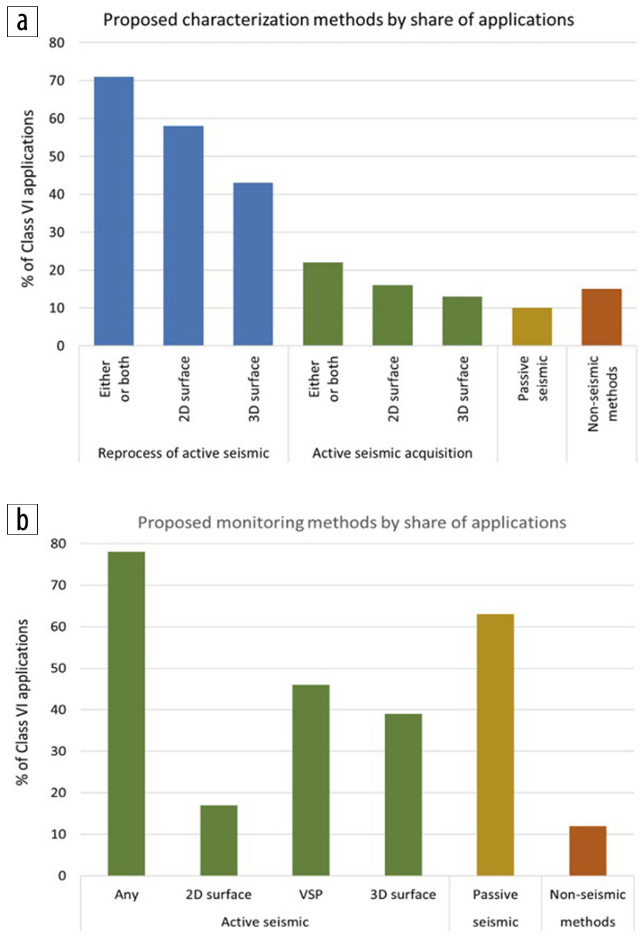

Figure 1. Share of applications that (a) used a particular geophysical method for site characterization and (b) proposed a particular method for monitoring.

A summary of the geophysical surveys planned in the EPA Class VI permit applications is shown in Figure 1a for the site characterization phase and Figure 1b for the testing and monitoring phase. Figure 1a indicates that the site characterization phases tend to be dominated by the reprocessing of existing or legacy seismic data. As mentioned previously, this is because most of the regions/basins being considered for GCS operations are also areas where previous oil exploration surveys have been conducted, and thus a wealth of legacy data exists. Reprocessing legacy seismic data using improved demultiple and imaging algorithms can improve the final quality of the data. Also note that nonseismic surveys traditionally used in oil and gas exploration, such as gravity and magnetic surveys, were not mentioned in any of the Class VI permits that we had access to for the characterization phase.

In terms of geophysical data acquisition for monitoring, Figure 1b indicates that the dominant proposed monitoring method is passive seismic monitoring. Note that the principal reason this methodology is dominant is for monitoring induced seismicity risks. For plume conformance, VSP and 3D surface seismic imaging are listed as the two dominant techniques (41% and 39%, respectively) followed by 22% of the permits stating that their project will use 2D surface seismic data analysis. Note that many of the VSP surveys may be acquired at the same time that the 2D and 3D surface seismic surveys are acquired. Last, 12% of the projects reported that they were planning to acquire some type of nonseismic data, primarily gravity and/or EM data as part of their monitoring strategy. The applications did not include details on how these methods would be incorporated in the indirect monitoring and the frequency of data acquisition, although some of the applications proposing 3D seismic imaging suggested data acquisition every 5 years, and some of the applications proposing VSP suggested acquisition every year or every 2 years.

One interesting observation is that the projects proposing passive seismic acquisition for induced seismicity monitoring tend to be clustered in regions. For example, all applications for region 9, which includes the Pacific Southwest area, propose passive seismic acquisition. Additionally, region 5 also seems to have most projects proposing passive seismic monitoring. One can conclude that each region represents its own unique geologic context, and/or the states that these projects are located in require this type of monitoring in addition to what is required by the EPA.

Potential estimates for the future of geophysics in GCS projects

Estimates of future number of GCS projects. Suter et al. (2022) studied the supply chain regarding the steel pipe, pumps, etc. necessary to develop the CCUS/GCS industry. The study presumed 2.0 Gt CO_2 captured in 2050 based on rounding up from high values in published scenarios, some of which were mentioned in this paper's introduction. On this basis, it estimated a total of 403 projects and when each would start injecting, shown by the green columns in Figure 2. Its estimate of the number of projects starting up this decade also appears low relative to the number of Class VI permit applications as of late 2023 alone.

