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SHASTA
Subsurface Hydrogen Assessment, Storage, and Technology Acceleration

Risk Assessment Considerations for Underground Hydrogen Storage in Depleted Gas Reservoirs

SHASTA: Subsurface Hydrogen Assessment, Storage, and Technology Acceleration Project

May 2025

Prepared for the U.S. Department of Energy, Office of Fossil Energy and Carbon Management by:

Sandia National Laboratories: Michael C. Devin, Marina Miletic, Melissa S. Louie, and Brian D. Ehrhart

U.S. DEPARTMENT OF ENERGY | Fossil Energy and Carbon Management

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Executive Summary

Underground hydrogen storage (UHS) in depleted reservoirs presents a promising solution for large-scale energy storage as hydrogen demand grows. As the UHS industry emerges, robust risk assessments are critical to ensuring safe operation of the storage facilities and minimizing the risk of accidents. This work explores risk assessment protocols for underground natural gas storage (UGS) in depleted reservoirs and identifies key considerations for repurposing these facilities for UHS. By examining the differences in physical and chemical properties between hydrogen and natural gas, this work highlights new and modified hazards that merits a reevaluation of traditional natural gas risk assessment practices.

This investigation synthesizes insights from previous literature reviews and interviews with UGS industry experts and operators to identify key areas for adapting risk assessment methodologies for hydrogen. The insights gleaned from expert interviews indicate that existing risk assessment standards are non-prescriptive, leading to diverse company-specific risk assessment methodologies requiring substantial additions to become practical. Due to a lack of concrete risk assessment requirements, experience, and relevant data, this uncertainty is expected to be magnified considerably when considering hydrogen.

This study identifies several areas for potential modification of existing risk assessment practices that could be considered by those developing standards or performing risk assessments for UHS. Specifically, risk assessments may be improved by including risks unique to hydrogen in existing standards, changing the magnitude of different risk factors in existing risk assessment protocols, and improving methods of data collection and communication across the industry to address large areas of uncertainty.

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Acronyms and Abbreviations

ALARP	as low as reasonably practicable
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
CBL	cement bond log
C-FER	Centre for Frontier Engineering Research Institute
CFR	Code of Federal Regulations
EPA	Environmental Protection Agency
GRNT	gamma ray neutron temperature
HNBR	hydrogenated nitrile butadiene rubber
ISO	International Organization for Standardization
m Nm^3	million normal cubic meters
MFC	multifinger caliper
MFL	magnetic flux leakage
NFPA	National Fire Protection Association
NORSOK	Norsk Sokkels Konkurranseposisjon (Norwegian Standards Organization)
PIR	potential impact radius
P&M	preventative and mitigative
PHMSA	Pipelines and Hazardous Materials Safety Administration
PT	pressure/temperature
QRA	quantitative risk assessment
RP	recommended practice
SHASTA	Subsurface Hydrogen Assessment, Storage, and Technology Acceleration
SME	subject matter expert
SRB	sulfate-reducing bacteria
TFL	transverse flux leakage
UGS	underground [natural] gas storage
UHS	underground hydrogen storage
UIC	underground injection control
USIT	ultrasonic imager tool
VDL	variable density log

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1.0 Introduction

Hydrogen as an energy carrier is emerging as an important complement to other fuel sources, especially for use in transportation and industrial/chemical processes. Hydrogen can blend with or be used as an alternative to natural gas, be used as a lightweight fuel for heavy transport with only water as a byproduct, and could potentially be used as a feedstock in steel production [1]. The use of hydrogen can also bolster grid resilience through its use as a dispatchable energy storage source that can help balance fluctuating power supply and demand from intermittent energy sources. After appropriate modifications, hydrogen may be able to be used with existing natural gas combustion engines, power plants, and pipeline infrastructure [2]. As hydrogen is becoming a more ubiquitous energy source, the need to explore a breadth of safe storage options becomes a necessity. Researchers are currently exploring underground hydrogen storage (UHS) for its potential to use economies of scale to enable affordable hydrogen, one of the greatest barriers to greater adoption [3].

Underground storage of natural gas is currently far more developed than underground storage of hydrogen. Developing safe and economical underground storage options for hydrogen is a critical step towards enabling wider hydrogen use by overcoming affordability issues and balancing intermittency in energy supply [4]. Additionally, underground hydrogen storage can leverage nearly a century of experience from underground natural gas storage (UGS), especially if repurposing depleted reservoirs used previously for UGS [5].

Performing risk assessments for underground storage is important for proactively identifying, preventing, and mitigating operational hazards that could impact the environment and the safety of the public and site workers. Through years of experience, UGS engineers and operators have developed protocols and standards providing recommended practices for conducting a comprehensive risk assessment. However, the underground storage research community and industry experts have not developed standards and best practices for risk assessments for UHS due to the uncertainties related to hydrogen interactions in an underground environment, nascence of the technology, and lack of hands-on experience in the field.

1.1 Risk Assessment Research Findings

Various researchers and projects have explored the logistics, feasibility, and barriers of UHS, which has been documented in numerous literature reviews [6–12], though few of these have addressed risk assessment specifically. Portarapillo and Di Benedetto [13] performed an example preliminary risk assessment for hydrogen storage in a salt cavern, conducting a bowtie analysis for the case of a rupture at the base of the riser pipe connecting to the wellhead after 2.5, 21, and 30 years of simulated hydrogen storage. The results show unconfined vapor cloud explosions pose the greatest individual risk, though the overpressure risk decreases while the risk of a toxic sulfur dioxide (SO_2) or hydrogen sulfide (H_2S) release increases over time. Pique et al. [14] performed a preliminary risk assessment for a 9-month demonstration of hydrogen storage in a salt cavern in Ain, France, as part of the STOPIL-H_2 project. The researchers established hazards that could occur during the demonstration and established corresponding preventative and mitigative (P&M) measures. They found the highest risk events to be jet fire, flashfire, unconfined vapor cloud explosion resulting from hydrogen loss, and unexpected pressure

increases. The identified primary mitigation measures included ensuring cavern leak-tightness and isolation from the surface, installing and maintaining integrity of pressure relief devices, and improving leak and fire detection. Louie and Ehrhart [15] conducted an example quantitative risk assessment (QRA) for UHS considering both the wellhead and processing facility, using data sources from UGS wellhead configurations integrated with processing facility equipment for filtering and compressing extracted hydrogen. Jet fires were found to be the greatest individual risk, with hydrogen leaks from the processing facility occurring far more frequently than leaks from the wellhead. Results from a sensitivity study in the same work show uncertainties in Mach flame speed and ambient temperature having significant impacts on the overpressure risk and heat flux risk, respectively.

1.2 Demonstration Projects

Despite the number of projects investigating the prospects of UHS, only a handful of demonstrations have performed and documented risk assessments and the differences in the assessments compared to UGS. There are six underground salt caverns currently used to store hydrogen: three in the United States in Texas and Louisiana, and three in the United Kingdom at Teesside [16]. However, many operational details for these sites are not publicly available, including information about their risk assessment procedures. The HyChico project [17] conducted a demonstration of hydrogen storage in a sandstone-clay reservoir with 0.75 m Nm^3 (million normal cubic meters) gas storage in Patagonia, Argentina and found "good behavior of the selected depleted gas reservoirs" in initial testing, but no material has been published on the project since 2016. RAG Sun Storage [18] conducted a demonstration project of a 10 vol% hydrogen blend in a depleted sandstone reservoir with 1.22 m Nm^3 gas storage in Upper Austria to provide backup demand for a grid powered by wind and solar power. The final report provides risk assessment information for the project, with results showing that stored hydrogen did not increase risk compared to stored natural gas during the 6-month window of the project, though a measured increase in microbiological activity raised concerns about H_2S generation. A second phase of the project, RAG Sun Storage 2030, is currently demonstrating storage for pure hydrogen, with results forthcoming [19]. Hy4GET [20] is an active Norwegian-based large-scale offshore hydrogen storage project aimed at evaluating the economic, technical, and safety feasibility of hydrogen production and storage in salt caverns on the Norwegian continental shelf, likely powered by wind energy. Their goals include developing risk assessments for these offshore hydrogen installations.

1.3 Scope of Work

Researchers and industry remain uncertain of the long-term impacts of hydrogen in an underground storage environment, and UGS standards have not been established with updated recommended practices to account for hydrogen due to the lack of experience in the field. This report aims to consolidate existing guidance on risk assessment for UGS and provide recommendations for future standards development to account for the effects of hydrogen. This is important particularly when converting existing depleted reservoirs used for UGS to store hydrogen.

Though depleted gas reservoirs, salt caverns, and aquifers are being considered for UHS, this report primarily focuses on UHS in depleted gas reservoirs. While utilizing salt caverns for UHS

may be worth pursuing due to a much lower cushion gas requirement and the low reactivity of salt with other chemicals [7,10], depleted gas reservoirs currently dominate the UGS industry, comprising 75% of the total stored volume globally. Due to this, storage considerations for depleted gas reservoirs often drive risk assessment protocols used in industry and is therefore most relevant to discuss here.

These risk assessment protocols are based on a review of existing standards and literature relevant to UGS, which guided interviews with subject matter experts (SMEs) on UGS risk assessment and their suggested changes to account for hydrogen. While standards and literature are cited throughout the report, responses from interviews remain uncited and anonymous.

2.0 Current Underground Gas Storage Risk Assessments

2.1 Safety Codes and Standards

The general workflow for a typical contemporary UGS risk assessment is shown in Figure 2-1. Risk assessments for UGS in the United States are currently standardized by 85 FR 8104 administered by the Pipeline and Hazardous Materials Safety Administration (PHMSA) [21]. For depleted underground reservoirs, 85 FR 8104 mandates safety practice to abide by the American Petroleum Institute Recommended Practice 1171 (API RP 1171) [22]. Section 8 of API RP 1171, "Risk Management for Gas Storage Operations", specifies the mandatory risk assessment procedure. The standard provides a basis for natural gas well operators to develop risk assessment protocols for their own wells to stay compliant with enforcement from PHMSA. While API RP 1171 is the basis used by PHMSA to ensure all safety requirements are followed, Section 8 is largely nonprescriptive (apart from certain minimum intervals for data collection and monitoring) and requires well operators and managers to develop their own risk assessment procedures and processes for their specific wells.