Mark McKoy, technology lead for CCUS at the DOE's National Energy Technology Laboratory (NETL), has estimated that 600 projects sequestering 0.7 to 1.9 GT per year will be operational in 2050, with the total mass of each equal to the minimum mass eligible for a DOE CarbonSAFE) grant (50 MMt) (M. McKoy, personal communication, 2023). He estimated the number of projects commencing operation through time, shown by the blue columns in Figure 2. McKoy also stated that because many projects will have lower total mass injected than the minimum for a CarbonSAFE project, and some higher, he estimates there will be somewhere between 500 and 1500 CCUS projects between now and 2050.

For our estimate of future geophysics effort, we also assumed that the number of projects in operation in 2050 will inject 2.0 Gta for consistency with Suter et al. (2022). This requires that the 45Q or equivalent tax credits and/or other financial support, such as LCFS markets, will remain in place and possibly increase to make projects sufficiently profitable for industry to construct and operate them. This is a big assumption as future federal or state administrations may change or even eliminate these incentives. In addition, the cost of the sequestration infrastructure must be manageable. If these costs become greater than the revenue provided by policy, the technology will not move forward at a rate that will allow the United States to meet its goal.

We compiled data from aforementioned Class VI permit applications relevant to estimating the number of projects commencing operation through 2050 (data available in SI-1). While the characteristics of projects are likely to change over this period, we used these data because they are the best available currently, and we judged that using them would lead to better assumptions than could be made were they not considered. Statistics regarding various parameter values compiled are given in Table 1. These values are used for forecasting cumulative values of potential project populations in this study. As described in SI-2, the distribution of each value is readily characterized in log space. Supplemental information file SI-2 also provides pairwise correlation coefficients between values. For selecting values for random unknown projects, which could be useful in various other studies, both the linear and logarithmic values in SI-2 should be used rather than those in Table 1.

To provide 2.0 Gt injected in 2050, the average injection rate per project of 2.6 MMt/yr from Table 1 indicates approximately 770 projects need to be in operation that year. This is larger than NETL's estimate of 403 projects and a bit higher than McCoy's estimate of 600 projects. McCoy's estimate is based on 50 MMT per project, whereas ours is based on the average of 46 MMT from current permit applications. This accounts for part of the difference between his estimate and ours.

As of late 2023, three Class VI projects are operational. In addition, another is permitted to inject and one to construct (after which it refiles the application to inject updated with site-specific values). A draft permit has been issued for another, and a decision will foreseeably be issued by mid-2024 for another seven for a total of 10 additional potential CO_2 injection projects. Thus, we assumed 13 projects will be operational by the end of 2024. The outcome of the analysis is relatively insensitive to this value though.

Larson et al. (2021) projects roughly linear growth of geologic carbon sequestration from 2030 to 2050 in the four scenarios that include this approach. Suter et al. (2022) presented the growth of capture to 2050 from one of the scenarios in the U.S. Department of State and Office of the President (2021), which was generally linear from 2020 with some rate increase with time. The International Energy Agency (2021) projected approximately linear growth in capture globally from 2025 to 2050 with some rate decrease. Based on the average of these projected trends, we

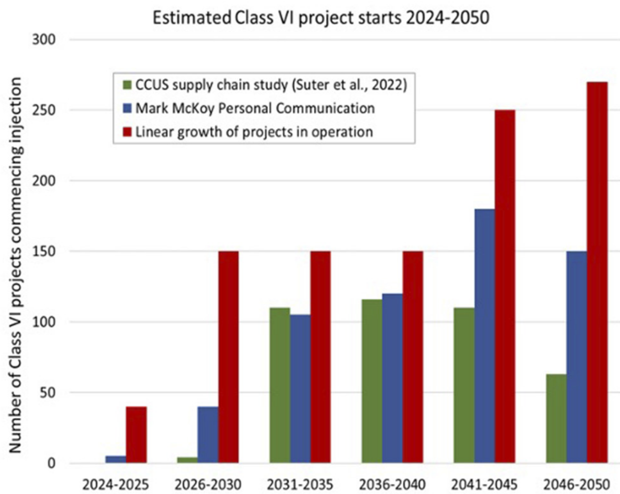

Figure 2. Estimated number of projects commencing injection.