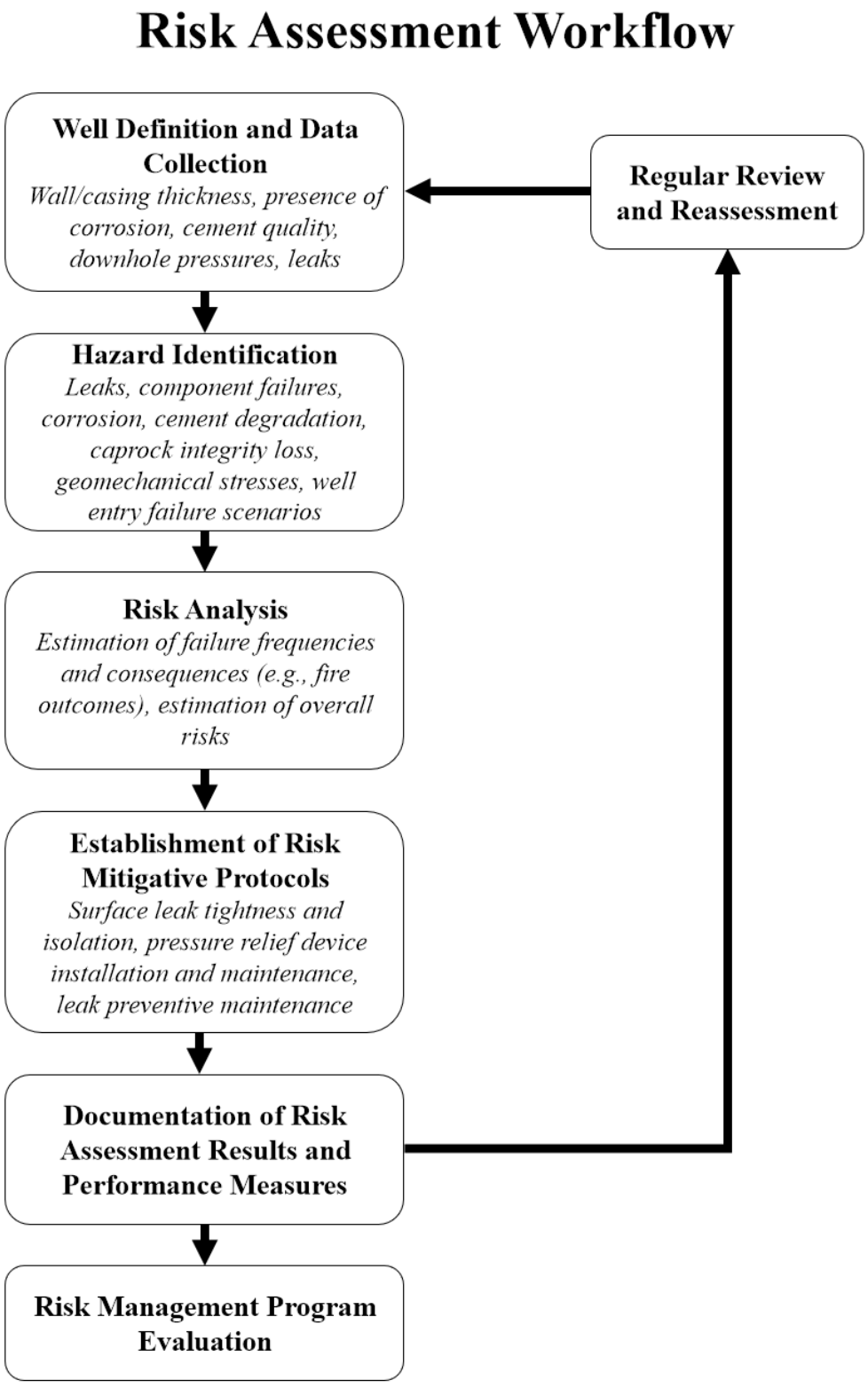


Figure 2-1. Flowchart of the risk assessment process used for underground gas storage.

API RP 1171 introduces the general risk assessment procedure as follows:

- Data collection and integration
- Threat & hazard identification and analysis
- Risk analysis
- Risk evaluation for preventive and mitigative (P&M) measures
- Periodic review and reassessment
- Recordkeeping and documentation
- Evaluation of Risk Management Program using performance measures

For wells that began operation prior to 2015, risk assessment protocols can be grandfathered in from 49 CFR Part 192.12 [23], which heavily informed the creation of API RP 1171. 49 CFR Part 192.12 mandates requirements for design, construction, operations, maintenance, and reporting for pipeline facilities transporting natural gas. While superseded by API RP 1171 in PHMSA audits, older wells can continue using protocols that were developed to adhere to 49 CFR Part 192.12 at the time of construction, given that the well has not since been modified since its construction [24]. For example, valves on older wells currently in operation would not violate regulation if the material used was originally compliant with 49 CFR Part 192.12 but would be out of compliance with API RP 1171. However, operators would need to comply with API RP 1171 if they were to replace the valves.

Well operators must comply with Underground Injection Control (UIC) regulations mandated by 40 CFR Part 144.12 [25] and managed by the Environmental Protection Agency (EPA) to ensure injecting or withdrawing gas does not endanger underground sources of drinking water. While not addressing risk assessment explicitly, operators account for these regulations in risk assessments when quantifying the risk of groundwater contamination near the well.

Well operators may be required to adhere to state regulations, codes, and standards that are stricter than API RP 1171 and therefore must be factored into their risk assessments. Notably, various states require tubing and packer completions for any new well, which are not mandated in API RP 1171 [26–28]. Additional requirements are often time-dependent rather than risk-dependent. For example, while API RP 1171 only requires risk assessments to be performed at a minimum of seven-year intervals, Kansas requires various risk assessment elements (particularly component inspections) to occur at five-year intervals or shorter [26].

Various other documents related to risk assessment and underground wells are also used by some well operators to develop their risk assessment protocols beyond what is provided in API RP 1171. While these are not mandatory, they provide greater prescriptive detail that can be used to build a thorough risk assessment protocol. These supplementary standards and documents are included in Table 2-1.

Table 2-1. Supplementary standards, codes, regulations, and documents used to inform risk assessment protocols for UGS.

Title	Industry	Application to UGS Risk Assessment	Citation
API RP 580: Risk Based Inspection	Oil & Gas, Petrochemical	Provides methodologies and information on risk-based inspection and preventative maintenance. Applicable to surface facilities (vessels, piping, processing equipment). Provides guidance on inspection based on failure probability and consequence.	[29]
API RP 90-2: Annular Casing Pressure Management for Onshore Wells	Onshore Oil & Gas	Provides guidance on risk-driven assessment for measuring and managing annular casing pressure, with operating envelopes and specific corrective maintenance actions to prevent gas leaks.	[30]
ISO 16530-1: Well integrity – Part 1: Life cycle governance	Oil & Gas	Provides a framework and best practices for managing well integrity throughout its life cycle. Includes a risk register to identify risks and threat hazards, definitions of specific P&M actions, and techniques for a comprehensive well integrity analysis.	[31]
NORSOK D-010: Well integrity in drilling and well operations	Oil & Gas	Provides detailed requirements for well barrier envelopes, considering design, material selection, testing, monitoring, and maintenance. Informs risk assessment by detailing possible leak avenues and various component failure modes.	[32]
C-FER Technologies Risk Assessment and Treatment of Wells	Oil & Gas, Geothermal, UGS	Provides methodologies, tools, techniques, and examples for a QRA for UGS, specifically for well entry.	[33]
ASME B31.8: Gas Transmission and Distribution Piping Systems	Oil & Gas	Provides information on the design, installation, inspection, and operation of gas pipelines, which informs integrity assessment of surface piping infrastructure for UGS wellheads and processing facilities.	[34]

2.2 Experience from Industry Experts

Various subject matter experts (SMEs) in the UGS industry were interviewed while writing this report to provide insight on how risk assessments are carried out in practice. Given the nonprescriptive nature of API RP 1171 and differences in well size and locations, the interviews revealed that risk assessment protocols differ substantially between companies and are continuously evolving, with no standardized best practice for performing a risk assessment.

Historically, some companies even faced challenges regarding the precise definition of "risk assessment" itself, with ambiguity stemming from whether they are required to perform a comprehensive assessment of the entire well or more basic wall integrity measurements. However, common themes and trends emerged among the companies interviewed, which are documented here.

The companies of all the interviewees perform risk assessment for their wells using API RP 1171 as a baseline – particularly the threats and P&M measures provided in the tables in Chapter 8 – but expand upon the standard significantly to address their specific fleet of wells based on internal expertise and historical practices. Each company applies their internal risk assessment protocol uniformly to all wells unless the well has not been modified since 2015 (the original publication date of API RP 1171), in which case the preexisting protocol is applied. While API RP 1171 only requires risk assessments to be performed at least every seven years, most SMEs perform risk assessments on wells more frequently, particularly if maintenance is required on a given well. All companies update their risk assessment protocols annually to address emerging risks based on new measurement data so specific P&M measures for each well continue to be appropriate.