Table 1. Statistics regarding various parameters from Class VI project applications. Note that the term "Count" in the first row refers to the number of Class VI applications reporting that particular value.

	Total CO_2 (MMt)	Rate per project (MMt/yr)	Injection wells per project	Rate per well (MMt/yr)	CO_2 area (mi^2)	CO_2 per area (MMt/mi^2)
Count	37	40	60	40	27	27
Mean	46	2.6	3.0	0.88	9.7	5.4
Median	26	1.5	2.0	0.71	8.0	4.0
Maximum	290	15	9	2.4	33	18
Minimum	1.4	0.1	1	0.10	1.0	0.8

assume the number of projects in operation each year increases linearly from 13 at the end of 2024 to 770 at the start of 2050.

This results in more projects commencing operation in 2024 to 2030 than Suter et al. (2022) assumes and McCoy estimates. This assumption is supported by the number of project applications currently submitted being approximately equal to the number of projects that would start up in 2024–2025 under our linear growth assumption from this start year.

The linear growth assumption results in 30 projects becoming operational each year over the previous year. The average 46 MMT with an average injection rate of 2.6 MMT/yr per project gives an average injection period of 18 years. This is less than the time from 2024 to 2050. As such, an additional 30-plus projects per year need to commence operation late in the period in order to replace those that shut down after commencing early in the period. The result is shown by the red columns in Figure 2.

The total number of projects commencing operation over the period resulting from our linear assumption is about 1000. This is midway between McCoy's lower and upper estimate. Given the similar project size upon which each estimate is based, this consistency between his expert judgment and our judgment informed by data from tens of applications increases confidence in the estimate.

Estimates of future geophysical surveys and projects for CCUS. Using the statistics provided in Figure 1 on methods used for characterization and proposed for monitoring coupled with our project injection starts shown in Figure 2, we estimated how various geophysical methods will be used in a CCUS industry that meets the 2050 goal. For use in site characterization, we multiplied the percentage of projects using each type shown in Figure 1a by the number of projects commencing injection 5 years later. This accounts for the characterization lead time relative to commencement of injection. The results are shown on Figure 3. We did not include nonseismic methods because the use of those in characterization was mostly via already processed data, often in published literature.

Of the applications from which it could be determined, 71% of all projects and 85% of projects that used seismic data in characterization used legacy data. Ten of the projects were determined to be in depleted reservoirs, and the rest are in saline aquifers. All but one of the depleted reservoir projects are in the San Joaquin and Sacramento basins in California. Of the saline reservoir projects that used legacy seismic data for characterization, almost half also acquired data. All of these were in the Illinois Basin except one in the Williston Basin. This suggests use of the two data sources is not mutually exclusive. These factors indicate the use of legacy data will not decrease in the future due to a shift from depleted to saline reservoirs but rather that there is more scope for a shift from saline to depleted.

All projects but one were in onshore basins with oil and gas in the continental United States. The area of these oil and gas basins comprises 70% of all basin areas and 72% of basin areas assessed as having sequestration potential (areas being composed of single or stacked basins) (NETL, 2022). This suggests scope for projects to shift into basins with less legacy data. Given this and the countervailing factors described earlier, we presume the current share of projects utilizing legacy seismic data versus acquiring new data will remain the same in the future.

The use of geophysics increases in 2036–2040 followed by a peak in 2041–2045. This is due to the lead time characterizing sites for new projects to replace those that have ended in addition to those needed to continue increasing the total number of operational projects. The geophysics effort declines afterward because from 2050 the number of operational projects is assumed constant rather than continuing to increase. As such, the number of new projects per year declines to only those needed for replacement.

To estimate the number of projects using geophysical surveys for monitoring, we made assumptions regarding baselines and repeats. We assumed projects that acquired seismic data of the same type for characterization would use the results as baseline for subsequent repeats. For the other projects, we assumed the baseline was collected 1 year before the start of injection. This accounts for projects waiting for an injection permit for this expenditure. For repeat surveys, we assumed a 5-year interval from the start of injection because this was commonly mentioned in the Class VI permit applications.