The internal risk assessments at each company contain a set of variables gathered from well equipment during routine inspections and maintenance and applied to a risk assessment matrix. While the specific application and weighting of these variables in the risk evaluation differs across companies based on their unique historical data and practices, common variables of interest include:

- Setback distances
- Maximum flow rate out of wells
- Proximity to other wells
- Presence and history of H_2S
- Presence and functionality of safety valves
- Style of well completion (if single points of failure are present near the wellhead)
- Complexity of surface facilities (e.g., the number of structures and workers present during operation)
- Age and distance of wellhead barriers to prevent surface damage
- External and subsurface corrosion
- Atmospheric conditions

Operators pay particular attention to monitoring the mechanical integrity of the well casing and tubing, and these components are frequently considered the most critical measurement during data collection. Casing monitoring involves tracking the integrity of the casing cement, the last

time quality testing occurred, the completeness of testing records, and the repair history, age, and corrosion of the well. Several operators put substantial weight on selecting proper tubing material, as the tubing is subjected to the highest pressures in the well. Companies gather data on the quality of downhole components using various inspection tools, summarized in Table 2-2.

Table 2-2. Common downhole inspection tools that gather data for use in UGS risk assessments.

Tool	Measurement Principle	Data Gathered
Magnetic Flux Leakage (MFL) log	Induces magnetic field in casing; defects cause flux leakage detected by sensors	Metal loss and corrosion in well casing
Transverse Flux Leakage (TFL) log	Induces magnetic field in casing; same general principle as MFL logs, but oriented lengthwise along well	Average wall thickness and cracks in well casing
Gamma Ray Neutron Temperature (GRNT) log	Measures variation in gamma radiation emitted along the well hole to identify changes in rock type	Leakage and leak pathways (especially at collar connections)
Multifinger Caliper (MFC)	Mechanical fingers measure radial distance to casing inner wall	Well casing thickness and corrosion
Cement Bond Log (CBL)	Measures attenuation/travel time of acoustic waves along casing	Quality of cement bond to well casing
Variable Density Log (VDL)	Measures acoustic waves and travel time along casing; often used in conjunction with a CBL	Quality of cement bond to well casing
Pressure/Temperature (PT) gauge	Piezoresistive or piezoelectric sensor relays pressure and temperature	Downhole pressure, leakage and leak pathways
Ultrasonic Imager Tool (USIT)	Measures acoustic impedance contrast between casing, cement, and formation using pulses	Provides map of casing wall, including casing thickness, corrosion, and cracks

Pressure and leakage measurements are performed every 3 to 5 years, though this varies based on the distance of the well from other surface buildings and historical gas leakage in the well (i.e., wells with few leaks can have longer intervals between measurements). Most operators measure casing corrosion and cement thickness and bonding annually. Certain wells are measured more frequently if the well is new, old, deformed, or if the operator suspects H_2S is present. Operators modify P&M measures in their risk assessments annually based on new logs and events, which are shared with PHMSA.

Other areas of interest on the well during a risk assessment include valving and piping at the surface and wellhead seals. Operators give particular importance to these areas for older wellheads, as historical data often exclude details about how the well was built, particularly the sizing of the components and thickness of the cement. Operators also regularly monitor surface activity adjacent to the wellhead, as accidental drilling into the well by other parties (e.g., other oil and gas operators) presents a significant hazard.

Operators usually account for uncertainty using a deterministic margin of safety rather than probabilistic risk models. Several SMEs commented that probabilistic risk models are challenging and rarely used due to lack of data. UGS has a relatively good public safety record, with a total of 6 fatalities, 62 injuries, and 6,700 evacuations across its history as of 2007 [35]. This leaves operators with little data to construct risk models with high confidence, especially since few major UGS incidents have occurred recently. Additionally, risk events and hazards are often only recorded internally and are not publicly disseminated unless a high-profile accident occurs. Many in the industry thus depend on expert judgment for analyzing risk in their assessments, though the uncertainty in this practice is explicitly acknowledged and accounted for when considering P&M measures.

A 2020 report by Stephens et al. [33] published by C-FER Technologies summarizes additional interviews and documentation from industry experts and provides a comprehensive example of a risk assessment for an underground natural gas well in Section 5 of their report. More broadly, the C-FER report breaks down some steps of the risk assessment process defined in API RP 1171 in more detail, including the following steps:

- Well definition
- Threat identification
- Well entry scenario definition
- Frequency and consequence estimation
- Risk estimation
- Risk evaluation

The industry survey results identified corrosion, cement degradation, connection leaks, casing wear/damage, packer failure, formation breakdown/losses, geomechanical impacts (e.g., stress changes due to pressure cycling), caprock integrity issues affecting the wellbore, and surface equipment failures impacting the well as areas of greatest failure concern. Respondents identified well entry as the greatest threat, largely due to the addition of human factors. Challenges with probabilistic risk modeling due to lack of data also being reported as a major area of concern, echoing findings from the SME interviews conducted for this work.

3.0 Considering Changes to Risk Assessments for Underground Hydrogen Storage

3.1 Differences in Physical Properties

The motivation to consider modifications to UGS risk assessments for UHS is due to the differences in material properties and behavior between methane (the primary constituent of natural gas) and hydrogen. The thermochemical differences in these gases can potentially introduce new hazards or change the probability of existing hazards compared to UGS, thus those creating risk assessment protocols should consider these changes and adjust accordingly. Table 3-1 shows key differences between hydrogen and methane compiled from various sources [36–41]. These data are presented not to imply any fuel is inherently unsafe, but rather to highlight the relevant factors which may affect system design and risks.

Table 3-1. Comparison of properties of hydrogen and methane and their impacts.

	Hydrogen (H_2)	**Methane (CH_4)**	**Impact of differences**
Buoyancy	14x lighter than air	1.8x lighter than air	Hydrogen diffuses more rapidly in air than natural gas.
Flammability limits in air	4 – 75 vol%	7 – 20 vol%	Hydrogen fires can occur in a broader range of fuel/air conditions than natural gas.
Minimum ignition energy in air	0.02 mJ	0.3 mJ	Hydrogen ignition can occur under less energetic conditions than natural gas.
Flame speed	1.7 m/s	0.4 m/s	Hydrogen flames travel faster and subside sooner than natural gas flames.
Adiabatic flame temperature	2182°C	1937°C	Components adjacent to a potential hydrogen fire may be subject to higher temperatures than for a natural gas fire.
Thermal radiation emission	10% relative thermal radiation	33% relative thermal radiation	Hydrogen combustion gives off less radiative heat than natural gas combustion.
Flame appearance	Nearly invisible, though other constituents can appear as red, yellow, or blue	Faint blue, possibly yellow or red	Hydrogen flames are more difficult to see than natural gas flames.