Figure 4 shows the results in terms of data acquisition campaigns per year. As expected, the number of surveys for monitoring are dominated by 3D surface and VSP with 2D surface and nonseismic repeat surveys having much lower numbers. Unlike uses of geophysics for characterization, the rate of uses for monitoring increases through 2046–2050 due to the number of repeats occurring increasing following the number of projects in operation increasing. Note that we have not included passive seismic monitoring here as it (1) will not require regular crews to perform repeated field surveys, and (2) will likely only be used for monitoring the risk of induced seismicity rather than for conformance and leak imaging.

Estimates of future geophysical effort for GCS. The last step in our analysis regards how CCUS will affect the applied geophysics market. Figure 5 compares historic and current crew counts for 2D, 3D, and 4D surveys in the contiguous United States. The 2023 levels shown in Figure 5 are estimates based on discussions with various members of the geophysics/seismic acquisition

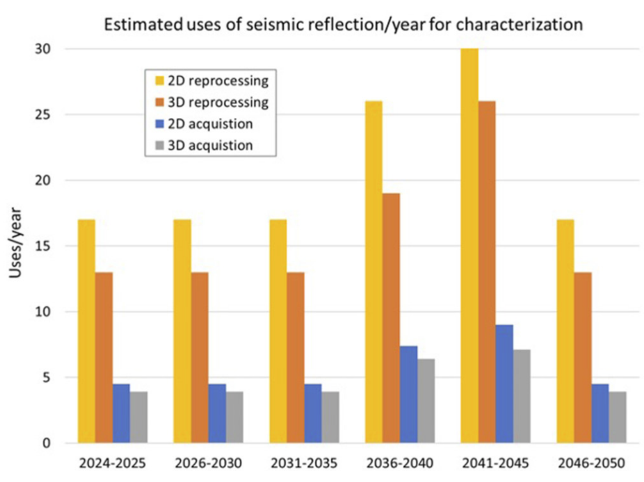

Figure 3. Estimated number of seismic reflection reprocessing operations and survey acquisitions for characterization through time.

industry. Note that 3D seismic surveys, which are for exploration, dominate the market. Also note how weak the current geophysical survey market is compared to 2001 and especially 2011.

Figure 2 shows slightly more than 40% of projects propose VSP for monitoring, the largest share of the proposed geophysical methods. However, the applications also indicate two-fifths of the projects proposing to use VSP are also proposing to use 3D. From this we assume that many of the VSP surveys will be acquired concurrently using the same shot positions as the 3D. Further, the applications are silent regarding the VSP area, but we assume 3D surveys will be larger. The 3D acquisition effort will be greater than that of VSP due to the combination of these factors. Figure 4 shows the effort of either is greater than for the other methods. As a result, we focus on estimating the number of 3D crews needed through 2050.

To estimate the number of such crews that would be employed, we made additional assumptions regarding productivity. We assume a single crew can survey 50 mi^2 in six weeks. We also assume one week for mobilization and another for demobilization (mob/demob).

We estimated the maximum 3D survey area per project as five times the average maximum CO_2 footprint from Table 1, which is 9.7 mi^2. The factor of five accounts for shooting area beyond the forecast CO_2 footprint to account for uncertainty and the distance beyond that to attain the desired angle from shot to reflector to receiver.

Multiplying the average maximum 3D survey area per project by the number of such surveys for characterization and monitoring across all projects yields the total survey area per year. Multiplying this area by six weeks per 50 mi^2 gives the total survey time. Adding two weeks per survey for mob/demob gives total crew weeks. Dividing by 50 weeks/year, rather than 52 to account for crew downtime, gives the maximum number of crews needed per year as we presume for this case each repeat is equal to the full baseline area, an approach that assures the most sensitive differencing between surveys. The orange bars in Figure 6 show the resulting number of required crews, assuming the same aerial shot and receiver coverage is used for each of the time-lapse surveys.

We also assumed a minimal 3D survey area scenario to bracket the projected crew count. First, each repeat survey area only covers the forecast CO_2 footprint plus uncertainty at that time. Second, the CO_2 footprint area grows linearly from the start of injection to its maximum at the end of injection. While the footprint area can increase after the cessation of injection, the applications indicate this is forecast to be minimal on average. Figure 6 shows the estimated crew count resulting from this scenario in yellow bars.

Comparing the data and estimates shown in Figures 5 and 6, respectively, indicates that while CCUS projects will provide some growth to the geophysical industry in the future, it is likely that it will only slightly exceed the business provided by the current seismic exploration market, and it will not provide the same level of business as in the first 12 years of the 2000s. We also note that the amount of growth will be small initially and will not peak until the 2046–2050 time window.