Quenching distance	0.6 mm	1.2 mm	Hydrogen flames can move through smaller openings more easily than natural gas flames.

3.2 Differences in Hazards and Risks

3.2.1 Pure Hydrogen

The differing material properties of hydrogen impact the hazards considered when repurposing depleted reservoirs used for UGS to instead store hydrogen, posing new or heightened individual and environmental hazards compared to natural gas. Previous literature has found the greatest risks to be mechanisms that can compromise well integrity and generate leaks, including microbial corrosion and sulfidation, hydrogen blistering or cracking, hydrogen embrittlement, cement degradation, elastomer failure, and caprock sealing failure [6–8]. These hazards may be due to several possible reaction pathways [5]:

- Sulfur conversion where SO_4 combines with hydrogen to form H_2S
- Methane production via hydrogen reacting with CO_2
- Oxidation of hydrogen to form water
- Iron reducing to a lower oxidation state ($Fe^{3+} \rightarrow Fe^{2+}$ or Fe^0) using hydrogen as a reducing agent
- Organic acid production (e.g., sulfuric acid)
- Biofilm formation

These processes likely involve concurrent, cascade, and side reactions which are largely unknown due to current lack of understanding of the effects of hydrogen on the geochemistry of different subsurface compositions. These reaction pathways and their chemical favorability should be better understood to assess risk more precisely.

The higher diffusivity of hydrogen may increase the likelihood of leaks through containment materials, as hydrogen has a higher potential to permeate and escape through microscopic gaps in the underground storage system when compared to natural gas. Notably, new leak pathways may occur due to the low viscosity, small size, and low interfacial tension between groundwater and hydrogen compared to that of water and natural gas. The hydrogen-water interaction results in low capillary pressure, which could increase the risk of diffusion of hydrogen through caprock along leak paths not observed previously with natural gas [8]. Depending on the mineral composition of the caprock, hydrogen diffusion through the caprock can also lead to alkaline environments that may result in CO_2 and CH_4 forming [9]. However, the low viscosity may also cause UHS to have higher withdrawal efficiencies and lower dissolution losses [10]. Nonetheless, more data is needed to quantify the significance of these differences in a real hydrogen storage environment and the degree of response it merits.

As with pipelines, UHS heightens the risk of corrosion from hydrogen embrittlement for materials used in UGS wells and processing facilities, especially carbon and high-strength steel. Additionally, interactions with residual microbes or caprock minerals could induce microbial corrosion not frequently seen with UGS, as hydrogen is more reactive with microbiology than methane [7]. Corrosion from both hydrogen embrittlement and microbiological effects would most directly impact carbon steels commonly used in well tubing, casings, valves, and steel reinforcement in concrete, which would increase the risk of leaks in wellbores.

The probability of H_2S forming is likely greater in UHS, as hydrogen can react with sulfate-reducing bacteria (SRB) that may exist in pockets of the reservoir or with rock clay surrounding the well [6]. H_2S generation is a significant concern in underground storage due to its toxicity and corrosion potential that pose a hazard to site workers and wellhead components during withdrawal from the well. Additionally, the low density of hydrogen impacts mixing in the reservoir and propagation through the caprock. The release of other compounds that accumulate in the underground reservoir is also of concern, as the remains of hydrocarbons and inorganic molecules in the caprock could sink or interact in novel ways upon contacting hydrogen. The degree to which unintended and hazardous products form depends on the properties of the storage material, the site, and residual gases present. These compounds present various hazards if dislodged and interact with downhole equipment or are withdrawn from the reservoir [9].

The larger flammability range, higher flame temperature, smaller quenching distance, and reduced visibility of hydrogen fires pose more severe hazards to aboveground components in UHS compared to natural gas. Similarly, the increased detonation range and smaller critical detonation energy pose hazards and risks to human life. Both events in turn increase the importance of leak detection, especially in aboveground areas adjacent to the wellhead where workers are frequently present.

While introducing hydrogen is unlikely to change existing well entry protocols themselves, implementing and maintaining new sensors for the detection of hydrogen leaks or the presence of H_2S may require workers to enter the well more frequently. This presents a substantial increase in risk, as well entries are the dominant source of failure probability considered in risk assessments due to the direct interaction of the worker with downhole equipment and the greater possibility of human error [33].

3.2.2 Hydrogen/Natural Gas Blends

Blending hydrogen into natural gas has been explored as a way to introduce hydrogen to existing infrastructure and gain an understanding of its compatibility in a lower risk context with fewer barriers. In the context of pipelines, it is seen as a transition step with lower uncertainty and less modification to existing natural gas infrastructure than pure hydrogen. This may lead to greater understanding of the impacts of hydrogen on these systems and facilitate replacing natural gas systems with a pure hydrogen feed. Hydrogen blends in pipelines are currently being explored in the HyBlend project [2,42] and in research funded by PHMSA [43]. The SHASTA (Subsurface Hydrogen Assessment, Storage, and Technology Acceleration) project is considering a similar motivation for testing hydrogen in depleted reservoirs used for natural gas storage, thus exploring unique impacts on risk assessment for natural gas/hydrogen blends different than storing pure hydrogen is worth considering [4,5].

Many of the fundamental risks for a well containing a hydrogen/natural gas blend are identical to a pure hydrogen well, including the risk of hydrogen embrittlement, H_2S formation, greater flammability, and potential challenges with leak formation, pathways, and detection. However, the magnitude of difference in the well risks of a blend compared to pure hydrogen is a topic of ongoing research. The UGS SMEs interviewed for this report notably differ in their judgment on the matter. Some consider blends to be inherently less risky due to the lower volume percentage of hydrogen leading to diminished risk of hydrogen-induced outcomes when stored with natural gas at nominal well pressures. Others considered the risks of blends to be identical to those for pure hydrogen, requiring identical risk assessments. Others speculated that a blend with hydrogen-enriched natural gas could result in an even more stringent risk assessment than pure hydrogen due to potentially greater H_2S generation and potential impact radius (PIR) compared to pure hydrogen. Additionally, risks may be higher due to blends likely reusing existing natural gas or oil storage equipment that may be less suitable for hydrogen. There is also some concern among operators regarding lack of knowledge and thoroughness in converting a reservoir to a different storage type, especially for older wells that may lack some specification information.