Potential growth opportunities for geophysics in CCUS

While the analysis presented here attempts to forecast future growth in the geophysical industry for CCUS, it is based largely on currently submitted Class VI permit applications. However, those regulations mandate monitoring for up to five decades after injection ceases, providing some stability to the forecast. As mentioned, states such as California have imposed even longer postinjection monitoring periods. Furthermore, many CCUS site operators originate from backgrounds unrelated to geoscience, including ethanol production and the cement industry. This diverse array of stakeholders underscores the need for a monitoring solution that can be easily deployed and operated across CCUS sites, simplifying the task of meeting regulatory monitoring demands.

Seismic monitoring often provides the highest resolution and sensitivity to changes in the reservoir from measurements made on the surface. As a result, it is not surprising that applications propose its use for indirectly monitoring compliance of evolving CO_2 footprints with forecasts. However, conventional seismic monitoring technologies typically rely on vibroseis trucks as sources along with the deployment of thousands of geophone receivers. Such surveys are costly, demand significant human

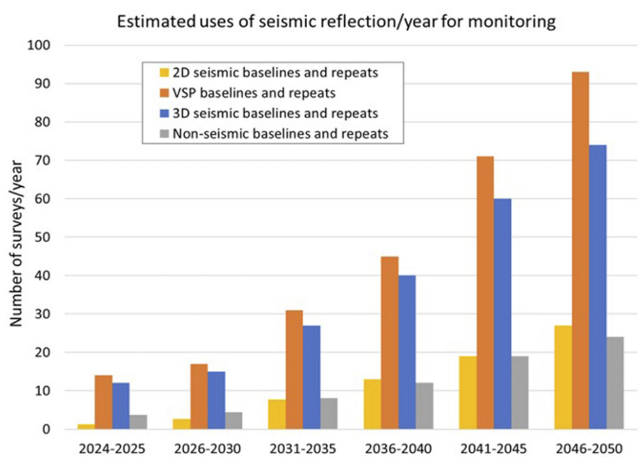

Figure 4. Estimated number of geophysical surveys for monitoring through time.

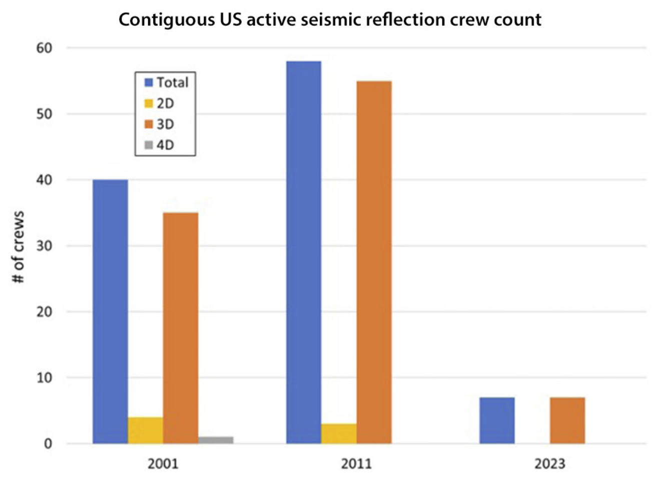

Figure 5. Number of seismic crews working in select past years.

resources, and can be time-consuming, often taking weeks to months to complete depending on survey size. Furthermore, the inherent impact of surface seismic surveys on land use is often a concern for landowners. Given the demand for multidecadal monitoring incurred by CCUS, cost-effective and autonomous monitoring solutions are a pressing need.

According to Detomo and Quadt (2011), permanent reservoir monitoring (PRM) techniques can be cost-effective in the context of oil and gas production when it comes to “life-of-field” surveillance approaches, especially when there is a combination of high well costs and reservoir complexity. Recent technological advancements hold significant promise in facilitating PRM. Innovations in fiber-optic sensing enable permanent and on-demand seismic data acquisition, introducing flexibility into monitoring processes (Mateeva et al., 2017). The installation of permanent fiber-optic cables in both injection and monitoring wells can allow for passive and active seismic monitoring using the same cable and equipment, which can significantly facilitate the acquisition of necessary data to satisfy Class VI monitoring requirements. Additionally, the deployment of permanent and autonomous seismic sources, such as the surface orbital vibrator or accurately controlled and routinely operated signal system, presents an attractive option for conducting active seismic surveys autonomously (Kasahara et al., 2017; Correa et al., 2021). Such technologies can contribute to cost-effective and efficient long-term monitoring at GCS sites.

Although seismic reflection is the method most used for repeat surveys, applying a multiphysics monitoring plan in which other geophysical methods are leveraged may provide the efficiency of time-lapse seismic technology (Sambo et al., 2020). For example, while seismic P-wave velocity generally shows a rapid decrease from zero to about 10% CO_2 saturation, as the saturations go above 10%, the velocity changes with increasing saturation tend to flatten out, as shown in Figure 7. Electrical resistivity, on the other hand, does not change much at lower saturations but then increases rapidly with saturation changes above 10%. In addition, as supercritical CO_2 is of lower density than the brine it is replacing when injected into saline reservoirs, the density of a porous reservoir rock will decrease linearly as more CO_2 is injected. Thus, advances in EM/electrical and gravity geophysical technologies offer the possibility of providing the ability to monitor a wider range of saturation changes than seismic methods alone may be able to — especially if the data acquisition hardware for each is permanent and can be operated remotely or autonomously. Several studies have demonstrated the feasibility of other geophysical techniques for monitoring, such as gravity and EM, though integration of them with current time-lapse seismic techniques is still challenging (Sambo et al., 2020).

Permanently installed ERT measurements have been used for nearly 30 years to monitor fluid saturation and conductivity changes for shallow environmental monitoring purposes (LaBrecque et al., 1996). The larger area required for monitoring a CCUS project compared to that for shallow environmental monitoring poses some installation problems, but the technology does exist to instrument an autonomous version of the EM monitoring methodology outlined by MacLennan (2022).

Similar advances can be made with gravity measurement systems, especially if new quantum technologies are built for permanent monitoring installations (Freier et al., 2016). These monitoring technologies become especially powerful when combined with repeat pulsed-neutron logging for estimating CO_2 saturation in injection and monitoring wells along with associated sonic, resistivity, and density repeat logging. In addition, if sparse-autonomous controlled-source EM stations can also be used to acquire magnetotelluric data, these measurements could be combined with airborne helicopter or drone EM measurements to

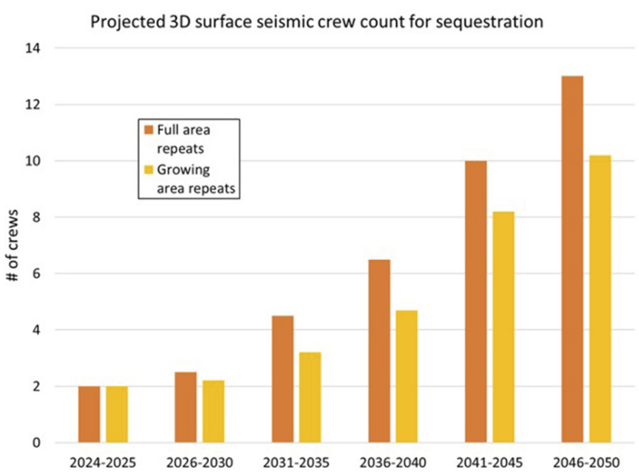

Figure 6. Projected number of 3D surface seismic crews for characterizing sequestration sites and monitoring injected CO_2 through time.