Some researchers have found that the risk of hydrogen leaks through caprock is potentially lower than pure hydrogen. Modeling results from Heagle [44] show groundwater absorbs methane before hydrogen when a leak of 20 vol% hydrogen blend occurs. However, the researchers make clear that these results have not yet been replicated experimentally.

Underground storage is inherently a much larger and more loosely controlled environment than pipelines, which should be considered when updating risk assessments with respect to those for blended pipelines. The size and storage duration of a blend in a depleted reservoir is more heterogeneous and dynamic compared to a pipeline due to the gradual cycling and mixing of gases, increasing uncertainty of the properties of the blend at a given location and time. The upper regions of the reservoir will likely have a higher hydrogen concentration than the lower regions due to the lower density of hydrogen, resulting in the tubing and production casing interacting with higher concentrations of hydrogen than expected based on the nominal blend composition. However, the exact gradient of gas concentration throughout the reservoir and the degree of mixing remains largely unknown [7], and additional experiments and modeling would inform the risks and reduce uncertainty surrounding this.

Reusing depleted natural gas storage reservoirs for underground hydrogen storage will always create some degree of a hydrogen blend (even if the intent is to use pure hydrogen), as the depleted reservoir will likely contain up to 5 vol% of natural gas functioning as a cushion gas to maintain adequate pressure, prevent water intrusion, and reduce potential contamination from other residual gases in the cavern [6]. Again, experts are currently uncertain about the degree of interaction of hydrogen with other gases over long durations, and experimental tests would be valuable in enabling more precise risk assessment protocols.

The results of the RAG Underground Sun Storage project provide some initial results indicating potential considerations for underground storage of hydrogen blends [18]. Laboratory testing found no additional embrittlement of steels typically used for UGS after 1 year subjected to 10 bar for a 20 vol% hydrogen blend. Elastomers were largely unaffected by the additional presence of hydrogen, with only minor mass and volume gains in hydrogenated nitril butadiene rubber (HNBR) reported. The 6-month demonstration phase of the project included a risk assessment

which identified “no hydrogen induced issues” for a 10 vol% hydrogen blend, though 18% of the stored hydrogen was lost due to solubility and diffusion. These results suggest that blends with relatively low percentages of hydrogen do not introduce unique risks to well equipment, though uncertainty regarding potential hydrogen leaks merits greater consideration in risk assessments compared to UGS. Furthermore, the short duration of the experiment and relatively small size of the project (1.22 m Nm^3 of total injected gas) make it difficult to provide conclusive statements about the impacts of hydrogen blends on risk assessments.

3.3 Potential Modification to Existing Risk Assessment Methodology

3.3.1 Impacts on Risk Assessment Practice

The UGS SME interviews conducted while creating this report involved discussing the material and hazard differences between hydrogen and natural gas (as discussed in Sections 3.1 and 3.2) and sharing their judgment on how their risk assessments would change if their UGS wells were to instead store hydrogen. The prominent responses are outlined here; many of the comments relate to adding or modifying rates of occurrence and mitigation factors for corrosion, caprock integrity, migration pathways, faulting, and annular gas issues. Interestingly, respondents were more uniform in their UHS risk assessment suggestions compared to their responses about current UGS risk assessment discussed in Section 2.2.

Generally, many aspects of existing risk assessment protocols for UGS are flexible enough to account for the differences in risk for UHS. While operators may need to introduce some additional variables to their models to account for the unique behavior and properties of hydrogen as discussed later in this section, UHS ultimately presents many of the same risks as UGS, though the input values for risk and mitigation factors may require adjustment to account for thermochemical differences.

The emerging UHS industry should focus on characterizing the magnitude of hydrogen embrittlement and microbial-induced corrosion on well casing, tubing, and the wellhead by measuring and monitoring the corrosion rate of different materials at different pressures following initial hydrogen exposure. Hydrogen embrittlement risk invoked the strongest responses from the SMEs since corrosion risk of the wellbore is one of the most important considerations for existing UGS risk assessments. Operators could consider replacing standard materials used for UGS with more corrosion-resistant material (such as N80 pipe) as part of their P&M measures for UHS to reduce the effects of embrittlement, especially for new reservoirs designed specifically for UHS. Operators may also consider adjustments to the design of components and operating conditions (such as pressure), which also affect the impacts of hydrogen embrittlement. Well operators for UHS should also consider more frequent inspection and preventative maintenance to monitor the potential for more rapid corrosion and to replace components as needed, especially for wells that continue to reuse components predating the conversion to hydrogen storage.

Those modifying risk assessments for UHS should also consider accounting for the additional risks, hazards, and P&M measures related to new leak pathways that were not previously

considered for UGS. Well operators should consider narrow pathways that were not of concern for natural gas as the smaller molecular size and higher diffusivity of hydrogen may make these potential leak pathways. Workers performing downhole measurements may find greater use for TFL logs over MFL logs due to the crack detection capabilities, as MFL is unable to detect cracks that may be hydrogen leak locations. Notably, operators should consider developing new methods to collect data related to leakage through the caprock; this was a prominent consideration discussed by nearly all interviewed SMEs. Relatedly, industry should explore improving methods for fault detection. While few UGS facilities are in seismically active regions, historical data finds acute microseismicity often occurs during gas injection into or withdrawal out of the reservoir [45], which may result in hydrogen leaks through the caprock. Several respondents in interviews stated they do not have a consistently effective approach to detect and measure faults in the vicinity of their reservoirs.

Those developing risk assessments for UHS should also consider quantifying the more frequent generation of H_2S. For example, operators could introduce new variables in risk models to account for the risks of smaller pockets of SRBs in the reservoir than currently considered, as these would pose a higher risk of creating H_2S with UHS. However, lack of data quantifying the occurrence of H_2S generation may make adding these considerations to risk assessments challenging; interviewed SMEs and existing literature on UHS hazards [6] highlight a data gap regarding the effects of hydrogen on reservoir impurities and reservoir quality over long periods after substantial cyclic loading. To this end, operators developing risk assessments should carefully consider the uncertainty of potential chemical interactions when reusing former natural gas reservoirs for UHS. Additionally, operators should consider more intensive initial data gathering of the reservoir chemical composition as a P&M method in the event that SRB or H_2S is detected in the cavern. Researchers should consider modeling chemical interactions within different reservoir types and the rate and frequency of H_2S formation for different chemical compositions to assess the occurrence of H_2S formation with greater accuracy. Finally, operators should consider less commonly used materials for wellhead components, such as nickel-coated steels or chromium-coated casing, as possible measures to limit H_2S exposure.