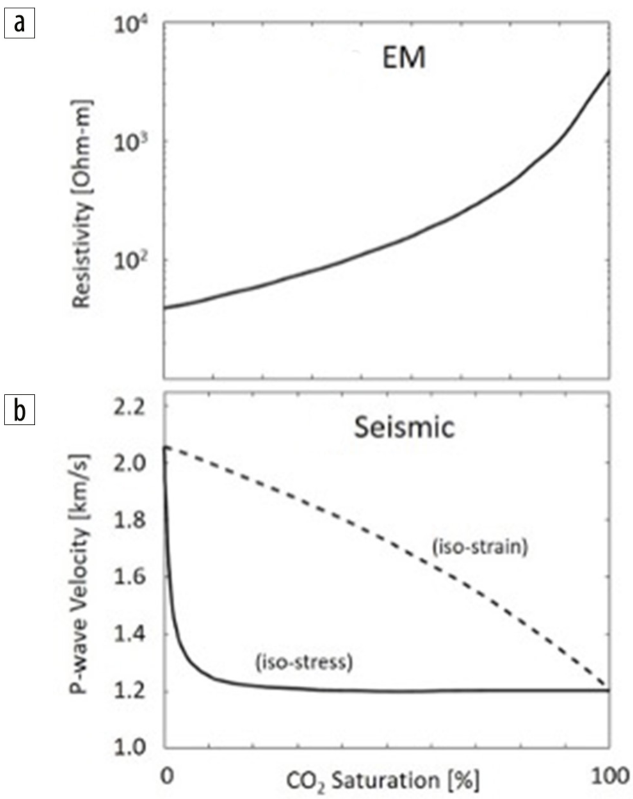

Figure 7. (a) Electrical resistivity as a function of CO_2 saturation (modified from Gasperikova and Hoversten, 2006). (b) The lower (Reuss, iso-stress) and upper (Voigt, iso-strain) bounds of P-wave velocity as a function of CO_2 saturation (modified from Vasco et al., 2014).

provide groundwater quality assessments over the area of interest. Class VI regulations require monitoring groundwater above the storage reservoir for leakage from depth. Leak detection not only needs to include CO_2 leaking upward, but also a potentially higher impact scenario of saline brines forced upward along faults or abandoned wells by reservoir pressure increase caused by injection collecting at the bottom of a potable water aquifer. Most permits simply propose to do so via a few groundwater wells, but these are very localized measurements. EM measurements such as that described here may provide a better method to detect leaks between groundwater wells.

In the context of monitoring of CCUS projects, the need for easy, cost-effective, long-term, and reliable monitoring techniques is apparent. When it comes to multidecadal monitoring, where terabytes of data can be generated each year for a project, new procedures for data management are needed. Additionally, advancements in data processing and imaging, such as via edge computing and machine learning, can make the generation of data products and visualizations to monitor CO_2 projects faster and more efficient, thereby increasing storage security. Edge computing to reduce data size and complexity of monitoring data offers the possibility to provide on-site processing before data are uploaded autonomously to the web. Machine learning algorithms can provide additional signal enhancement as well as near real-time imaging of reservoir properties of interest such as CO_2 saturation, rather than geophysical properties such as seismic velocity, resistivity, and density (e.g., Liu et al., 2023; Um et al., 2024).

Discussion and conclusions

The aim of this paper has been to summarize and discuss the potential growth of geophysical methods as applied to GCS projects in the contiguous United States. To accomplish this, we first provided a summary of the proposed geophysical characterization and monitoring techniques in current public Class VI applications. From these we developed statistics regarding the use of each method for site characterization as well as those proposed for subsurface CO_2 and groundwater monitoring. These statistics showed that, aside from petrophysical well logging, reprocessing of previously acquired surface seismic reflection data was the most commonly used method for characterization, and 3D surface seismic imaging and VSP were the most commonly proposed methods for monitoring.

From the applications, we then developed statistics on proposed project sizes. Based on literature review, we chose a notional amount of CO_2 to be injected in 2050 to achieve the U.S. net-zero greenhouse gas emission goal established by policy and the rate of increase in geologic carbon sequestration projects. We used these to forecast the number of projects each year through 2050, resulting in more than 700 that year and a thousand total commencing injection during that time, the difference being retirement of the earlier projects before 2050.

We combined statistics regarding the share of currently proposed and operating projects that used or proposed to use each geophysical method with the forecast of the number of projects to estimate the number of geophysical surveys of each type annually through 2050. We applied estimates of crew time acquiring 3D surface seismic data to the forecast of the number and size of those surveys to develop high and low crew counts. This estimates that two seismic field crews are needed to meet demand through 2030 growing to 10–12 by 2046–2050. Note that these numbers are similar to the current number of crews working in oil and gas exploration but are much smaller than previous crew counts when oil and gas exploration was more prominent.

We made a number of assumptions to conduct this analysis. First, we assumed that the type of geophysical methods and the share of currently operating and proposed projects utilizing each would remain constant through 2050. Based on literature review, we next hypothesized that the number of projects in operation each year would increase linearly to attain a total injection rate of 2.0 Gt in 2050. Next, we assumed that the average size of future projects would be the same as currently operating and proposed projects. We then applied estimates of 3D surface seismic survey area relative to CO_2 footprint size and for 3D surface seismic crew time to survey such area based on our experience.