Operators should also consider new fire-related risks in their hazard identification to account for the wider flammability range of hydrogen and greater propagation of hydrogen jet flames. Relatedly, risk and P&M metrics should be reassessed for UHS to account for the higher diffusivity of hydrogen relative to natural gas. Metrics related to distance, such as PIR and setback distances for aboveground well equipment, should be given particular attention.

It is currently difficult to recommend changes to risk assessment protocols specifically for storing hydrogen blends due to the lack of knowledge, experience, and data about its behavior in a depleted reservoir compared to pure hydrogen. Conservatively, risk assessment protocols for underground storage of a hydrogen blend should parallel those developed for pure hydrogen. Particular attention could be given in the protocols to properly qualifying well equipment and gas conversion to ensure operators sufficiently consider the needed changes to account for the new risks presented by hydrogen. Additionally, academic and industry researchers should pursue further modeling and demonstration testing of UGS for hydrogen blends to improve understanding of unique risks that may exist for storing hydrogen blends not present with pure hydrogen to help develop future risk assessments to account for these phenomena.

Finally, literature and SMEs alike emphasize that introducing hydrogen will substantially increase uncertainty until more data is gathered. Thus, it will be crucial for UHS operators to maintain an effective risk management program with regular inspections, data collection, and reevaluation of existing risk assessments on a regular basis. Additionally, communication across companies regarding risk identification and data collection could provide mutual benefit for all industry stakeholders by improving risk assessments protocols and reducing uncertainty. Communicating with operators of existing salt caverns used for UHS may prove highly valuable as well, as these operators have the greatest direct experience with the risks associated with UHS and how risk assessments have been adapted to account for hydrogen.

Even with optimistic outlooks of data collection and modeling resolving some current uncertainties with UHS, details of various UHS risks will likely not be known until many years after the first UHS wells begin operating. Therefore, leveraging experience from UGS SMEs should also be considered in the early years of UHS to help verify results from risk assessment models. SMEs familiar with the overall risk assessment process for UGS could be highly valuable, as the general UHS risk assessment protocol will likely be similar to UGS even if certain variables are added or removed, or if occurrence and mitigation factor values are adjusted within models.

3.3.2 Impacts on Risk Assessment Standards

Louie and Ehrhart [24] conducted a review and gap analysis of the existing standards regarding UGS, hydrogen, and the handling of hazardous materials, identifying that existing standards would largely be applicable to UHS as written. However, given the differences in hazards and risks, experts could consider reviewing and modifying language pertaining to risk assessment in existing UGS standards to better account for differences in hazards and risks discussed in this report. Accounting for UHS could also involve consolidating existing standards used by UGS operators with hydrogen standards used in other industries.

Several of the potential adjustments to existing UGS risk assessments to account for hydrogen hazards involve modifying current recommended practices to properly account for the unique behavior of hydrogen. Some of the changes merely involve documenting the difference in properties of hydrogen and natural gas, while others are more extensive and require changes to protocol. However, extensive revisions should be treated with caution, as regulations must remain sufficiently general to be applicable across various underground storage facilities to enable operators to develop individual risk assessment protocols that work best for their specific facilities. In other words, while all well operators should consider modifying their internal risk assessment protocols to account for the risk factors discussed in Section 3.3.1, authors of risk assessment standards should be judicious in updating guidance so newly prescribed practices are applicable to all underground storage locations.

One of the most significant modifications to existing risk assessment standards is emphasizing the importance of data beyond historical sources. Most of the data sources recommended in API RP 1171 Section 8.3.2 are historical, including drilling and material records, well performance data, and reservoir studies. Hydrogen underground storage has not been extensively conducted and thus risk assessments have limited historical data as a basis for quantifying frequencies and consequence probabilities. UHS data gathered from reservoir studies, computer modeling, and

experimental research will be more abundant than historical data in the near term, and standards could be written to emphasize this.

There are also few experts in UHS, so reliance on them where historical data is lacking (as discussed in Section 2.2) may increase uncertainty further. Future standards writers should consider consolidating the resources used in current industry practice into a more universal procedure to facilitate consistent data collection and uniformity, such as incorporating guidance from the standards included in Table 2-1.

API RP 1171 provides a large list of hazard and mitigation measures in Tables 1 and 2 of Section 8, and these will largely continue to apply when a well is converted for hydrogen storage use. However, several additions could be made to properly account for the unique properties of hydrogen:

- Currently, API RP 1171 provides language regarding hazards related to wall integrity, including corrosion, though it references "failure due to inadequately sealed storage well(s)" as the hazard. It could be helpful to expand this language for hydrogen storage to include the risk of hydrogen embrittlement or microbial-induced corrosion contributing to potential failures in the casing and cement bonds, which could be propagated by embrittlement of the well concrete reinforcement.

- API RP 1171 includes geochemical hazards from mixing of stored gas with other reservoir fluids in Table 1, even specifying "H_2S generating bacteria", though this language could be strengthened to account for the increased likelihood of H_2S production even if smaller concentrations of SRB are present in the UHS reservoir.

- Similarly, more explicit language could be included regarding enhanced detection systems and geochemical analyses for H_2S and other hazardous byproducts of hydrogen reactions.

- While the provided mitigative measures regarding leaks are comprehensive in Table 2, the specific guidelines provided elsewhere in API RP 1171 could account for the increased risk of gas leakage, particularly for the wellhead and production casing where failures are more common [33].

Future standards for UHS could incorporate more quantitative risk evaluation metrics to address the heightened uncertainty surrounding the use of hydrogen. The language surrounding acceptable levels of risk under uncertainty is not provided in detail in API RP 1171, defaulting to "as low as reasonably practicable" (ALARP). The 2020 C-FER report [33] provides safety risk thresholds common in industry use, including an individual risk of 10^{-6} to 10^{-5} fatalities per year. Introducing these or other metrics, such as those derived from existing hydrogen standards (discussed below), could be beneficial.

The NFPA 2 standard [46] provides more thorough guidance on risk evaluation, especially regarding leak and fire hazards associated with hydrogen. The performance-based design option in NFPA 2 Chapter 5 also includes language on using conservatism, sensitivity analyses, and safety factors to account for uncertainty, which could be adopted by UHS standards due to the

lack of historical data. NFPA 2 Chapter 5 also includes more detailed performance criteria and required design scenarios pertaining to hydrogen risks, which could be incorporated into future UHS standards to both synergize it with existing hydrogen standards and to guide industry to account for hydrogen-specific fire risks and account for greater uncertainty compared to UGS.

API RP 1171 also does not provide specific requirements for setback distances for aboveground equipment. Several respondents in SME interviews stated that setback distances for UGS are inconsistent across the industry, which may present increased risk if converting existing UGS facilities to hydrogen storage due to the greater flammability range and flame speed of hydrogen. presents increased risk and uncertainty due to the increased flammability range and flame speed of hydrogen. NFPA 2 [46] includes setback distances for outdoor storage of hydrogen and provides further guidance for both above and below ground storage. While the standard is specific to compressed tank storage rather than lower pressure underground storage, the standard could serve as a starting point for setback distances for potential leak locations in the underground storage well that could affect individuals working near the wellhead. This gap in regulation highlights the need for more clear setback distance requirements for larger scale hydrogen storage such as in underground wells and caverns.

Environmental standards regulating UIC to protect underground sources of drinking water do not explicitly consider UHS in depleted reservoirs, which impacts how well operators account for the risk of groundwater contamination in risk assessments. The EPA classifies wells used for UGS as Class II injection wells (designated for “oil and gas related” wells) and existing salt caverns used for UHS as Class V wells (designated for “non-hazardous fluids”) [47,48]. However, it is unclear if depleted reservoirs repurposed from UGS to UHS would be classified as Class II, Class V, or a new class altogether. As some UIC well classes are regulated more rigorously than others, regulators should consider clarifying UIC standards to provide operators sufficient framework to quantify these risks for UHS risk assessments.

Finally, no risk assessment standards were found explicitly defining practices for when a UGS facility is converted to UHS use. Several interviewed UGS operators also expressed concern about other operators lacking attention to detail when converting a gas reservoir to another storage type. As many P&M measures related to material replacement are most pertinent during this conversion process, defined conversion practices could reduce risk and decrease the potential incidents later in the lifetime of the well post-conversion. To this end, authors of risk assessment standards for UHS should consider adding explicit language surrounding well conversions and actions of high importance to take during this time, especially regarding replacing components with materials that are more corrosion-resistant, are less likely to crack, and have tighter tolerances in subcomponents to reduce hydrogen leak pathways.

4.0 Summary and Conclusions

The focus of this report is to discuss current risk assessment protocols for underground natural gas storage in depleted reservoirs and considerations for repurposing these assessments for underground hydrogen storage. Identifying gaps and building effective risk assessments early in the development of the UHS industry is critical to ensuring safe operation of storage facilities and minimizing the risk of accidents as hydrogen demand grows. However, the distinct physical and thermochemical properties of hydrogen compared to natural gas introduce new and modified hazards, demanding a reevaluation of traditional risk assessment practices to ensure the safety of workers, the environment, and the public.

Interviews with UGS industry experts and operators reveal a consensus that existing risk assessment standards (primarily based on API RP 1171) provide a baseline for risk assessment but are nonprescriptive, leading to diverse internal risk assessment methodologies that require substantial additions to be practical. UGS operators leverage various other related documents plus historical internal data and expert judgment when faced with uncertainty. This uncertainty is expected to substantially increase when considering hydrogen due to lack of knowledge, experience, and data with the underground storage of hydrogen. Based on these interviews and a review of the current literature, this report identifies key areas of consideration when incorporating hydrogen into underground storage facilities, including the heightened risk of hydrogen embrittlement and microbial corrosion impacting well integrity, the potential for new leak pathways due to hydrogen's small molecular size and high diffusivity, and the increased likelihood of H_2S formation. Additionally, the larger flammability range, faster flame speed, and lower thermal radiation of hydrogen fires compared to natural gas fires necessitates a reassessment of fire and explosion risk mitigation strategies.

This work identifies several key areas in existing risk assessment practices that could potentially be modified for UHS by those writing standards or performing risk assessments with hydrogen storage in mind:

- Emphasizing the importance of using corrosion-resistant materials for well casings, tubing, and wellhead components.
- Performing more frequent inspection and preventative maintenance to mitigate corrosion risk deriving from hydrogen embrittlement and microbial-induced corrosion.
- Implementing enhanced leak detection systems capable of identifying small cracks and leaks where hydrogen may be able to escape the reservoir.
- Identifying and implementing methods for fault detection around reservoirs to improve data collection and account for the hazards and consequences of hydrogen leaks through caprock.
- Strengthening language in standards to promote geochemical analyses to identify and mitigate the potential for H_2S formation.

- Investigating modifications to existing UGS standards (such as API RP 1171) to more explicitly address the risks associated with hydrogen embrittlement, microbial corrosion, H_2S formation, and modified fire/explosion hazards.

- Integrating relevant guidance from existing hydrogen standards (such as NFPA 2) with existing UGS standards, especially regarding setbacks, time-based risk analysis, and practice for performance-based designs.

- Developing a robust data collection strategy at the onset of UHS facility design to characterize the long-term effects of hydrogen on reservoir materials, caprock integrity, and geochemical processes.

- Promoting research into modeling hydrogen interactions in reservoirs with various microbiological, geological, and chemical compositions – especially the rate and frequency of H_2S formation – and emphasizing or de-emphasizing language in standards based on the frequency and magnitude of these occurrences compared to UGS.

- Adding language to standards to consider practices and hazards associated with modifying existing UGS wells to hydrogen storage to better account for lack of knowledge on this process in the current industry.

- Actively communicating new findings and best practices across the industry to reduce the high uncertainty and lack of experience in UHS hazard identification and risk analysis, including communication opportunities with workers for existing UHS salt caverns.

There are numerous other thoughts on how to improve risk assessments discussed in existing literature and SME interviews, with differing opinions on their relative importance, which are discussed in greater detail in the body of this report.

Beyond these considerations, future work in the industry to improve UHS risk assessment should explore more long-duration, commercial-scale demonstration projects to validate models and theoretical research and address the lack of operational data. This includes measuring and quantifying hydrogen interactions with reservoir impurities more thoroughly, especially the rates of H_2S formation under cyclic loading conditions. These efforts will aid the development of more refined and empirically supported risk assessment protocols to further reduce the uncertainties surrounding underground hydrogen storage.

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