The sensitivity of the results to each of these assumptions varies. Holding other assumptions constant, the estimate of 3D surface seismic crew count is relatively insensitive to project size. The amount of CO_2 sequestered per unit area presuming supercritical phase injection in saline reservoirs varies little with project size. The estimate is not sensitive to the share of projects reprocessing rather than acquiring new seismic data for characterization because (1) seismic data for monitoring constitute the vast majority of efforts due to repeats, and (2) projects monitoring via seismic data that do not acquire in the characterization phase will acquire a baseline in the monitoring phase. Conversely, the forecast number of projects and seismic crews is sensitive to the 2050 injection rate target given its range of estimates. The forecast number of projects and crews does scale with the assumption of a different 2050 injection amount relative to the 2.0 Gt used in this study. For instance, applying the other assumptions to 1.0 Gt results in five to six 3D surface seismic crews to meet GCS project demand in 2050.

Assuming the policy goal remains constant, perhaps the most substantial assumption is constancy in the type and share of geophysical methods that GCS projects will utilize. Although the use of geophysical tools in subsurface oil and gas extraction translates well to GCS, they are very different businesses. Oil and gas is a producers' market. Investment in information acquisition, such as via geophysics, is necessary to accurately identify and evaluate resources, leading to profit from their extraction. GCS, on the other hand, is a waste disposal and regulators market. Investment in information acquisition, again such as via geophysics, is in proving that a project is behaving according to plan after it has commenced. Oil and gas geophysics operates in a positive feedback loop where success encourages reinvesting product sales profits into more geophysics for additional profitable resource management. GCS is financed by tax credits and so the present net project profits are reduced with every implementation of geophysical acquisition and analysis (Figure 8).

The consequence of depleting operator profits using geophysics is to discourage its excessive use in GCS. The regulators' desire to have necessary and sufficient subsurface GCS geophysical information is in conflict with the operators' desire to minimize

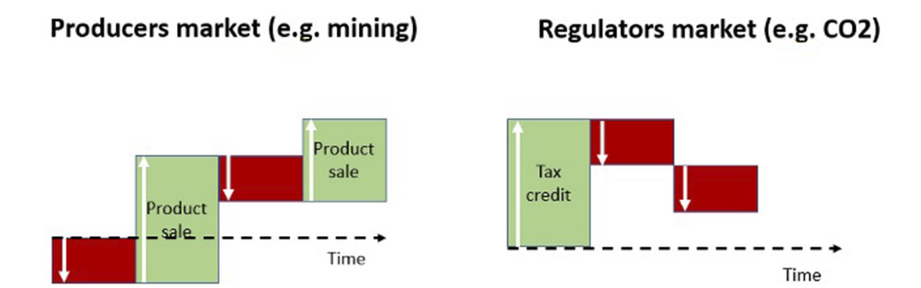

Figure 8. Geophysical value of information in two different markets. Green represents positive net present cash flow anticipated from a project at its startup, and red represents negative cash flow due to data acquisition and analysis, such as via geophysics, for that project.

losses though excessive and potentially unnecessary geophysical activities. Because of this, there are several important initiatives to lower geophysical costs by better engineering the necessary and sufficient conditions of its use. Examples of this are (1) testing and deployment of low-cost fiber-optics systems, (2) spot monitoring (Khatib et al., 2021), and (3) DOE programs such as SMART, NRAP, SBIR, regional initiatives, and other DOE Office of Fossil Energy and Carbon Management applied-science funding programs. Such efforts will likely change the cost of applying various geophysical methods. This may result in less effort as operators seek to maximize returns, constant expenditure resulting in more geophysical data as regulators seek to maximize storage security assurance, or most likely an intermediate outcome.

The future of geophysics in GCS within the U.S. jurisdiction also relies on the regulations of federal waters, which are in the process of being drafted. Currently, the EPA sets the requirements and standards for carbon storage onshore and in state waters. Section 40307 of the BIL amended the Outer Continental Shelf Lands Act to enable the Secretary of the Interior to support injection of carbon for storage in federal waters. The Bureau of Ocean Energy Management and Bureau of Safety and Environmental Enforcement are currently developing the regulations for such projects (Batum, 2022). These will dictate offshore monitoring plans, which may have a different configuration than the trends observed from the current Class VI permit applications.

Another purpose of geophysical monitoring of GCS that was not discussed in detail is to provide transparency and a greater understanding of carbon storage to communities. As the CCUS industry evolves, it is important to continue to share data to technical and nontechnical communities. These monitoring plans and the knowledge gathered from them provide a greater understanding of the safest and most efficient practices and will provide assurances to the communities that choose to welcome GCS. TLE

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Data and materials availability

Data related to this paper are included as supplemental material in the SEG Library at https://doi.org/10.1190/tle43020072.1.

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